

Rulemaking: 17-06-026
Exhibit No.:
Date: April 2, 2018
Witness(es): Various

**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY**

POWER CHARGE INDIFFERENCE ADJUSTMENT

PREPARED TESTIMONY

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
POWER CHARGE INDIFFERENCE ADJUSTMENT
PREPARED TESTIMONY

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**PACIFIC GAS AND ELECTRIC COMPANY
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**CHAPTER 1
INTRODUCTION**

PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
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CHAPTER 1
INTRODUCTION

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SOUTHERN CALIFORNIA EDISON COMPANY**
3 **SAN DIEGO GAS & ELECTRIC COMPANY**
4 **CHAPTER 1**
5 **INTRODUCTION**

6 **A. Executive Summary**

7 Much has changed in the California energy markets since 2006 when the
8 Power Charge Indifference Adjustment (PCIA), an administrative mechanism
9 intended to ensure bundled service customers remain financially “indifferent” to
10 other customers’ departure to take service from another service provider, was
11 adopted by the California Public Utilities Commission (CPUC or Commission).
12 Since 2006, there have been two fundamental changes in California’s energy
13 markets. First, the costs of renewable power have declined significantly. This
14 is, of course, a significant benefit for California energy consumers. However,
15 due in part to the foundational long-term renewable contracts entered into by the
16 investor-owned utilities (IOUs) that transformed the renewables market
17 consistent with state policy and Commission direction, those initial financial
18 commitments are now significantly “above-market.” In addition, the growth of
19 Community Choice Aggregation (CCA) has contributed to shifting approximately
20 40 percent of Northern California load away from Pacific Gas and Electric
21 Company’s (PG&E) bundled service portfolio, and approximately 35 percent of
22 Southern California Edison Company’s (SCE) retail load is in the process of
23 CCA formation. And this trend is continuing—and, indeed, accelerating—on a
24 state-wide basis, with the Commission’s Energy Division projecting up to
25 85 percent load departure from the IOUs by the mid-2020s.¹ The combination
26 of these two developments leaves high-cost, long-term renewable contracts in
27 the IOUs’ bundled service customer portfolios that are far in excess of their
28 need.

1 CPUC Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*, May 2017, p. 3. Available at:
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf

1 PG&E, San Diego Gas & Electric Company (SDG&E), and SCE (the Joint
2 Utilities) submit that these market changes have undermined the continuing
3 ability of the PCIA to ensure remaining bundled service customer indifference to
4 departing load.

5 Although much has changed over the last 12 years, one thing has remained
6 indisputably constant: state law requires that when a customer chooses to
7 receive procurement service from another provider, that customer's choice may
8 not increase the costs borne by remaining bundled service customers. In short,
9 cost shifts between bundled service customers and departing load customers, in
10 either direction, are prohibited by the statutes that allow for retail choice for
11 customers in the IOUs' service areas. Because the PCIA is no longer able to
12 ensure that bundled service customers are financially indifferent to departing
13 load, a new methodology is needed to recover from, and return to, departing
14 load customers their pro rata share of the costs and benefits of resources
15 procured on their behalf by the Joint Utilities.

16 The Joint Utilities propose such a new methodology in Chapter 4 of this
17 Testimony (Proposal). As the Commission is aware, the Joint Utilities initially
18 proposed to reform the PCIA by adopting the Portfolio Allocation Methodology
19 (PAM), a methodology based on an allocation by load share of the total benefits
20 and net costs of past IOU procurement to those customers for whom the assets
21 were originally procured or constructed.² In light of feedback received on the
22 PAM proposal from stakeholders, in particular from CCAs, that they wish to
23 develop their own clean energy portfolios and minimize the amount of "brown"
24 resources allocated to them, the Joint Utilities have modified their proposal to
25 seek to address this feedback while continuing to ensure that bundled service
26 customers are financially indifferent to departing load. However, the Joint
27 Utilities still support their original PAM proposal as being a viable and relatively
28 straightforward methodology to implement to ensure an equitable and efficient
29 allocation of benefits and costs among all customers should the Commission
30 wish to consider it.

² Application (A.) 17-04-018. The Joint Utilities' PAM direct testimony is attached hereto as Appendix B.

1 Rather than allocating the entirety of the attributes from the Joint Utilities’
2 respective portfolios to load-serving entities (LSEs) as proposed in PAM, the
3 Joint Utilities now propose to allocate only “green” portfolio resource attributes
4 associated with Renewables Portfolio Standard (RPS)-eligible resources and
5 large hydro-electric resources³ to LSEs, while monetizing other “brown” portfolio
6 resource attributes based on actual market outcomes, subject to a true-up.⁴

7 The Joint Utilities’ Proposal appropriately balances CCA policy objectives
8 with the legislative imperative that both departing load customers and remaining
9 bundled service customers pay the same net costs for each PCIA-eligible
10 resource for which they are collectively responsible. Importantly, the Joint
11 Utilities’ Proposal can scale to any level of departing load, including 100 percent,
12 while also accommodating the ability of customers to return to bundled service.

13 Any methodology ultimately chosen by the Commission must first and
14 fundamentally comply with state law. As discussed at length in Chapter 4,
15 because the Joint Utilities’ Proposal complies with the statutory mandate to
16 achieve customer indifference, while also meeting multiple other policy
17 objectives identified by the Commission as critical, the Joint Utilities urge the
18 Commission to adopt the Joint Utilities’ Proposal.

19 To be clear, because the Joint Utilities’ procurement costs are passed
20 through to customers with no mark-up, the Joint Utilities’ interest in this
21 proceeding is limited solely to ensuring appropriate cost allocation between
22 groups of customers. Creating an equitable, transparent and effective cost
23 allocation methodology is undoubtedly a difficult task given the complexities of
24 the energy markets and the varied resources in the Joint Utilities’ respective
25 generation portfolios. The Joint Utilities appreciate the Commission’s efforts to
26 uphold the indifference requirement and the refinement of the PCIA over the
27 past decade. However, given the unprecedented pace and extent of the
28 industry changes described in this Chapter, it is urgent that the Current
29 Methodology be reformed to reflect the new market dynamics as well as the
30 Joint Utilities’ current portfolios and continued obligations.

31 The balance of this Chapter is organized as follows:

3 “Large hydro-electric resources” includes pumped storage hydro-electric resources.

4 A high-level summary of the Joint Utilities’ Proposal is presented in graphical form in
Figure 4-1 in Chapter 4 of this Testimony.

1 Section A discusses the changes in California’s energy markets since 2006,
2 focusing on the extensive development of renewable resources and the growth
3 of retail choice. These two developments, more than any others, have
4 challenged the continuing ability of the PCIA to ensure bundled service customer
5 indifference.

6 Section B provides additional detail on the evolution of California’s energy
7 markets, and describes how the availability of excess capacity and renewable
8 resources in the market exerts substantial downward pressure on the cost of
9 those products which, in turn, severely undermines the current PCIA
10 methodology. Section B also details the significant shift in load from bundled
11 service to non-IOU service which has resulted in the IOUs holding significantly
12 more renewable resources and capacity than needed to serve bundled service
13 load, thereby exacerbating the cost shift under the current PCIA methodology.

14 Finally, Section C introduces the Joint Utilities’ Proposal to replace the
15 current PCIA methodology with a methodology that allocates the net costs and
16 benefits of RPS-eligible resources and large hydro-electric resources to LSEs,
17 while collecting from LSEs their pro rata share of the above-market costs of
18 other “brown” resources whose above-market costs can be readily discerned
19 through transactions in liquid markets. The Joint Utilities’ Proposal appropriately
20 balances the concerns of all parties while ensuring compliance with state law.

21 **B. Evolution of the California Energy Market**

22 Over the past fifteen years, California has pursued aggressive reductions in
23 greenhouse gas (GHG) emissions from its electric sector in support of a broader
24 state goal to transition to a sustainable, low-carbon economy. To that end, the
25 Joint Utilities have collectively entered into hundreds of long-term contracts for
26 renewable energy to comply both with California’s RPS Program⁵ and with
27 individual mandates to procure specific renewable technologies or small-scale
28 renewable generation. These programs and mandates were enacted under the
29 California Legislature’s guidance through various statutes, and the contracts
30 were executed with the approval and oversight of the Commission. The RPS

5 The California RPS Program was established by SB 1078 in 2002, and has been subsequently modified by SB 107, SB 1036, SB 2 (1X), and SB 350. The RPS Program is codified in Public Utilities Code (Pub. Util. Code) Sections 399.11-399.32. All statutory references herein are to the Pub. Util. Code unless otherwise specified.

1 Program and mandated renewable resource procurement have been, and
2 continue to be, critical and effective components of the state's GHG reduction
3 strategy. These policies simultaneously fostered the growth of a strong green
4 energy industry within the state.

5 While the RPS Program has been successful in helping California meet its
6 policy goals, the procurement conducted in the first several years of the RPS
7 Program was much more expensive than renewable resources currently
8 available in the market. Early contracting, as required by legislation and
9 approved by the Commission, was needed to promote development of a
10 relatively new market segment. Indeed, the early procurement of renewable
11 energy generation resources, which by spurring world-wide investment in
12 renewable technologies and driving economies of scale, significantly contributed
13 to the rapid decrease in market prices for resources that are accessible to CCAs
14 and Electric Service Providers (ESPs) today, constitutes the majority of the
15 above-market portfolio costs underlying the PCIA, the reform of which is the
16 subject of this proceeding.⁶ Importantly, every one of the Joint Utilities'
17 contracts was approved by the Commission as just and reasonable, and was
18 executed and approved to help California meet its ambitious policy goals.

19 Concurrent with its efforts to reduce GHG emissions, the California
20 Legislature enacted statutes to facilitate customer choice of other providers
21 through a limited reopening of Direct Access (DA) and by authorizing the
22 formation of CCAs.⁷ While the CCA legislation was enacted in 2002, the first
23 operational CCA, Marin Clean Energy, did not launch service until 2010, with
24 other communities steadily following. Since then, load has shifted significantly
25 from Joint Utilities' bundled service to electric procurement services offered by
26 CCAs. Departing load in the Joint Utilities' service territories has increased from

6 The approximate proportion of above-market costs in the Joint Utilities' respective portfolios attributable to PCIA- and CTC-eligible RPS resources is (i) PG&E: 70 percent; (ii) SCE: 72 percent; and (iii) SDG&E: 64 percent.

7 Assembly Bill (AB) 117 was signed into law in 2002 and authorized the creation of CCAs. SB 695, signed in October 2009, allowed for a limited reopening of DA for non-residential customers. The CPUC issued D.10-03-022 in March 2010, implementing a phased partial reopening of DA for non-residential customers subject to enrollment caps.

1 7 percent in 2008 to 25 percent in 2017, and may reach up to 85 percent by the
2 middle of the 2020s.⁸

3 The Joint Utilities support customers' right to choose other providers that
4 best meets the customers' needs, provided that exercising that choice does not
5 negatively affect customers who continue to take procurement service from the
6 utility. The California Legislature, as an express condition of authorizing retail
7 choice, required that procurement costs incurred on behalf of utility customers
8 not be bypassed when customers choose to depart utility service for another
9 provider.⁹

10 Indeed, for more than a decade, the California Legislature consistently
11 enacted laws intended to ensure the equitable allocation of electricity
12 procurement costs among the Joint Utilities' bundled electric service customers
13 and customers who depart bundled electric service to receive service from
14 another procurement service provider. Most recently, in Senate Bill (SB) 350,
15 codified in Section 366.3 of the California Pub. Util. Code, the Legislature
16 provided:

17 Bundled retail customers of an electrical corporation [*i.e.*, a utility] shall not
18 experience any cost increase as a result of the implementation of a
19 community choice aggregator program. The commission shall also ensure
20 that departing load does not experience any cost increases as a result of an
21 allocation of costs that were not incurred on behalf of the departing load.

22 The Legislature enacted a comparable statute to address the situation
23 where an electric service customer departs to receive DA service from
24 an ESP.¹⁰

25 These statutes are unambiguous: when a customer chooses to receive
26 service from another procurement service provider, that customer's choice may
27 not increase the costs for remaining bundled service customers, nor should that
28 customer be required to pay for costs not incurred on the customer's behalf.
29 This prohibition against cost shifting as a result of customers departing bundled

8 See CPUC Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*, p. 3.

9 Sections 365.2, 366.2, and 366.3 prohibit cost shifting or cost increases to remaining bundled service customers as a result of departing or migrating load, and, correspondingly, require that departing load customers not pay costs that were not incurred on their behalf.

10 Section 365.2.

1 service is at the heart of all statutory provisions on departing load cost allocation
2 and responsibility. Because the Joint Utilities procure generation resources on
3 behalf of all then-bundled service customers, including those that later decide to
4 take service from another procurement service provider, it is axiomatic that all of
5 the then-bundled service customers pay their share of costs to avoid cost
6 shifting as a result of departing load. In short, equitable cost allocation is a
7 foundational requirement to enabling customer choice and achieving the societal
8 benefits of competition among providers.

9 The current PCIA methodology (Current Methodology), adopted over ten
10 years ago, was intended to preserve the indifference requirement and was first
11 established in Decision (D.) 02-11-022 for DA customers. It reflected a
12 consensus recommendation and belief among the active parties at that time that
13 the PCIA methodology, which includes the use of administratively-set
14 benchmarks as proxies for certain market costs, “will allow the indifference
15 calculation to better reflect the cost impact on the resource portfolio serving
16 bundled customers if the DA load were to return to bundled service.”¹¹

17 However, as discussed throughout this Testimony, the Current Methodology
18 no longer accomplishes equitable cost allocation and, therefore, no longer leads
19 to customer indifference to departing load, as required by statute. The Current
20 Methodology does not achieve bundled service customer indifference in large
21 part because in determining the “above-market” costs of a given resource, it
22 relies on administratively-set benchmarks to value both the renewable attributes
23 of RPS resources (*i.e.*, Renewable Energy Credits (RECs)), and the capacity
24 attributes of resources (*i.e.*, their Resource Adequacy (RA) value). These
25 administratively-assigned values —by their nature—do not reflect actual market
26 conditions and therefore shift costs in one direction or the other. The Current
27 Methodology achieves bundled service customer indifference (*i.e.*, bundled
28 service customer generation rate before any load has departed is equal to
29 bundled service customer generation rate after load departure) if, and only if, the
30 benchmark is exactly equal to the actual price that could be obtained in the

11 *Final Report of the Working Group to Calculate CRS Obligations Associated with Municipal Departing Load and DA*, February 1, 2006, p. 6, entered in the record in R.02-01-011 pursuant to February 23, 2006 *Ruling Incorporating Report and Letter Into the Record and Providing Comments Thereon*.

1 market from selling the departing load customers' share of the generation
2 portfolio (with its various attributes). As a practical matter, it is extraordinarily
3 unlikely, if not impossible, for that exact result to occur when employing a
4 methodology that uses pre-determined, administratively-set benchmarks to
5 assign values to market-based commodities. Moreover, when this condition is
6 inevitably not met, and if the benchmark is set at a level above the actual price
7 that can be obtained from the market, as is the case today, the cost shift to
8 bundled service customers increases exponentially at higher levels of departing
9 load because a smaller subset of customers is paying for an increased level of
10 cost shifts.

11 Importantly, the Current Methodology was not adopted in an environment of
12 rapid load departure and therefore was not designed to be highly scalable to any
13 level of load departure. Rather, it was developed at a time when there were no
14 CCAs and the need for a scalable mechanism to accommodate current and
15 future expected levels of load departure was not contemplated. Moreover, the
16 Current Methodology was established before the development of thousands of
17 megawatts (MW) of new renewable generation significantly reduced the market
18 price of capacity and renewable energy products. These two factors, more than
19 any others, have undermined the effectiveness of the Current Methodology to
20 equitably allocate costs among departing load customers and remaining bundled
21 service customers, with the absence of a true-up further exacerbating the
22 problem.

23 An equitable allocation of the costs and benefits of generation investments
24 is critical to meet the state's policy objectives. The costs must be equitably
25 allocated among customers – bundled service and departing load alike—based
26 on the financial commitments made by the Joint Utilities on behalf of
27 then-bundled service customers. Burdening one set of customers with a
28 disproportionate share of these costs is not only inconsistent with the
29 indifference principle embedded in state law, but is also neither equitable nor
30 sustainable. Furthermore, burdening a subset of California's population with
31 artificially high costs can negatively affect public support for the state's policy
32 objectives. In short, inequitable cost allocation puts at risk both public support
33 for, and industry ability to implement, California's ambitious GHG reduction
34 policies.

C. Impacts of the Renewables Portfolio Standard and Increased Retail Choice

1. The Renewables Portfolio Standard Program Has Contributed to Excess Capacity and Renewable Energy Credits in the Market, Undermining the Current Methodology

The success of California's RPS Program has created a market surplus for RA and RECs which, in turn, has driven down the price for these products. However, the administratively-set benchmarks for RA and RECs do not reflect these market realities. The Current Methodology establishes RA and REC values well above current market opportunities, which results in substantial cost shifts from departing load customers to bundled service customers.

As described above, California's energy supply has been fundamentally transformed over the past fifteen years in response to ambitious state goals to reduce GHG emissions. To achieve this broader state policy objective, and at the direction of the CPUC, the Joint Utilities through the use of their credit worthy balance sheets, have committed billions of dollars by signing hundreds of long-term contracts for renewable resources, thereby creating the infrastructure needed to support California's policy objectives. The long-term contracts executed by the Joint Utilities, typically 15 to 20 years in length, financed the building of over tens of thousands of 15,000 MWs of renewable energy generation resources, contributed to significant price reductions for renewable energy resources currently available in the market, and enabled California's rise as one of the world's green energy leaders.¹² Table 1-1 shows the substantial increase in RPS supply added to the Joint Utilities' generation portfolios since 2010.

¹² In addition, the Joint Utilities have entered into agreements for other generating resources, or built or contracted for utility-owned generating resources, that help ensure all Californians are able to enjoy safe, reliable and affordable electricity service. Collectively, these commitments by the Joint Utilities directly or indirectly benefit all Californians and were made to provide reliable and clean power for future customers for the next thirty to forty years.

TABLE 1-1
TOTAL PORTFOLIO SUPPLY BY THE JOINT UTILITIES (GIGAWATT-HOUR (GWH))

Line No.	Year	PG&E ^(a)		SCE ^(b)		SDG&E ^(c)	
		Total Supply	RPS Supply	Total Supply	RPS Supply	Total Supply	RPS Supply
1	2010	77,772	6,906	71,558	14,444	17,038	2,506
2	2011	74,864	8,864	67,938	15,223	16,624	2,211
3	2012	76,205	9,983	48,070	14,986	17,165	2,190
4	2013	75,705	12,870	52,227	15,972	16,048	4,540
5	2014	74,547	16,699	48,860	17,734	16,012	4,929
6	2015	72,113	18,533	47,506	18,316	16,291	5,294
7	2016	68,441	19,779	46,509	20,735	16,429	6,724
8	2017	61,937	18,271	51,572	24,257	14,617	7,269
9	2018	61,940	17,588	48,337	25,742	16,136	7,233

(a) PG&E data source: PG&E's 2010-2017 Annual Reports (Generation Delivered); PG&E's 2018 ERRR Forecast, November Update.

(b) SCE data source: SCE Power Content Label 2010-2017; SCE ERRR Forecast Update 2018; SCE August 2017 RPS Compliance Report.

(c) SDG&E data source: SDG&E's 2010-2018 ERRR Forecast, November Updates.

The data shown in this table includes all procurement. Some of the costs of this procurement may not be recoverable through the PCIA or the Competition Transition Charge (CTC), such as Cost Allocation Methodology (CAM)-eligible resources.

This early procurement of renewable energy generation resources, which ultimately contributed to the steady decrease in market prices that are accessible to CCAs and other LSEs today, constitutes the majority of the above-market portfolio costs that have contributed to recent increases in the PCIA. It is also the reason why those early-procured renewable resources are now well above-market when compared to today's prices. For example, successful bidders in PG&E's 2011 Solar Photovoltaic Program Power Purchase Agreement solicitation executed transactions for an average of \$116 per Megawatt-hour (MWh). That price is consistent with the findings of a 2017 study of utility-scale solar development by the Lawrence Berkeley National Laboratory which found that "[a]s recently as 2011, solar PPA prices in excess of \$100/MWh were quite common."¹³ However, as the report notes,

Five years later, most PPAs in the sample are priced at or below \$50/MWh levelized (in real, 2016 dollars), with a few priced as aggressively as ~\$30/MWh. Though this price decline is impressive in

¹³ Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (September 2017) at p. 33. Available at: <https://emp.lbl.gov/sites/default/files/utility-scale-solar-2016-report.pdf>.

1 terms of both scale and pace, it is also worth noting that in some
2 markets with high solar penetration, the *wholesale market value* of solar
3 energy has also declined over time as solar penetration has
4 increased.¹⁴

5 Of course, even though the “market value” of these legacy resources
6 has declined over time, the Joint Utilities’ payment obligations to the
7 generator counterparties have remained fixed at the original contract prices.

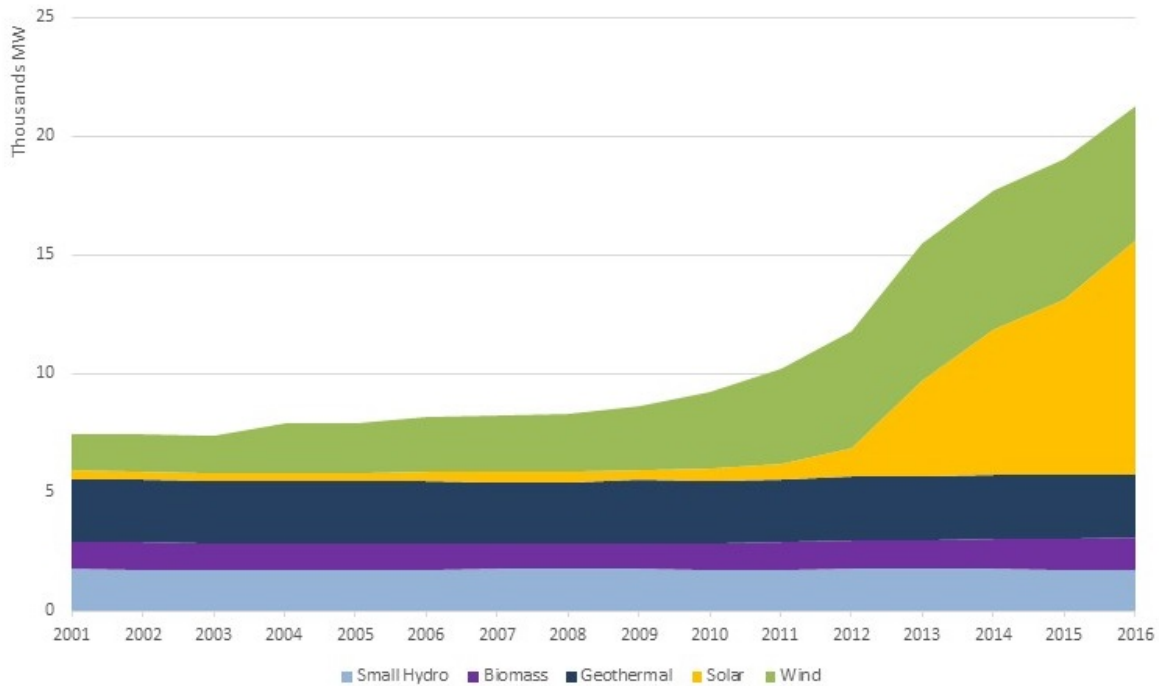
8 While the RPS program has succeeded in reducing state GHG
9 emissions and fostering a strong in-state renewables industry, the rapid
10 construction of new renewable resources has led to a significant surplus in
11 state-wide resource capacity and associated RA products.¹⁵ Figure 1-1,
12 below, shows in-state renewable capacity from 2001-2016. Capacity
13 additions over this period, driven by the construction of new wind and solar
14 facilities, significantly exceeded growth in demand: total in-state capacity
15 (including non-renewable resources) increased by 43 percent from
16 2001-2016, compared with a 13 percent increase in California peak demand
17 over a similar timeframe, from 2000-2016.¹⁶

¹⁴ *Id.* (emphasis in original).

¹⁵ Typically, as occurred prior to the RPS Program, new capacity is added in response to capacity needs identified through regulatory processes (e.g., the CPUC’s Long-Term Procurement Plan proceeding) due to increases in demand or retirements of older capacity or, in the absence of a reliability planning process, in response to high prices due to shortages. In contrast, during the last fifteen years capacity was indirectly added primarily to achieve RPS compliance requirements.

¹⁶ California Energy Commission, *Tracking Progress* (Nov. 2017), page 3. Available at: http://www.energy.ca.gov/renewables/tracking_progress/documents/statewide_energy_demand.pdf.

FIGURE 1-1
CALIFORNIA IN-STATE INSTALLED REWEWABLE CAPACITY, 2001-2016 (MW)^(a)



Source: California Energy Commission Energy Almanac. In-state Electric Generation Capacity by Fuel Type.

(a) Note: The information shown in this figure reflects the nameplate capacity. This does not reflect the amount of capacity that can be used for compliance with CPUC RA requirements.

1 While the installed capacity total may exceed the amount of capacity
2 that can be used for compliance with CPUC RA requirements, particularly
3 for intermittent resources such as wind and solar, even applying a
4 discounted capacity value to wind and solar resources to reflect Commission
5 RA counting rules, in-state capacity increased over the time period by
6 28 percent.¹⁷

¹⁷ Since the 2018 RA Compliance filing, the Commission has applied an Effective Load Carrying Capability (ELCC) multiplier to the nameplate capacity of wind and solar resources to determine the amount of RA credit for the resource. For 2018, these factors were 41 percent for solar resources and 26.5 percent for wind resources for August. Prior to the implementation of ELCC, the Commission used an exceedance methodology to determine the RA credit for wind and solar resources. The exceedance methodology generally resulted in higher RA values than the ELCC methodology.

1 Furthermore, it is important to note that Figure 1-1 also does not include
2 import capabilities; in recent years imports have accounted for more than
3 25 percent of annual generation in California.¹⁸

4 In short, although some resource retirements have occurred—including
5 certain legacy plants subject to once-through-cooling requirements—there
6 remains excess resource capacity in the state as the rate of new
7 installations has far outpaced the combined effect of retirements and
8 load growth.

9 The success of the RPS Program has also led to renewable generation
10 in excess of annual RPS requirements. This, in turn, has led to a surplus of
11 RECs in the market. State-wide, approximately 28 percent of in-state
12 energy generation in 2016 was produced by RPS-eligible resources (*i.e.*,
13 solar photovoltaic, solar thermal, wind, small hydro, geothermal and
14 biomass).¹⁹ This figure exceeds the 25 percent RPS requirement for 2016
15 without accounting for qualifying out-of-state renewable generation.

16 An excess of resource capacity and RECs undermines the Current
17 Methodology. A capacity surplus situation puts downward pressure on
18 prices for capacity products, in particular for RA products, and undermines
19 the Current Methodology in two ways. First, the administratively-set
20 benchmark price for RA is set at the going-forward costs of a simple-cycle
21 combustion turbine. In a market with surplus capacity and low prices, this
22 significantly overstates the actual value of capacity in the Joint Utilities'
23 portfolios. Because there is more capacity currently available to the system
24 than needed, the prices the Joint Utilities can realize when selling excess
25 RA capacity is lower than the going-forward cost of the benchmarked
26 resource. Figure 1-2, below, illustrates the difference between the existing
27 RA benchmark price and the volume-weighted average price (VWAP) of RA

¹⁸ California Independent System Operator 2016 Annual Report on Market Issues and Performance. Page 36. Available at: <http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerformanceReports/Default.aspx>

¹⁹ California Energy Commission. Energy Almanac. 2016 Total System Electric Generation in GWh. Available at: http://www.energy.ca.gov/almanac/electricity_data/total_system_power.html

1 sales based on CPUC reporting from 2012 to the present, and demonstrates
2 the trend in declining RA market value.²⁰

FIGURE 1-2
COMPARISON OF RA BENCHMARK PRICE AND CPUC RA REPORT VOLUME-WEIGHTED
AVERAGE SYSTEM RA PRICE, 2012-2016



3 Second, surplus conditions complicate the valuation of RA because
4 unsold volumes of RA should have a value of zero; the Current Methodology
5 values unsold excess capacity at the full benchmark price. PG&E, which of
6 the three IOUs has experienced the greatest amount of CCA load departure
7 to date, attempts to sell RA on monthly, quarterly and long-term bases.
8 However, PG&E has not received bids for much of its excess RA and largely
9 has not received bids at benchmarked prices for volumes it is able to sell.
10 PG&E has calculated the weighted-average price for RA, including unsold
11 RA, and presents both the unsold volumes and average price in
12 Appendix G.²¹

13 Similar to the impact of a capacity surplus on the RA market, the
14 availability of renewable compliance products (*i.e.*, RECs) in excess of RPS
15 compliance requirements has put downward pressure on REC prices and

²⁰ The CPUC began publishing annual RA reports in 2007, but did not publish VWAPs until the 2012 RA report.

²¹ The confidential version of Appendix G is bound separately.

1 undermined the ability of the Current Methodology to ensure customer
2 indifference to departing load. The Current Methodology values RECs at
3 the weighted average of the cost of newly-delivering IOU renewable
4 resources (68 percent) and the average price of voluntary green pricing
5 programs spread throughout the territory of the Western Electric
6 Coordinating Council, as published by the United States (U.S.) Department
7 of Energy (32 percent). This calculation significantly inflates the actual value
8 of RECs in the Joint Utilities' portfolios to bundled service customers.
9 Because the REC benchmark calculation largely reflects the cost of new
10 construction for RPS projects recently delivering to the grid (*i.e.*, delivering in
11 the current or prior year), this higher "new-build" cost basis is not reflective
12 of the value the Joint Utilities could reasonably expect to realize in the
13 market should they seek to dispose of excess (*i.e.*, "long") REC positions
14 due to departing load.

15 The REC benchmark calculation is further complicated because it is
16 based in large part on the cost of recently-delivering renewable resources
17 procured by the Joint Utilities only. As discussed in further detail in
18 Section C.2, below, the Joint Utilities are long on renewable energy and are
19 no longer procuring renewable resources unless required to do so by the
20 Commission pursuant to a technology-specific mandate. These technology-
21 specific mandates are generally much higher-cost than procurement
22 conducted through all-source RPS solicitations, which further artificially
23 inflates the REC benchmark.

24 Moreover, and as discussed further in Chapter 7 of this Testimony, such
25 state-mandated procurement applies only to the Joint Utilities. Thus,
26 although these programs are mandated to meet state policy goals, only
27 bundled service and vintaged departing load customers (at the time
28 contracts were executed), pay for them. Such a result is inequitable and not
29 sustainable going forward given increasing load departure from bundled
30 service. Rather, the costs and benefits of these state-wide initiatives should
31 apply equally to all customers regardless of which LSE procures on their
32 behalf or when the customer departed bundled service. As a matter of
33 sound policy, their costs should be collected from all customers on a

1 non-vintaged basis.²² At a minimum, these programs should not be used to
2 set the PCIA REC benchmark.

3 **2. Increased Retail Choice Has Resulted in the Joint Utilities Holding**
4 **Long Resource Adequacy and Renewable Energy Credits Positions**
5 **that Exacerbate Cost Shifts Under the Current Methodology**

6 At the same time that California state environmental policy has changed
7 the composition and volume of energy supply, California state policies
8 facilitating customer choice and allowing for retail electric competition have
9 changed the composition of retail service providers and contributed to
10 significant departures from IOU bundled service. This load shift, in turn, has
11 resulted in the Joint Utilities' bundled service portfolios holding long
12 positions with respect to RA and RECs, which further exacerbates cost
13 shifts to remaining bundled service customers given the Current
14 Methodology's attribution of inflated market values to those products.

15 Legislation in 2002 enabled the formation of CCAs and established
16 CCAs as the presumed providers in their respective service areas (*i.e.*, all
17 retail customers are automatically enrolled into a new CCA unless they
18 affirmatively opt out, although the Joint Utilities remain the Providers of Last
19 Resort). In 2010, the first CCA launched within California. Also in 2010, the
20 CPUC, under the direction of the state legislature, authorized a limited
21 reopening of DA, allowing non-residential customers to select a non-IOU to
22 procure energy on their behalf.²³

23 Since 2009, the share of system load (defined as electricity historically
24 delivered by each of the Joint Utilities) that each of the Joint Utilities supplies
25 has declined. Table 1-2 shows the cumulative increase in departing load for
26 each IOU. The significant increase shown for PG&E is primarily driven by
27 CCA formation. Based on expressed interest in CCA formation in SCE's
28 service territory, similar levels of departing load for SCE can be expected to

22 The Joint Utilities' Proposal, set forth in detail in Chapter 4, incorporates this concept of non-vintaging of certain resources that are procured by the Joint Utilities to meet state policy goals irrespective of load.

23 DA was first established during the deregulation of the California electric industry in 1998, but was suspended to new customer enrollment after the 2000-2001 energy crisis.

commence in 2019. DA reopening for the three IOUs had a relatively small effect for departing load levels compared to the amount of load that has and may depart to CCA service.

TABLE 1-2
DIRECT ACCESS AND CCA LOAD AS PERCENT OF JOINT UTILITIES' LOAD

Line No.	Year	PG&E	SCE	SDG&E
1	2010	7%	10%	16.6%
2	2011	10%	12%	16.6%
3	2012	11%	13%	17.6%
4	2013	12%	13%	18.3%
5	2014	13%	13%	18.3%
6	2015	16%	13%	18.1%
7	2016	17%	14%	18.7%
8	2017	25%	14%	17.9%
9	2018	39%	17%	19.3%
10	2019	54%		
11	2020	55%		
12	2021	56%		
13	2022	58%		

Source: Data for years 2010 through 2017 based on actual retail sales. Data for 2018 forward based on current internal load forecasts.

Because many of the resources in the Joint Utilities' respective generation portfolios were constructed or procured: (i) prior to the 2002 legislation authorizing the formation of CCAs; (ii) under long-term contracts; or (iii) pursuant to mandates imposed by the Commission irrespective of load forecasts, the Joint Utilities' bundled service portfolios are currently long (*i.e.*, the IOU bundled portfolios have more RA, RECs, and energy than needed to serve remaining bundled service load). In fact, the Joint Utilities have generally not procured any long-term resources based on forecasted load needs, other than for locational needs, for several years. PG&E has not executed any new RPS contracts through an RPS solicitation since those selected through PG&E's 2012 RPS solicitation, due to a lack of need. PG&E is similarly long in RA.²⁴

²⁴ See PG&E Confidential Appendix G.

1 The Current Methodology does not achieve customer indifference when
2 the Joint Utilities are long. Under the Current Methodology, Joint Utility
3 bundled service customers effectively buy back the energy, REC and RA
4 attributes from contracts and utility-owned generation (UOG) that were
5 entered into or constructed on behalf of now-departed load. The Joint
6 Utilities' bundled service customers purchase these attributes through
7 credits to departing load customers in the PCIA at the administratively-set
8 PCIA benchmark prices. Since the Joint Utilities' bundled portfolios are
9 generally long, bundled service customers do not need these attributes and
10 can only realize a portion of the value for the attributes through resale at
11 current market prices. Cost shift is created by the difference between:
12 (a) the administratively-set benchmark and the realized market price from a
13 potential sale when a sale can be executed; or (b) the difference between
14 the benchmark and \$0 when no sale is executed.²⁵ As stated previously,
15 PG&E has not been able to fully sell its long capacity positions. Importantly,
16 the shifted costs are borne not by the Joint Utilities, but by their remaining
17 bundled service customers, which is a result inconsistent with state law, and
18 which must be remedied.



19 Significantly, many of the communities that have formed CCAs to date
20 are wealthier on average than the communities that have remained on
21 bundled service. That is particularly true in PG&E's service territory where
22 13 of the state's 15 wealthiest counties are located and where 12 of those
23 15 counties are served entirely, or in part, by CCAs. In contrast, of the
24 40 counties that fall below the state-wide median income, only seven are
25 served entirely or partly by a CCA. Thus, the cost shift that has occurred to
26 date under the Current Methodology has been disproportionately borne by
27 bundled service customers in communities below the state-wide median
28 income level.

29 Table 1-3, below, shows the median income by county and notes which
30 counties have formed CCAs or contain communities that have formed
31 CCAs.

²⁵ As discussed above, surpluses of capacity and RECs have depressed the market prices for these attributes significantly below the benchmark prices.

**TABLE 1-3
CALIFORNIA COUNTIES RANKED BY MEDIAN HOUSEHOLD INCOME AND EXISTING CCA**

Key

	Entire county has a CCA
	Some cities within the county have CCAs

Line No.	Rank	County	Median Household Income	Rank	County	Median Household Income
1	1	Santa Clara ¹	\$101,173	30	San Bernardino	\$54,469
2	2	Marin	\$100,310	31	Calaveras	\$53,502
3	3	San Mateo	\$98,546	32	Sutter	\$52,943
4	4	San Francisco ¹	\$87,701	33	Stanislaus	\$51,591
5	5	Contra Costa ¹	\$82,881	34	Lassen	\$51,457
6	6	Alameda ¹	\$79,831	35	Tuolumne	\$50,731
7	7	Ventura	\$78,593	36	Plumas	\$50,125
8	8	Orange County	\$78,145	37	Kern	\$49,788
9	9	Placer	\$76,926	38	Mariposa	\$49,265
10	10	Napa	\$74,609	39	Yuba	\$48,739
11	11	San Benito	\$73,814	40	Inyo	\$47,278
12	12	El Dorado	\$72,586	41	Kings	\$47,241
13	13	Santa Cruz	\$70,088	42	Fresno	\$45,963
14	14	Solano	\$69,227	43	Madera	\$45,742
15	15	Sonoma	\$66,833	44	Shasta	\$45,582
16	16	San Diego	\$66,529	45	Merced	\$44,397
17	17	Santa Barbara	\$65,161	46	Butte	\$44,366
18	18	San Luis Obispo	\$64,014	47	Sierra	\$43,984
19		California	\$63,783	48	Mendocino	\$43,510
20	19	Alpine	\$62,375	49	Tulare	\$42,789
21	20	Monterey ¹	\$60,889	50	Humboldt	\$42,685
22	21	Mono	\$58,937	51	Imperial	\$42,560
23	22	Riverside	\$57,972	52	Del Norte	\$42,363
24	23	Los Angeles	\$57,952	53	Glenn	\$41,699
25	24	Yolo ¹	\$57,663	54	Modoc	\$41,194
26	25	Sacramento	\$57,509	55	Tehama	\$40,687
27	26	Nevada	\$57,429	56	Siskiyou	\$38,524
28	27	Amador	\$57,032	57	Lake	\$36,132
29	28	San Joaquin	\$55,045	58	Trinity	\$35,270
30	29	Colusa	\$54,946			

Source: Median Household Income Data from U.S. Census Bureau Median Income in the Past 12 Months (in 2016 Inflation-Adjusted Dollars), 2012-2016 American Community Survey 5-Year Estimates

- 1 The following new CCAs or expansions are planned for 2018: Marin Clean Energy (Contra Costa expansion), Valley Clean Energy (Yolo County), East Bay Community Energy (Alameda County), Silicon Valley Clean Energy (Milpitas expansion in Santa Clara County), Clean Power SF (San Francisco County), and King City (Monterey County).

- 1 As discussed above, the Joint Utilities' long position is driven by load
2 shifts. However, managing the Joint Utilities' position to forecasted load is
3 complicated by the lumpy, unpredictable nature of customer departure to

1 CCAs and misalignment between regulatory compliance requirements and
2 CCA formation timelines.

3 First, unpredictable CCA launch dates and inaccurate load forecasts are
4 a consistent problem even as CCA formation has accelerated in recent
5 years. For example, San Joaquin Valley Power Authority's (SJVPA)
6 implementation plan, filed in 2009, included a 2018 retail load forecast of
7 2,718 gigawatt-hours (GWh). However, SJVPA never launched its service.
8 San Francisco Community Choice Aggregation (now known as Clean Power
9 San Francisco (CPSF)) filed its first implementation plan in 2005. That plan
10 included a 2016 retail load forecast of 6,709 GWhs. However, CPSF's
11 actual retail load in 2016, according to its 2017 Integrated Energy Policy
12 Report filing, was less than one GWh.

13 Second, even when the Joint Utilities have forecasted load departure,
14 they are still obligated to procure on behalf of forecasted departing load.
15 This has occurred in annual RA filings in which the Joint Utilities had a
16 compliance obligation to procure on behalf of load to be served by
17 newly-forming or expanding CCAs in the operational year. In addition, in the
18 absence of a CCA filing a Binding Notice of Intent (BNI), the incumbent
19 utility remains legally responsible to procure for, and stand-by ready to
20 serve, the customers in the prospective CCA's territory.²⁶

21 Finally, even as CCAs form and phase in the default of customers to
22 their service, the Joint Utilities are required to serve all customers prior to
23 their being defaulted.²⁷ Moreover, the Joint Utilities serve as the backstop
24 provider should a customer return due to choice, the CCA ceasing
25 operations, or if the CCA returns a customer for non-payment.²⁸ All of the
26 uncertainties described above make it difficult to accurately determine the
27 amount and timing of the loads for which the Joint Utilities are responsible.

²⁶ It is exceedingly rare for CCAs forming in California to submit a BNI.

²⁷ As highlighted in Resolution 4907, the RA Program has historically required the IOU to meet year-ahead compliance requirements on behalf of departing load for the first year that a CCA forms or expands even when the CCA formation or expansion date is set.

²⁸ PG&E Electric Rule 23.U.2 allows CCAs to request a transfer of service to PG&E bundled service due to customer non-payment. See also SCE Tariff Rule 23.U.2 and SDG&E Electric Tariff Book Rule 27.U.2.

1 In summary, increased departures from Joint Utility bundled service,
2 coupled with the Joint Utilities’ decades-long and extensive procurement of
3 renewable resources to facilitate state policy objectives, have created long
4 positions for the Joint Utilities that exacerbate cost shifting under the Current
5 Methodology. It is imperative that the Current Methodology be reformed
6 expeditiously and in a manner that eliminates cost shifts and ensures
7 bundled service customer indifference to departing load consistent with law.
8 The Joint Utilities’ Proposal for accomplishing that goal, and others, is
9 introduced below

10 **D. Joint Utilities’ Proposal for Replacing the Current Methodology**

11 In response to stakeholder feedback on the PAM proposal, the Joint Utilities
12 have modified their proposal for reforming the PCIA. Rather than allocating the
13 entirety of the Joint Utilities’ respective portfolio attributes to all LSEs as
14 proposed in PAM, the Joint Utilities now propose to allocate only “green”
15 resource attributes associated with RPS-eligible resources and large hydro-
16 electric resources, while monetizing other “brown” resource attributes based on
17 actual market outcomes, subject to a true-up. This modification is intended to be
18 responsive to CCAs’ desire to build “green” portfolios and to avoid a need to
19 allocate “brown” resource attributes to them. The Joint Utilities’ Proposal is
20 discussed at length in Chapter 4. A brief summary is provided here.

21 The Joint Utilities propose to replace the Current Methodology with a new
22 cost recovery framework that consists of two parts: The Green Allocation
23 Mechanism (GAM), and the Portfolio Monetization Mechanism (PMM). The
24 GAM, which applies to RPS-eligible and large hydro-electric facilities, retains the
25 concept of a pro rata allocation of net costs and benefits that the Joint Utilities
26 first proposed in their PAM Application. GAM is also methodologically similar to
27 the CAM adopted by the Commission in D.06-07-029,²⁹ whereby the benefits of
28 the generation resources (e.g., enhanced system reliability and capacity that is
29 applied towards each LSE’s RA requirements) are shared equitably by all
30 customers, and the “net costs,” defined as the total cost of the resource less the

²⁹ Many of the detailed mechanics of the methodology were refined and adopted in D.07-09-044 and D.15-11-041.

energy revenues associated with the dispatch of the resource, are also shared equitably by all customers.³⁰

Because RPS-eligible and large hydro-electric resources will be critical resources to meet California's policy objectives, and calculating separate REC, RA, energy, and ancillary services values over time in an environment of changing market dynamics for such resources cannot be done accurately or without harming California's market operations, allocating portfolio attributes and net costs of these resources will ensure that all customers equitably benefit and pay for these important resources.

Under the Joint Utilities' Proposal for GAM, the costs recovered from departing load customers will equal the actual pro rata costs incurred (e.g., contract costs owed to the generators, UOG capital costs, variable Operations & Maintenance costs, and California Independent System Operator generation-related charges), less the actual pro rata revenues received from the markets for those resources (e.g., energy and ancillary services (A/S) revenues).

The PMM, which applies to nuclear, gas, and energy storage resources, is similar to the Current Methodology in that it does not allocate portfolio attributes but instead only collects the pro rata share of the above-market costs of the PMM resources from departing load customers. However, unlike the Current Methodology, which relies on administratively-set benchmarks to estimate the above-market costs of the portfolio, PMM uses actual market transactions to calculate the cost responsibility of departing load customers. Under PMM, the cost recovered from departing load customers will equal their pro rata share of the above-market costs of the PMM portfolio (i.e., actual incurred costs, less the actual energy and A/S revenues received from the markets for those resources and the actual value of the RA capacity as determined in an annual RA sales process).

While the initial rates for both the PMM and GAM portions of the portfolio will be set in the Joint Utilities' respective annual Energy Resource Recovery Account (ERRA) Forecast proceedings based on a forecast of costs and offsetting market revenues³¹ (forecast net resource costs), those rates will be

³⁰ D.06-07-029, p. 7.

³¹ PMM RA capacity value will be forecast using the average price specified in the Commission's Annual RA report adjusted for market depth.

1 trued-up annually based on actual portfolio performance and realized market
2 revenues (actual net resource costs), as well as billed revenues (*i.e.*, sales)
3 received from customers. This method ensures that all customers pay their
4 actual pro rata share of the net resource costs for which they are responsible.

5 The Joint Utilities' Proposal of combining the allocation of RECs and RA
6 from RPS and large hydro-electric resources (GAM) with a cost-based allocation
7 approach for other resources (PMM) appropriately balances the concerns of all
8 parties while ensuring compliance with state law and public policy. CCA
9 stakeholders have communicated a preference for developing clean energy
10 portfolios while minimizing the size of the legacy portfolios allocated to them. As
11 described in Chapter 2, the Joint Utilities are concerned that accurate and
12 scalable market indices, in particular for the various RPS compliance categories
13 and contract tenors, are exceedingly difficult to construct, and that not all
14 products are equally liquid in the marketplace. Under GAM, the costs and
15 benefits of clean energy resources are directly allocated to LSEs, thereby
16 avoiding the use of inaccurate and imprecise benchmarks and ensuring the use
17 of these policy-preferred resources in meeting all customers' needs.

18 The proposal to allocate the benefits of RPS resources (*i.e.*, RECs) as part
19 of the GAM also comports with sound public policy. While the Joint Utilities have
20 long RPS positions well into the future, it stands to reason that recently formed
21 and newly-forming CCAs will have to engage in significant RPS contracting to
22 meet their SB 350 compliance obligations of 50 percent RPS by 2030 (of which
23 65 percent must be long-term commitments). The Joint Utilities' Proposal
24 efficiently and rationally allocates existing IOU RPS commitments to all LSEs on
25 a load-share basis, ensuring that all customers continue to benefit from their
26 IOU's RPS commitments and pay their equitable share of such resources. This
27 proposal optimizes existing RPS resource commitments already approved by
28 the CPUC, while still allowing CCAs an opportunity to add new RPS resources
29 to their portfolios. Importantly, the GAM avoids the potential for unnecessary
30 double-procurement of long-term RPS resources to meet SB 350 requirements.

31 In contrast to GAM, PMM provides a means to quantify the actual above-
32 market costs of resources with attributes that are transacted in relatively-liquid
33 markets, thereby completely eliminating the need to allocate and/or benchmark
34 the benefits of gas, nuclear, and energy storage resources. Together, GAM and

1 PMM ensure that departing load customers retain the inherent value of actions
2 taken to support the state’s regulatory and public policy objectives, and pay their
3 equitable pro rata share of the costs of those actions taken on their behalf,
4 without unduly hindering their LSE’s ability to exercise procurement autonomy
5 on their behalf.

6 GAM and PMM protect all customers through a transparent process that
7 uses actual market results rather than hypothetical, administratively-set, Market
8 Price Benchmarks (MPBs). Both the PMM and the GAM replace an “estimation”
9 construct that relies entirely on inaccurate and contentious administratively-set
10 MPBs with actual and verifiable net resource costs and actual market revenues.
11 The Joint Utilities’ Proposal results in both departing load customers and
12 remaining bundled service customers paying the same above-market and net
13 costs, on a per-kilowatt-hour basis, for each PMM and GAM resource,
14 respectively, for which they are collectively responsible, thus ensuring customer
15 indifference as required by law.

16 The Joint Utilities respectfully submit that their proposal complies with the
17 statutory mandate to achieve customer indifference, while also meeting multiple
18 other policy objectives identified in this OIR by the Commission as critical.
19 Consequently, the Joint Utilities urge the Commission to adopt the Joint
20 Utilities’ Proposal.

21 The balance of this Testimony follows the Common Testimony Outline and
22 is organized as follows:

23 Chapter 2 discusses in greater detail the shortcomings of the Current
24 Methodology in today’s energy markets.

25 Chapter 3 discusses the Joint Utilities’ proposal for optimizing their
26 respective portfolios on a going-forward basis.

27 Chapter 4 discusses the Joint Utilities’ Proposal for replacing the Current
28 Methodology.

29 Chapter 5 discusses the potential approach of “sun-setting” or capping the
30 PCIA, and explains that the Joint Utilities oppose both concepts as being
31 inconsistent with customer indifference requirements and impracticable.

32 Chapter 6 discusses the Joint Utilities’ proposal for developing a
33 standardized methodology that allows LSEs to develop forecasts of the
34 attributes and costs allocated to them under the Joint Utilities’ proposed

1 methodology, while maintaining critical confidentiality protections for market
2 sensitive data.

3 Finally, Chapter 7 (Other Issues) discusses the following two proposals:
4 (1) retroactively applying the departing load cost allocation methodology adopted
5 in this proceeding; and (2) recovering the costs of certain state-mandated
6 procurement from all customers on a non-vintaged basis.

**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
CHAPTER 2
CURRENT METHODOLOGY**

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CHAPTER 2
CURRENT METHODOLOGY

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**PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 2
CURRENT METHODOLOGY**

A. Does the Current Methodology Prevent Cost Shifts Between Bundled Service Customers and Departing Load Customers? (Scoping Memo Issues 1 and 2)

1. Introduction

No, the Current Methodology does not prevent cost shifts between bundled service customers and departing load customers (i.e., Community Choice Aggregation (CCA), Direct Access (DA), Customer Generation (CG) and Community Aggregator customers).

Since the 2000-2001 Energy Crisis, the California Public Utilities Commission (CPUC or Commission) has implemented statutory requirements regarding departing load cost allocation with regulatory decisions that embrace what is known as the “indifference principle.” The indifference principle seeks to implement the statutory requirement that bundled service customers remain financially indifferent to the impact of departing load by requiring that departing load customers pay their pro rata share of the “above-market” costs, as determined using the Current Methodology, of all resources built or procured on their behalf prior to their departure through the Competition Transition Charge (CTC) and Power Charge Indifference Adjustment (PCIA) rates. Bundled service customers pay their pro rata share of the “above-market” costs of those resources through their generation, i.e., Energy Resource Recovery Account (ERRA) rates.

The Current Methodology has undergone a number of modifications since it was first adopted by the Commission under the Cost Responsibility Surcharge (CRS) framework in 2002.¹ The central driver for these modifications has been a desire on the part of the Commission and the

¹ See Decision (D.) 02-11-022 (adopting the initial CRS).

1 parties to more accurately determine and apportion the above-market costs
2 of utility-procured resources.

3 The Joint Utilities' generation rates, set annually on a forecast basis
4 in their respective ERRRA Forecast proceedings and trued-up on an
5 actual basis the following year, recover the total resource costs (less the
6 "Indifference Rate" payments by departing load customers) from bundled
7 service customers. For departing load customers, an "Indifference Rate"
8 is determined using the Current Methodology to approximate their
9 pro-rata share of above-market costs associated with the bundled
10 service portfolio, and is recovered through the CTC and PCIA rates. To
11 approximate the above-market costs, the Indifference Rate starts with
12 the forecast costs of the utility generation portfolio (e.g., contract
13 payments, utility-owned generation revenue requirements), and
14 subtracts a proxy of the revenue those resources could garner in the
15 market using forecasts of energy prices and administratively-determined
16 benchmarks, which collectively comprise the Market Price Benchmark
17 (MPB). However, neither the forecast costs nor the forecast revenues of the
18 resources subject to the MPB are trued-up after the fact. Thus, the
19 Indifference Rate is the resulting combination of a forecast of portfolio
20 costs that is inherently inaccurate due to the inevitable variance that
21 exists with such forecasts, and an imprecise proxy of theoretical market
22 outcomes, leading to inequitable results for some customers. Moreover,
23 because the value of the Renewable Energy Credits (REC) and
24 Resource Adequacy (RA) attributes is dependent on the disparate
25 underlying resources and changes over time, a one-time "mark" of the
26 forecast or assessed actual value will not provide an accurate market
27 value assessment.²

28 The Current Methodology implicitly assumes that the Joint Utilities'
29 excess remaining RA, RECs, and other potential portfolio attributes after
30 load departs can either be sold at the MPB value or used to offset future

2 The benchmark prices are fixed for the year, but the value of the RA, REC (if applicable), and energy changes throughout the year. Additionally, the value of an RA or REC attribute is dependent upon prevailing market conditions and the underlying asset from which it arises, making a proxy benchmark price nothing more than a single-point estimate of value over a wide distribution of potential values.

procurement that would have been priced at the MPB. However, administratively-set benchmarks—by their nature—do not reflect actual market conditions and therefore shift costs in one direction or the other. As demonstrated algebraically in the Joint Utilities’ presentation at the January 16, 2018 workshop, the Current Methodology could achieve bundled service customer indifference (i.e., bundled service customer generation rate before any load has departed is equal to bundled service customer generation rate after load departure) **if, and only if**, the administratively-set benchmarks could perfectly predict the weighted-average market price for the forecast year – i.e., the MPB is equal to the actual prices that can be obtained in the market from selling the departing load customers’ share of the generation portfolio.³ While this assumption is flawed even when small amounts of load depart (as discussed below in detail), the flaws are amplified with increasing levels of load departure. Because there is no true-up based on actual market outcomes, bundled service customers are at risk for any difference between the forecast and actual costs, and between the MPB and the realized actual market value of the resources, which may be zero given the illiquidity that may exist in the market under expected load departure level assumptions.

Therefore, as the level of departing load increases, the Current Methodology, in construct, results in ever-increasing cost shifts between customers. If the MPB is set at a level above the actual price that can be obtained from the market (as is currently the case), the cost shift to bundled service customers increases exponentially at higher levels of departing load, because a smaller subset of customers is paying for an increased level of cost shifts.⁴ For example, as shown in Table 2-1 below, a 30 percent “overstatement” of the benchmark (i.e., actual realized market prices are

³ See Appendix C at slides 9-11 of the Joint Utilities’ presentation, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Costs_and_Rates/PCIA%20Workshop%202%20-%20Joint%20Utilities%20Presentation%20-%20Final%20V2.pdf.

⁴ See Appendix C at slide 12 of the Joint Utilities’ presentation, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Costs_and_Rates/PCIA%20Workshop%202%20-%20Joint%20Utilities%20Presentation%20-%20Final%20V2.pdf.

equal to 70 percent of the MPB) at 80 percent load departure would result in a 3.25¢/kWh increase to Southern California Edison Company's (SCE) remaining bundled service customers' generation rates—a 43 percent increase in the bundled service customer generation rate.⁵ The Currently Methodology, in fact, results in an ever-decreasing number of remaining bundled service customers absorbing an increasing level of above-market portfolio costs, because the MPB is materially overstated as is discussed in further detail below.

**TABLE 2-1
IMPACT ON BUNDLED SERVICE CUSTOMER GENERATION RATE AT DIFFERENT LEVELS OF
DEPARTING LOAD ASSUMING 30 PERCENT DIFFERENCE BETWEEN MPB AND MARKET
PRICES**

Line No.	% Load Departures	Impact of Understated Benchmark on Generation Rate (¢/kWh)	Impact of Overstated Benchmark on Generation Rate (¢/kWh)	% Impact on Generation Rate (2018 SCE)
1	20%	-0.20	0.20	(+/-) 3%
2	30%	-0.35	0.35	(+/-) 5%
3	40%	-0.54	0.54	(+/-) 7%
4	50%	-0.81	0.81	(+/-) 11%
5	60%	-1.22	1.22	(+/-) 16%
6	70%	-1.90	1.90	(+/-) 25%
7	80%	-3.25	3.25	(+/-) 43%
8	90%	-7.32	7.32	(+/-) 96%
9	99%	-80.51	80.51	(+/-) 1056%

The simple example above assumes that all excess resources in the bundled service portfolio can be sold for the same price (70 percent of MPB). However, in the situation of significant levels of load departure—which the state may soon face based on projections of departing load provided by CCAs—the Joint Utilities would need to liquidate the excess resources in the bundled service portfolio and will likely be unable to sell all the excess supply in the bundled service portfolios and their attributes at prices anywhere near the MPB because the market will be saturated with

⁵ See Appendix C at slide 12 of the Joint Utilities' presentation, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Costs_and_Rates/PCIA%20Workshop%20%20-%20Joint%20Utilities%20Presentation%20-%20Final%20V2.pdf. This increase relates only to the generation rate, and is not meant to estimate customer "total bill impacts."

1 excess bundled service portfolio attributes for certain periods of time. This
2 is especially true for attributes from Renewables Portfolio Standard (RPS)-
3 eligible resources because of the relative illiquidity of that market,
4 particularly for long-term contracts with existing contract terms that do not
5 allow the investor-owned utilities (IOU) to unilaterally assign such contracts
6 to new off-takers.

7 Simply put, greater departing load will significantly increase the supply
8 of attributes from RPS-eligible resources and RA resources available for
9 sale in the market, which will drive prices lower, and possibly to zero at
10 times. The Current Methodology offers no way to account for changing
11 prices (i.e., price elasticity impacts) due to the shifts in supply and demand
12 that are inherently created by load departing from bundled service without
13 an allocation mechanism. Indeed, even a more accurate market-based
14 index, if one existed, would be unable to capture the dynamic price elasticity
15 effects of such a scenario given the magnitude of the Joint Utilities'
16 portfolios. This systematic cost shift to remaining bundled service
17 customers is inherently inequitable, unsustainable, and incompatible with
18 the indifference requirement mandated by statute.

19 When the Commission adopted the Current Methodology for use in
20 determining departing load customers' cost responsibility for generation
21 procured or built after the Energy Crisis, it acknowledged that:

22 If, due to future changing circumstances, the processes adopted by this
23 decision for determining the [PCIA and CTC] become unworkable,
24 unbalanced, or unfair, parties may propose and request, for our
25 consideration, modifications to the form of the [PCIA and CTC] or the
26 manner in which [it] should be determined or calculated.⁶

27 As is described throughout this Testimony, circumstances have
28 dramatically changed: departing load in the Joint Utilities' service territories
29 has increased from 7 percent in 2008 to close to 25 percent in 2017, and
30 may reach up to 85 percent by the middle of the 2020s.⁷ Additionally, the

6 D.08-09-012, p. 58.

7 See CPUC Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*, May 2017, p. 3. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

1 Joint Utilities have procured or caused to be built over 15,000 megawatts
2 (MW) of new renewable resources⁸—the vast majority of which are secured
3 under long-term contracts, and as a result, the market price for renewable
4 resources has significantly declined. Given the significant increase in
5 departing load and increased resource commitments for which remaining
6 bundled service customers are disproportionately being required to pay, the
7 Current Methodology has become “unworkable, unbalanced, and unfair.”

8 **2. History and Description of the Current Methodology**

9 In D.02-11-022, the Commission first established the CRS to recover
10 from departing load customers their share of the “(1) costs incurred by the
11 Department of Water Resources (‘DWR’) on behalf of customers in the
12 service territories of the three IOUs (‘DWR Power Charge’), and (2) costs
13 incurred by each of the IOUs for their own resources and contracts (CTC).”⁹
14 The method adopted for calculating these components of CRS was known
15 as the “DA In – DA Out methodology,” which used a production cost model
16 to determine the increase in the average generation cost to the bundled
17 service customers as the result of some customers switching to DA service,
18 and the CRS applicable to those DA customers to keep the average bundled
19 service generation rate at the same level.

20 Due to the complexity and lack of transparency in this methodology,
21 especially as related to the market-clearing prices used in the modelling
22 process, a working group established by the assigned Administrative Law
23 Judge in Rulemaking (R.) 02-01-011 proposed the Current Methodology for
24 calculating the CTC and PCIA using a MPB that was comprised of a forward
25 market energy price and a negotiated administratively-set capacity adder on
26 a \$/megawatt-hour (MWh) basis. The Commission adopted this proposed

8 See CPUC November 2017 Renewable Portfolio Standard Annual Report, p. 17,
available at:
[http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/
Energy/Reports_and_White_Papers/Nov%202017%20-
%20RPS%20Annual%20Report.pdf](http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Nov%202017%20-%20RPS%20Annual%20Report.pdf).

9 D.02-11-022, p. 3. The adopted CRS also included the Historical Procurement Charge for SCE’s Departing Load customers to recover the procurement costs SCE incurred prior to DWR assuming the responsibility to procure energy for the Joint Utilities’ customers.

1 methodology in D.06-07-030.¹⁰ The Commission ordered that the working
2 group be reconvened in August 2006 to discuss and propose a capacity
3 adder for 2007 and beyond.¹¹ However, due to the lack of a functioning and
4 transparent capacity market or a suitable public index, the working group
5 proposed to continue the use of a negotiated administratively-set capacity
6 adder until such a market was developed.¹²

7 The last and most recent decision to modify the MPB to arrive at its
8 current structure was D.11-12-018. In that decision, the Commission
9 decided that because a larger portion of the Joint Utilities' respective
10 portfolios would consist of relatively more expensive renewable resources
11 procured to comply with the RPS, it was reasonable to augment the MPB
12 with an "RPS adder." Again, because of the lack of a robust and transparent
13 renewable market or suitable public index at the time, the Commission
14 adopted an administratively-set benchmark based on the average price of
15 the Joint Utilities' newly-delivering (but not newly-executed) contracts (IOU
16 RPS Premium, weighted at 68 percent) and the average price of voluntary
17 green-pricing programs spread throughout the Western Electricity
18 Coordinating Council (WECC) geographical footprint (Department of Energy
19 [DOE] Adder, weighted at 32 percent).¹³

20 In the same decision, due to the lack of a transparent market price for
21 RA capacity and having relied on an administratively-set negotiated number
22 for many years, the Commission adopted an administratively-set capacity
23 adder equal to the going-forward costs of a simple cycle combustion turbine

¹⁰ Although the methods for calculating the CRS were determined and adopted by the Commission for DA and CG departing load in R.02-11-011, they were also adopted for calculation of CCAs' CRS in R.03-10-003 (see D.04-12-046 and D.07-01-025).

¹¹ D.06-07-030, p. 13.

¹² D.07-01-030, pp. 3-4. This decision also updated the line loss factors used in the calculation of MPB and modified the forward energy prices used in the calculation of MPB to reflect the availability of published prices for both on- and off-peak future power deliveries.

¹³ Specifically, as described in D.11-12-018, the RPS adder is to be calculated as the weighted average of DOE data for premiums paid by customers under voluntary green pricing programs (32 percent) and the premium paid by the Joint Utilities for renewable resources delivered in the year when the CRS is calculated and the prior year (68 percent).

as estimated by the California Energy Commission (CEC) and intended to be updated biannually.¹⁴

These efforts by the Commission and interested parties over the last 15 years have resulted in the Current Methodology, under which:

- 1) The forecast costs of the total portfolio of generation resources for each vintage are determined;
- 2) The value of the energy, capacity, and RECs (if applicable) provided by those resources is approximated using the administratively-set MPB as described above;
- 3) The value determined in Step 2 is subtracted from the forecast costs determined in Step 1 to determine the above-market costs of the total portfolio--the above-market costs of the resources in the portfolio that are identified in Section 367¹⁵ are the costs used to set the CTC, and the above-market costs of the remaining resources in the portfolio are the costs used to set the PCIA;
- 4) The above-market costs of the CTC and PCIA portfolios determined in Step 3 are then allocated to various rate groups based on their contributions to the highest 100 hours of system load to establish the CTC and PCIA rates, which are collectively referred to as the Indifference Rate;¹⁶ and
- 5) The Indifference Rate is set annually in each utility's ERRRA Forecast proceeding and is not subject to a true-up.¹⁷

The Current Methodology has significantly evolved over time in an effort to balance multiple, sometimes competing, objectives such as: (1) reduce the administrative burden of performing and validating the annual

¹⁴ *Id.*, p. 30.

¹⁵ Pursuant to Section 367(e)(2), bundled service customers "shall not experience rate increases as a result of the allocation of transition costs." Those transition costs include the costs of "Old World" generation resources, as identified in Section 367(a)(1)-(6).

¹⁶ For example, if the Indifference Rate is determined to be 2.0¢/kWh, and the CTC is determined to be 0.5¢/kWh, the PCIA is set at 1.5¢/kWh. See D.06-07-030, pp. 13-16 and pp. 27-28.

¹⁷ Although these costs were subject to a true-up when the Commission first adopted this methodology, the true-up was later eliminated due to parties seeking more certainty and simplicity in the calculation of CTC and the PCIA. See D.08-09-012, p. 69.

calculation, but maintain “reasonabl[e] accura[cy];”¹⁸ (2) increase transparency, but appropriately protect market-sensitive information;¹⁹ and (3) capture the current market value of the historical generation portfolio, but reasonably limit uncertainty.²⁰ The September 25, 2017 Scoping Memo and Assigned Commissioner Ruling in this proceeding outlines additional objectives that should be considered. Although the ultimate requirement of customer indifference is the same today as it has been since 2002, circumstances such as significantly-increased departing load levels, changed regulatory requirements (e.g., increased RPS targets, additional local and flexible RA requirements), and changing market conditions (e.g., current and future market prices for renewable energy) have dramatically changed the landscape since the Current Methodology was first adopted and subsequently modified. These changed circumstances warrant significant reform and replacement of the Current Methodology because an approximation of indifference is no longer sufficient, especially given the potential scale of load departure.

3. A Benchmark Approach is Outdated and Currently Results in Cost Shifts between Bundled Service and Departing Load Customers

As the above section describes, the Commission has consistently sought to update the MPB to better reflect the market prices for various attributes of the Joint Utilities’ portfolios. In doing so, the Commission has expressed a desire to rely on prices from transparent and liquid markets when such markets for portfolio attributes exist.²¹ To date, the Commission has relied on administratively-set price inputs as proxies of market value for RECs and RA. However, this approach has not been successful in maintaining customer indifference given the market changes and increased levels of departing load described above, and has resulted in disconnected and inaccurate MPBs. Administratively-set benchmarks, by definition, rely

¹⁸ See D.06-07-030, pp. 7-16 and D.11-12-018, pp. 34-35.

¹⁹ See Section 454.5(g) and D.06-06-066; D.11-12-018, pp. 22-23 and 34-35, Finding of Fact 22.

²⁰ See D.11-12-018, pp. 23-24, Finding of Fact 1, 5, 6, and 7, and D.08-09-012, p. 69.

²¹ For example, see D.11-12-018, p. 24 (discussing the Commission’s desire to use market information for renewable energy adder when information becomes available).

1 on incomplete information about markets and thus can deviate substantially
2 from actual market outcomes.

3 At best, benchmarks are single-point “educated guesses” about future
4 market outcomes, and when administratively set, they may become even
5 more disconnected from actual market conditions, which themselves are
6 continuously changing.

7 The values of the current administratively-set RPS and RA benchmarks
8 are materially overstated relative to what can be monetized in today’s
9 markets. In other words, current market prices for these attributes are much
10 lower than the benchmarks used in the Current Methodology. The RPS
11 value is overstated because the costs of recently-delivering resources, on
12 which the administratively-set RPS benchmark largely relies, are based on
13 contracts negotiated and executed several years prior, when prices were
14 much higher than they are today, or that were procured through state-
15 mandated “carve-out” programs, that costs of which are also much higher
16 than the average RPS values in the Joint Utilities’ portfolios.²² Furthermore,
17 the premiums associated with the voluntary green-pricing programs are
18 inflated since they include administrative costs of these programs.

19 To illustrate, the Joint Utilities have compiled the following publicly-
20 available information on other (i.e., non-IOU) Load Serving Entities’ (LSE)
21 recently-executed renewable contracts, which demonstrates that there is a
22 wide-range of prices and contract tenors—all of which are lower than the
23 current value ascribed to renewable resources under the Current

²² Examples include feed-in tariff programs such as the Renewable Market Adjusting Tariff and the Bioenergy Market Adjusting Tariff, and the Renewable Auction Mechanism program.

1 Methodology.²³ The administratively-set value of RECs under the Current
2 Methodology for 2018 is \$25.11/MWh, as contrasted with the implied market
3 value of RECs for the actual contracts listed below.

²³ This chart is not intended to be exhaustive. It is clear that pricing of new RPS-eligible contracts reflects the maturing of the market for renewable resources, and that current pricing is much lower than pricing of earlier RPS contracts entered into when the market was in a nascent state. A 2017 study of utility-scale solar development by the Lawrence Berkeley National Laboratory found that “[a]s recently as 2011, solar PPA prices in excess of \$100/MWh were quite common. Five years later, most PPAs in the sample are priced at or below \$50/MWh levelized (in real, 2016 dollars), with a few priced as aggressively as ~\$30/MWh.” Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (September 2017) at page 33. Available at <https://emp.lbl.gov/sites/default/files/utility-scale-solar-2016-report.pdf>. NV Energy, which participates in the California Independent System Operator (CAISO) Energy Imbalance Market (EIM), recently paid \$30.99/MWh (with 2% annual escalation) for a project contracted in 2017. See <https://pv-magazine-usa.com/2017/11/09/nv-energy-seeks-approval-for-31-34mwh-solar-ppas/>. Sacramento Municipal Utility District (SMUD) publicly reported that it has executed an in-state solar contract scheduled to begin commercial operation in 2018 at a contract price of \$43.83/MWh. See <http://www.sacbee.com/news/business/article128434029.html>.

TABLE 2-2
PUBLICLY-AVAILABLE INFORMATION ON RECENT CALIFORNIA RPS CONTRACTS
(ORDERED BASED ON LOWEST TO HIGHEST “IMPLIED VALUE OF REC”)

Buyer	Facility	Resource Type	Total MWh Delivered	Contract Term	Contract Signed	Energy and Attributes	Contract Price (\$/MWh)	Current Methodology Energy MPB in Contract Delivery Year (\$/MWh) ^{1/}	Implied Value of REC ^{2/} -- Contract Price less Energy MPB (\$/MWh)	Facility Location (SP (SCE and SDG&E)/NP (PG&E))	Source Links
Imperial Irrigation District	Citizens Energy	Solar	1,719,932	2018-2042	11/14/2017	Energy, PCC1	\$29.75	\$32.37	-\$2.62	SP-15 (Imperial County)	http://citizensenergy.com/news/articles/community-solar-project-becomes-reality http://imperialid.granicus.com/MetaViewer.php?view_id=3&clip_id=371&meta_id=29771 California Energy Markets - 11/17/2017 No 1463 page 10 http://www.newsdata.com/cgi-bin/viewpdf.cgi?iss=cem1463&cid=YaHxJxATP41q
Modesto Irrigation District	Mustang Two Barbaro	Solar	Undisclosed	2020-2039	9/26/2017	Energy, PCC1 and RA	\$33.60	\$33.77	-\$0.17	NP-15 (Kings County)	Error! Hyperlink reference not valid.
Modesto Irrigation District	Blythe IV	Solar	2,500,000	2020-2039	9/26/2017	Energy, PCC1 and RA	\$34.22	\$32.37	\$1.85	SP-15 (Riverside County)	https://www.desertsun.com/story/tech/science/energy/2017/09/29/riverside-county-solar-project-scores-131-million-deal-central-valley-farm-district/717036001/ California Energy Markets - 10/13/17 No 1458 page 2 http://www.newsdata.com/cgi-bin/viewpdf.cgi?iss=cem1458&cid=YaHxJxATP41q
City of Palo Alto	Wilsona	Solar	Undisclosed	2021-2060	3/21/2016	Energy, PCC1 and RA	\$36.76	\$32.37	\$4.39	SP-15 (LA County)	California Energy Markets – 1/15/16 No 1368 page 2 http://www.newsdata.com/cgi-bin/viewpdf.cgi?iss=cem1368&cid=YaHxJxATP41q https://paloaltocityca.igm2.com/Citizens/FileOpen.aspx?Type=30&ID=9171&MeetingID=1965 https://www.cityofpaloalto.org/civicax/filebank/documents/50532
SMUD	Tranquility 8 Verde	Solar	Undisclosed	2017-2036	1/12/2017	Energy, PCC1 and RA	\$43.83	\$37.33	\$6.50	NP-15 (Fresno County)	California Energy Markets 1/20/17 No 1420 page 9 Error! Hyperlink reference not valid.
Silicon Valley Clean Energy	Regenerate	Solar	520,000	2018-2021	2/8/2017	Energy, PCC1	\$40.00	\$32.37	\$7.63	SP-15 (Imperial County)	https://www.desertsun.com/story/tech/science/energy/2017/11/09/controversial-consultant-stopped-working-silicon-valley-utility-but-its-still-doing-business-silicon/842821001/
Peninsula Clean Energy	Buena Vista	Wind	450,000	2017-2022	3/23/2017	Energy, PCC1 and RA	\$55.55	\$37.33	\$18.22	NP-15 (Alameda County)	https://www.peninsulacleanenergy.com/wp-content/uploads/2016/05/00-PCE-BOD-20170323-Agenda-FINAL.pdf Peninsula Clean Energy 2016 RPS Compliance Report and Peninsula Clean Energy 2018 IRP https://www.peninsulacleanenergy.com/wp-content/uploads/2018/01/PCE-FINAL-2017-IRP-Updated.pdf
Peninsula Clean Energy	Cuyama	Solar	115,200	2018-2018	3/23/2017	Energy, PCC1	\$52.08	\$33.77	\$18.31	NP-15 (Santa Barbara County)	https://www.peninsulacleanenergy.com/wp-content/uploads/2016/05/00-PCE-BOD-20170323-Agenda-FINAL.pdf Peninsula Clean Energy 2016 RPS Compliance Report

TABLE 2-2
PUBLICLY-AVAILABLE INFORMATION ON RECENT CALIFORNIA RPS CONTRACTS
(ORDERED BASED ON LOWEST TO HIGHEST “IMPLIED VALUE OF REC”)
(CONTINUED)

Buyer	Facility	Resource Type	Total MWh Delivered	Contract Term	Contract Signed	Energy and Attributes	Contract Price (\$/MWh)	Current Methodology Energy MPB in Contract Delivery Year (\$/MWh) ^{1/}	Implied Value of REC ^{2/} -- Contract Price less Energy MPB (\$/MWh)	Facility Location (SP (SCE and SDG&E)/NP (PG&E))	Source Links
Southern California Public Power Authority	Springbok 2	Solar	Undisclosed	2016-2035	11/2/2015	Energy, PCC1 and RA	\$55.65	\$34.87	\$20.78	NP-15 (Kern County)	https://solarindustrymag.com/partners-commission-springbok-2-solar-farm-near-los-angeles http://clkrep.lacity.org/online/docs/2014/14-1232-S1_MISC_6-3-15.pdf http://clkrep.lacity.org/online/docs/2014/14-1232-S1_rpt_ATTYY_06-03-2015.pdf https://www.8minutenergy.com/2015/11/8minutenergy-renewables-signs-power-purchase-agreement-to-develop-191mw-springbok-2-solar-farm
Southern California Public Power Authority	Antelope DSR 1&2	Solar	Undisclosed	2016-2035	10/21/2015	Energy, PCC1 and RA	\$53.75	\$31.79	\$21.96	SP-15 (LA County)	California Energy Markets – 10/30/15 No 1358 page 2 http://www.newsdata.com/cgi-bin/viewpdf.cgi?iss=cem1358&cid=YaHxJxATP41q https://renewablesnow.com/news/spower-wins-ppa-for-688-mw-of-solar-in-california-498532/
Lancaster Choice Energy	Western Antelope Dry Ranch	Solar	600,000	2016-2035	8/11/2015	Energy, PCC1 and RA	\$55.00	\$31.79	\$23.21	SP-15 (LA County)	California Energy Markets – 8/14/15 No 1347 page 11 http://www.newsdata.com/cgi-bin/viewpdf.cgi?iss=cem1347&cid=YaHxJxATP41q Lancaster Choice Energy 2016 RPS Compliance Report

1/ Used 2018 Erra Energy MPB for contracts scheduled to begin deliveries in 2019 and beyond

2/ Implied value of REC for contracts that have energy and PCC1 attributes; The Implied value of REC for contracts that have energy, PCC1, and RA should be further reduced by \$0.96 - \$1.50/MWh to account for the RA value. This range of values is calculated in the following manner, consistent with Resolution E-4475:

The Commission-adopted RA MPB is \$58.27/kW-year, or \$58,270/MW-year. \$58,270/MW-year is converted into a \$/MWh value by dividing it by 8,760 hours, which equals \$6.65/MWh.

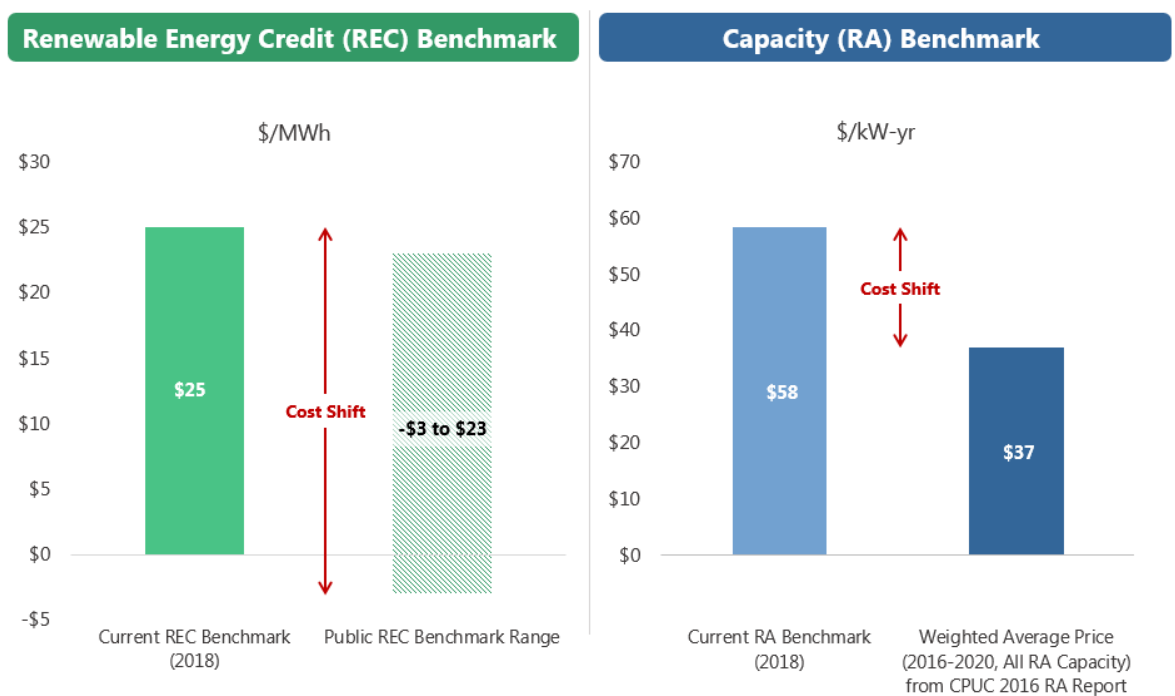
The average solar effective load carrying capacity, as calculated using CAISO's 2018 NQC values, is 22.6%. \$6.65/MWh multiplied by the ELCC is approximately \$1.50/MWh RA value for each MWh of solar.

The average RA value for each MWh of solar as calculated using the CPUC's RA Report Price of \$37.20/kW-year is approximately \$0.96/MWh.

The ascribed RA value in the Current Methodology is also overstated, because it is set equal to the going-forward cost of a simple cycle combustion turbine at a time when there is excessive capacity available in the market. RA capacity can generally be procured at prices much lower than the administratively-set benchmark price of \$58.27 per kilowatt-year (kW-year), and excess RA cannot be monetized at prices approaching the benchmark price, if at all. The RA benchmark has also not been updated since 2016 because of a lack of a more recent CEC report.

Figure 2-1 demonstrates the magnitude of the overstated benchmarks, relative to the publicly-available information listed in Table 2-2 and the most recent CPUC RA report:

**FIGURE 2-1
COMPARISON OF 2018 CURRENT METHODOLOGY BENCHMARKS TO PUBLIC AND MARKET INFORMATION^(a)**



** Estimates shown are based on publicly available information only. Market benchmarks at these prices may still result in cost shifts to bundled customers since they represent transactions different from those the utility may be able to obtain when selling excess power and capacity.*

- (a) Public REC Benchmark range developed using the highest and lowest “Implied Contract Value of REC” values from Table 2-2 and ignoring any RA value.

1 Because the Current Methodology defines departing load customers’
2 cost responsibility as the difference between the costs of the utility
3 generation portfolio and its market value, as determined using the
4 administratively-set benchmark, any variance between the administratively-
5 set benchmarks and current market prices for those products results in an
6 improperly-calculated market value that shifts costs between bundled
7 service and departing load customers. The estimates shown in Figure 2-1
8 are based strictly on public and readily-available market information, and
9 reflect a conservative estimate of the current, substantial costs that are
10 being shifted from departing load customers to bundled service customers.

11 **a. The RPS Adder Does Not Accurately Reflect Market Conditions and**
12 **Parties Agree That It Is Outdated**

13 The RPS adder is set using two sources of data: (1) the IOU RPS
14 Premium, based on the weighted-average cost of the Joint Utilities’
15 newly-delivering (not newly-contracted) RPS-eligible resources,
16 weighted at 68 percent; and (2) the DOE adder, based on the average
17 price of voluntary green-pricing programs spread throughout the WECC,
18 weighted at 32 percent. Because a significant portion of the Joint
19 Utilities’ eligible generation portfolios are comprised of renewable
20 resources,²⁴ it is critical that the RPS adder be reflective of the current
21 market value of renewable resources. However, because each of the
22 two sources of data have significant deficiencies, the RPS adder has
23 become unreliable, inflated, and disconnected from current market
24 conditions. Indeed, the RPS adder is the primary source of cost shifts
25 from departing load to remaining bundled service customers.

26 **1) The IOU RPS Premium Is Materially Overstated**

27 As described above, the RPS adder is, in large part, set using
28 the average cost of newly-delivering utility renewable contracts.
29 Because the Joint Utilities’ newly-delivering renewable resources
30 are the result of contracts that were executed several years prior to

24 The renewable “share” of the eligible generation portfolios is expected to grow over time as non-renewable resources, which tend to be shorter in contract duration, expire and are removed from the portfolio.

1 the commencement of deliveries,²⁵ the RPS adder lags actual
2 market prices for newly-contracted renewable resources and fails to
3 reflect the market price utilities could obtain through sales of those
4 resources. In addition, several of the Joint Utilities' newly-delivering
5 renewable resources were procured as a result of mandated carve-
6 out programs that are not indicative of fully-competitive RPS
7 markets, as they restrict participation by requiring procurement from
8 a specific market segment (e.g., specific technology, project size, or
9 location). As a result, the RPS adder has persistently and materially
10 overstated the market value of the Joint Utilities' renewable energy
11 portfolios, which results in impermissible cost shifts to remaining
12 bundled service customers.

13 The significant decline in pricing of renewable resource
14 contracts over time is illustrated by a comparison of the prices of
15 certain recent RPS procurement provided in Table 2-2²⁶ to the
16 utility RPS procurement cost data provided in the Joint Utilities'
17 matrices. It is important to note while departing load customers
18 (through their LSEs) can now procure RPS-eligible resources on the
19 open market at significantly lower prices due, in part, to the Joint
20 Utilities' early RPS procurement, remaining bundled service
21 customers are paying a higher proportion of the fixed (high) costs of
22 the early RPS contracts.

23 The Legislature enacted the statutes prohibiting the cost-shifting
24 that would result if departing load customers were permitted to avoid
25 some of these unavoidable historical costs. The Commission

25 For example, the historical "lag" between contract execution date and contract online date for SCE's post-2001 RPS-eligible resources (not including CTC-eligible resources) is approximately two to three years (on average).

26 Even the data provided in Table 2-2 demonstrates a 47 percent decrease in prices between 2015 and 2017. The Joint Utilities note that the data in Table 2-2 is not intended to be exhaustive, but believe it to be representative of current RPS prices non-IOU LSEs are paying in the market for new contracts. The Joint Utilities welcome all non-IOU LSEs in this proceeding to voluntarily make part of the record their own data that corresponds to the exhaustive and extensive Joint Utilities' data provided in the data matrices.

recently observed when approving Pacific Gas and Electric Company's (PG&E) 2017 PCIA calculation:

Many of the above-market contracts in PG&E's portfolio are for renewable resources procured in the early years of California's [RPS] program and were relatively higher cost because the technologies and programs were developing. Contracts signed by PG&E were reviewed and approved by the Commission and were found to be just and reasonable at the time they were entered into. **This early contracting, as required by legislation and approved by the Commission, served its intended purpose and promoted the development of a robust renewable resource market. Californians now enjoy lower renewable energy costs in part due to these early contracts.** These early contracts were entered into on behalf of all customers of PG&E at the time, and departing load customers should pay their share of the costs rather than shifting them to bundled [service] customers.²⁷

That cost-shift will only continue to increase if not addressed now. As might be expected and pursuant to design, the RPS adder has been coming down in recent years as renewable prices have steadily declined, albeit not nearly by as much or as quickly as necessary to prevent cost shifts. But looking ahead, under the Current Methodology, the RPS adder component of the MPB is likely to experience even more divergence from realizable market outcomes. As the Joint Utilities have indicated in their recent RPS plans, they have little to no need for incremental renewable procurement in the near future based on the current process for establishing the PCIA.²⁸ This would result in an RPS benchmark calculated based on a limited set of resources—most, if not all, of which will be procured pursuant to state-mandated carve-out programs. This limited pool of resources that would set the future RPS benchmark under the Current Methodology is thus much more expensive than the current prices for fully-competitive, market-based, renewable resource procurement, and entirely unreflective of the prices the Joint Utilities could realize should they attempt to dispose of long RPS positions in the market. This would result in greater (artificial) inflation of the RPS adder that does not reflect the

²⁷ See D.16-12-038, p. 11 (emphasis added).

²⁸ D.16-12-044 (approving 2016 RPS Plans).

monetizable market value of RPS resources in the Joint Utilities’ portfolios.

2) Parties Agree That the DOE Adder Is Outdated

In the discussion establishing the RPS adder, the Commission explained its intent to establish a benchmark that was representative of the entire California RPS market²⁹ and adopted the use of the DOE adder as a way to account for non-IOU LSEs’ transactions (32 percent of the California load in 2011).³⁰ However, the DOE adder, which was maintained by the National Renewable Energy Laboratory and last updated nearly three years ago, is no longer available on the DOE website.

All parties agree that the DOE adder is outdated and flawed. CCA parties in SCE’s and PG&E’s 2018 Erra Forecast Proceedings protested the use of the DOE adder in the 2018 PCIA calculation,³¹ calling it “fatally flawed and unusable.”³² Additionally, the 32 percent weighting has not been updated since 2011 despite the significant growth in load served by non-IOU LSEs (largely by CCAs) since that time. The RPS adder is thus outdated, unreliable, and not reflective of the current California RPS market as originally intended by the Commission.

b. The RA Benchmark Is Overstated, Outdated, and Oversimplified

Since first adopting the RA benchmark in 2006, the Commission has attempted to identify a suitable index to estimate the current market

²⁹ D.11-12-018, p. 22.

³⁰ See D.11-12-018, pp. 18-19 (noting that “IOUs also have restrictions on contracting that do not apply to Energy Service Providers (ESP) or CCAs, which tends to restrict what IOUs can do to meet RPS. Thus, the inclusion of ESP and CCA cost data would be expected to lower the perceived market value.”).

³¹ See Testimony of Richard McCann on behalf of California Choice Energy Authority and Public Agency Coalition, served August 7, 2017, in A.17-05-006; see also Testimony of Richard J. McCann on behalf of Sonoma Clean Power Authority, served September 8, 2017 (revised) in A.17-06-005.

³² See Testimony of Richard McCann on behalf of California Choice Energy Authority and Public Agency Coalition, served August 7, 2017, in A.17-05-006 at p. 12.

1 value of short-term³³ capacity. In the absence of a transparent capacity
2 market, the Commission adopted the use of a utility-specific settled
3 value (2006-2011) and the CEC's estimate of the going-forward costs of
4 a simple cycle combustion turbine (2012-today) as the RA benchmark.
5 This simplistic approach has resulted in an RA benchmark that is
6 overstated, outdated, and fails to appropriately reflect the various
7 nuances of the RA market.

8 First, the current RA benchmark of \$58.27/kW-year, or
9 \$4.86/kW-month, is significantly overstated. The difference between the
10 current benchmark and actual market pricing can be seen by comparing
11 the RA benchmark price to the prices that the Joint Utilities were actually
12 able to obtain through their historical RA sales, and to the prices that the
13 Joint Utilities actually paid for their recent RA contracts.³⁴ Moreover,
14 the RA benchmark is over 50 percent higher than the \$3.10/kW-month
15 weighted-average price compiled by the Commission in its annual RA
16 report.³⁵ In addition, the CEC-calculated capacity value is a going-
17 forward cost value, which is not relevant in a market with capacity over-
18 supply. This difference between the RA benchmark price and the actual
19 prices paid and received for RA capacity effectively results in over-
20 compensating the departing load customers for their share of RA
21 capacity in the generation portfolio at the expense of bundled service
22 customers, and therefore impermissibly shifts costs to remaining
23 bundled service customers.

24 Second, despite expectation that the CEC would update its Cost of
25 Generation study bi-annually,³⁶ that report has only been updated twice

33 See D.11-12-018, p. 29, which states that the RA benchmark is intended to reflect the short-term value of capacity.

34 The individual transactions are confidential, and have previously been provided to parties who have executed relevant Non-Disclosure Agreements pursuant to the Commission's confidentiality decisions in data matrix item E12 (historical quarterly compliance reports).

35 See Table 7 of the CPUC's 2016 Resource Adequacy Report, published June 2017, which lists a \$3.10/kW-month weighted-average price for all 2016-2020 RA contracts. The RA benchmark of \$58.27/kW-year, or \$4.86/kW-month, is about 56 percent higher than the CPUC RA Report price.

36 D.11-12-018, p. 30.

1 in the last ten years, and once since it was adopted as the source for the
2 RA benchmark in 2011.³⁷ By definition, a value derived from an
3 outdated report that is not regularly updated cannot be expected to
4 reflect current market conditions.

5 Finally, it is an oversimplification to use a single, statewide,
6 \$/kW-year benchmark (i.e., a flat \$/kilowatt-month (kW-month)
7 benchmark) to value **all** of the RA capacity in the Joint Utilities'
8 portfolios. As Energy Division explained in its 2016 RA Report, "the
9 price of capacity varies significantly between month, local area, and
10 zone,"³⁸ and monthly prices can vary by as much as 30 percent.³⁹
11 Valuing all of the RA capacity in the Joint Utilities' portfolio under the
12 Current Methodology at \$4.86/kW-month, even in months when RA
13 capacity is of little value, results in cost shifts to remaining bundled
14 service customers.⁴⁰ In addition, long RA capacity in the Joint Utilities'
15 portfolios has value that under certain circumstances approaches zero.

16 These anomalies are further amplified by the fact that not every MW
17 of capacity is equal in terms of its ability to satisfy the CPUC's RA
18 requirements. The CPUC's RA Program has significantly evolved since
19 2011 and now includes flexible RA requirements in addition to system
20 and local RA requirements. The application of any single \$/kW-month
21 benchmark to all of the RA capacity in the Joint Utilities' portfolios,
22 regardless of whether the capacity provides only system RA compliance
23 or if it instead provides system, local, and flexible RA compliance,
24 overestimates the market value of certain resources (e.g., renewable
25 resources, which rarely provide any flexible RA capacity and limited

³⁷ See http://www.energy.ca.gov/almanac/electricity_data/cost_of_generation_report.html for links to all published reports. The only reports published and finalized since 2008 are the 2009 and 2015 final reports.

³⁸ 2016 CPUC RA Report, p. 6.

³⁹ See Figure 10 on page 30 of the 2016 CPUC RA Report, which illustrates a January 2017 weighted-average capacity price of less than \$2.60/kW-month, and a July 2017 weighted-average capacity price of over \$3.40/kW-month.

⁴⁰ See Appendix C at slide 15 of the Joint Utilities' presentation, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Costs_and_Rates/PCIA%20Workshop%202%20-%20Joint%20Utilities%20Presentation%20-%20Final%20V2.pdf,

1 local RA capacity).⁴¹ As discussed above, cumulatively the Current
2 Methodology's RA benchmark materially overstates the market value of
3 the RA in the Joint Utilities' portfolios.

4 **c. The Energy Benchmark Generally Reflects the Market Value of the**
5 **Energy Provided by the Resources but is Imprecise**

6 Under the Current Methodology, the energy benchmark is based on
7 forward on- and off-peak market quotes⁴² that are weighted based on
8 each utility's bundled service load profile. Although this approach
9 provides a fairly accurate estimate of the market value of the energy
10 provided by their generation portfolios—by comparison, it is less
11 problematic than the RPS and RA benchmarks—it ultimately results in
12 cost shifts (either to bundled service customers or to departing load
13 customers) because it is imprecise and not trued-up based on actual
14 market outcomes.

15 First, the energy benchmark is imprecise. The Current Methodology
16 applies a single \$/MWh energy price benchmark to all energy forecast to
17 be produced by the generation portfolio, despite the fact that market
18 energy prices can vary significantly based on the time of day and year.
19 That energy benchmark is imprecise for two reasons: first, it is based
20 on annual on-peak (6 a.m. – 10 p.m., Monday through Saturday) and
21 off-peak (all other hours and WECC-recognized holidays) forward prices
22 that aggregate and average together all 8,760 hours into two broad
23 categories—hours that may have completely different prices; and
24 second, it is weighted using bundled service on- and off-peak energy
25 consumption ratios, not the actual generation profile of the resources.

⁴¹ In 2018, SCE's RPS-eligible resources have a total August Net Qualifying Capacity of approximately 4,400 MW. Of that, approximately 3,800 MW, or 84 percent, is associated with resources in the CAISO System delivery zone, and thus cannot be used to meet local RA requirements. SCE's RPS-eligible resources have a total 2018 Effective Flexible Capacity of zero. See SCE's March 12, 2018 errata Standard Data Matrix provided pursuant to the *Amended Scoping Memo and Ruling of Assigned Commissioner* issued on March 2, 2018.

⁴² Unlike RPS and RA, energy markets are generally robust and liquid because all relevant energy transactions are cleared through liquid markets. As such, there are observable clearing prices that specify the actual market value of energy in any given time interval.

1 While this may result in a reasonably-accurate forecast of the market
2 value of the energy on a total portfolio basis, it will certainly under- or
3 over-estimate the market value on an individual-resource basis, which
4 may be important when looking at equity between different vintaged
5 portfolios.

6 Second, the energy benchmark is not trued-up for market results.
7 Unlike bundled service customers' generation rates, which are set on a
8 forecast basis based on energy production simulation models, but are
9 then trued-up the following year, the Current Methodology uses those
10 same production simulation model results to set the PCIA on a forecast
11 basis, but does not true-up for actual market outcomes. While the
12 models are reasonably accurate when the price indexes are close to
13 actual value, they are not perfect, as it is impossible to perfectly forecast
14 the future dispatch of all generation units in the portfolios and the future
15 market revenues resulting from that dispatch.

16 **B. If Not, How Can the Current Methodology Be Revised to Prevent Cost**
17 **Shifts? (Scoping Memo Issue 3)**

18 As demonstrated in the algebraic proof reviewed during the Joint Utilities'
19 presentation at the January 16, 2018 workshop, the Current Methodology results
20 in indifference **if, and only if**, the MPB is equal to the actual prices that can be
21 obtained in the market from selling the departing load customers' share of the
22 Joint Utilities' generation portfolio. This indifference outcome, however, will
23 require a "true-up" of the MPB based on actual market outcomes.⁴³ However,
24 the challenge faced by parties and the Commission in 2011 still exists today—
25 there is no transparent and robust market, or market index, for RPS.
26 Additionally, the value of RECs is often dependent upon the underlying
27 generation resource, which makes it more difficult to quantify on a macro-basis.
28 More importantly, the underlying assumption that the utility can easily monetize
29 the resources that were procured for departing load customers or simply use

43 In addition to an MPB true-up, the forecast of generation output must be trued-up to reflect actual resource production, and any under- or over-collection of revenues actually received from customers must be collected or returned the following year.

1 them to avoid future purchases for bundled service customers⁴⁴ with no cost
2 shift no longer applies given the level of current and expected future load
3 departure.⁴⁵ Although a modification to the Current Methodology to include a
4 “true-up” mechanism that results in the use of actual recorded costs and a MPB
5 that is equal to the actual price that could be or was obtained in the market by
6 selling the departing load customers’ share of the Joint Utilities’ generation
7 portfolio could theoretically satisfy the requirement of customer indifference, the
8 result may not satisfy other Guiding Principles (GP) identified in this Order
9 Instituting Rulemaking (OIR).

10 As described in detail above, there is a fundamental lack of agreement on a
11 proper market index for RPS because of the complexity of the product, limited
12 market depth, and wide range of prices. Thus, it is nearly impossible to identify
13 a simple method to “true-up” the MPB to a single value that reflects the
14 outcomes of all market transactions. Indeed, even if such an index existed, it
15 would be unreasonable to impute the “market value” of the entire generation
16 portfolio using that single MPB because the utility may not be able to realize the
17 MPB for all of its portfolio sales if the market is saturated. The only scalable,
18 accurate, and transparent way to determine the actual market value of the
19 departing load customers’ share of the generation portfolio would be to market
20 and sell their entire share of those resources. However, this would raise the
21 following issues:

- 22 • First, it is nearly impossible to identify a set of resources with attributes that
23 exactly match each departing load customer vintage’s share of the
24 generation portfolio; a task that would be even more difficult as additional
25 load departs and the “pool” of remaining resources left to monetize shrinks.
26 This fails to satisfy GP 1c, which states that the methodology should be

⁴⁴ Utilizing resources left behind by departing load customers to meet residual bundled service customer needs limits the ability of bundled service customers to procure lower-priced resources on the open market.

⁴⁵ In other words, the Current Methodology essentially requires bundled service customers to compensate the departing load customers with a fixed price, the administratively-set MPB, for a defined volume of resources based on a year-ahead forecast. There is no mechanism to ensure that: (1) the imputed market value of the portfolio, as determined using the administratively-set MPB, is equal to its actual market value; (2) the costs recovered from departing load customers equal their pro-rata share of the actual incurred costs based on the actual performance of the resources; and (3) the revenues collected from departing load customers are decoupled from the forecast of their usage.

flexible enough to maintain its accuracy and stability at all levels of departing load.

- Next, even if resources that perfectly matched the departing load customers' share of the generation portfolio could be identified, contract counterparties may not agree to the sale of their contracts to a third party. A methodology that is necessarily dependent upon liquidation of the Joint Utilities' portfolios will likely fail to satisfy GP 1k, which states that the methodology should respect the terms of existing Power Purchase Agreements (PPA) between power suppliers and IOUs.
- Prospective buyers may also be unwilling to enter into contracts for all the attributes and/or contract terms and conditions associated with a resource, including the full term of the underlying contract.⁴⁶ If certain contract attributes could not be marketed, this could result either in resources being left unsold or undervalued. This may fail to satisfy GP 1j, which states that the methodology should accurately reflect and seek to preserve short-, medium- and long-term value of resources.
- Because of the lack of robust market indices, the forecast of market outcomes will likely differ significantly from actual outcomes and cause significant volatility in the departing load charges. This fails to satisfy GP 1b, which states that the methodology should have reasonably predictable outcomes that promote certainty and stability.
- More generally, the liquidation of the utilities' portfolios is contrary to GP 1e, which states that the methodology should be consistent with California's energy policy goals and mandates. Liquidating the resources into relatively illiquid markets may result in a near-term glut of resources in the market, resulting in inefficient market outcomes and an underutilization of resources previously procured by the Joint Utilities to serve their then-bundled service customers and meet the state's policy goals. This underutilization may also

⁴⁶ Indeed, as part of its efforts to manage its long positions and reduce its supply portfolio, in February 2018, PG&E issued a Request for Bids (RFB) for potential buyers to assume PG&E's interest in long-term RPS PPAs. In the RFB, PG&E offered the type of products parties to this proceeding have expressed interest in procuring: long-term RPS PPAs satisfying the criteria for portfolio content category one (PCC 1) RPS procurement. Ultimately, there was insufficient interest and the RFB did not result in any executed transactions. For further detail, please see Chapter 3 of this Testimony.

1 lead to inconsistencies with state and Commission objectives⁴⁷ and
2 societally-inefficient double procurement.

3 **C. Other**

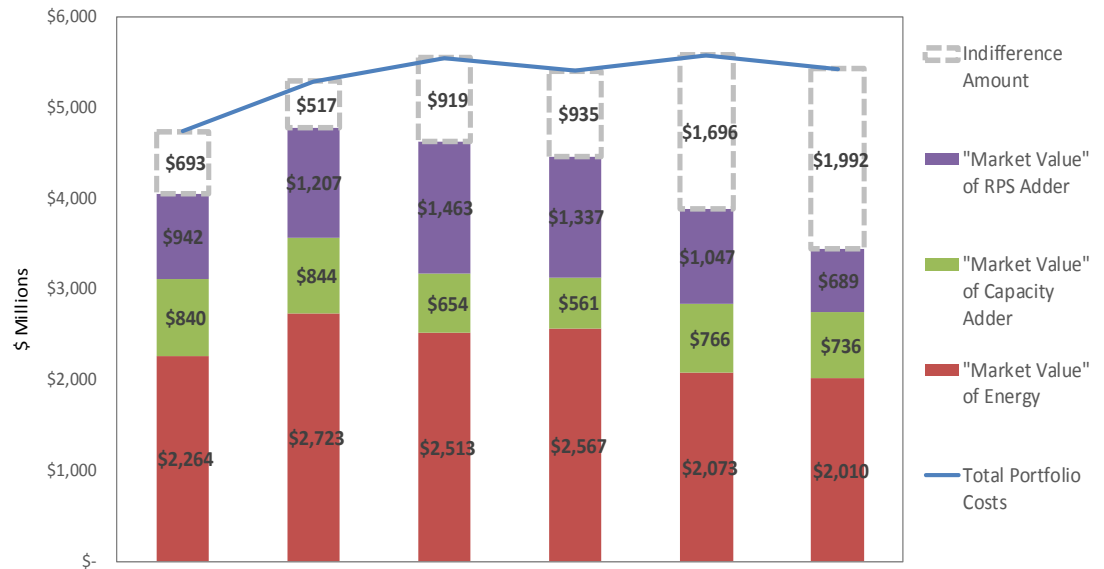
4 **1. Current Methodology Results in Volatility in the Departing Load** 5 **Charges**

6 The Indifference Rate, as calculated under the Current Methodology, is
7 inherently volatile because it is, by definition, intended to be tied to
8 estimations of current market conditions. As such, the Indifference Rate is
9 difficult to forecast because it necessarily requires an agreed-upon set of
10 assumptions on future market outcomes. As shown in the charts below, the
11 volatility and uncertainty in historical CTC and PCIA rates have been largely
12 driven by the volatility in the market value of energy and the RPS adder.
13 The market value of energy is a result of numerous supply and demand
14 fundamentals that can be difficult to forecast over an entire year. The RPS
15 adder has fluctuated significantly since its introduction in 2012, and is based
16 largely on confidential RPS utility contract-pricing data that is finalized and
17 validated by the Commission's Energy Division in October of each year.⁴⁸
18 Of note, even the utilities are challenged in forecasting the Indifference Rate
19 because they do not have visibility into the other IOUs' RPS contract pricing
20 terms, which are used by the Energy Division to calculate the subsequent
21 year's RPS adder.

⁴⁷ For example, underutilization could lead to the stranding of RA from preferred resources, allowing non-IOU LSEs to procure cheaper gas-based RA from the market.

⁴⁸ See Resolution E-4475.

FIGURE 2-2
2012 – 2017 INDIFFERENCE CALCULATION FOR PG&E'S 2012 VINTAGE^(a)



Includes Line Losses to Customer Meter	2012	2013	2014	2015	2016	2017
REC Benchmark (\$/MWh)	\$63.94	\$63.78	\$69.76	\$61.15	\$47.75	\$33.54
Total RPS Energy (MWh)	14,735	18,926	20,968	21,866	21,672	20,558
Capacity Benchmark (\$/kW-Year)	\$50.17	\$50.17	\$50.17	\$50.17	\$58.26	\$58.26
Total Net Qualifying Capacity (MW)	16,740	16,823	13,036	11,174	13,140	12,637
Energy Benchmark (\$/MWh)	\$35.23	\$41.27	\$41.39	\$43.73	\$34.87	\$37.33
Total Energy (MWh)	64,259	65,992	60,725	58,701	59,437	53,857

- (a) (1) Indifference Calculation excludes Franchise Fees and Uncollectibles and includes ongoing CTC;
(2) All energy (MWh) and benchmark prices (\$/MWh) are at the Customer Meter level and reflect an average of 6 percent line losses from Generation to Load level.

This volatility and lack of predictability would persist even if the administratively-set MPB was set using readily-available market indices because of the market-depth issues described in Chapter 4.

Moreover, any volatility in the MPB is amplified in the final Indifference Rate simply because of the basic mathematical definition of the Indifference Rate. Assume, for example, that the average cost of the resources in the utility portfolio for a given year (Year 1) is \$100/MWh, and assume that the market price benchmark for that portfolio is \$90/MWh. The Indifference Rate for that year is thus \$10/MWh, or \$0.01/kWh (\$100/MWh-\$90/MWh). Now assume the following year, the average cost of the same resources in the same utility portfolio stays at \$100/MWh, but that the market price benchmark drops to \$80/MWh. In Year 2, the Indifference Rate is now

1 \$20/MWh or \$0.02/kWh (\$100/MWh-\$80/MWh). Thus the Indifference Rate
2 is increased by 100 percent simply due to a change in the market price
3 benchmark of 11 percent.

4 GP 1c of the OIR states that “any PCIA methodology adopted by the
5 Commission...should have reasonably predictable outcomes that promote
6 certainty and stability for all customers within a reasonable planning
7 horizon.” The Current Methodology is inherently volatile and difficult to
8 predict, and thus does not satisfy this principle. In contrast, the Joint
9 Utilities’ Proposal provides significant certainty on the allocation of portfolio
10 attributes, and each LSE will have sufficient information to make their own
11 informed forecasts of net costs.

**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
CHAPTER 3
PROPOSALS FOR GOING-FORWARD IOU
PORTFOLIO OPTIMIZATION
(SCOPING MEMO ISSUE 6)**

PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
CHAPTER 3
PROPOSALS FOR GOING-FORWARD IOU
PORTFOLIO OPTIMIZATION
(SCOPING MEMO ISSUE 6)

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SOUTHERN CALIFORNIA EDISON COMPANY**
3 **SAN DIEGO GAS & ELECTRIC COMPANY**
4 **CHAPTER 3**
5 **PROPOSALS FOR GOING-FORWARD IOU**
6 **PORTFOLIO OPTIMIZATION**
7 **(SCOPING MEMO ISSUE 6)**

8 **A. Introduction**

9 In this chapter, the Joint Utilities first provide a general description of actions
10 taken to match their respective generation portfolios with bundled service
11 customer load, and to otherwise reduce overall generation costs for customers.
12 The chapter next introduces the Joint Utilities' proposal for pursuing additional
13 sales of forward energy products, a topic discussed in comprehensive detail in
14 Chapter 4. Finally, the chapter discusses how the Joint Utilities' proposal fits
15 within the existing procurement framework established by the California Public
16 Utilities Commission (CPUC or Commission).

17 **B. Joint Utilities' Current Portfolio Optimization Activities**

18 As a standard practice, each of the Joint Utilities routinely conducts portfolio
19 management activities to align supply obligations with the needs of bundled
20 service customers. These activities include the procurement and/or sale of
21 energy and energy products pursuant to each investor-owned utility's (IOU)
22 Bundled Procurement Plan (BPP) and Renewables Portfolio Standard (RPS)
23 Plan. These plans, which are approved by the Commission, establish explicit
24 targets and limitations for energy product transactions and provide detailed
25 guidance regarding regulatory oversight of such transactions to ensure bundled
26 service customers' interests are well-served and that the Joint Utilities have an
27 upfront, achievable compliance and prudence framework consistent with
28 Assembly Bill (AB) 57. As discussed further in Section D, below, this oversight
29 includes consultation with a Procurement Review Group (PRG) throughout the
30 procurement process and the use of an Independent Evaluator (IE), as required,
31 to ensure fairness among potential counterparties and transparency of individual
32 transactions.

1 In addition, and as discussed further in Section D, the Commission reviews
2 the Joint Utilities' procurement activities each year in their respective annual
3 Energy Resource Recovery Account (ERRA) compliance proceedings and
4 Quarterly Compliance Reports (QCR). In these proceedings and submittals,
5 which are open to interested parties and fully transparent, the Joint Utilities
6 describe their various portfolio management activities, such as contract
7 modifications and terminations, and the Commission evaluates each IOU's
8 compliance with its approved BPP and RPS Plan.¹

9 Through a combination of regulatory actions and commercial activity, the
10 Joint Utilities have sought to achieve alignment between their resource portfolios
11 and bundled service customer need. Illustrative examples of regulatory and
12 commercial actions taken by the Joint Utilities to optimize their respective
13 portfolios are provided below. While the examples cited below are neither
14 exhaustive, nor intended to quantify the total customer benefits resulting from
15 these activities, it demonstrates the proactive approach the Joint Utilities have
16 taken to portfolio management. A more detailed description of the Joint Utilities'
17 portfolio management activities can be found in the Commission's final decisions
18 in the various BPPs, RPS Plans, ERRA compliance proceedings, and QCR
19 submittals.²

20 **1. Regulatory Actions**

21 Within the regulatory context, the Joint Utilities have sought to bring
22 procurement undertaken on behalf of bundled service customers in line with
23 bundled service customer need. While consistently striving to achieve state
24 policy goals, the Joint Utilities have raised concerns regarding continued
25 procurement in a declining load environment and have requested
26 reduction/elimination of certain procurement mandates. In addition, the
27 Joint Utilities have pointed out that increasing levels of actual and forecasted

1 The Joint Utilities' compliance with Least-Cost Dispatch (LCD) protocols for their respective generation portfolios is also reviewed in the annual ERRA Compliance proceedings, but those activities are not discussed in this Testimony.

2 See, e.g., Southern California Edison Company (SCE): Application (A.) 13-04-001; A.14-04-006; A.15-04-002; A.16-04-001; A.17-04-004; A.18-03-xxx (filed March 29, 2018); Pacific Gas and Electric Company (PG&E): A.14-02-008; A.15-02-023; A.16-02-019; A.17-02-005; A.18-02-015; San Diego Gas & Electric Company (SDG&E): A.14-05-026; A.15-06-002; A.16-06-002; A.17-06-006.

1 departing load exacerbates concerns regarding the equitable and
2 transparent allocation of supply portfolio costs, and gives rise to a need for a
3 mechanism for allocating resource benefits to all load serving entities (LSE).

4 The following are examples of the Joint Utilities' efforts in this regard:

- 5 • Development and submission of alternate load forecasts in the 2014
6 BPP proceeding requesting the Commission consider greater load
7 departure than projected in the Commission's approved load forecast;³
- 8 • Advocacy for reduced or suspended RPS procurement, noting a lack of
9 need in the Joint Utilities' respective RPS Plans;^{4,5}
- 10 • Advocacy for the reduction and elimination of costly, mandated RPS
11 procurement programs;⁶
- 12 • Advocacy for the ability to make forward RPS sales through the BPP
13 framework;⁷
- 14 • Development and submission of the Joint Utilities' Portfolio Allocation
15 Mechanism Application, filed April 25, 2017, designed to allocate the
16 total benefits and costs of prior IOU procurement to those customers for
17 whom the assets were originally procured⁸; and
- 18 • Filing with the CPUC a settlement for the closure of the
19 2,200 megawatt (MW) Diablo Canyon nuclear units, based on the lack

³ Decision (D.) 15-10-031, pp. 13-14.

⁴ D.15-12-025, p. 34.

⁵ 2014: D.14-11-042, Ordering Paragraph (OP) 17. 2015: D.15-12-025, OPs 8 and 9. 2016: D.16-12-044, OPs 7, 8 and 9. 2017: D.17-12-007, OPs 6, 7 and 8.

⁶ See SDG&E Advice Letter (AL) 2849-E, filed January 15, 2016, requesting relief from the mandate to procure uncompetitive Renewable Auction Mechanism (RAM) projects in its RAM VI solicitation and for relief from further procurement under its RAM obligation. Resolution E-4783 denied this request. See also SDG&E's Application for Modification of Resolution E-4783 to terminate its Renewable Auction Mechanism Procurement Requirement, filed October 27, 2016; and SDG&E's Petition to Modify D.10-12-048, D.12-02-002 and D.14-11-042, filed October 27, 2016. See also PG&E's Petition to Modify D.14-11-042 to eliminate the requirement that PG&E procure the remaining capacity associated with the terminated solar photovoltaic program through the RAM program. D.17-08-025 denied PG&E's Petition for Modification, and D.18-03-039 denied PG&E's Application for Rehearing of D.17-08-025.

⁷ See, e.g., D.15-10-031, pp. 8-9, OP 1.a and D.12-01-033, pp. 39-40, OP 14 (denying requests by SCE to include renewable resources as eligible products under the BPP for transactions less than five years in duration).

⁸ A.17-04-018.

of need for the energy outputs of those units after expiration of their operating licenses in 2024 (Unit 1) and 2025 (Unit 2).⁹

2. Commercial Actions

The Joint Utilities have also acted in the commercial context to manage their supply portfolios. The Joint Utilities have taken proactive steps, consistent with their respective BPPs and RPS Plans, to manage the products and attributes comprising their energy supply positions. Examples include:

- Suspension of voluntary procurement of new RPS resources beyond an explicit identification of need;
- Conducting periodic Resource Adequacy (RA) capacity and Renewable Energy Credit (REC) sales solicitations to reduce long positions on a forward basis;
- Execution of bilateral transactions to sell surplus energy products;
- Bidding RA capacity not shown for compliance purposes into the California Independent System Operator's (CAISO) monthly/annual competitive solicitation process; and
- Execution of prudent contract administration activities, including amending or restructuring contracts to yield additional value to customers, reducing collateral held for certain contracts in exchange for one-time payments and terminating contracts where appropriate to yield value to customers. For example, SCE filed an application on March 19, 2018 to request Commission approval of an agreement to terminate two contracts totaling 181 MW in exchange for SCE making a buy-out payment to the counterparty, which is expected to provide substantial savings to customers.¹⁰

⁹ PG&E Application for Approval of the Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs through Proposed Ratemaking Mechanisms. A.16-08-006 (filed August 11, 2016).

¹⁰ A.18-03-010.

C. Joint Utilities' Going-Forward Portfolio Optimization Activities

1. Continuation of Portfolio Management Activities

The Joint Utilities intend to continue to actively manage their respective generation portfolios through a multitude of regulatory and commercial actions, including those described in Section B, above. Such active management will include the execution of sales transactions involving different types of energy products when such transactions are deemed by the Joint Utilities to be commercially reasonable. In addition, despite the difficulty of ensuring customer indifference with respect to the sales of renewable resources due to the relative illiquidity of the market for RECs, discussed in more detail in Chapter 2 of this Testimony, the Joint Utilities will actively explore opportunities to increase their sales of renewable products, or reduce or terminate purchases, when doing so is deemed by the IOU to be commercially reasonable.

2. Joint Utilities' Proposal Regarding Annual Sales of Certain Resource Adequacy Products

Beyond continuation of their current portfolio management activities, the Joint Utilities describe herein their proposal to pursue, and coordinate the timing of, multi-year forward sales of RA capacity associated with non-renewable resources in order to reduce the overall volume of RA product assignment to departing load customers. This proposal is described comprehensively in Chapter 4 of this Testimony as a component of the Joint Utilities' proposed Portfolio Monetization Mechanism (PMM).

The Joint Utilities' proposal to coordinate sales of multi-year forward RA capacity associated with non-renewable resources is designed to serve two purposes. First, coordinating the timing of sales activities will provide further certainty and predictability to LSEs seeking to procure forward to fulfill their RA compliance requirements. Over the course of this proceeding, Community Choice Aggregator (CCA) parties have asked for greater insight into the timing of IOU sales activities, presumably to help CCAs plan over a long-term horizon. Through the Joint Utilities' proposal, CCAs will have the clarity necessary to coordinate their procurement and planning activities to

1 ensure they have every opportunity to participate in each IOU's PMM
2 solicitations.

3 Second, the Joint Utilities' proposal, through approved annual year-
4 ahead sales activities, will allow for a reduction of the allocation of costs
5 and/or capacity to departing load customers.

6 Notably, the PMM sales activities discussed in this chapter are for the
7 portion of the portfolio allocated to departing load customers. The Joint
8 Utilities may also, as they each determine to be appropriate, buy and sell
9 energy and capacity products, consistent with the needs of bundled service
10 customers and the authorities granted in their respective BPPs and RPS
11 Plans,¹¹ for CCAs and Energy Service Providers to acquire or transact
12 products with the Joint Utilities.

13 **3. Regulatory Treatment of Joint Utilities' Sales Activities Prior to and** 14 **Independent of the Proposed PMM**

15 Prior to, and independent of, the adoption of the Joint Utilities' sales
16 framework proposal (*i.e.*, the PMM) discussed in detail in Chapter 4, the
17 Joint Utilities will continue to conduct discretionary sales activities, within the
18 limitations of their respective BPPs and RPS Plans, to manage their supply
19 positions and supply portfolios more broadly. For example, PG&E is
20 currently in various stages of three distinct sales solicitations—the 2018
21 Long-term RPS Contract Sales Solicitation, the 2018 Bundled Energy Sales
22 Solicitation, and the 2018 Multi-year Forward RA Sales Solicitation—and is
23 also participating in solicitations conducted by CCAs.

24 More specifically, as part of its efforts to manage its long positions and
25 reduce its supply portfolio, PG&E issued a Request for Bids (RFB) for
26 potential buyers to assume PG&E's interest in long-term RPS Power
27 Purchase Agreements (PPA).¹² Under the proposed assignment structure,
28 PG&E would ultimately compensate the successful bidder for the difference

11 Any such transactions undertaken by the Joint Utilities will be conducted pursuant to applicable safeguards and Commission requirements, including the separation of employees engaged in buying and selling of energy products.

12 Details concerning the solicitation schedule and its protocol are available at https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/rps-contract-sales.page.

1 between the price the successful bidder agreed to pay to assume the PPA,
2 and the contract price under the original PPA.¹³

3 Through its RFB, PG&E offered PPAs from a portfolio of long-term,
4 operational RPS-eligible projects, with a sufficient tenor remaining to
5 facilitate achievement of long-term contracting mandates. The RFB also
6 presented a potential opportunity for PG&E's customers to capture any
7 value that long-term RPS transactions might present. Specifically, PG&E
8 offered seven solar photovoltaic resources located within the state of
9 California and connected to the CAISO grid, with remaining delivery terms of
10 11-15 years. The PPAs offered were scalable to any size of LSE, ranging in
11 size from 5 MW to 150 MW. Ultimately, there was insufficient interest and
12 the RFB did not result in any executed transactions.¹⁴ Only five entities
13 expressed potential interest. Only a single bidder participated but
14 subsequently withdrew from the RFB. No CCA submitted a bid into the
15 solicitation.

16 PG&E observed broader market interest in its 2018 Multi-year RA Sales
17 Solicitation ("RA Solicitation"). Under the RA Solicitation, PG&E offered to
18 sell multi-year RA products from its portfolio of resources. Specifically,
19 PG&E offered to sell System, Flexible, and Local RA capacity for delivery
20 from January 2019 through December 2022. The RA Solicitation presented

13 PG&E proposed an Assignment and Assumption Agreement under which the successful bidder would be an assignee. That assignee would assume PG&E's products, rights, responsibilities, and obligations under the PPA.

14 PG&E conducted significant outreach to attract bidders and encourage their participation in the RFB, including the following:

- 1) PG&E transmitted its RFB announcement and materials to its extensive market e-mail list of approximately 70 parties, including contacts for all LSEs in the state of California, power marketers, and brokers. PG&E reviewed this list with the IE, and the IE provided additional contacts.
- 2) PG&E offered 30-minute phone conversations to any interested party via an e-mail market notice issued on March 5, 2018. Three entities reached out for a conversation.
- 3) Separate from the phone calls, PG&E responded to two inquiries submitted via email. All questions asked, whether via phone or email, were aggregated into a Q&A, which was posted to the solicitation's website. Within a similar timeframe, Sonoma Clean Power, Monterey Bay Community Power, Marin Clean Energy and several other CCAs conducted their own solicitations for both short- and long-term products. PG&E responded to several of these solicitations by either submitting a bid or sending a notification of PG&E's existing solicitations.

1 a potential opportunity for PG&E to reduce its long capacity positions, for
2 other entities to procure multi-year products, and for PG&E's customers to
3 capture value from multi-year RA products.

4 Ultimately, the RA solicitation was broadly subscribed, with 16 entities
5 providing bids to PG&E. PG&E is currently in the process of evaluating the
6 bids received and shortlisting potential transactions. Despite robust
7 participation, it is clear that market interest in PG&E's multi-year RA Product
8 is insufficient to fully monetize the long RA position PG&E currently holds
9 due to departing load. Based on bids received, PG&E estimates that no
10 more than 33 percent of its long system RA position will be monetized
11 through the RA Solicitation. Furthermore, the bid prices were all significantly
12 lower than the PCIA RA benchmark price in all the delivery years offered in
13 the solicitation. Finally, PG&E observes that market interest in longer-term
14 RA products may be limited given that bid volumes for deliveries beyond two
15 years forward decrease significantly and products with deliveries beyond
16 three years forward, make up less than six (6) percent of the total. PG&E
17 will continue to offer to monetize its long RA positions but there is the
18 potential that significant quantities will remain unsold, resulting in unrealized
19 market value.¹⁵

20 However, to the extent multi-year transactions are executed and
21 subsequently approved by the Commission, PG&E will request crediting of
22 these revenues to all customers either through the PCIA or a revised/new
23 methodology adopted in this proceeding, or through a different mechanism
24 as proposed in separate applications.

25 In instances where counterparties default on these transactions, or the
26 source contract outlives these multi-year forward sales transactions, the
27 residual term of the contracts will retain their original vintage and be treated
28 under the PCIA mechanism, as amended or replaced through this
29 proceeding.

¹⁵ Detail concerning the volumes and bid pricing under PG&E's RA Solicitation is contained in Confidential Appendix H.

1 **D. Consistency with the Existing Commission Procurement Framework**
2 **(AB 57 and Public Utilities Code § 454.5)**

3 AB 57, as codified in Public Utilities Code Section 454.5, establishes an
4 electric generation procurement framework for the Joint Utilities pursuant to
5 which all procurement conducted by the Joint Utilities that is consistent with
6 Commission-approved procurement plans is recoverable and not subject to
7 after-the-fact reasonableness review. All sales activities undertaken by the Joint
8 Utilities, including sales conducted under the proposed PMM, as well as sales
9 transacted prior to and independent of the adoption of the PMM, will continue to
10 comply with the Commission's overarching procurement framework, as
11 discussed below. In particular, all sales will be conducted pursuant to the
12 authority granted in each IOU's respective BPP and/or RPS Plan.

13 **1. Sales Activities Will Be Planned and Executed Within the Existing**
14 **Regulatory Authority Granted in the Bundled Procurement Plan and/or**
15 **RPS Plan**

16 The Joint Utilities' respective Commission-approved BPPs and RPS
17 Plans establish the upfront standards and criteria that guide their
18 procurement activities and enable cost recovery in accordance with AB 57.
19 The BPPs set guidelines for procurement of Commission-approved
20 products, such as electricity and electric capacity, and incorporate long-term
21 procurement planning policies adopted by the Commission. The Joint
22 Utilities implement their respective Commission-approved BPPs through
23 various procurement methods and practices, including competitive
24 solicitations, bilateral negotiations, and participation in various markets.
25 RPS Plans establish purchase and sales processes that the Joint Utilities
26 must follow related to transactions involving RPS-eligible resources.

27 The Commission expressly requires the Joint Utilities to include in their
28 BPPs targets or maximum/minimum limits for purchasing energy, capacity,
29 fuel and hedges. These targets and limits expressly define Commission-
30 approved procurement and are included in each of the IOU's BPPs.

31 The Joint Utilities' BPPs were originally developed primarily to guide
32 procurement of authorized energy products. While the BPPs do establish
33 targets and limits applicable to sales of energy products, to the extent the
34 Joint Utilities may be undertaking sales activities at a greater frequency and

1 volume in the future to address departing load, the Joint Utilities may seek to
2 incorporate additional clarity and guidance in their respective BPPs moving
3 forward.

4 **2. Approved Products for Procurement and Sales under the Bundled** 5 **Procurement Plan**

6 Each IOU's BPP is approved by the Commission and provides explicit
7 direction regarding the energy products, energy-related products, and
8 procurement-related financial products that the IOU may transact. The
9 BPPs also include procurement targets and limits, and justifications for
10 those targets and limits. Specifically included within the list of approved
11 products is the purchase or sale of RA.¹⁶ All proposed sales of forward RA
12 would be conducted and executed pursuant to the authority granted by the
13 Commission and within the pre-approved limitations of each IOU's BPP.
14 The Joint Utilities may request Commission authorization to execute RPS
15 sales through their BPPs.¹⁷

16 **3. Joint Utilities' Procurement Activities, Including Sales, Are Reviewed** 17 **Through Open and Transparent Commission Processes**

18 IOU procurement activities undertaken pursuant to the BPP framework
19 are thoroughly reviewed by the Commission through two separate
20 processes to ensure transparency, prudence, and compliance.

21 First, a month following the end of each quarter, each IOU submits a
22 QCR via advice letter for Commission review. The QCR is audited and
23 reviewed by Commission staff and ultimately, through delegated authority,
24 the audit and review findings are approved by the Director of the Energy
25 Division. The QCR includes the procurement-related transactions that
26 occurred during the prior quarter, including sales. The IOUs serve the QCR
27 AL publicly and parties have an opportunity to provide comments.

28 Second, the Joint Utilities each file an annual ERRR Compliance
29 Application, which includes detailed testimony and supporting work papers

16 See D.15-10-031; AL 2615-E; and AL 2897 E.

17 See, e.g., D.15-10-031, pp. 8-9, Ordering Paragraph 1.a; and D.12-01-033, pp. 39-40, Ordering Paragraph 14 (denying requests by SCE to include renewable resources as eligible products under the BPP for transactions less than five years in duration).

describing IOU procurement and contract administration for the previous calendar year and demonstrating compliance with the Commission's Standard of Conduct for LCD requirements. The ERRR Compliance proceeding is an open and transparent process overseen by the Commission in which interested parties may participate.

4. Procurement Review Group

In addition to the Commission processes discussed above, the PRG provides further visibility into IOU procurement activities. The PRG is comprised of non-market participants, including the Commission's Energy Division, consumer advocacy groups, environmental groups, and other parties, and was established by the Commission to serve in a consultative capacity on a wide range of IOU procurement activities.

The Joint Utilities consult with their respective PRG on a monthly basis, or more often if necessary. Although the PRG acts primarily in an advisory capacity, the Joint Utilities actively solicit input from PRG participants and take participants' feedback into account in their respective procurement processes. Transactions and solicitations requiring PRG review are clearly identified in each IOU's BPP.

5. Independent Evaluator

The Commission also requires participation of an IE in IOU competitive solicitations for energy solicitations, utility-built projects, utility turnkey projects, and bilaterally-negotiated contracts. The purpose of the IE is to ensure the fairness and transparency of the energy procurement contract selection process. Consistent with requirements outlined in each IOU's BPP, each IOU maintains an active pool of at least three IEs. IEs typically generate an independent report associated with a specific solicitation or transaction which is filed with the IOU's QCR. Public versions of IE reports redacted to protect market-sensitive data are made available to interested parties.

The existing processes described above will be utilized by the Joint Utilities with respect to any sales transactions resulting from the adoption of the Joint Utilities' proposed sales framework.

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CHAPTER 4

**PROPOSALS FOR ALTERNATIVES TO THE PCIA TO UPHOLD
STATUTORY REQUIREMENTS AND MEET THE GUIDING
PRINCIPLES OF THE PROCEEDING**

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SAN DIEGO GAS & ELECTRIC COMPANY
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A. Description of Joint Utilities' Proposal

On April 25, 2017, the Joint Utilities filed an application seeking to replace the current Power Charge Indifference Adjustment (PCIA) methodology (Current Methodology) with the Portfolio Allocation Methodology (PAM), an alternative methodology based on an allocation of the total benefits and net costs of past utility procurement to those customers for whom the assets were originally procured or constructed.¹ That application was dismissed without prejudice in favor of the current rulemaking proceeding. The fundamental goal of PAM was to ensure that customers who depart from bundled service received their *pro rata* share of the benefits from—and paid their *pro rata* share of the net costs of—resources that were procured or built on their behalf. To be consistent with California law, PAM was designed to ensure that cost shifting did not occur between customers remaining on bundled service and customers served by an alternative procurement service provider. This fundamental goal is mandated by statute and the Joint Utilities believed PAM was the most effective method for achieving it at all levels of departing load.²

The Joint Utilities still believe that PAM is the most effective method to achieve customer indifference at all levels of departing load.³ However, in response to feedback received from stakeholders, the Joint Utilities have developed a revised proposal for reforming the PCIA (Proposal) that attempts to address some of the concerns expressed by parties at the workshops held in this proceeding, to retain certain concepts of the Current Methodology, and

¹ Application (A.) 17-04-018.

² Sections 365.2 and 366.2.

³ The Joint Utilities propose to revert to the PAM proposal if parties prefer it over the revised proposal.

continues to support the state's public policy objectives, while addressing the realities of changed energy markets and investor-owned utility (IOU) portfolios in the years since the Current Methodology was adopted. Specifically, the Joint Utilities' Proposal addresses the following issues:

- Under the Current Methodology, departing load customers currently pay for some portion—but do not receive any—of their pro-rated share of attributes from the resources and contracts they continue to be responsible for through the PCIA;
- Community Choice Aggregators (CCA) wish to develop clean energy portfolios while minimizing the size of the utility portfolio potentially allocated to them;
- Resource Adequacy (RA) and energy value from gas and nuclear resources can be efficiently monetized, however, Renewables Portfolio Standard (RPS)-eligible resource attributes and large hydro-electric generation resources cannot; and
- The increasing magnitude of departing load due to CCA formation, which:
 - Exacerbates any divergence between market price benchmarks and actual market prices;
 - Results in resource levels greater than remaining bundled service load (long positions) for the Joint Utilities to monetize in thin markets; and
 - Exposes bundled service customers to significant market risk related to monetizing the legacy generation resources.

The Joint Utilities' Proposal consists of two parts: the Green Allocation Mechanism (GAM) and Portfolio Monetization Mechanism (PMM). The GAM, which applies to RPS-eligible and large hydro-electric facilities,⁴ retains the PAM concept of a *pro rata* allocation of benefits and net costs. Meanwhile, the PMM, which applies to nuclear, gas, and (non-pumped-hydro) energy storage resources, is similar to the Current Methodology in that it only collects the *pro rata* share of above-market costs of the PMM resources from departing load customers.⁵ However, unlike the Current Methodology, which relies on administratively-set benchmarks to estimate the above-market costs of the

⁴ "Large hydro-electric facilities" includes pumped hydro-electric facilities.

⁵ See Chapter 4, Section A.2 for a discussion of the GAM/PMM eligibility of various resources.

1 portfolio, PMM uses actual market transactions to calculate the cost
2 responsibility of departing load customers and establishes an annual true-up of
3 above-market costs.

4 **1. Joint Utilities' Proposal Overview and How It Protects All Customers**

5 The Joint Utilities' Proposal would replace the Current Methodology with
6 GAM and PMM. GAM is methodologically similar to the Cost Allocation
7 Methodology (CAM) adopted by the California Public Utilities Commission
8 (CPUC or Commission) in D.06-07-029,⁶ whereby the benefits of the
9 generation resources (e.g., enhanced system reliability and capacity that is
10 applied towards each load-serving entity's (LSE) RA requirements) are
11 shared equitably by all customers, and the "net costs," defined as the total
12 cost of the resource less the energy revenues associated with the dispatch
13 of the resource, are also shared equitably by all customers.⁷ Under the
14 Joint Utilities' Proposal for GAM, the costs recovered from all customers,
15 including departing load customers, will equal the actual costs incurred
16 (e.g., contract costs owed to the generators, utility-owned generation (UOG)
17 capital costs, and California Independent System Operator (CAISO)
18 generation-related charges), less the actual revenues received from the
19 markets for those resources (e.g., energy and ancillary services (A/S)
20 revenues), and will be allocated *pro rata* to all customers. Similarly, the
21 attributes of GAM resources will be allocated *pro rata* to customers' LSE.

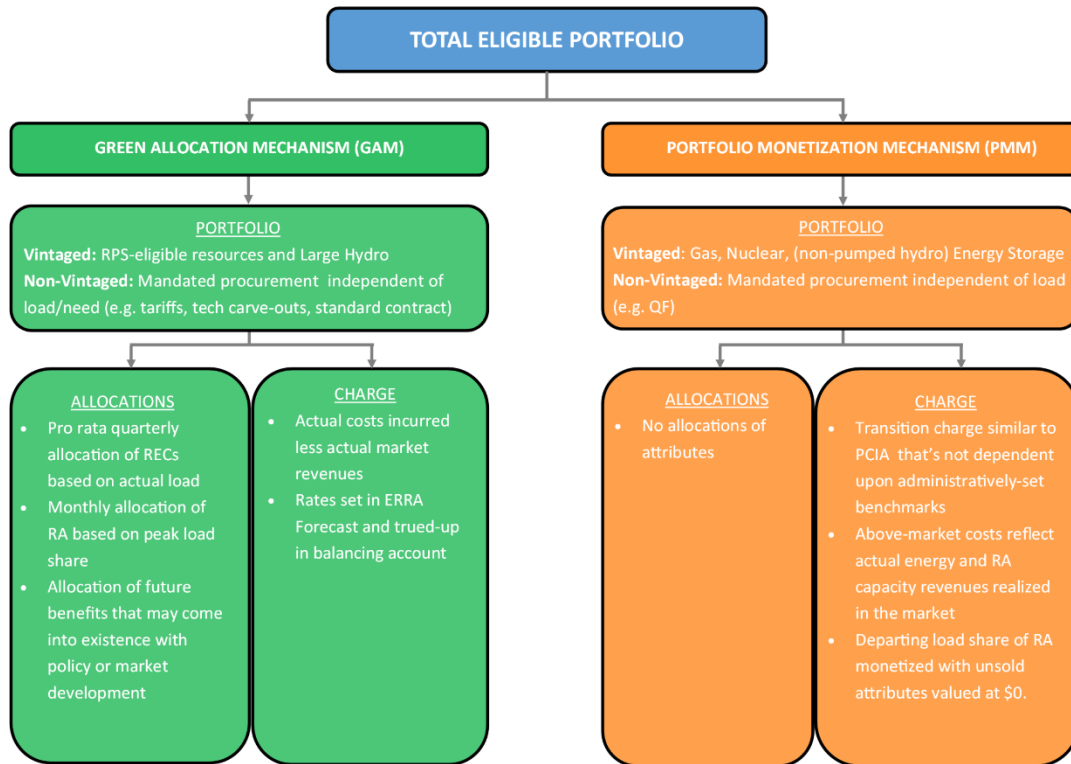
22 PMM is similar to the Current Methodology, but with (1) modifications to
23 determine costs and revenues based on actual market outcomes, and
24 (2) the addition of an annual true-up. Under PMM, the cost recovered from
25 departing load customers will equal their *pro rata* share of the above-market
26 costs of the PMM portfolio (i.e., actual incurred costs, less the actual energy
27 and A/S revenues received from the markets for those resources and the
28 actual value of the RA capacity as determined in an annual RA sales
29 process).

6 Many of the detailed mechanics of the methodology were refined and adopted in D.07-09-044 and D.15-11-041.

7 D.06-07-029, p. 7.

Figure 4-1 illustrates the Joint Utilities' Proposal and reflects the two mechanisms, the associated resources and allocation processes, and the related charges for each.

**FIGURE 4-1
GAM AND PMM PORTFOLIO TREATMENT**



While the initial rates for both the GAM and PMM portions of the portfolio will be set in the Joint Utilities' respective annual Energy Resource Recovery Account (ERRA) Forecast proceedings based on a forecast of costs and offsetting market revenues⁸ (forecast net resource costs), those rates will be trued-up annually based on actual portfolio performance and market settlement data (actual net resource costs), as well as billed revenues received from customers.⁹ This method follows the process used

⁸ PMM RA capacity value will be forecast using the average price specified in the Commission's Annual RA report adjusted for market depth (i.e., adjusted for an assessment of the amount of RA that can be monetized).

⁹ A description of the cost true-up process is described in further detail in Chapter 4, Section D.1.

1 to set bundled service generation rates and CAM rates,¹⁰ and most
2 importantly, ensures that all customers pay their *pro rata* share of the net
3 resource costs for which they are responsible.

4 Furthermore, net resource costs will be reviewed and verified annually in
5 each utility's ERRA Compliance proceeding to ensure that the utility
6 prudently managed its resources pursuant to the Commission's Standard of
7 Conduct 4 (SOC 4) Least-Cost Dispatch (LCD) requirements. This is the
8 same review the Commission currently conducts for the Joint Utilities'
9 bundled service customers' portfolios in the annual ERRA Compliance
10 proceedings, and under the Joint Utilities' Proposal, the utilities will continue
11 to be required by SOC 4 to efficiently dispatch the portfolio for all customers,
12 both bundled service and departing load. In the ERRA Compliance
13 proceedings, the Commission will also continue to review the Joint Utilities'
14 prudent contract administration obligations on behalf of all customers.

15 **a. Green Allocation Methodology for RPS-Eligible and Large**
16 **Hydro-Electric Resources**

17 Under the Joint Utilities' Proposal for GAM, the costs recovered from
18 departing load customers will equal the actual costs incurred
19 (e.g., contract costs owed to the generators, UOG capital costs,
20 and CAISO generation-related charges), less the actual revenues
21 received from the markets for those resources (e.g., energy and
22 A/S revenues).

23 The Joint Utilities' Proposal establishes a process for an equitable
24 and efficient allocation of all of the attributes (benefits) of the
25 RPS-eligible and hydro-electric resources in the Joint Utilities' portfolios,
26 including the value of the energy and A/S (which will be realized through
27 the market revenues that are used to offset the resource costs),¹¹

¹⁰ CAM rates refer to SCE's and PG&E's New System Generation rates and to San Diego Gas & Electric Company's (SDG&E) Local Generation Charge, and collect the net costs of all CAM-eligible resources from all delivery service (i.e., bundled service and departing load) customers.

¹¹ The Joint Utilities' RPS contracts are largely fixed-price contracts. To the extent that market prices at any point exceed those contract-defined prices, the resources will be "in the money" in the energy markets, and all customers will equitably benefit from the resulting market revenues in excess of contract costs. See Figure 4-2.

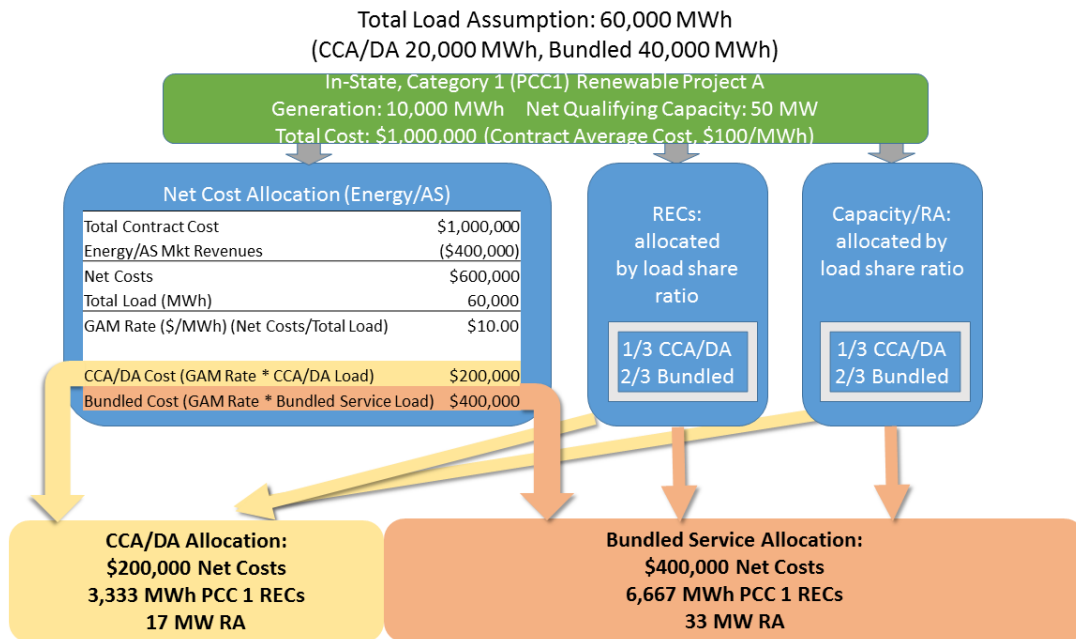
1 and allocation of Renewable Energy Credits (REC), RA, and any future
2 benefits that may come into existence with policy or market
3 development, as appropriate. Actual REC and RA allocations for
4 GAM resources will take place quarterly after-the-fact and monthly on
5 a prospective basis, respectively, including a year-ahead allocation for
6 applicable RA, and will reflect actual load (for REC allocation) and
7 forecast peak load shares (for RA allocation)¹² to ensure alignment
8 between actual revenues received from customers and benefit
9 allocations.

10 The allocation of GAM resource attributes will reduce Energy
11 Service Providers' (ESP) and CCAs' future needs for RA and RPS
12 procurement, thereby providing departing customers with direct
13 resource value for their departing load charges and serving as a
14 long-term hedge against fluctuations in the prices for those products
15 (symmetrical to the functions those resources serve for bundled service
16 customers).¹³ Importantly, these allocations will also ensure that the
17 substantial existing preferred-resource commitments that the Joint
18 Utilities have already made on behalf of customers are efficiently
19 accounted for in the collective planning and procurement processes of
20 all LSEs, and avoids the potential for costly double-procurement and
21 potential stranding of policy-preferred resources.

12 Load and peak load share in this context means the individual CCA's or ESP's portion of sales and peak demand, respectively, which accounts for reductions in load due to distributed generation and energy efficiency and increases in load due to electric vehicle charging. Load and peak load shares are calculated regularly on a vintaged basis. See Appendix E for an illustrative example.

13 As described below and in more detail in Chapter 6, LSEs will receive relevant portfolio data to allow them to develop their own long-term forecasts of the portfolio attributes that will be allocated to them.

FIGURE 4-2
HIGH LEVEL OVERVIEW OF GAM COST AND BENEFIT ALLOCATION^{14,15}



1 GAM will also include a “vintaging” process, similar to that under the
 2 Current Methodology,¹⁶ to ensure that customers are responsible for
 3 only the resources that were procured on their behalf. If a customer
 4 departs bundled service, that customer will neither be allocated benefits
 5 nor costs for resources procured after the customer’s departure, with the
 6 exception of certain procurement that is required by the Commission
 7 regardless of need (e.g., feed-in-tariffs, technology carve-outs, etc.).
 8 As discussed in more detail in Chapter 7, the Joint Utilities propose that

¹⁴ Example scenario and illustrative of a one-resource allocation only based on CCA, Direct Access, and bundled service load. Actual allocations will occur for RPS-eligible and large hydro-electric resources on a resource-specific basis, and would include Community Aggregator (CA) load, as well.

¹⁵ The figure is intended to provide a high-level overview of the RPS-eligible and large hydro portion of the Joint Utilities’ Proposal and does not detail the annual true-up process.

¹⁶ Pursuant to D.08-09-012, resources are assigned to a vintaged portfolio based on the year the generation resource commitment is made (i.e., contract execution date or Commission approval of UOG) and customers are assigned to a vintage based on their departure date. Specifically, customers who depart before July 1 of a given year are assigned to the prior year’s vintage. The Commission clarified the vintaging rules for customers served by a CCA in D.16-09-044.

1 these latter mandated resources be allocated to all customers
2 regardless of their vintaging. A list of the eligible resources that the
3 Joint Utilities propose allocating through GAM is provided in Appendix F.

4 **b. Portfolio Monetization Mechanism for Gas, Nuclear and**
5 **Non-Pumped-Hydro Energy Storage Resources**

6 The Joint Utilities' Proposal determines the above-market costs of
7 PMM resources by utilizing a financial settlement approach for energy
8 and RA capacity from gas, nuclear and (non-pumped storage) energy
9 storage resources, similar to the Current Methodology, except the
10 above-market costs will reflect actual energy and RA capacity revenues
11 realized in the market, rather than be based on administratively set
12 benchmarks. The basic mechanics of PMM are simple: the utility retains
13 all of the RA and energy from PMM resources and will monetize the
14 *pro rata* share of those attributes on behalf of departing load customers.
15 The initial rates for the PMM portfolio will be set in the Joint Utilities'
16 respective annual ERRA Forecast proceedings based on a forecast of
17 costs and offsetting market revenues¹⁷ (forecast net resource costs),
18 and those rates will be trued-up annually based on actual portfolio
19 performance, including forward RA sales, and market settlement data
20 (actual net resource costs), as well as billed revenues received from
21 customers. As discussed in more detail in Chapter 7, the Joint Utilities
22 propose that mandated resources in the PMM procured irrespective
23 of bundled service customer need in support of public policy
24 (e.g., Qualifying Facility (QF) resources¹⁸) be allocated to all customers
25 (and therefore not "vintaged"). A list of the resources that the Joint
26 Utilities propose to receive PMM treatment is provided in Appendix F.

¹⁷ During the annual ERRA Forecast proceeding, PMM energy revenues will be estimated based on a forecast of energy prices, and RA revenues will be estimated based on the weighted average price specified in the Commission's annual RA Report adjusted for market depth. See Chapter 4, Section D.1 for more details.

¹⁸ The federal Public Utility Regulatory Policy Act of 1978 (PURPA), 16 U.S.C. Section 824a-3 *et seq.*, requires electric utilities to purchase the electric energy and capacity made available by QFs.

1 **c. Market Revenues for Energy and Ancillary Services**

2 The Joint Utilities propose that, instead of allocating to each LSE its
3 customers' estimated share of the energy-related (e.g., energy and A/S)
4 benefits from the GAM- and PMM-eligible resources, the eligible
5 resources be bid or sold into energy and A/S markets in accordance
6 with the Commission's LCD protocols, and the actual revenues they
7 garner be allocated to all customers for whom the resources were
8 procured. The actual revenues received from the energy and A/S
9 markets (i.e., the energy benefits) will be netted against the cost of the
10 resources to reduce the costs of the resources ("net costs") that will be
11 recovered *pro rata* from all customers.¹⁹ The same treatment of energy
12 and A/S revenues will be applied to all GAM and PMM resources
13 subject to the Joint Utilities' Proposal (Eligible Resources). This
14 approach is both consistent with CAM, in which the Joint Utilities use
15 market revenues (or a proxy calculation of market revenues) to reduce
16 the costs of the CAM-eligible portfolio, and ensures that the energy
17 benefits of the eligible portfolio, including any energy price hedge value,
18 are shared equitably by all customers.

19 Under the Joint Utilities' Proposal, the Joint Utilities will continue to
20 manage the Eligible Resources and bid or sell their generation into
21 energy markets if the utility is the Scheduling Coordinator (SC).²⁰
22 However, instead of exclusively using those market revenues to offset
23 the costs of meeting the bundled service customers' generation
24 requirements as is currently done, the Joint Utilities will use the
25 revenues received from participation in the energy markets²¹ to directly
26 offset the costs of the Eligible Resources, resulting in a reduced net cost

¹⁹ Additional coordination with the California Energy Commission (CEC) will be required to ensure that energy associated with the Eligible Resources is accounted for in the Power Content Label calculation. See Section C for more details.

²⁰ Resources for which the utility is not the SC will continue to be offered into the energy markets by the responsible party.

²¹ The energy market revenues include all energy, residual unit commitment, and A/S payments from the CAISO day-ahead, CAISO real-time, and/or bilateral markets net of any charges that result from participation in the energy markets. An example of these charges is CAISO deviation charges for a resource that generates above or below its scheduled output.

1 to bundled service and departing load customers. This proposal
2 eliminates the enormous complexity that would be involved in attempting
3 to allocate a *pro rata* share of the energy to all LSEs—a process which
4 would require LSEs to submit inter-SC trades for their small slices of
5 power from hundreds of resources per hour with the respective
6 resources' SCs—and is reasonable given the Joint Utilities' obligation to
7 realize market revenues by abiding to SOC 4's LCD principle,²²
8 which requires that “[t]he utilities ... prudently administer all contracts
9 and generation resources and dispatch the energy in a least-cost
10 manner.”²³

11 Additionally, the Joint Utilities' Proposal ensures that the customers
12 who are responsible for the costs of the resource receive the energy
13 price benefit that the resource provides, regardless of their current LSE.
14 This aspect of the Joint Utilities' Proposal will provide the same energy
15 price protection to departing load customers as will be received by
16 remaining bundled service customers. Because the majority of the
17 Joint Utilities' resources are fixed-price long-term contracts, under the
18 Joint Utilities' Proposal each LSE is naturally hedged against price
19 fluctuations in the energy market by the amount of fixed price energy
20 that represents its load share ratio of the utility's portfolio. To illustrate,
21 in the example below, the utility contract provides a fixed cost of
22 \$60/megawatt-hour (MWh) regardless of whether the spot price is lower
23 (\$40/MWh in Scenario 1) or higher (\$80/MWh in Scenario 2) than the
24 contract price of \$60/MWh.

²² SOC 4, which articulates the LCD principles, was initially adopted in D.02-10-062 and is further discussed in D.02-12-069, D.02-12-074, D.03-06-076, D.05-01-054, and D.15-05-057.

²³ Compliance with these LCD principles is verified annually in each utility's respective ERRA Compliance proceeding.

TABLE 4-4
ILLUSTRATIVE EXAMPLE OF ENERGY PRICE HEDGE FROM AN RPS RESOURCE

Line No.	Item	Contract Cost	Market (Revenue)/Cost	Net Cost
1	<u>CAISO Price Scenario 1 (\$40/MWh)</u>			
2	GAM RPS Delivery (1 MWh)	60.00	(40.00)	20.00
3	Customer Load (1 MWh)	N/A	40.00	40.00
4	Total Cost			60.00
5	<u>CAISO Price Scenario 2 (\$80/MWh)</u>			
6	GAM RPS Delivery (1 MWh)	60.00	(80.00)	(20.00)
7	Customer Load (1 MWh)	N/A	80.00	80.00
8	Total Cost			60.00

d. Advantages of the Joint Utilities' Proposal

The Joint Utilities' Proposal of combining the allocation of RECs and RA from RPS and large hydro-electric resources (GAM) with a cost-based allocation approach for other resources (PMM) balances the resource technology concerns of a number of CCA parties while ensuring compliance with state law and continued support of state policy objectives. Some CCA stakeholders have noted that they would like to focus on developing clean energy portfolios while minimizing the size of the utility portfolio allocated to them, or avoiding an allocation entirely. As described in Chapter 2, the Joint Utilities are concerned that accurate and scalable market indices, in particular for the various RPS compliance categories and contract tenors, are impossible to construct, and not all products are equally liquid in the marketplace. Under GAM, the costs and benefits of clean energy resources are directly allocated to LSEs, thereby avoiding the use of unreliable benchmarks for RECs and capacity attributes that fluctuate with the time of the year. PMM, on the other hand, provides a means to quantify the actual above-market costs of resources with attributes that are transacted in relatively liquid markets, thereby completely eliminating the need to allocate and/or benchmark the benefits of gas, nuclear, and energy storage resources. Together, GAM and PMM ensure that departing load customers retain the inherent value of utility actions taken to support the state's regulatory and public policy objectives and pay their equitable *pro rata* share of the

1 costs of those actions taken on their behalf, without unduly hindering
2 their LSE's ability to exercise considerable procurement autonomy on
3 their behalf.

4 There are several advantages to the Joint Utilities' Proposal
5 compared to the Current Methodology. First, GAM and PMM protect all
6 customers by ensuring that all customers equitably benefit from and pay
7 for their *pro rata* share of their utility's portfolio procured to serve their
8 needs and meet state objectives. The Joint Utilities' Proposal uses
9 actual market results rather than hypothetical, administratively-set,
10 Market Price Benchmarks (MPB). Both the GAM and PMM replace a
11 "proxy" construct that relies entirely on inaccurate and contentious
12 administratively-set MPB with actual market revenues and verifiable net
13 resource costs. The Joint Utilities' Proposal results in both departing
14 load customers and remaining bundled service customers paying the
15 same net cost and above-market cost, on a per-kilowatt-hour (kWh)
16 basis, for each GAM and PMM resource, respectively, for which they are
17 collectively responsible.

18 Second, the attribute allocation process as proposed under GAM
19 addresses a variety of issues, as described in further detail below.

20 **1) GAM Resources Were Built to Support Public Policy and Their**
21 **RA Should Be Shared Equitably**

22 RPS-eligible and large hydro-electric resources were built to
23 serve important public policy purposes such as energy portfolio
24 diversification, clean energy generation, renewables market
25 transformation, and water conveyance and recreation. Departing
26 load customers continue to enjoy the benefits of those resources as
27 a result of their contribution to California's energy system, therefore
28 GAM ensures they also carry their fair share of the related costs.
29 More importantly, allocating the RA capacity of these clean
30 resources guarantees they are used first to meet the RA compliance
31 obligations of benefiting LSEs, thereby ensuring they do not become
32 stranded. The Commission has continually expressed a desire to

1 prioritize preferred resources, such as RPS-eligible resources, in
2 meeting RA requirements.²⁴

3 **2) RPS-Eligible and Hydro Resources Are Intermittent**

4 Most of California’s installed RPS-eligible resources—namely
5 wind and solar units—generate intermittently due to an inherent
6 dependency on local meteorological conditions. Others, including
7 geothermal, bioenergy and run of-river small hydro-electric
8 resources, often generate at a baseload profile, but on an
9 “as available” basis as input fuels allow. Similarly, large
10 hydro-electric resources, while often dispatchable, must co-optimize
11 power generation with water delivery obligations, environmental and
12 recreational flow requirements, operating license requirements
13 imposed by the Federal Energy Regulatory Commission (FERC),
14 and prudent reservoir management, among other considerations.
15 All hydro-electric generation is also subject to the natural variability
16 of annual precipitation, which has fluctuated significantly across the
17 state over the past decade.

18 Due to the inherent intermittency and variability of most of these
19 technologies, delivery of energy directly to the CAISO market is the
20 most practicable way to monetize the resources. Because of the
21 uncertainty of the energy production related to these resources, it is
22 difficult to forecast the quantity of RA provided by, and RECs
23 generated by, RPS-eligible and hydro-electric resources. As such,
24 these resources are best suited to a transparent allocation of
25 benefits and net costs rather than an auction approach requiring the
26 forecast, sales, and true-up of forward products and attributes
27 associated with their intermittent and variable generation.

28 **3) Allocation of GAM Resources Allows Policy to Be Implemented** 29 **Efficiently**

30 Allocating the attributes of the Joint Utilities’ respective portfolios
31 to all LSEs that serve departing load customers would enable those
32 LSEs to scale their operations and to plan to serve their load in a

24 R.14-10-010, Concurring Opinion of Commissioners Peterman and Guzman-Aceves.

1 manner that optimizes the existing resources, which were also
2 procured to serve the departing load customers. This will ensure
3 greater societal efficiencies in achieving the state's clean energy
4 policy goals and mandates, including the requirement that
5 65 percent of each LSE's RPS compliance requirement be met with
6 long-term RPS energy deliveries starting in 2021.²⁵ Absent such an
7 allocation of attributes, as the level of departing load increases,
8 there will be a near-term glut of those attributes in the market
9 resulting in inefficient market outcomes, and an underutilization of
10 resources previously procured by the Joint Utilities to serve their
11 then-bundled service customers.

12 **4) GAM Results in Predictability and Transparency**

13 Given the Joint Utilities' Proposal's reliance on long-term
14 contract information and actual market data, predictability and
15 transparency of the rates are improved. Long-term contracts have
16 predictable costs, and accordingly portfolio managers can forecast
17 around the resulting, more-predictable, costs, revenues and
18 benefits. Indeed, long-term renewable contracts, which comprise
19 the majority of the GAM portfolio, have little to no variable operating
20 costs and a "fixed price" per MWh of generated energy. CCAs and
21 ESPs can use this predictable resource-specific cost data, along
22 with their own forward energy price curve forecasts, to develop their
23 own forecasts of future departing load rates.

24 **5) RPS Benchmarks Are Difficult to Establish**

25 As described in Chapter 2, establishing valid benchmarks for
26 RPS- eligible resources is difficult. RPS resources currently come in
27 seven compliance varieties (Portfolio Content Category (PCC) 0 and
28 either long-term or short-term for PCC 1, PCC 2, PCC 3). Although
29 some data may be available to establish a market-based value for
30 some of these categories, definitive market data is not available for
31 all of them. In particular, the range of values for PCC 1 generation
32 can be very wide, making it difficult to benchmark. This is the

²⁵ See Cal. Public Utilities Code (Pub. Util. Code) § 399.13(b).

category that makes up the vast majority of the Joint Utilities' RPS-eligible portfolios. Therefore, the inability to value it accurately is a fatal flaw of any benchmarking scheme. Instead, by allocating those attributes to departing load customers, the issue of valuation for RPS-eligible resources is avoided, preventing unlawful cost shifts from occurring. Additionally, the allocation of the RECs to departing load customers' LSEs ensures that they are optimally accounted for and used, which will reduce the overall cost associated with achieving California's ambitious RPS program.

6) Reliability Resources in Local Areas Raise Market Power Concerns

Many large hydro resources contribute directly to grid reliability as generating capacity located in Local Capacity Areas (LCA), as established by the Commission and the CAISO. The Local Capacity Requirements (LCR) protect against reliability issues developing in particular locations on the grid, and are studied annually by the CAISO in its Local Capacity Technical Study to determine the capacity needs of each area. The Commission uses this technical study to establish the local RA requirements in the RA Program.

Because there are a small number of generators in some LCAs, the Commission and CAISO have gone to great lengths to develop and implement market power mitigation measures and policies to allay concerns associated with local generation suppliers exercising inappropriate influence over market pricing of local capacity. For example, as shown in Table 4-1 below, Pacific Gas and Electric Company's (PG&E) contracted or owned Non-RPS Hydro and RPS-eligible resources in the Fresno LCA meet 92 percent of the capacity needed to meet the LCR. Southern California Edison's (SCE) portfolio has a similar situation for the Big Creek-Ventura LCA.²⁶ Although the Joint Utilities unflinchingly comply with CAISO (and FERC) rules prohibiting market manipulation, in some LCAs

²⁶ SCE's utility-owned Big Creek Hydro System (1,000 MW Aug 2018 NQC) represents 55 percent of the Big Creek-Ventura LCR net of the CAM allocation (1,825 MW).

the Joint Utilities' generation resources constitute sufficient generating capacity to trigger market power implications. And as a practical matter, it would be very challenging for the IOUs to sell the precise amount of Local RA that each LSE would need for its Local RA compliance in an environment of multiple, small LSEs.

**TABLE 4-1
LOCAL CAPACITY RESOURCES IN PG&E'S PORTFOLIO TO BE ALLOCATED THROUGH GAM**

Line No.	Local Capacity Area (LCA)	[A]	[B]	[C] = [A] + [B]	[D]	[E] = [C] / [D]
		Total MWs (Large Hydro) ^(a)	Total MWs (Other Renewable) ^(a)	Total Allocated	Local Capacity Requirement Net of CAM Allocation ^(b)	% of CAISO LCR
1	Bay Area	0	194	194	4,311	4.5%
2	<u>Other PG&E Area</u>					
3	Fresno	1,705	215	1,920	2,081	92.3%
4	Humboldt	0	2	2	169	1.1%
5	Kern	0	82	82	151	54.1%
6	NCNB	0	305	305	634	48.1%
7	Sierra	670	289	959	2,106	45.5%
8	Stockton	91	54	145	719	20.2%
9	<u>Non PG&E TAC</u>					
10	Big Creek-Ventura	0	57	57	2,017	2.8%
11	LA Basin	0	3	3	7,525	0.0%

(a) Total MW based on August 2018 Net Qualifying Capacities (NQC).

(b) 2018 CAISO LCR Study.

Given the well-documented concerns regarding market power in LCAs, a transparent allocation of benefits (i.e., RA capacity) and net costs associated with large hydro-electric resources and RPS-eligible resources would be a more suitable mechanism than forward sales that would necessitate the development of complex rules and oversight to ensure fair and effective market power mitigation.

It is worth noting that the Joint Utilities' proposed allocation of benefits and net costs associated with reliability resources in LCAs is consistent with the Commission's existing CAM, which was

designed as a regulatory process to allocate capacity costs of reliability-based utility procurement across all benefitting customers.

7) FERC-Licensed Large Hydro-Electric Resources Provide Public Benefits

Hydro-electric resources provide significant public benefits. Investments made in dams, water conveyance infrastructure, and associated watershed lands serve the interests of individual communities, and the state more broadly, regardless of which retail energy provider serves those customers. For example, investments required as part of the FERC licensing process may include protection of natural habitat for fish, wildlife and plants; compliance with conservation easements on watershed lands; management of public access to watershed lands, including maintenance of access roads and infrastructure and mitigation of unauthorized use; installation and maintenance of public campgrounds, picnic areas, boat docks and boat launches; and protection of historic resources under the implementation of resource management and protection plans. Furthermore, the Joint Utilities operate hydro-electric resources in a manner consistent with complex water delivery obligations to local water agencies, agricultural off-takers, and other constituent stakeholders. As such, the Joint Utilities propose the benefits and costs associated with large hydro-electric infrastructure be broadly allocated across all customers. It would be highly impractical to try to parse out and establish a market price benchmark for each element of a large hydro-electric system, particularly given the significant annual variability in operations that occurs with changes in precipitation and snow pack. Allocating actual RA values and recording actual costs and market revenues will be much more straightforward for all parties to understand and verify.

2. Resources Subject to the Joint Utilities' Proposal

The Eligible Resources subject to the Joint Utilities' Proposal include all resources eligible for cost recovery under the Current Methodology.

1 In addition, as discussed in Chapter 5 of this Testimony, the Joint Utilities
2 propose to eliminate the current 10-year cost allocation period limit for
3 post-2002 fossil UOG and certain energy storage resources, and to treat
4 these resources as Eligible Resources for the full period of utility cost
5 recovery. Eligible Resources, which have been approved by the
6 Commission or procured through rules adopted by the Commission in the
7 Joint Utilities' respective Bundled Procurement Plans (BPP), RPS Plans,²⁷
8 and Energy Storage Plans were procured or built on behalf of then-bundled
9 service customers, and any forecast bundled service load growth, to meet
10 bundled service load requirements or the state's policy directives.
11 Therefore, full cost recovery for these resources should extend to all
12 customers on whose behalf they were procured.

13 All costs associated with the Eligible Resources will be included in the
14 calculation of their net costs. These direct resource costs, and any
15 associated indirect resource costs, are currently included in the
16 "Total Portfolio Costs" used in the Current Methodology to calculate the
17 PCIA and Competition Transition Charge (CTC) and are described in further
18 detail in Appendix D.

19 **a. Eligible Resources**

20 The Joint Utilities propose that all contracted and utility-owned
21 resources subject to the Current Methodology be considered eligible for
22 GAM or PMM. As will be described in further detail in Chapter 4,
23 Section D.1, the net or above-market costs of contracts that are
24 currently recovered through the CTC will be recovered through a
25 modified CTC component based on the Joint Utilities' Proposal,²⁸ and
26 the net costs of resources that are currently recovered through the PCIA
27 will be recovered through a new vintaged Portfolio Allocation Charge
28 (PAC) rate component which would be applicable to non-exempt

²⁷ Resources procured through approved RPS Plans include those procured through utility-scale solicitations, feed-in tariff solicitations, and approved bilateral transactions.

²⁸ Inclusion of the CTC-eligible resources in the portfolio of resources used to determine the full cost responsibility of departing load customers is consistent with the Total Portfolio Approach adopted for calculating the Indifference Rate (i.e., sum of CTC and PCIA) in D.06-07-030. Under the Joint Utilities' Proposal, the Indifference Rate will consist of the sum of the CTC and the PAC.

1 departing load customers. Additionally, as discussed herein and in
2 Chapter 5 of this Testimony, the Joint Utilities propose that all
3 generation resources be considered eligible for equitable cost recovery
4 for their entire terms (identical to the treatment of PCIA-eligible RPS
5 contracts under the Current Methodology), including all UOG and
6 energy storage contracts not subject to another broad cost allocation
7 mechanism.

8 To the extent the Commission continues to mandate procurement
9 by the Joint Utilities independent of their respective load or need,
10 in furtherance of specific state policy objectives, the resulting contract
11 costs should be borne by *all* benefitting customers, not just by bundled
12 service customers. Therefore, the Joint Utilities propose that going
13 forward, such costs be included in a non-vintaged non-bypassable
14 charge, similar to CAM. Further, the Joint Utilities' current portfolios
15 each include numerous resources that were procured pursuant to such
16 mandates (e.g., feed-in-tariffs, technology-specific carve-outs, etc.).
17 The Joint Utilities propose that these costs also flow to all customers on
18 a non-vintaged basis, which is a change in current treatment, as the
19 benefits are provided to all customers.

20 **b. Resources Ineligible for the Joint Utilities' Proposal**

21 The Joint Utilities' Proposal will exclude any current or new
22 resources such as system reliability-, emergency-, and policy-based
23 procurement that the Commission determines are eligible for broad cost
24 allocation through other ratemaking mechanisms such as CAM and
25 Public Purpose Program (PPP) charges. Additionally, the Commission
26 and the Legislature have previously concluded that all customers,
27 including departing load customers, bear responsibility for the cost of the
28 Joint Utilities' procurement of biomass resources in response to the
29 Governor's emergency proclamation on tree mortality.²⁹ As such, the
30 Joint Utilities do not propose any changes to the current cost allocation
31 mechanisms for these existing programs.

²⁹ See Cal. Pub. Util. Code Section 399.20.3(f) and CPUC Resolution E-4805 (2016).

1 The Joint Utilities' Proposal excludes any short-term power
2 purchase agreements (PPAs) or transactions shorter than one year in
3 length.³⁰

4 **c. Future Cost Allocation Changes for Certain Eligible Resources**

5 The Joint Utilities also preserve their ability to seek alternate cost
6 recovery mechanisms for a subset of Eligible Resources that provide
7 critical benefits, including, but not limited to flexible operating
8 characteristics and local sub-area capacity. These alternate cost
9 recovery mechanisms may encompass both future and current
10 mechanisms developed by the CPUC and/or CAISO. For instance,
11 due to emerging issues in California's electric sector, the CPUC is
12 considering potential new frameworks to preserve and ensure reliability
13 of the grid in its RA rulemaking proceeding. For example, the Energy
14 Division has proposed a multi-year local RA framework with the
15 distribution utilities as the central buyer for residual local RA
16 requirements. While the Joint Utilities do not take a position on the
17 Energy Division proposal here, and no decision has yet been issued,
18 the important point is that new allocation mechanisms are under
19 discussion and should not be precluded by changes to the PCIA
20 methodology adopted in the instant proceeding. Additionally, there are
21 existing mechanisms, including the CAM, which were established to
22 support the development of new generation resources to ensure electric
23 reliability, that may be better suited for certain Eligible Resources.
24 The Joint Utilities believe that these current and future mechanisms will
25 ensure a least-cost solution for all customers, both bundled service and
26 departing load, support local reliability procurement consistent with
27 Senate Bill (SB) 350 policy goals, align with preferred resource
28 mandates, and mitigate the need for potential expensive backstop
29 procurement.

30 Sales of RA pursuant to PMM that are shorter than one year in length will be proportionally counted as revenue against the costs of long-term contracts that are covered by PMM.

1 **d. Elimination of Arbitrary Limits to Cost Recovery Periods**

2 The Joint Utilities' Proposal will apply to all UOG not subject to
3 another cost allocation treatment.³¹ As explained in Chapter 5 of this
4 Testimony, UOG was approved by the Commission, based on the same
5 justifications as contracted generation, at a time when departing load
6 customers were still bundled service customers. The UOG resources
7 were identified as being either the lowest-cost, best-fit solution at the
8 time they were built or were needed to carry out a specific Commission
9 policy directive. As explained in detail in Chapter 5, there is no policy or
10 legal reason why UOG should be treated differently than contracted
11 generation for purposes of the Joint Utilities' Proposal.

12 The Joint Utilities propose that cost allocation for UOG resources be
13 consistent between "Legacy" (i.e., pre-2002) and post-2002 UOG
14 resources. As the Commission noted in D.08-09-012, "bundled [service]
15 customer indifference will only be maintained if all resources are
16 included in the portfolio used to calculate the related charges...
17 therefore, the use of the total portfolio and the inclusion of the [Legacy]
18 resources in that portfolio is the appropriate approach to use for the
19 duration of [new world generation] cost [allocation]."³² Consistent with
20 that conclusion and the existing treatment of Legacy UOG under the
21 Current Methodology, the Joint Utilities propose that both Legacy and
22 post-2002 UOG resources be considered as Eligible Resources under
23 the Joint Utilities' Proposal until the last of the long-term contracts
24 associated with those customers' vintaged portfolios expires, with the
25 caveat that the Joint Utilities specifically reserve the right to seek
26 Commission approval of future UOG cost allocation should
27 circumstances so warrant.³³

31 For example, the costs for SCE's five UOG peaker plants are CAM-eligible, so those resources would not be subject to PMM treatment.

32 D.08-09-012, p. 51.

33 For example, if a utility experiences an unexpectedly-large load departure after the presumptive cost-recovery period ends but before the UOG resource is retired, it may become necessary to revisit the cost-recovery issue to preserve bundled service customer indifference as mandated by state law. In such a situation, the Joint Utilities reserve their rights to seek appropriate relief at the Commission.

3. GAM Mechanics

As described above, GAM functions by assigning a *pro rata* share of the net costs and REC and RA attributes of RPS-eligible and large hydro-electric resources to departing load customers. Net costs are calculated as the difference between the resource costs and realized revenues for energy and A/S from those resources in various energy markets. A detailed discussion of how those processes will be implemented is provided below.

a. REC Allocation Process

The Western Renewable Energy Generation Information System (WREGIS) creates one REC for each whole MWh of electricity that was generated from a qualified renewable energy resource.³⁴ The REC allocation process under the Joint Utilities' Proposal will result in a proportionate sharing of RECs among the LSEs on a vintaged basis. The Joint Utilities propose that each utility allocate a portion of its total GAM-eligible REC portfolio (including previously generated excess RECs before load departed)³⁵ to CCAs and ESPs based on each LSE's load share, and that REC allocations not disrupt the content categorization of the RECs in the allocated portfolio, nor the underlying contract tenors for the RECs in the allocated portfolio. In Section C, the Joint Utilities propose certain clarifying REC attribute language that the Commission could adopt to confirm the content category of REC allocations under GAM.

1) REC Allocation Basis and Mechanism for Transfer

The quantity of RECs to be transferred to the CCA or ESP will be calculated based on the actual generation of the renewable facilities within the vintaged portfolio and the proportion of actual

³⁴ See Section 399.12(h). Any fraction of a MWh of renewable energy generation is carried over into the next month.

³⁵ Under GAM, to the extent the utility banked RECs before customers departed bundled service, a proportionate share of RECs banked on behalf of those customers prior to their departure will be allocated to the applicable CCA or ESP. The RECs will be transferred to the CCA or ESP ratably over the term spanning the latest delivering contract in their vintaged portfolio(s).

customer sales of the CCA or ESP during the previous quarter. The utility will calculate the load share ratio during the REC certificate generation period so that the correct amount of RECs can be transferred during the subsequent transfer window.³⁶ There will likely be no need for a material true-up at the end of each year because RECs are created subsequently (i.e., 90 days following the month of generation), and the actual quantity of RECs as well as CCA or ESP sales will be known at the time the RECs are allocated.³⁷

All retail sellers in California, including CCAs and ESPs are already registered in WREGIS for the purpose of RPS compliance. Therefore, no further administrative setup will be needed.

2) REC Allocation Timing

A utility will transfer RECs to a CCA or ESP in WREGIS no later than 60 days following the end of the quarter in which they are created in WREGIS (“transfer window”). Transferring RECs on a quarterly basis is optimal for all parties involved as it minimizes administrative processing time and provides sufficient time for all parties to use their RECs for compliance or as part of other transactions as Fourth Quarter RECs will be provided to retail sellers prior to all reporting deadlines:

All RECs used for compliance for the previous year must be reported to the CEC by July of the following year.³⁸

36 “Transfer Window” denotes the 60-day period following the date upon which RECs from the prior quarter are available.

37 The CEC verifies the RECs reported by all IOUs, CCAs, and ESPs, and the CPUC determines RPS compliance for all IOUs, CCAs, and ESPs. All IOUs, CCAs, and ESPs bear the same risk—the IOUs are not responsible for the results of these verification and compliance determination processes, and any rejection or reclassification of any transferred RECs will not be subject to a replacement process.

38 Retail sellers must request WREGIS to email the WREGIS RPS State Provincial Voluntary Compliance Report to the CEC and CPUC, along with attestation of these forms using the CEC RPS Online System. The CEC verifies the amounts of retired RECs are correct based on the generation amounts received by the generators and other methods, and works with the retail seller to resolve any discrepancies. Final RECs are posted by the CEC on the Verification Report, and findings are reported to the CPUC.

1 All RECs used for compliance for the previous year must be
2 reported to the CPUC by August of the following year.

3 **3) REC Adjustments**

4 There are occasional non-material adjustments in the WREGIS
5 system based on meter issues or other unforeseen events.
6 Typically, these issues involve a small amount of RECs (even as
7 small as one REC), and may require a true-up REC transfer to
8 ensure equitable treatment between the utility and a CCA or ESP.

9 In the event an adjustment occurs within WREGIS that requires
10 a true-up, the utility will determine how all of the adjusted RECs from
11 a given quarter should have been allocated based on the CCA's or
12 ESP's load share, and will then make this allocation during the next
13 transfer window. This true-up of the REC allocation process may
14 require the utility to transfer additional RECs to a CCA or ESP, or it
15 may require a CCA or ESP to transfer (or credit) RECs back to the
16 utility. The Joint Utilities propose that all REC allocations and
17 necessary true-ups be subject to CPUC audit and/or Energy
18 Division review for verification purposes.

19 **b. RA Allocation Process**

20 The RA attribute allocation process for GAM resources should
21 ultimately align with the allocation of costs, distribute the attributes in
22 proportion to compliance requirements, and provide portfolio
23 predictability to the participating LSEs. Much of the Joint Utilities'
24 Proposal for GAM resources relies on the existing RA allocation
25 framework and process used for CAM, with a few modifications to
26 accommodate the vintaged nature of Joint Utilities' Proposal portfolios,
27 equally distribute the risk exposure associated with managing RA
28 obligations, and match the timing of RA program requirements to
29 allocations of RA.

30 The current CAM process requires the Joint Utilities to submit to the
31 Commission a list of their CAM-eligible resources (Eligible Resource
32 List). This list identifies each resource's CAISO ID, System, Local and
33 Flexible RA NQC, and other relevant attributes, and is refreshed

1 annually around August for the subsequent year's CAM allocation
2 (Year-Ahead CAM list), and again quarterly for CAM System RA
3 allocation updates (Quarterly CAM list). The Joint Utilities propose to
4 use the same CAM data template for allocation of GAM RA capacity
5 under the Joint Utilities' Proposal, whereby each utility will submit to the
6 Commission a list of eligible resources with corresponding CAISO IDs,
7 RA attribute designations and "portfolio vintage" identifier based on the
8 resource's contract execution date.³⁹ This "GAM resource list" will
9 allow the Commission to identify the resources and corresponding
10 attributes that are eligible for allocation in each of the Joint Utilities'
11 vintaged portfolios. The year-ahead GAM list will be submitted with the
12 year-ahead CAM list, and in addition to submitting quarterly updates as
13 is the case for CAM, the Joint Utilities propose monthly allocation
14 updates for GAM that account for changes in load forecasts. This
15 monthly allocation update interval will allow the Commission to conduct
16 monthly GAM RA allocations to ensure greater equity in the allocation of
17 RPS-eligible and large hydro-electric RA benefits to LSEs, as discussed
18 in detail below.

19 **1) RA Allocation Basis for GAM Resources and Mechanism for** 20 **Transfer**

21 The Joint Utilities recommend using the same LSE-submitted
22 load forecasts currently used to set the RA compliance requirements
23 and corresponding CAM load share amounts to perform the GAM
24 load share calculation. These forecasts include the year-ahead load
25 forecasts that set the RA requirements and Year-Ahead CAM
26 allocations and monthly and mid-year load migration forecasts that
27 update the requirements⁴⁰ and refresh the CAM allocations.⁴¹

³⁹ For UOG, the portfolio vintage identifier will be based on the date the utility's initial UOG cost recovery application is approved.

⁴⁰ Annual system, local, and flexible RA requirements are set using the year-ahead forecasts. System RA requirements are updated monthly to account for monthly load migrations, and local and flexible RA requirements are updated mid-year.

⁴¹ CAM allocations and re-allocations rely on the same load forecast data used to set RA requirements. CAM allocations for system RA are updated quarterly, while CAM allocations for local and flexible RA are updated mid-year.

1 These same forecasts provide the information required to calculate
2 each LSE's share of the utility's vintaged GAM portfolios.

3 As described above, the GAM resource list will identify the
4 portfolio vintage of each resource. Similar to the calculation of CAM
5 load share within a utility service area, the Commission will be able
6 to utilize the vintaged Joint Utilities' Proposal resource lists and
7 LSE-submitted load forecasts⁴² to calculate a load share amount,
8 by vintaged portfolio, for each LSE whose customers are
9 responsible for the net costs of that portfolio. This vintaged monthly
10 load share amount, by LSE, will determine the RA attributes
11 received through GAM.

12 The mechanics of attribute transfer should follow that of the
13 existing CAM contracts accounting process whereby the IOU's RA
14 requirement increases (i.e., a GAM debit) by the quantity of RA
15 transferred to Joint Utilities' Proposal participants, and a receiving
16 LSE's RA requirement decreases (i.e., a GAM credit) by its peak
17 load share of the GAM portfolio, resulting in a net zero total
18 RA requirement change among all entities receiving GAM RA
19 allocations. This process is conducted for System RA, Local RA,
20 and Flexible RA attributes. This process is well-established in CAM,
21 and should result in minimal incremental administrative burden to
22 adopt a GAM RA attribute allocation process.

23 **2) GAM RA Allocation Timing**

24 Similar to the intent to utilize as much of the CAM process as
25 possible for resource identification, peak load share determination,
26 and transfer of attributes, the Joint Utilities propose to utilize the
27 timing of the CAM allocation for GAM RA allocation, with the
28 exception of the month-ahead allocation described in
29 Section A.3.2.b, below. The allocations would occur commensurate
30 with all RA compliance requirement determinations, which are done
31 annually, monthly, and a mid-year update.

⁴² The Joint Utilities may need to supply the Commission additional, more granular, load data to facilitate the allocations for LSEs with phased-in CCA service that spans multiple GAM vintages.

1 **a) Year-Ahead Allocation**

2 Year-ahead System, Local, and Flexible RA obligations are
3 established for each of the LSEs utilizing the
4 Commission-jurisdictional LSE Load Forecast Template.
5 This process also establishes the CAM allocations, and would
6 also set the GAM allocations. System, Local, and Flexible RA
7 attributes would be allocated to the GAM entities at this time,
8 and net requirements (net of CAM and GAM credits and debits)
9 would be provided to all LSEs. This typically occurs around
10 August for the upcoming year's RA compliance cycle.

11 **b) Month-Ahead Allocation**

12 The forecasts submitted on the Month Ahead Load Forecast
13 Template, which captures each LSE's forecast load migration
14 amounts, sets each LSE's Month Ahead System RA
15 requirements. These Month Ahead requirements should trigger
16 a reallocation of GAM System RA among the LSEs that
17 captures the load migration, as well as an allocation of any
18 GAM RA that has not already been allocated (e.g., newly
19 delivering resources). This will ensure that the RA attributes
20 follow the actual load, just as they would before the load
21 departed. These requirements are typically established 60 days
22 prior to the compliance showing deadline.

23 **c) Mid-Year Local and Flexible Update**

24 The Commission employs a process to calculate a Local
25 and Flexible RA requirement update for the second half of the
26 year for all LSEs. This is typically based on a load forecast
27 submitted in March of that year, and also triggers a CAM
28 re-allocation for Local and Flexible attributes. This update
29 should also trigger a GAM re-allocation of those same attributes
30 because, as in the case of the Month Ahead allocation of
31 System RA, the RA attributes should follow the actual load.

1 **d) RA Adjustments for Replacement and Substitution**

2 Because the Joint Utilities will be the entities responsible for
3 submitting GAM resources on behalf of all LSEs in the RA
4 compliance filings, the Joint Utilities will also be responsible for
5 submitting replacements or substitutions,⁴³ if needed by
6 CAISO, on behalf of those same LSEs. As such, the Joint
7 Utilities must be assured recovery of any incremental costs
8 associated with such a replacement or substitution on behalf of
9 remaining bundled service customers. Consequently, the RA
10 attribute benefits from such replacements or substitutions will
11 also be allocated to all LSEs during the monthly allocation
12 process for non-outage related replacements or substitutions.
13 The potential options for RA replacement or substitution include:
14 (1) GAM- or CAM-eligible resources that are not fully utilized in
15 the IOU's showing; (2) bundled service customer-only resources
16 that are not fully utilized in the IOU's showing; (3) newly sourced
17 resources from the market; (4) unsold RA from the PMM
18 portfolio; or (5) via the then-existing CAISO mechanism for
19 capacity replacement or substitution. In the event that a utility
20 uses GAM- or CAM-eligible resources for substitution, there
21 should be no incremental costs borne by the utility and therefore
22 no incremental costs charged to the LSEs for this action.
23 These resources are already paid for by all benefitting
24 customers, available for RA compliance, and are therefore justly
25 utilized for substitution at no incremental cost. If the utility is
26 unable to substitute with a GAM- or CAM-eligible resource, it
27 must use its discretion whether to source the capacity from its
28 unused bundled service resource portfolio, unsold RA from
29 PMM resources, incremental purchases from the market,

⁴³ RA replacement or substitution needs could arise from planned outages, forced outages, de-rates of a resource's capacity, use-limitations, differences between CPUC and CAISO RA rules, delays in achieving commercial operations and/or related NQC, etc.

1 or allow the CAISO to provide pursuant to its then-existing tariff
2 authority.

3 Consistent with the methodology approved by the
4 Commission for CAM substitutions, in the event that a bundled
5 service customer resource is utilized for the replacement or
6 substitution, then the utility's bundled service customers should
7 be reimbursed for the RA at the weighted average RA capacity
8 price by zone and month from the most recent CPUC Resource
9 Adequacy report. If the replacement or substitution is sourced
10 from the market or CAISO, then the actual costs incurred should
11 be paid for by all benefitting LSEs in proportion to their peak
12 load share. If the replacement is sourced from unsold RA
13 from departing load's share of nuclear and gas resources
14 (PMM Portfolio), then similar to the reimbursement described
15 above for the use of a bundled customer resource, departing
16 load customers should receive a credit to the PMM portfolio and
17 the GAM portfolio will receive a debit for the same amount.

18 **e) Consideration for Imports**

19 Contracts that deliver energy to a CAISO intertie can
20 receive System RA credit only when coupled with an intertie
21 allocation. These intertie allocations are made on a load share
22 basis, and as load departs from bundled service, the utility's
23 intertie allocations decrease. This creates the potential for
24 "stranding" import-based RA, causing a situation where the
25 value of an import contract is lowered due to a load departure.
26 Under the Joint Utilities' Proposal, since LSEs will be obligated
27 to pay their share of net costs for such a contract, they should
28 also be afforded the opportunity to receive their share of GAM
29 resources. The Joint Utilities propose that a stakeholder
30 process including the Joint Utilities, CCAs, ESPs, and the
31 CAISO should be convened to create a process that allows all
32 GAM entities to receive their share of GAM RA through a
33 modified CAISO import allocation process.

4. Portfolio Monetization Methodology Mechanics

PMM assigns to departing load customers their *pro rata* share of the actual above-market costs of the PMM portfolio (i.e., actual realized costs for eligible resources net of actual realized value of the resources' production and attributes in the market). RA capacity is monetized via an annual RA sales process as described in detail below.

a. Resource Adequacy Monetization Process

In order to quantify the above-market costs of the PMM resources, the IOU will seek to monetize the departing load customers' *pro rata* share of RA through an annual sales process. First, the available RA amount in each vintage will be divided proportionally between departing load and bundled service customers based on each LSE's year-ahead RA obligation as determined through the Commission's year-ahead RA showing process. For example, if bundled service represents 70 percent of the load responsible for the PMM portfolio, then 70 percent of the PMM portfolio RA capacity will be assigned to bundled service customers and 30 percent of the PMM portfolio RA capacity will be assigned to departing load customers for cost accounting purposes (no physical allocation of attributes takes place).

1) PMM RA Request for Offer Sales Processes

The IOU will then run a RA sales Request for Offers (RFO) in which it will offer the full quantity of departing load RA for sale to determine and establish the annual PMM RA value. Additionally, if the IOU has a long position in RA, it may also offer product for sale in the same RA sales RFOs with proceeds allocated on a *pro rata* basis.⁴⁴ Conversely, if the IOU is short in a particular RA category (i.e., local RA), and wishes to procure RA from the departing load customer allocation, it may bid into the RFO (subject to appropriate safeguards, policies and procedures similar to the

⁴⁴ This approach ensures that all customers are given an opportunity to reduce their portfolio obligations for excess RA while avoiding a structure that would advantage one customer group over another, because the proceeds are allocated proportionally.

1 CAM Energy Auctions that the Commission authorized utilities to
2 conduct and simultaneously participate in) to procure the products.

3 The PMM RA monetization process will include two RFOs to
4 monetize the departing load customers' share of RA from PMM
5 resources: one in the first quarter of each year where long-term RA
6 contracts will be offered, and a second to be concluded by
7 mid-October of each year where the remaining RA will be sold under
8 short-term contracts. The timing of the first quarter auction is
9 designed to allow the utilities to reflect actual RA prices in their
10 annual ERRA forecast proceedings. The timing of the October
11 auction is designed to allow LSEs to transact for residual
12 requirements needed for the subsequent year's year-ahead and
13 month-ahead RA showing process.

14 The timing of the RA RFOs will be coordinated on a scheduled
15 basis among the Joint Utilities and to facilitate regulatory timelines.
16 Through coordination with existing procurement and planning
17 processes, surplus RA made available to the market by each IOU
18 will benefit other LSEs, and the system, by ensuring the voluntary
19 transaction of those products is completed prior to year-ahead RA
20 allocations, ERRA Forecast filings (e.g., departing load charge
21 rate-setting proceedings), and RA showings to support existing
22 planning processes administered by both the Commission and
23 the CAISO.

24 To that end, the long-term RA sales will be conducted in the
25 first quarter in advance of the planning milestones associated with
26 annual CPUC RA Processes and ERRA Forecast proceedings, as
27 identified in Table 4-2 and shown in Figure 4-3. Any remaining RA
28 that would have been allocated to departing load customers will be
29 offered in a short-term RA RFO by mid-October of each year to
30 provide LSEs an opportunity to fulfill any remaining RA needs for the
31 coming year and to give departing load customers an additional
32 opportunity to monetize their portion of the PMM RA portfolio.

TABLE 4-2
YEAR-AHEAD TIMELINE FOR ERRA FORECAST AND RESOURCE ADEQUACY FILINGS FOR
PROMPT COMPLIANCE YEAR

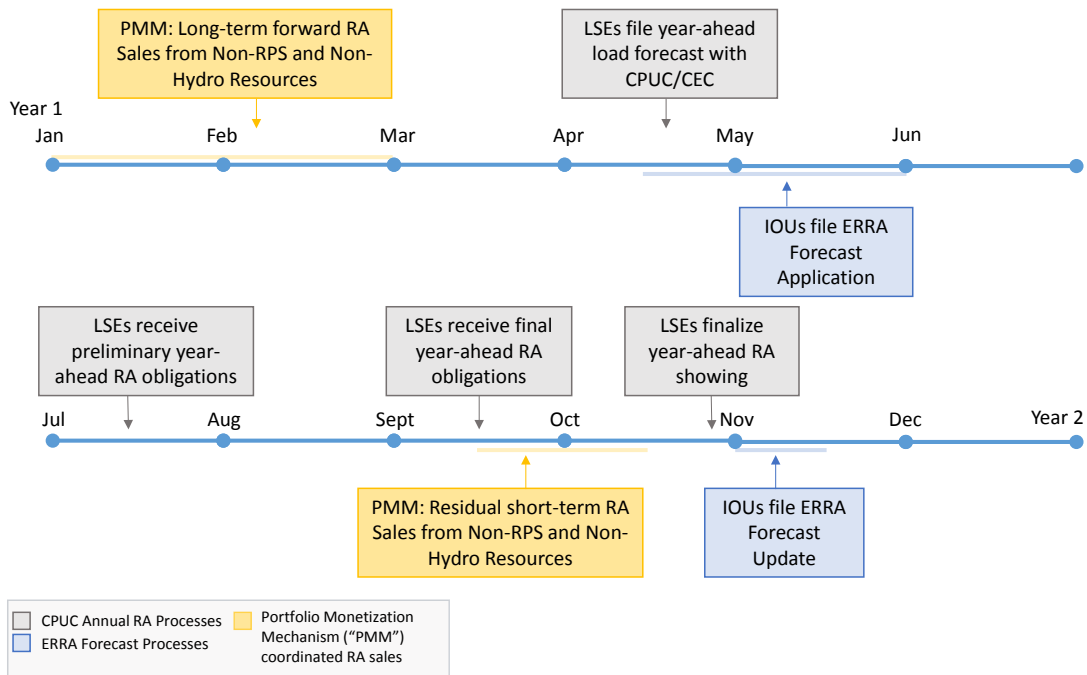
Line No.	Action	Due Date ^(a)
1	IOUs conduct year-ahead long-term sales PMM RA	Jan. 1 – Mar. 1
2	LSEs file year-ahead load forecast	Apr. 21
3	IOUs file ERRA Forecast Application and departing load rates are set ^(b)	Mid-April - June 1
4	LSEs receive preliminary year-ahead RA obligations	July 21
5	LSEs receive final year-ahead RA obligations	Sept. 20
6	IOUs conduct additional year-ahead short-term RA sales of PMM RA	Sept. 20 – Oct. 20
7	Final year-ahead RA showing	Oct. 31
8	IOUs file ERRA Forecast Update ^(c)	Early Nov.

(a) Due date in year prior to compliance year.

(b) PCIA set based on current energy supply portfolio reflecting all Q1 sales activities.

(c) ERRA Forecast Update to reflect all sales activities completed to date.

FIGURE 4-3
PROPOSED TIMELINE FOR PMM PORTFOLIO REDUCTION AND RESIDUAL
SALES ACTIVITIES



1 **2) Use of PMM RA Sales Outcomes to Determine PMM**
2 **Above-Market Costs**

3 As described in detail in Chapter 4, Section D, the annual PMM
4 RA value is based on the actual PMM RA sales revenues and will
5 be used to calculate the “above-market” costs of departing load’s
6 *pro rata* share of the PMM portfolio.⁴⁵ If some of the departing
7 load’s portfolio share of the RA is left unsold after the two annual
8 RFOs and is not later used for substitution⁴⁶ or sold by the IOU in
9 intra-year transactions (i.e., if the RA goes unused for compliance),
10 then such RA will not receive any RA revenue credit against the
11 actual cost of the resource. Bundled service customers will pay for
12 the *pro rata* share of the PMM portfolio RA that is assigned to them,
13 and not otherwise monetized through the PMM RA RFO sales
14 processes, through the ERRRA.

15 **B. Consistency of the Joint Utilities’ Proposal With the Overall Goal and**
16 **Guiding Principles of Proceeding (Scoping Memo, pp. 13-14)**

17 As discussed in detail below, the Joint Utilities’ Proposal fully addresses the
18 overall goal and the guiding principles of the instant proceeding by ensuring that
19 customers who depart from bundled service receive their *pro rata* share of the
20 benefits from—and pay their *pro rata* share of the net costs of—resources that
21 were procured or built on their behalf, and ensuring that cost shifting does not
22 occur between customers who remain on bundled service and customers that
23 are served by an alternative procurement service provider.

24 **1. Overall Goal**

25 The scoping memo specifies the overall goal of this proceeding as
26 follows:

27 The Commission shall ensure that bundled retail customers of an
28 electrical corporation shall not experience any cost increases as a result
29 of either (1) retail customers of an electrical corporation electing to

45 Departing load customers will pay for the above-market costs of the PMM portfolio through their PAC rate, while bundled service customers will pay for both the above-market costs of the PMM portfolio and the cost of any PMM portfolio RA that is assigned to them through their generation rates.

46 Any unsold RA in the PMM portfolio may be used to substitute RA in the GAM portfolio (as discussed above in Section A.4.a.2).

1 receive service from other providers or (2) the implementation of a
2 community choice aggregator program.

3 The Commission shall also ensure that departing load does not
4 experience any cost increases as a result of an allocation of costs that
5 were not incurred on behalf of the departing load.⁴⁷

6 The Joint Utilities' Proposal is designed to prevent cost shifts to either
7 bundled service or departing load customers. By allocating to all customers
8 their *pro rata* share of the attributes and net costs from procurement
9 undertaken on their behalf via GAM, and monetizing all attributes of PMM
10 resources on behalf of departing load customers, cost shifts, in either
11 direction, are completely avoided. GAM and PMM meet this test by first
12 taking the total resource costs, which are easily calculated by the utility and
13 transparent to the relevant stakeholders. Then, these costs are netted by
14 the offsetting revenues that are actually realized in transparent and liquid
15 energy markets. The net costs are then allocated to each customer group
16 based on its responsibility for the procurement of those products. And,
17 for GAM resources, all customers receive a *pro rata* allocation of the REC
18 and RA attributes through their LSE.

19 To provide predictability for all customers, these costs and revenues are
20 forecast in the ERRA Forecast proceeding for rate-setting purposes,
21 then trued-up at the end of the year based on actual market outcomes.
22 The true-up is a key component to meeting the overall goal of the
23 proceeding because forecasts of complex market outcomes are inherently
24 inaccurate. By adjusting the costs and revenues to reflect actual outcomes
25 at the end of each year, the goal of ensuring that neither bundled service nor
26 departing load customers experience cost shifts is met.

27 In the case of GAM resources, what remains after net costs are settled
28 is the RA and RECs that were procured on behalf of all customers.
29 However, no transparent, liquid market exists to accurately assess the value
30 of REC attributes. Furthermore, if such markets did exist and the utility were
31 to offload a large quantity of such attributes due to high levels of departing
32 load, the prices would likely decrease significantly and result in higher
33 above-market costs for all customers. Moreover, if the utility had to sell
34 RECs on a short-term basis, the long-term designation that almost all the

⁴⁷ Scoping Memo, p. 13.

1 Joint Utilities' RPS-eligible resources currently enjoy would be undermined
2 and create a significant loss of value for customers. RA attributes for GAM
3 resources also present a challenge due to the largely intermittent nature of
4 the underlying GAM resources and the public policy aspect of using
5 preferred resources first to meet reliability needs. Instead, GAM allocates
6 those attributes directly to customers to ensure that preferred resources are
7 used first to meet RA requirements. In the case of PMM resources, the
8 energy and the departing load customers' *pro rata* share of the RA is offered
9 in the markets to reduce their net cost responsibility, so no allocation is
10 required. In all instances, in part because there is no shifting of costs
11 between customers, the Joint Utilities' Proposal is equally effective at all
12 levels of departing load.

13 **2. Guiding Principles**

14 The September 25, 2017 Scoping Memo and Ruling of Assigned
15 Commissioner established that any PCIA methodology adopted by the
16 Commission to prevent cost shifts to either bundled service or departing
17 load customers should be consistent with the following guiding principles.

18 **a. "Should Have Reasonably Predictable Outcomes That Promote** 19 **Certainty and Stability for All Customers Within a Reasonable** 20 **Planning Horizon."**⁴⁸

21 The Joint Utilities' proposed GAM and PMM generate predictable
22 outcomes compared to the PCIA, because fewer variables impact the
23 net costs allocated to the departing load customers. Resource costs will
24 be predictable over time, because a significant portion of each utility's
25 Eligible Portfolio is comprised of renewable contracts that generally
26 have fixed prices and predictable quantities over time. And, because
27 energy and A/S revenues are inversely correlated with each LSE's
28 energy and A/S procurement costs, any changes in market conditions
29 that increase the net costs of the Eligible Portfolio will directly
30 correspond with a decrease in LSEs' market procurement costs.
31 Most importantly, as discussed in Chapter 2, volatility around the REC
32 MPB in particular has been the key driver of past fluctuations in the

⁴⁸ Guiding Principle 1b, *id.* at p. 14.

1 PCIA. Within GAM, all volatility associated with the value of RECs is
2 eliminated, because the attribute itself is conveyed to the departing load
3 customer's LSE, rather than an imprecise single-point price assessment
4 of above-market cost for the REC.

5 **b. “Should be Flexible Enough to Maintain Its Accuracy and Stability**
6 **if the Number of Departing Customers Changes Significantly, and**
7 **to Maintain Its Accuracy and Stability if Customers Return to**
8 **Bundled-Customer Service.”⁴⁹**

9 Because the Joint Utilities' Proposal allocates a proportionate share
10 of the attributes for GAM resources to the LSE serving the departing
11 load customers and allocates the net costs for GAM and PMM
12 resources to customers based on a vintaged portfolio method, it ensures
13 that costs and attributes of a vintaged portfolio are allocated equitably
14 and that all customers are treated the same. In addition to ensuring
15 equity between customers, in the event of a mass involuntary return⁵⁰
16 of departing load customers to a utility's procurement service, that
17 proportionate share of GAM attributes would also return with the
18 customers, and therefore reduce the need for the utility to procure
19 resources to serve the returned load, thereby mitigating some of the
20 exposure to the incremental procurement cost risk resulting from such
21 mass return of customers. Finally, and most importantly, the Joint
22 Utilities' Proposal is fully-scalable (i.e., able to meet any level of
23 departing and returning load) and will retain its “accuracy” at all potential
24 levels of departing load (up to 100 percent). In contrast, the current
25 PCIA would likely have unmanageable over- or under-collections that
26 would have to be amortized to remaining bundled service customers,
27 if any, in an environment with significant levels of departing load.

⁴⁹ Guiding Principle 1c, *id.*

⁵⁰ Mass involuntary return is defined in Rule 22 of the Joint Utilities' respective tariffs.

1 **c. “Should Not Create Unreasonable Obstacles for Customers of**
2 **Non-IOU Energy Providers”⁵¹**

3 The Joint Utilities’ Proposal does not hinder the formation of new
4 non-IOU energy providers, and in fact supports nascent and existing
5 providers by ensuring a transparent, equitable, predictable allocation of
6 legacy procurement costs and benefits while adhering to state law.
7 New departing load will immediately benefit from GAM by avoiding the
8 need for new procurement to meet the portion of needs that were
9 already met by IOU procurement. Existing energy providers will gain the
10 benefits of the diverse resources, including from long-term contracts,
11 which exist within the IOU portfolios, avoiding inefficient
12 double-procurement of new resources when existing resources have
13 already been procured that meet precisely the same need (e.g., SB 350
14 requirements that 65 percent of RPS requirements be sourced from
15 long-term resources beginning in 2021). The scalability of GAM makes
16 it an appropriate methodology in an environment of increasing load
17 departure because the utility’s RPS-eligible and large hydro-electric
18 resource attributes will transfer to the departing load’s new LSE and not
19 be potentially stranded as could result under any mechanism that
20 requires the utilities to dispose of unneeded resources to serve
21 remaining bundled service customers.

22 PMM was added to the Joint Utilities’ Proposal in response to
23 concerns raised by stakeholders about the allocation of non-green
24 resource attributes and reducing the size of the portfolio that the IOUs
25 are seeking to allocate. By first seeking to monetize the PMM portfolio
26 via the RA sales process, the IOUs are ensuring that every reasonable
27 step will be taken to reduce the cost obligation retained by departing
28 load for PMM resources. And by limiting attribute allocations to
29 RPS-eligible and large hydro-electric resources, there is no transfer of
30 “brown” or non-preferred resources to LSEs.

51 Guiding Principle 1d, Scoping Memo, p. 14.

1 **d. “Should be Transparent and Verifiable, Including the Most Open**
2 **and Easily Accessible Treatment of Input Data, While Maintaining**
3 **Confidentiality of Information That Should Remain Confidential”⁵²**

4 GAM and PMM are fully transparent and verifiable because they use
5 actual market results and/or result in a *pro rata* allocation of resource
6 attributes. To ensure transparency and verifiability in the forecasting
7 process, the Joint Utilities propose a forecasting methodology in
8 Chapter 6 that will allow LSEs to forecast the GAM and PMM,
9 while protecting bundled service customers’ confidential procurement
10 information. In addition, the Commission’s ERRR Compliance
11 proceeding supports the objective of ensuring transparency and
12 verifiability of GAM and PMM allocations. Finally, because both GAM
13 and PMM net costs will be trued up annually based on actual market
14 results and generation performance, the net costs allocated to all
15 customers will be fully verifiable and compliant with the customer
16 indifference requirement.

17 **e. “Should be Consistent With California Energy Policy Goals and**
18 **Mandates”⁵³**

19 The Joint Utilities’ Proposal is consistent with California’s energy
20 policy goals and mandates. GAM allows all customers to apply the
21 progress made by over a decade of procurement toward the state’s RPS
22 goals by allocating them the RECs that were procured on their behalf.
23 If departing load customers wish or need to achieve higher levels of
24 RPS procurement, they will be starting from the base of utility
25 procurement conducted on their behalf.

26 Importantly, GAM prevents inefficient double-procurement that could
27 result in higher costs and increased operational challenges in managing
28 the electric grid. Allocating RPS attributes to departing load obviates the
29 need to procure a similar attribute while adding more resources to the
30 grid without consideration of existing resources. GAM also ensures that

52 Guiding Principle 1a, *id.* at p. 13.

53 Guiding Principle 1e, *id.* at p. 14.

1 already-procured preferred resources are used first to meet RA
2 requirements.

3 PMM provides a source of liquidity to the RA market by ensuring
4 that all RA capacity that was procured on behalf of departing load
5 customers is offered in the market for resale each year. This will help all
6 LSEs ensure the reliability of the grid in accordance with state
7 mandates.

8 **f. “Should Allow Alternative Providers to be Responsible for Power**
9 **Procurement Activities on Behalf of Their Customers, Except as**
10 **Expressly Required by Law”⁵⁴**

11 Under the Joint Utilities’ Proposal, alternative providers will continue
12 to be responsible for procurement activities on behalf of their customers.
13 The fact that some attributes will be conveyed to alternative providers
14 should be considered in the context that most of those attributes were
15 already procured before those entities came into existence. Most new
16 procurement is fully under the purview of the alternative provider.
17 In addition, the Joint Proposal recognizes that certain procurement is
18 required of the IOU independent of the bundled service load in its
19 service territory to achieve specific policy goals or mandates.
20 Other LSEs do not share this obligation. Accordingly, the benefits and
21 costs of those resources should be equally shared independent of the
22 date of load departure.

23 Taking this guiding principle to mean that no legacy procurement
24 costs or attributes may be assigned to departing load customers would
25 be inconsistent with the statutory requirement recognized in this
26 proceeding prohibiting cost shifts to any customer group.
27 Namely, any method that does not allocate RPS attributes to departing
28 load customers and continues to depend on unreliable benchmarks to
29 estimate their market value will result in increased costs for either
30 departing load or bundled service customers. Allocating RPS attributes
31 to alternative providers via GAM is consistent with statutory
32 requirements, facilitates an efficient use of the procured resources,

54 Guiding Principle 1f, *id.*

1 allows providers to be responsible for all procurement activities that
2 were not already conducted, and is consistent with the overall goal of
3 this proceeding. In an environment of significant departing load, it is
4 highly impractical and certainly very costly to require the utilities to
5 liquidate their substantial existing long-term RPS portfolio holdings
6 because new LSEs (whose formation is wholly discretionary) do not
7 want an allocation of RPS attributes that were previously procured for
8 their customers.

9 In contrast to the sound public policy reasons for allocating RECs
10 and RA associated with GAM resources, PMM is designed in
11 recognition that non-RPS and non-large hydroelectric resources can be
12 more readily monetized in the market without loss of value or impacting
13 grid operations. As a result, to reduce the amount of bundled service
14 portfolio allocations to departing load customers to the greatest extent
15 possible, the PMM is designed to limit portfolio allocations to only
16 RPS-eligible and large hydroelectric resources. The combination of
17 PMM and GAM appropriately balances the legal mandate that the cost
18 allocation methodology not create cost shifts, while maximizing the
19 amount of procurement to be performed by alternative providers.

20 **g. “Should Allow an Alternative Provider to Elect to Pay for Its Share**
21 **of Above-Market Costs in a Manner That Complements the CCA’s**
22 **Particular Procurement Needs and Goals”⁵⁵**

23 In order for the guiding principle of allowing an alternative provider
24 to elect to pay for its share of above-markets costs to be implemented,
25 it must be consistent with statutory requirements and the overall goal of
26 this proceeding to prevent cost shifts to any customer group as a result
27 of the retail service choices of other customers. As discussed at length
28 in this Chapter, REC attributes, particularly long-term attributes, do not
29 transact in a liquid, transparent market and, therefore, will always be
30 valued inaccurately when settled against administratively set
31 benchmarks. Additionally, the value of RECs varies significantly
32 amongst the various portfolio content categories (i.e., PCC 1, PCC 2,

55 Guiding Principle 1g, Scoping Memo, p. 14.

1 PCC 3). An inaccurate valuation will result in a cost shift to either
2 bundled service customers or departing load customers, which is
3 contrary to the statutory indifference requirement and the overall goal of
4 this proceeding. It should be noted that LSEs are not required to use
5 the allocation of attributes they receive on behalf of their customers, and
6 can instead elect to sell them (or not use them, although it would be
7 uneconomic to do so). Any concerns LSEs express about their inability
8 to sell allocated attributes would be equally relevant, if not more so, to
9 requiring the Joint Utilities to monetize those same attributes because of
10 the scale involved with the bundled service customer portfolios.

11 In contrast, the inclusion of PMM in the Joint Utilities' Proposal
12 reduces the allocation of attributes in a manner that complements CCA
13 procurement goals while ensuring satisfaction of statutory requirements
14 and policy goals.

15 **h. “Should Only Include Legitimately Unavoidable Costs and Account**
16 **for the IOUs’ Responsibility to Prudently Manage Their Generation**
17 **Portfolio and Take All Reasonable Steps to Minimize Above-Market**
18 **Costs”⁵⁶**

19 As discussed in greater detail in Chapter 3 describing IOU portfolio
20 optimization and management activities, the Joint Utilities' Proposal will
21 only include legitimately unavoidable costs and account for the IOUs'
22 responsibility to prudently manage their portfolios. All of the IOUs'
23 procurement is either approved as necessary by the Commission on an
24 upfront basis or after-the-fact according to requirements of the IOUs'
25 BPPs, RPS plans, etc. The ongoing management of the resulting
26 portfolios is reviewed annually in the Joint Utilities' respective ERRA
27 Compliance proceedings. The IOUs are subject to comprehensive
28 oversight in a variety of forums and stakeholder processes before,
29 during and after procurement decisions have been made. Only those
30 costs resulting from the actions that are approved by the Commission
31 will be included in the GAM and PMM rates, making the Joint Utilities'
32 Proposal consistent with this guiding principle.

56 Guiding Principle 1h, *id.*

1 **i. “Should Reflect the Value of the Benefits That Departing**
2 **Customers Impart to Remaining Bundled Service Customers”⁵⁷**

3 The Joint Utilities know of no value/benefits that departing load
4 customers impart only to remaining bundled service customers. In fact,
5 in the current declining price environment, additional levels of departing
6 load limit remaining bundled service customers' ability to procure
7 relatively-inexpensive market resources to fill open portfolio positions,
8 which would reduce their average cost of service.

9 **j. “Should Accurately Reflect and Seek to Preserve All Short-,**
10 **Medium- and Long-Term Value of the Resources Procured by the**
11 **Utilities”⁵⁸**

12 REC attributes may have varying values depending on their status
13 as short- or long-term resources or their contract tenor generally.
14 GAM allocates attributes directly to departing load customers' LSEs
15 while maintaining the underlying duration of the attribute. This allows
16 customers to fully enjoy the benefits and underlying value of those
17 attributes, regardless of their duration. Moreover, each customer's LSE
18 will receive its share of all resources within its vintage for the term of the
19 underlying contract. This means the value of predictability, hedging, or
20 any other value associated with the term of the resource is fully realized
21 by the departing load customer and its LSE.

22 Energy and A/S are bid into the markets daily, so they do not have
23 any underlying long-term value on their own. Nonetheless, to the extent
24 that the underlying contract for the resource provides a long-term hedge
25 against daily market prices, that value is conveyed to the departing
26 load customer via the net cost calculation in the same manner that
27 bundled service customers receive. Similarly, RA resources covered by
28 PMM do not currently carry unique compliance value by virtue of their
29 underlying contract durations. However, to the extent that the
30 underlying contract for the resource provides a long-term hedge against
31 daily market prices, that value is conveyed to the departing load

⁵⁷ Guiding Principle 1i, *id.*

⁵⁸ Guiding Principle 1j, *id.*

1 customers via the net cost calculation. By accurately reflecting and
2 conveying the full value of all resources included in GAM and PMM to all
3 customers in a *pro-rata* manner, this guiding principle is met.

4 **k. “Should Respect the Terms of Existing Power Purchase**
5 **Agreements between Power Suppliers and IOUs”⁵⁹**

6 The Joint Utilities’ Proposal has no impact on the terms of existing
7 PPAs. Existing PPAs will continue to function at any level of departing
8 load and the allocation of attributes from the PPAs subject to GAM will
9 be done by the utility as an entirely separate transaction. This means
10 the PPAs’ counterparties will see no change in their operations or
11 financial outcomes.

12 **C. Need for Statutory Changes or Other Implementation Considerations**
13 **(Scoping Memo Issue 11)**

14 **1. Proposed REC Attribute Language to Enable REC Allocation**
15 **under GAM**

16 As discussed in Section A.3, the Joint Utilities propose to allocate a
17 portion of their total GAM-eligible REC portfolios⁶⁰ to CCAs and ESPs
18 under GAM. This proposal is designed to ensure that both bundled service
19 and departing load customers do not experience cost shifts and that the
20 value of the Joint Utilities RPS-eligible procurement continues to convey to
21 the customers for which it was procured. In the past, parties have
22 expressed some concern that allocating a PCC 1 REC⁶¹ would result in the
23 REC being classified as PCC 3,⁶² decreasing the value of this benefit.
24 Additionally, there may be questions regarding whether the full long-term
25 compliance benefits of RECs transferred to other entities under GAM will

⁵⁹ Guiding Principle 1k, Scoping Memo, p. 14.

⁶⁰ The total volume of RECs within the portfolio of an electrical corporation for a single quarter (Q1: Jan-Mar, Q2: Apr-Jun, Q3: Jul, Sep, Q4: Oct-Dec).

⁶¹ PCC 1 refers to the category of RPS-eligible procurement described in Section 399.16(b)(1). The Commission addresses implementation of that Section and described the PCCs more fully in D.11-12-052.

⁶² PCC 3 refers to the category of RPS-eligible procurement described in Section 399.16(b)(3), and, as implemented by the Commission in D.11-12-052, generally includes unbundled RECs that are procured separately from the associated energy.

1 count toward the transferee's long-term RPS compliance requirements
2 under SB 350.

3 In this proceeding, the Joint Utilities are requesting that the Commission
4 clarify D.11-12-052, which did not anticipate or address the issue of RECs
5 allocated pursuant to a Commission-approved allocation mechanism,
6 and confirm that RECs transferred under GAM and any other
7 Commission-approved allocation mechanisms retain their original PCC
8 attributes because they will continue to be delivered on behalf of the
9 customers that the RECs were procured for, and which those same
10 customers are paying for (i.e., there is no change to the underlying RPS
11 contract or customer responsibility to pay for the RPS-eligible product).
12 Specifically, the Joint Utilities request a finding that RECs transferred
13 pursuant to Commission-mandated allocation mechanisms do not, by virtue
14 of that allocation, become "unbundled RECs" as that term is used in
15 Section 399.16(b)(3) and in D.11-12-052.

16 Additionally, the Joint Utilities request that the Commission implement
17 the long-term procurement requirement in the RPS statute, as revised in
18 2015 by SB 350,⁶³ to the extent necessary to clarify that RECs associated
19 with either contracts between the procuring utility and the generator for
20 delivery terms of 10 years or more or the procuring utility's ownership or
21 ownership agreements for eligible renewable energy resources and
22 subsequently transferred to other LSEs under GAM or any other
23 Commission-approved allocation methodology, count for the transferee as
24 RECs from "its contracts of 10 years or more in duration" or "its ownership or
25 ownership agreements for eligible renewable energy resources."⁶⁴
26 These clarifications will allow other LSEs to realize the full benefits of

⁶³ See D.12-06-038, pp. 44-45; Section 399.13(b) (requiring that, by January 1, 2021, at least 65 percent of a retail seller's procurement be from "its contracts of 10 years or more in duration or in its ownership or ownership agreements" for RPS-eligible resources). The Joint Utilities have historically categorized their contracts in reporting on RPS compliance as long-term (durations of 10 years or more) or short-term based upon the delivery term of contracts. The Commission has not yet implemented Section 399.13(b) as revised by SB 350, but it has previously clarified that "repackaged contracts," meaning those entered into by one entity and then re-packaged and transferred to other entities to meet their long-term contracting needs, continue to count toward the RPS long-term requirements added by SB 2 (1X) (2011).

⁶⁴ *Id.*

renewable procurement done on behalf of their customers and for which those customers are paying their proportional share of the net costs.

2. Power Content Label Changes

The Eligible Portfolio will be split between GAM and PMM portfolios. The Joint Utilities propose that the utility Power Content Label would include only the utilities' share of the GAM and PMM resources; the departing load share of PMM resources would not be reflected on the utility power content label.⁶⁵

D. Cost Recovery and Rate Design

In this section, the Joint Utilities describe the ratemaking and rate design mechanisms to implement GAM and PMM and ensure that all customers pay the same rate toward the recovery of the actual "relevant" costs for which they are responsible. For GAM, the relevant costs are defined as the "net costs," or actual costs less actual energy and A/S revenues, of the vintaged GAM portfolios, and for PMM, the relevant costs are defined as the "above-market costs," or actual costs less actual energy and A/S revenues less actual RA revenues, of the vintaged PMM portfolios. As discussed below, bundled service customers will pay for the relevant costs of the GAM and PMM portfolios through their generation rates, with a portion of their generation billed revenue being applied towards the recovery of the vintaged GAM or vintaged PMM costs. Similarly, departing load customers will pay for the relevant costs of the vintaged GAM and PMM portfolios through the Indifference Rate, which will include the PAC and the Ongoing CTC.

1. Cost Recovery

a. Background

As described in Chapter 2, under the Current Methodology, all resources in the Joint Utilities' generation portfolios⁶⁶ are assumed to be used to meet bundled service customers' generation requirements,

⁶⁵ Any proposed changes will be coordinated with current activities related to AB1110.

⁶⁶ This does not include any CAM-eligible resources.

1 and the full costs,⁶⁷ including any that may be viewed as above-market,
2 of those resources, are recorded in the ERRA. In addition to the full
3 costs of those resources, which include contract costs, fuel costs, and
4 variable operations and maintenance (O&M) expenses as described in
5 Appendix E (as debits), the ERRA also records the market revenues
6 received for those resources' energy and A/S (as credits) and other
7 costs that are excluded from the Current Methodology, such as
8 short-term purchases (as debits).

9 The total cost of "fuel and purchased power" is forecast on a
10 year-ahead basis in the ERRA Forecast proceeding and bundled service
11 generation rates are set based on this forecast. The Current
12 Methodology utilizes that same forecast to determine the total
13 Indifference Amount, on a vintaged basis, and to set the departing load
14 Indifference Rate.⁶⁸ Revenues collected from both bundled service
15 customers' CTC and generation rates and departing load customers'
16 CTC and PCIA rates (billed revenues) are recorded in the ERRA
17 balancing account.^{69,70} In other words, the ERRA balancing account
18 has traditionally been the primary account used to record all
19 generation-related costs—both the net costs associated with
20 utility-owned and contracted resources and the costs of market
21 purchases. Revenues from departing load customers' PCIA rates,⁷¹
22 intended to account for their "share" of the above-market costs of the
23 utility-owned and contracted resources, are credited to the ERRA

67 The capital and O&M revenue requirements for UOG are recorded in each utility's General Rate Case (GRC)-related balancing account (SCE—Base Revenue Requirement Balancing Account, PG&E—Utility Generation Balancing Account, and SDG&E—Non-Fuel Generation Balancing Account) and the fuel and other variable operating costs for UOG are recorded in the ERRA.

68 The Indifference Rate is currently defined as the sum of the CTC and PCIA rate components.

69 For more detail on the current structure of ERRA, see SCE's Preliminary Statement YY, PG&E's Preliminary Statement CP, and SDG&E's ERRA Preliminary Statement.

70 PG&E and SDG&E maintain CTC as a separate rate component applicable to both bundled service and departing load customers and separate balancing accounts. SCE does not maintain a separate CTC rate component and balancing account and credits CTC billed revenues from departing load customers to its ERRA.

71 For SCE, this also includes revenues from CTC rate.

1 balancing account to theoretically ensure that bundled service
2 customers' generation rates are not impacted by any customer's
3 decision to depart bundled service.

4 But, as described in Chapter 2, the Current Methodology,
5 which relies on administratively-set benchmarks to determine the above
6 market costs, is not effective at quantifying and recovering the true
7 above-market costs of the Joint Utilities' generation resource portfolios.
8 Additionally, although revenues collected from both bundled service and
9 departing load customers are recorded in the ERRR, any differences
10 between forecast costs, actual costs, and billed revenues are solely
11 assigned to the bundled service customers. As such, the Current
12 Methodology cannot ensure the protection of bundled service customers
13 from cost shifts due to departing load. Although the Joint Utilities
14 believe that the Current Methodology has resulted in cost-shifts to
15 bundled service customers because the administratively set
16 benchmarks are higher than what can be monetized in the actual
17 markets, in theory, the issues with the Current Methodology could also
18 result in cost shifts in the other direction.

19 GAM and PMM offer the necessary changes to the Current
20 Methodology to address the changing markets and portfolio issues
21 described throughout this Testimony. First and foremost, GAM and
22 PMM provide a transparent process that uses actual market results to
23 ensure that departing load customers pay their *pro rata* share of portfolio
24 costs incurred on their behalf while providing those customers with
25 either the actual realized value for the portfolio monetized on their behalf
26 (PMM) or a direct allocation of the benefits of the portfolio (GAM).
27 GAM and PMM also result in both departing load customers and
28 remaining bundled service customers paying the same average cost, on
29 a per-kWh basis, for each resource for which they are collectively
30 responsible. In addition, because REC attributes will be directly
31 assigned to departing load customers' LSEs through the GAM, there will
32 be no need to forecast and true-up their market value, which will
33 enhance the predictability and transparency of the Indifference Rate.
34 Finally, the GAM and PMM offer a transparent and equitable means for

1 reflecting actual portfolio transactions in the Indifference Rate, which will
2 reduce volatility of the GAM and PMM charges over time.

3 The following sections describe the Joint Utilities' proposed changes
4 to the existing cost recovery methodology that achieve indifference and
5 provide transparency to that process. The Joint Utilities' proposal, which
6 tracks the actual net costs under GAM and the above-market costs
7 under PMM by vintage—based on actual costs and market revenues,
8 and actual billed revenues from customers—ensures that all customers
9 are responsible for only the actual relevant costs of the resources that
10 were procured on their behalf and for which their LSEs receive benefits.

11 **b. Ratemaking Proposal**

12 The Joint Utilities propose to modify the generation-related
13 balancing accounts to more clearly delineate the costs and the
14 associated market revenues of long-term⁷² generation resources
15 entered into on behalf of then-bundled service customers, the benefits of
16 which will be shared with those customers, and the costs of meeting the
17 residual requirements of the current bundled service customers.

18 To accomplish this objective, the Joint Utilities propose to
19 establish the Portfolio Allocation Balancing Account (PABA) with
20 two subaccounts: (1) Green Allocation Mechanism subaccount;
21 and (2) Portfolio Monetization Mechanism subaccount. Additionally,
22 the Joint Utilities will modify the ERRA and GRC Phase I
23 generation-related balancing accounts, as is described in detail
24 below.⁷³ The changes to the ERRA and the GRC Phase 1 generation-
25 related balancing accounts are necessary to ensure that costs and
26 revenues are not double-counted and that any UOG-related base
27 revenue requirements eligible for recovery from both bundled service
28 and departing load customers are also recorded in the PABA instead of

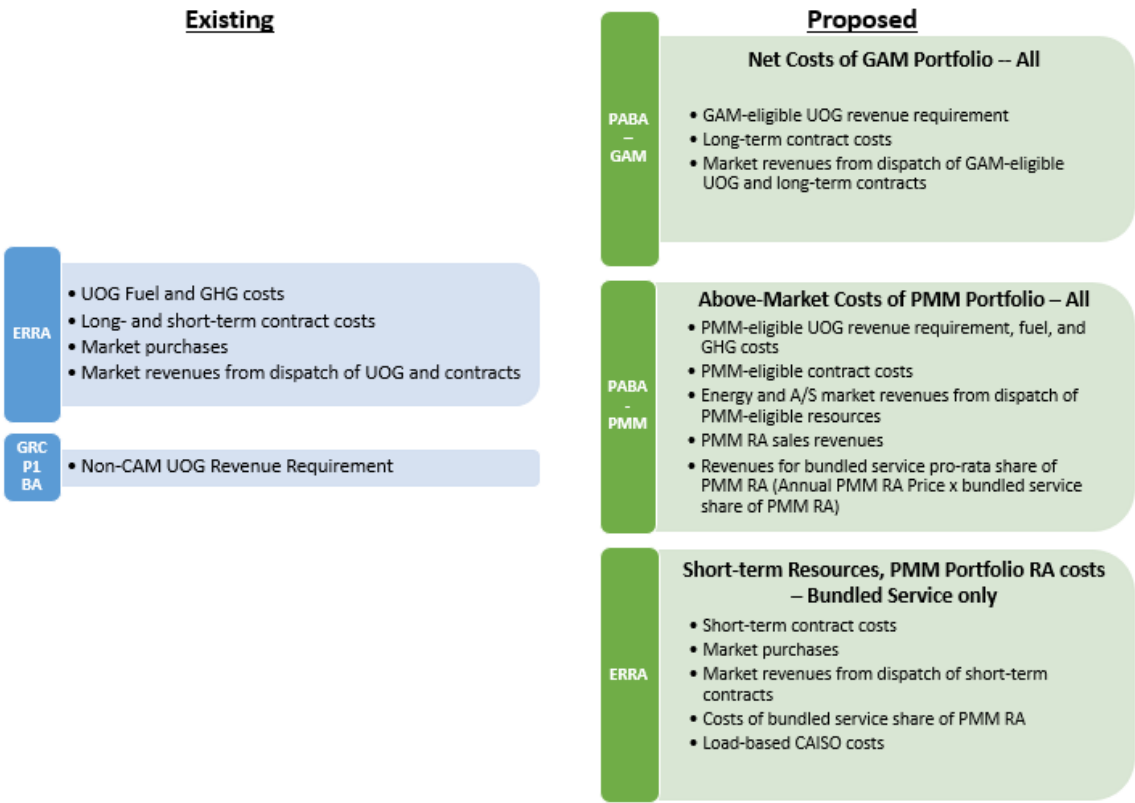
⁷² Long-term is defined as greater than one-year.

⁷³ The Joint Utilities' Phase I GRC generation-related balancing accounts are:
(1) PG&E – Utility Generation Balancing Account (UGBA); (2) SCE – the Generation
Sub-Account of the Base Revenue Requirement Balancing Account (BRRBA-G); and
(3) SDG&E – the Non-Fuel Generation Balancing Account (NGBA) is the Utility
Retained Generation Balancing Account.

in the Joint Utilities’ respective GRC Phase 1 generation-related balancing accounts.

Figure 4-4, below, illustrates the mapping of the costs and market revenues (billed revenues have been excluded for simplicity) under the existing and proposed cost recovery structures.

FIGURE 4-4
GENERATION BALANCING ACCOUNT PROPOSAL



As will be described in Section D.1.b.1, below, the costs and market revenues of the GAM- and PMM-eligible resources will be forecast annually on a vintaged portfolio basis in each utility’s ERRA Forecast proceeding to determine the revenue requirement for each vintaged GAM and PMM portfolio and to set rates for the following year.⁷⁴

⁷⁴ Bundled service generation revenue requirements will thus be set by multiplying the CTC and GAM/PMM rates for each portfolio by the forecast bundled service kWh usage, and adding the result to the modified ERRA revenue requirement (see Section D.1.b.2.c “ERRA” below) and any other bundled service customer-only balancing account revenue requirement.

1 However, as will be described in Section D.1.b.2, below, actual costs,
2 market revenues, and billed revenues will be recorded to the respective
3 GAM and PMM subaccounts of PABA, by vintaged portfolio, and any
4 over- or under-collections will be included in rates the following year.

5 **1) Initial Ratesetting Process**

6 To implement the GAM and PMM, a forecast of the Indifference
7 Rate must be developed and filed as part of each utility's ERRR
8 Forecast application. The Indifference Rate will be based on the
9 forecast costs less forecast market revenues from the GAM and
10 PMM portfolios for the upcoming year and a "true-up" of current year
11 activity. The true-up of current year activity will be based on the
12 balance recorded in the balancing account (i.e., under- or
13 over-collection) that captures the difference between (1) the actual
14 costs and market revenues; and (2) billed revenues received from
15 customers. For example, the 2020 forecast Indifference Rate that is
16 proposed in April-June 2019⁷⁵ will be based on the forecast of
17 portfolio costs and market revenues in 2020 plus the true-up of
18 recorded entries from 2019.

19 The forecast of the upcoming year's portfolio costs and market
20 revenues requires the use of a proxy to estimate the market
21 revenues of the GAM and PMM-eligible portfolios. Because the RA
22 and REC attributes of the GAM resources will be directly allocated
23 to departing load customers' LSEs, the only GAM products that will
24 be monetized are energy and A/S. All PMM energy and A/S will be
25 monetized, along with the departing load customers' share of the
26 PMM RA and any IOU long position, as described in Section A.3.b.
27 As such, the Joint Utilities have developed a methodology to
28 forecast energy and RA revenues for ratesetting purposes.
29 These proxies are merely a forecast starting point to estimate
30 market revenues and thus limit volatility later when truing-up to
31 actual market outcomes. The proxies are discussed below.

⁷⁵ SDG&E files its ERRR Forecast application in April, SCE files its ERRR Forecast application in May, and PG&E files its ERRR Forecast application in June. Each utility files an update to its Forecast application in November.

For clarity, it should be noted that this forecast alone will not assure indifference. However, when the forecast used to set the initial rate is paired with a true-up to actual costs and market revenues, the indifference required by statute will be achieved.

a) Forecast of Energy and Ancillary Services Market Revenues

The Joint Utilities propose that the forecast of energy and A/S market revenues be calculated by multiplying an Energy Proxy by the energy that is forecast to be produced by each resource in the GAM and PMM portfolios.⁷⁶ The Energy Proxy is based on monthly peak and off-peak prices from Platts for North of Path 15 and South of Path 15 markets and the estimated peak and off-peak volumes (MWh) for each resource. The individual Platts index prices are applied to the volumes of energy for each resource in the GAM and PMM portfolios to calculate the total forecast energy and A/S market revenues, as follows:

$$EAER^R = \sum_{M=1}^{12} (PLATTS_{P,M}^{MKT} * EV_{P,M}^R + PLATTS_{OP,M}^{MKT} * EV_{OP,M}^R)$$

Where

$EAER^R$ = Estimate of Annual Energy Revenues for resource R

$PLATTS_{P,M}^{MKT}$ = Platts peak index for month M and market MKT

$PLATTS_{OP,M}^{MKT}$ = Platts off-peak index for month M and market MKT

$EV_{P,M}^R$ = estimated peak energy volumes (in MWh) of resource R

$EV_{OP,M}^R$ = estimated off-peak energy volumes (in MWh) of resource R

⁷⁶ A/S revenues have historically been *de minimus* relative to energy revenues. As such, the Joint Utilities do not currently have a method for forecasting GAM and PMM A/S revenues. However, as described in Section b.2, actual revenues from all markets will be recorded in the GAM and PMM balancing accounts.

1 The EAER for a vintage is then the sum of the EMTV for
2 each resource in the vintage. Specifically:

$$3 \quad EAER_V = \sum_{V=1}^v EAER^R$$

4 Where

5 *EAER_V = the EAER for vintage V based on resources R in that vintage*

6 **b) Forecast Resource Adequacy Market Revenues**

7 The Joint Utilities propose to forecast the PMM RA market
8 revenues by multiplying an RA proxy by the quantity of RA in
9 the PMM portfolio.⁷⁷ The Joint Utilities propose that the RA
10 Proxy be based on the last available CPUC Annual RA report
11 for system, local and flexible RA values. The CPUC's RA report
12 is based on actual transactions⁷⁸ as reviewed and compiled by
13 the CPUC and therefore represents a reasonable starting point
14 upon which to base a later true-up. The Joint Utilities also
15 propose to adjust the volumes included in the forecast of RA
16 market revenues by the ratio of the sum of all RA sales for the
17 IOU from the previous year and the sum of all RA positions
18 offered for sale by the IOU from the previous year. This
19 adjustment is to account for the potential excess RA volumes
20 that cannot be sold due to insufficient market demand that could
21 create rate volatility between the forecast and true-up.

22 The Estimate of RA Market Revenues (ERAMR) is then
23 derived as the RA Market Price (RAMP) times the RA volumes
24 in each vintaged portfolio, as follows:

⁷⁷ This estimates the following two distinct entries: (1) PMM RA RFO; and (2) revenues for bundled service pro rata share of PMM RA (Annual PMM RA Price x bundled service share of PMM RA).

⁷⁸ Additionally, the Joint Utilities will submit the results of their PMM RA sales to the CPUC for use in subsequent CPUC RA Reports.

$$ERAMR_V = RAMP_{Y-1} * \left(\frac{\sum_{m=1}^{12} RAV_{m,Y}^V}{12} \right) * \frac{\sum_{m=1}^{12} RAS_{m,Y-1}}{\sum_{m=1}^{12} RAV_{m,Y-1}}$$

Where

$ERAMR_V$ is Market Value Benchmark for vintage V

$RAMP_{Y-1}$ = RA Market Price for previous year y

$RAV_{m,Y}^V$ is monthly volumes of RA position for year Y and vintage V

$RAV_{m,Y-1}$ is monthly volumes of RA position offered for previous year ($Y - 1$)

$RAS_{m,Y-1}$ is monthly volumes of RA sales for year Y

$$ERAMR_V = RAMP_Y * \sum_{V=1} RAV_Y^V$$

Where:

$ERAMR_V$ is Market Value Benchmark for vintage V

$RAMP_Y$ = RA Market Price for year y

RAV_Y^V is monthly volumes of RA for vintage V

2) Proposed Balancing Account Changes

a) PABA and the GAM Subaccounts

The PABA will have a subaccount for each vintaged GAM portfolio⁷⁹ for each year that records the costs (debits) and market revenues (credits) of all of the GAM-eligible contracts executed that year and the GAM-eligible UOG approved by the Commission for cost recovery during that year. The GAM will track the net costs that are the obligation of all customers who were bundled service customers that year—customers who are receiving the benefits of those resources (and on whose behalf

⁷⁹ In addition to subaccounts by year, the PABA may also include a single (non-vintaged) CTC subaccount that records the net costs of all CTC-eligible resources. Additionally, the PABA will include a single Legacy UOG subaccount that records the net costs of all Legacy UOG.

1 those resources were procured or built), as described in
2 Chapter 5.⁸⁰

3 For example, the GAM subaccounts will include a 2010
4 vintaged subaccount that will record the costs and market
5 revenues of all GAM-eligible generation contracts executed in
6 the calendar year 2010 and the GAM-eligible UOG approved by
7 the Commission for cost recovery in 2010. Departing load
8 customers who leave after July 2010 (i.e., those with customer
9 vintage 2010 or later) and current bundled service customers
10 are thus responsible for these costs. As such, they will be
11 responsible for the net costs recorded in that 2010 subaccount
12 and all “prior” 2004-2009 GAM subaccounts, which may include
13 the non-vintaged CTC and GAM-eligible Legacy UOG⁸¹
14 subaccounts. Conversely, customers who departed before
15 2010 were not bundled service customers at the time those
16 contracts were executed or UOG was approved by the
17 Commission for cost recovery and would not be responsible for
18 the net costs recorded in that 2010 GAM subaccount.⁸² This is
19 illustrated in Figure 4-5, below.

20 The billed revenues collected from bundled service and
21 departing load customers will also be recorded in the GAM
22 subaccount (credit) on a vintaged basis, as is described in
23 further detail below. Any differences between the actual
24 recorded net costs and the billed revenues will be carried
25 forward and included in bundled service and departing load

80 Bundled service customers in this sentence refers to the current bundled service customers and former bundled service customers that have subsequently departed after the GAM eligible resource was procured.

81 Currently, pursuant to D.08-09-012, Legacy UOG is included in the overall cost responsibility of all customers who pay PCIA. The Joint Utilities’ proposal to track net costs in a separate subaccount of PABA does not modify that aspect of the Current Methodology.

82 As described above, subaccounts represent portfolios of generation resources based on the year those resources were procured or approved. Accordingly, there will be subaccounts for each year that incremental procurement takes place—regardless of whether or not any load departs that year.

customers' rates in the following year, similar to what is done for bundled service customers' generation rates today. Each vintaged GAM subaccount of the PABA will thus include the following monthly debit and credit entries:

Debits

- 1) Fuel and Greenhouse Gas (GHG) costs associated with the GAM-eligible UOG resources in that vintaged portfolio;
- 2) Recorded utility payments to the counterparties of GAM-eligible long-term contracted generation resources in that vintaged GAM portfolio; and
- 3) GRC-derived base rate revenue requirement of the GAM-eligible UOG resources in that vintaged portfolio.

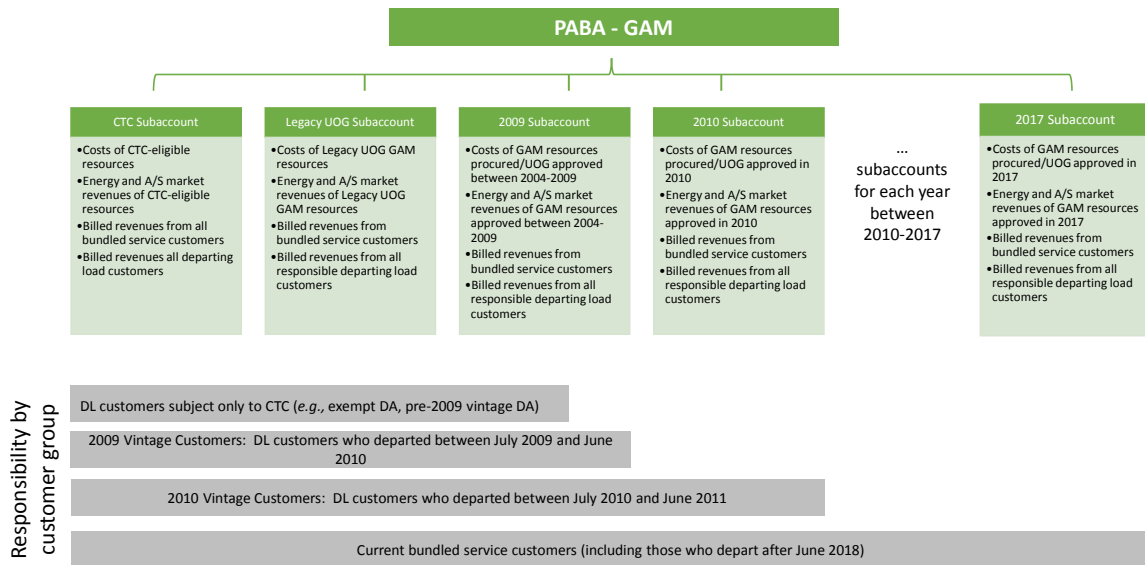
Credits

- 1) Market energy and ancillary service revenues, net of any CAISO costs, associated with the contracted and GAM-eligible UOG resources in that vintaged GAM portfolio;
- 2) A portion of bundled service billed generation revenues equal to the incremental rate for the particular vintaged portfolio multiplied by the actual bundled service kWh usage; and
- 3) A portion of billed revenues from departing load customers equal to the incremental rate for the particular vintaged GAM portfolio multiplied by the actual kWh usage of departing load customers responsible for the costs of that vintaged GAM portfolio.

Credits or Debits

- 1) Interest on any monthly over- or under-collection at the 3-month commercial paper rate.
End-of-Year balances in each GAM subaccount of PABA will be reflected in the vintaged rate in the following year.

FIGURE 4-5
PABA GAM PROPOSED STRUCTURE AND RESPONSIBILITY BY CUSTOMER GROUP



b) PABA and the PMM Subaccounts

The PABA will have a subaccount for each PMM vintaged portfolio that records the costs (debits) and energy and RA market revenues (credits) of the PMM eligible contracts executed that year and the PMM-eligible UOG approved by the Commission for cost recovery during that year. The PMM subaccounts will track the above-market costs that are the obligation of bundled service and non-exempt departing load customers and all RA market revenues.

As described in Section A.3.b, each IOU will monetize a portion (departing load customers' *pro rata* share of the PMM portfolio and any IOU long position) of the PMM portfolios' RA attributes through the annual PMM RA RFO. All market revenues received from the PMM RA RFO will be recorded in the PMM subaccount of PABA.

Additionally, the market revenues received from the PMM RA RFO will be used to establish the annual PMM RA values and determine the actual "market value" of the PMM RA that is

1 allocated to bundled service customers (and not monetized
2 through the PMM RA RFO). Each RA product will have an
3 annual PMM RA value, which is defined as the total revenues
4 received for a given RA product divided by the total quantity of
5 the RA product offered in the PMM RA RFO. The annual PMM
6 RA values will then be multiplied by the quantity of RA that is
7 allocated to bundled service customers to determine the
8 “imputed market revenues” associated with that PMM RA
9 allocation. The PMM subaccounts of PABA will reflect a credit
10 for the imputed market revenues associated with the bundled
11 service customers’ PMM RA allocation. The ERRA balancing
12 account, which is solely the responsibility of bundled service
13 customers, will reflect a corresponding debit for the “cost” of the
14 bundled service customers’ PMM RA allocation. In other words,
15 bundled service customers will pay the above-market costs of
16 the PMM RA portfolio through the PMM, and will pay for any
17 PMM RA that they utilize through the ERRA.

18 The billed revenues, based on the PMM rates, will be
19 recorded in the PMM vintaged subaccounts (credit), as is
20 described in further detail below. Any differences between the
21 actual recorded above-market costs and the billed revenues will
22 be carried forward and included in the PMM rates in the
23 following year, similar to what is done in ERRA today for
24 bundled service customers’ generation rates. Each vintaged
25 PMM subaccount of the PABA will thus include the following
26 monthly debit and credit entries:

27 Debits

- 28 1) Fuel and GHG costs associated with the PMM-eligible UOG
29 resources in that vintaged portfolio;
30 2) Utility payments to the counterparties of PMM-eligible
31 long-term contracted generation resources in that vintaged
32 PMM portfolio; and

- 1 3) GRC-derived base rate revenue requirement of the
2 PMM-eligible UOG resources in that vintaged PMM
3 portfolio.

4 Credits

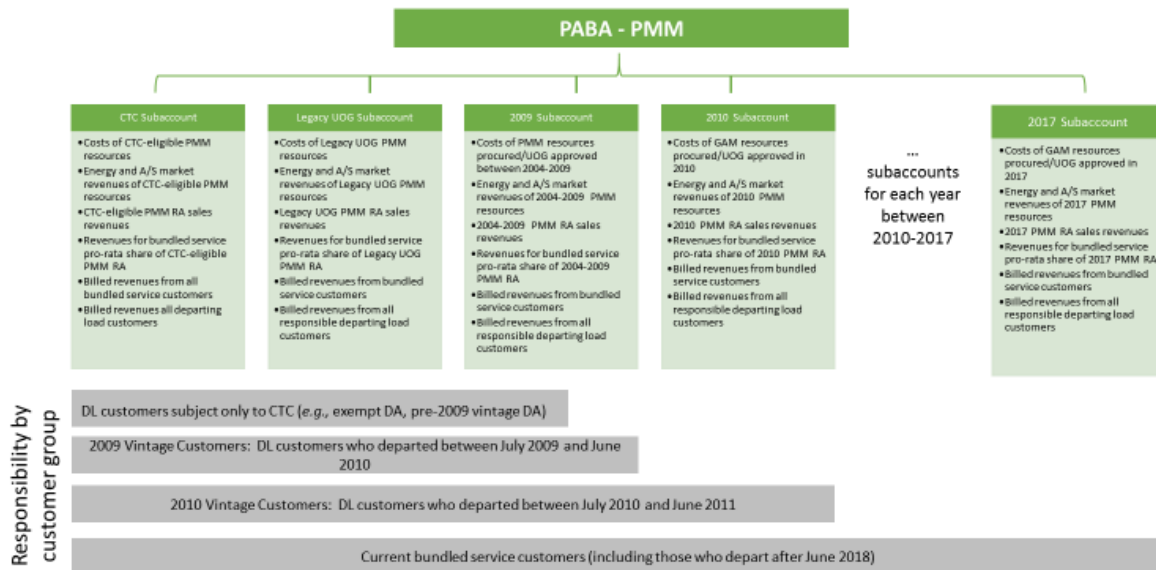
- 5 1) Market energy and ancillary services revenues, net of any
6 CAISO costs, associated with the PMM-eligible contracted
7 and PMM-eligible UOG resources in that vintaged PMM
8 portfolio;
9 2) Market revenues received through the PMM RA RFO;
10 3) Imputed market revenues from bundled service customers
11 for their *pro rata* share of the PMM RA;⁸³ and
12 4) A portion of billed revenues from bundled service and
13 departing load customers equal to the incremental rate for
14 the particular vintaged PMM portfolio multiplied by the
15 actual kWh usage of customers responsible for the costs of
16 that vintaged PMM portfolio.

17 Credits or Debits

- 18 1) Interest on any monthly over- or under-collection at the
19 3-month commercial paper rate.
20 End-of-Year balances in each PMM subaccount of
21 PABA will be reflected in the vintaged PMM rate in the
22 following year.

⁸³ This credit will correspond directly with a debit in the ERRR for the same amount.

**FIGURE 4-6
PROPOSED PABA / PMM STRUCTURE**



c) ERRA

The ERRA will be restructured to record the costs associated with wholesale market purchases (i.e., the costs of meeting remaining bundled service customers' full energy requirements), the fuel and purchased power costs of any resources that are ineligible for GAM, PMM, and CAM, and the cost of the bundled service customers' share of PMM RA. The responsibility for the costs recorded in the ERRA lies solely with then current bundled service customers.⁸⁴ Accordingly, the share of monthly bundled service billed generation revenues to cover these costs, as described below, will be recorded as a credit to the ERRA.

⁸⁴ Examples of this include the costs of short-term power purchases for terms of less than one year (see D.11-12-018, Finding of Fact 24 and Conclusion of Law 3), CAISO charges related to bundled service load, costs of incremental, short-term RA and REC attributes that are needed to meet bundled service load requirements.

1 **d) GRC Phase 1 Generation-Related Balancing Account**

2 The base rate revenue requirement for GAM-eligible UOG
3 and PMM-eligible UOG, as determined in each utility's
4 respective GRC proceeding, will now be recorded in the
5 respective GAM or PMM subaccount of PABA, and will no
6 longer be recorded as a cost in the GRC Phase I
7 generation-related balancing account. Additionally, the
8 portion of the monthly bundled service billed generation
9 revenues that would have been credited to the GRC Phase I
10 balancing account towards the recovery of the GAM-eligible and
11 PMM-eligible UOG base revenue requirement will now be
12 credited to the GAM or PMM subaccounts of PABA,
13 respectively.

14 **3) Determination of Billed Revenues to Be Recorded in Each**
15 **Balancing Account**

16 Billed revenues collected from bundled service customers' CTC
17 and generation rates and departing load customers' PAC and CTC
18 rates will be directed into the various subaccounts of PABA⁸⁵
19 for which they are responsible. This process, which is used today to
20 separate and direct bundled service customers' generation billed
21 revenues into the ERRA and GRC Phase I balancing accounts, is
22 described in the Preliminary Statements of the Joint Utilities'
23 tariffs⁸⁶ and updated regularly to ensure that the correct amount of
24 billed revenues, based on current revenue requirements, is directed
25 to each balancing account. The Joint Utilities propose to utilize this
26 same process to separate and direct billed revenues received from
27 bundled service and departing load customers to the appropriate
28 balancing accounts. A description of the process is included in
29 Appendix D.

⁸⁵ For SDG&E the CTC rate will be directed into its CTBA.

⁸⁶ See SCE's Preliminary Statement YY and ZZ, PG&E's Preliminary Statement I, and SDG&E's Preliminary Statements for ERRA and Non-Fuel Generation Balancing Account.

1 **c. ERRA Trigger**

2 Currently, the Joint Utilities are required to file an application with
3 the Commission to propose to adjust their bundled service generation
4 rates when the under- or over-collection in the ERRA balancing account
5 exceeds 5 percent of the prior year's revenue that is classified as
6 generation for retail rates. The Joint Utilities propose to combine the
7 balance in the modified ERRA and the bundled service customers'
8 share of the balances in the GAM and PMM subaccounts of PABA
9 (calculated based on the ratio of bundled service kWh usage to the total
10 system kWh usage) for this purpose.

11 **2. Applicability**

12 As a general matter, the Joint Utilities propose to apply the new CTC,
13 GAM, and PMM rates to customers in the same manner as CTC and PCIA
14 are applied today.⁸⁷ As discussed in the prior sections, the customer's LSE
15 (e.g., IOU, ESP or CCA) will then receive an allocation of RECs and RA for
16 the GAM portfolio. However, there are some categories of customers
17 whose departing load is not served by one of the LSEs described above.
18 These categories include Customer Generation Departing Load (CGDL),
19 New Municipal Departing Load (NMDL), Transferred Municipal Departing
20 Load, and customers that may be served by Western Area Power
21 Administration (WAPA) or a similarly-situated entity. Where possible, the
22 Joint Utilities propose to continue the process of allocating RA and REC
23 benefits to these customers' LSEs. Where these benefits may not be
24 allocated to the LSE, the Joint Utilities propose to monetize these benefits
25 and reduce the PAC and/or CTC responsibility for the customer.

⁸⁷ SCE currently charges its bundled service customers a composite generation rate that includes their CTC obligation. To increase the transparency of billed revenues to be credited to the CTC subaccounts of PABA, SCE will unbundle its bundled service generation rates into the CTC and the remaining part. The CTC component will be the same for bundled service and departing load customers in the same rate group.

1 One such example is CGDL.⁸⁸ Pursuant to D.03-04-030, nearly all
2 CGDL is subject to the CTC.⁸⁹ The Joint Utilities recognize that, under
3 the GAM proposal, it is impractical to allocate RECs and RA from the
4 CTC-vintaged portfolio to individual CGDL customers. Thus, the Joint
5 Utilities propose that bundled service customers “buy back” the RECs and
6 RA that would have otherwise been allocated to the CGDL customers.
7 In other words, bundled service customers will purchase the RECs and RA
8 from the CTC-eligible portfolio that would have otherwise been allocated to
9 the CGDL customers, and those proceeds will be subtracted from the net
10 costs to be collected from these customers. However, the Joint Utilities
11 propose that consideration of how to set the appropriate “purchase price”
12 for the RECs and RA be deferred to a Tier 3 Advice Letter, to be filed upon
13 issuance of a final decision in this proceeding.

14 The Joint Utilities have also identified an additional category of
15 customers that will need to be addressed. Pursuant to D.15-01-051,
16 Green Tariff and Shared Renewables (GTSR) customers are subject to CTC
17 and a vintaged PCIA based on the date they elect to begin service on
18 GTSR. The Joint Utilities acknowledge that GTSR customers are
19 responsible for the same generation-related above-market costs that are the
20 subject of this Testimony; however, GTSR customers are also responsible
21 for other generation-related costs that, together with the CTC and PCIA,
22 are meant to ensure non-participant indifference. In light of the fact that
23 indifference as it relates to GTSR customers consists of more than just the
24 relevant costs associated with the new CTC, GAM and PMM rates, the Joint

⁸⁸ Pursuant to D.98-12-067, new or incremental load that is served by a Customer Generation unit is considered “departing load” if it does not pass the “physical test.” The physical test “requires that new or incremental customer load be able to be ‘islanded’ to demonstrate that the direct transaction does not require the use of the utilities’ systems.” D.98-12-067, p. 24; Resolution E-3600, dated March 13, 1999.

⁸⁹ Pursuant to SCE Advice Letter (AL) 3263-E and 3263-E-A, SDG&E AL 2778-E and 2778-E-A, and PG&E AL 4743-E and 4743-E-A, certain CGDL installed in SCE’s and SDG&E’s service territories after February 2015 is subject to the 2001 vintage PCIA. However, as described in the February 1, 2018 *Motion for Settlement Agreement* in A.17-05-006, SCE and departing load interests in that proceeding proposed that the 2001 vintage PCIA be used solely for purposes of collecting or refunding, as the case may be, revenue requirements associated with the San Onofre Nuclear Generating Station (SONGS) and pending Energy Crisis-related litigation.

1 Utilities propose that GTSR non-participant indifference, including the
2 consideration of how the new CTC and PAC rates should be applied,
3 be considered once a final decision in this proceeding is issued.

4 **a. Rate Design**

5 This section describes the Joint Utilities' proposal to allocate the
6 costs recorded in PABA subaccounts to rate groups (e.g., residential,
7 small commercial, agricultural, etc.) and to set final rates. The Joint
8 Utilities propose to recover the net costs of GAM-eligible resources and
9 the above-market costs of the PMM-eligible resources from bundled
10 service customers through their new CTC and generation charges and
11 from departing load customers through their new CTC, GAM and PMM
12 charges. GAM and PMM result in both departing load customers and
13 bundled service customers paying the same net or above-market costs,
14 on a per-kWh basis, for each resource—a result that is wholly consistent
15 with the Joint Utilities' proposal to equitably allocate the benefits of the
16 GAM- and PMM-eligible resources to all customers.

17 Today, vintaged Indifference Amounts, as determined using the
18 Current Methodology, are allocated to rate groups based on the
19 contribution of each rate group⁹⁰ to the highest 100 hours of system
20 load. This methodology is known as the “Top 100 hours” methodology.
21 The resulting allocation factors are used to allocate costs to each rate
22 group, which are then divided by the rate group's total forecast system
23 sales to determine the Indifference Rate for that vintaged portfolio.

24 The Joint Utilities recommend changing the revenue allocation
25 factors to be consistent with the factors used to allocate generation
26 costs to their bundled service customers. This change will allow for
27 revenue allocation consistency between bundled service and departing
28 load customers. Both bundled service and departing load customers
29 are paying the same costs but through different mechanisms: bundled
30 service through the generation rate and departing load through the
31 PCIA. Both groups of customers pay the CTC. However, departing

⁹⁰ Both bundled service and departing load customers are included in each rate group for the purpose of determining these allocation factors.

1 load customers have the PCIA allocated to them using the Top 100
2 system hours allocation factors while bundled service customers have
3 those same costs allocated to them using the bundled service
4 generation allocation factors.⁹¹ The disparity caused by using
5 two different types of allocation factors in allocating the same costs
6 results in higher rates for departing load residential customers relative to
7 their bundled service counterparts, and lower rates for other departing
8 load customer classes relative to their bundled service counterparts.
9 Table 4-3 shows the allocation factors for PG&E's Bundled Generation
10 and PCIA rate components.

TABLE 4-3
PG&E REVENUE ALLOCATION FACTORS FOR PCIA AND GENERATION RATES

Line No.		Generation Allocation Factors	PCIA Allocation Factors (Current Methodology)	Difference
1	Residential	40.1%	43.4%	3.3%
2	Small Light and Power (L&P)	11.2%	9.6%	(1.5%)
3	Medium L&P	12.5%	11.5%	(1.0%)
4	E19	13.4%	13.5%	0.0%
5	Streetlights	0.4%	0.1%	(0.3%)
6	Standby	0.6%	0.3%	(0.3%)
7	Agriculture	8.7%	7.6%	(1.1%)
8	E20 T	4.7%	5.1%	0.4%
9	E20 P	6.2%	6.6%	0.4%
10	E20 S	2.4%	2.5%	0.1%

11 As this table demonstrates, PG&E's departing load residential
12 customers are paying roughly 8 percent more than bundled service
13 residential customers for their equitable share of the procurement
14 portfolio.⁹² Table 4-4 shows the actual PG&E PCIA rate difference due
15 to these different allocation factors.

⁹¹ These allocation factors are adopted in the Joint Utilities' respective GRC Phase II proceedings using marginal cost methodologies with the resulting allocation factors based on resolutions of key inputs used to determine the marginal costs values and other various considerations among parties.

⁹² 8.2 percent = 3.3 percent / 40.1 percent (Residential Allocation Factor Difference / Residential Generation Allocation Factor).

TABLE 4-4
PG&E 2018 PCIA RATES COMPARISON USING DIFFERENT ALLOCATION METHODS

Line No.	Rate Group	Rates from Generation Allocation Factors	Rates From Current Methodology	Difference (Proposed – Current)	Percent Difference (Difference/Proposed)
1	Residential	\$0.03039	\$0.03346	\$(0.00307)	(10.1%)
2	Small L&P	\$0.02947	\$0.02466	\$0.00481	16.3%
3	Medium L&P	\$0.02592	\$0.02502	\$0.00090	3.5%
4	E19	\$0.02200	\$0.02104	\$0.00096	4.4%
5	Streetlights	\$0.02723	\$0.00589	\$0.02134	78.4%
6	Standby	\$0.03856	\$0.01196	\$0.02660	69.0%
7	Agriculture	\$0.02934	\$0.02463	\$0.00471	16.0%
8	E20 T	\$0.01770	\$0.01735	\$0.00035	2.0%
9	E20 P	\$0.01595	\$0.01888	\$(0.00293)	(18.4%)
10	E20 S	\$0.02167	\$0.02025	\$0.00142	6.6%

1 Currently any cost shifts, including cost shifts from variances in
2 forecasted and actual load, are spread across bundled service
3 customers using the generation allocation factors. The simple solution
4 of using consistent allocation factors for both groups avoids further
5 distortion in customer indifference for residential customers and is easily
6 implemented.⁹³ These allocation factors are included in each IOU's
7 GRC Phase II so they can be updated as needed.

8 Once the PMM and GAM vintage subaccount revenue requirements
9 have been allocated to rate groups, the Joint Utilities propose to divide

93 As mentioned above, PG&E's current factors for allocating its generation costs to bundled service customer groups are based on customer group load profiles at the system level. Under the Joint Utilities' proposal to apply consistent allocation factors, the same allocation factors will be used to allocate the relevant costs to PG&E's departing load customer groups. For SCE, current factors for allocating its generation costs to bundled service customer groups are based on bundled service customer groups' load profiles. However, SCE also has Commission-adopted generation-related allocation factors that are based on the same marginal cost inputs but are developed using customer group load profiles at the system level (used to allocate certain demand response incentive revenues). Under the Joint Utilities' proposal to apply consistent allocation factors, SCE will continue to use its current factors for allocating its generation cost to bundled service customers and use the latter allocation factors (i.e., those based on customer group load profiles at the system level) for allocating the relevant costs to its departing load customers. SDG&E's current factors for allocating its generation costs to bundled service customer groups are based on bundled service customer groups' load profiles. SDG&E does not currently have Commission-adopted generation allocation factors based on customer group load profiles at the system level. As such, under the Joint Utilities' proposal to apply consistent allocation factors, SDG&E will use its current generation allocation factors based on bundled service customer groups' load profiles to also allocate the relevant costs to its departing load customer until it proposes and the Commission adopts allocation factors based on customer groups' load profiles at the system level in a future GRC Phase II proceeding

1 the rate group-level revenue requirements by the forecast rate
2 group-level sales of those responsible for that vintaged portfolio to
3 determine the applicable new CTC, GAM, and PMM rates.⁹⁴ Under the
4 Current Methodology, the CTC and PCIA rate group-level revenue
5 requirements are divided by the forecast rate group-level sales of all
6 system customers. Continuing to use forecast system level kWh sales
7 in the denominator used to set the rates, as opposed to forecast kWh
8 sales of those responsible for each vintaged portfolio, will result in lower
9 rates than are necessary to collect the revenue requirements.
10 This would perpetuate a systemic undercollection bias in the balancing
11 accounts because the rates are only applied to, and the revenues are
12 only being collected from, those customers responsible for each
13 vintaged portfolio.

94 Consistent with the Cost Recovery testimony included above, vintage PMM and GAM rates will be determined using the PMM and GAM subaccount revenue requirements. However, final PAC rates listed on customers' bills will reflect one single PAC rate component, which will be the sum of all of the incremental vintaged PMM and GAM rates for which they are responsible.

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CHAPTER 5

**SHOULD THE COMMISSION “CAP” OR “SUNSET” THE PCIA
OR ALTERNATIVE COST ALLOCATION METHOD?
(SCOPING MEMO ISSUES 9 AND 10)**

PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 5
SHOULD THE COMMISSION “CAP” OR “SUNSET” THE PCIA OR ALTERNATIVE
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CHAPTER 5

**SHOULD THE COMMISSION “CAP” OR “SUNSET” THE PCIA OR
ALTERNATIVE COST ALLOCATION METHOD?
(SCOPING MEMO ISSUES 9 AND 10)**

A. Introduction

In this chapter, the Joint Utilities address the question set forth in the Scoping Memo as to whether the Power Charge Indifference Adjustment (PCIA) or alternative cost allocation method adopted in this proceeding should be capped or made subject to a sunset requirement. As discussed below, capping or sunsetting the PCIA or alternative cost allocation method is inconsistent with statutory provisions requiring the California Public Utilities Commission (CPUC or the Commission) to ensure customer indifference and gives rise to significant practical concerns, particularly given the prediction of significant load departure within the next decade. Finally, the chapter discusses that fact that the existing 10-year time limit on recovery through the PCIA of costs related to certain energy storage resources and post-2002 utility-owned fossil generation (UOG) is illogical and violates the indifference requirement.

B. Applying a “Cap” or ‘Sunset’ Requirement to Allocation of Costs through the Power Charge Indifference Adjustment or Alternative Cost Allocation Method Would Violate Statutory Requirements

The Scoping Memo asks whether the PCIA or alternative cost allocation method adopted in this proceeding should be capped or made subject to a sunset requirement. Under either approach, cap or sunset, the cost of resources procured to benefit customers who later depart bundled service would at some point no longer be allocated to such customers and would instead be allocated to the remaining bundled service customers. In other words, upon reaching a predetermined cap or sunset date, bundled service customers would absorb the full cost of procurement undertaken to benefit departing load customers, while such departing load customers would pay none of the cost of the resources procured on their behalf. This outcome would clearly violate the

1 indifference principle described in Public Utilities Code Sections 365.2, 366.2
2 and 366.3. In addition, capping or sunseting the allocation of resource costs to
3 customers who depart bundled service is impractical, as discussed in more
4 detail below.

5 There can be no question that the Commission is required to ensure
6 equitable allocation of electricity procurement costs between the Joint Utilities'
7 bundled service customers and customers who depart bundled service to
8 receive service from another procurement service provider. This requirement in
9 the context of Community Choice Aggregation (CCA) departing load is evident
10 from the plain language of Section 366.3, which directs that “[b]undled retail
11 customers of an [investor-owned utility] shall not experience any cost increase
12 as a result of the implementation of a community choice aggregator program.”
13 Similarly, the Legislature made clear in Section 365.2 that when a bundled
14 service customer departs to receive Direct Access (DA) service from an Energy
15 Service Provider (ESP), “[t]he commission shall ensure that bundled retail
16 customers of an electrical corporation do not experience any cost increases as a
17 result of retail customers of an electrical corporation electing to receive service
18 from other providers.” Thus, it is beyond dispute that bundled service
19 customers must remain financially indifferent to the impact of departing load.

20 Regardless of the manner of implementation, a cap or sunset requirement
21 applied to the PCIA or alternative cost allocation method adopted in this
22 proceeding would violate the statutory requirements detailed above. If the utility
23 undertakes procurement on behalf of its bundled service customers, the cost of
24 such procurement must be shared by all benefitting customers, including those
25 who later depart to receive service from a CCA or ESP, for the full period of the
26 utility’s obligation. The statutory indifference requirement is not limited by time
27 or value; there is not a modicum of support for the notion that the intent of the
28 Legislature in adopting the relevant provisions was to at some point shift full
29 responsibility for costs incurred on behalf of departing load customers to
30 remaining bundled service customers. The Commission’s obligation to equitably
31 allocate electricity procurement costs among bundled service customers and
32 departing load customers is manifest and absolute—it applies for as long as
33 procurement costs incurred by the Joint Utilities on behalf of the departing load
34 customers continue to exist. Thus, terminating the PCIA or alternative cost

1 allocation method at any point prior to the end of the utility's cost responsibility
2 through application of a cap on the amount of costs subject to the departing load
3 ratemaking mechanism, or an automatic sunset of its applicable time period,
4 would represent a flagrant violation of the plain language of Sections 365.2,
5 366.2 and 366.3.

6 Applying balancing account treatment to the PCIA/alternative cost allocation
7 method would be equally problematic. In addition to adding unnecessary
8 complexity, an approach that would apply a rate cap to the PCIA/alternative
9 allocation method and then track/recover costs in excess of such rate cap
10 through a balancing account could result in a cost shift in a circumstance where
11 departed load returns to the utility. Moreover, a balancing account approach is
12 akin to requiring bundled service customers to finance departing load customers'
13 payment of the pro rata share of the costs appropriately allocated to them.
14 Given current predictions of load departure discussed below, it would be illogical
15 and inappropriate to impose this burden on the shrinking pool of bundled service
16 customers. Finally, approving this type of balancing account treatment for
17 departing load customers could create an artificial appearance that CCA
18 generation rates are lower than bundled service rates if the rate cap reduces
19 departing load charges. Generation costs for bundled service customers are
20 approved through the Energy Resource Recovery Account (ERRA) proceeding
21 and are generally simply passed on to customers on an annual (or more
22 frequent) basis irrespective of their volatility. Thus, adopting an annual PCIA
23 "cap" with resulting balancing account treatment in order to protect departing
24 load customers from the volatility inherent in the market would be inconsistent
25 with the way the Commission treats analogous generation costs for bundled
26 service customers.

27 **C. Capping/Sunsetting the PCIA or Alternative Cost Allocation Method Raises** 28 **Practical Concerns**

29 The concept of capping or sunseting the PCIA or alternative cost allocation
30 method makes little sense from a practical perspective. In the Commission Staff
31 Whitepaper, *Consumer and Retail Choice, the Role of the Utility, and an*
32 *Evolving Regulatory Framework*, it is predicted that up to 85 percent of retail
33 load will be served by sources other than the Joint Utilities within the next

decade.¹ Thus, capping or sunseting the PCIA or alternative cost allocation method in its entirety at some future point (e.g., 10 years from the date of a final decision adopting a revised PCIA/new cost allocation method) could lead to the absurd result that the 15 percent (or less) of customers who are still bundled service customers would be allocated the full cost of procurement undertaken by the Joint Utilities to serve all customers. This unsustainable outcome is illogical and clearly not in the public interest (in addition to running afoul of the statutory provisions requiring customer indifference, as described above). Moreover, if the PCIA or alternative cost allocation method were to be suspended on a set date or when a particular metric is reached, customers that elected to depart bundled service after that point would bear no responsibility for electric procurement costs incurred on their behalf prior to the time they departed bundled service.

Capping or sunseting the PCIA or alternative cost allocation method on a vintage basis is no less problematic. San Diego Gas & Electric Company, for example, has electric procurement contracts in its portfolio that extend through 2042. If electric procurement costs allocated to departing load customers in particular vintages revert back to bundled service customers prior to the end of the utility's cost responsibility due to termination of the PCIA or alternative cost allocation method, both bundled service customers and departing load customers in later vintages will be harmed. If allocation of electric procurement costs to earlier vintages is suspended due to a cap/sunseting, but the contracts included in those vintages remain in the utility portfolio, the result will be that: (i) remaining bundled service customers will bear an increased portion of cost responsibility for the contracts originally included in capped/sunsetted vintage, an outcome that is inequitable and inconsistent with the statutory "indifference" requirement; and (ii) departing load customers in later vintages will be allocated an increased portion of cost responsibility for contracts in the utility portfolio. As departing load vintages are sequentially excused from cost responsibility due to application of a cap/sunseting, if contracts in such vintages remain in the utility

¹ CPUC Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*, May 2017, p. 3. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

1 portfolio, the rates of bundled service customers would continue to increase
2 (assuming a declining market price environment) in direct violation of the plain
3 language of Sections 365.2, 366.2 and 366.3.

4 Similarly problematic, a cap or sunset requirement could interfere with
5 administration of the Joint Utilities' Green Allocation Mechanism (GAM)
6 proposal, if adopted, and could cause significant burden to both the Joint Utilities
7 and to certain Load Serving Entities (LSEs) serving departing load customers.
8 The Joint Utilities' GAM proposal would establish an allocation of resource
9 benefits and costs to LSEs serving departing load customers. If the cap/sunset
10 operated to revert cost responsibility (and associated benefits) for all existing
11 vintages back to bundled service customers at some point prior to expiration of
12 the utility's cost responsibility, it would cause considerable difficulty, both to the
13 Joint Utilities and to LSEs receiving benefit allocations. If allocated
14 costs/benefits were to revert back to bundled service customers, LSEs would be
15 deprived of benefits they would have relied upon in developing their portfolios
16 and could experience deficiencies; bundled service customers would not only
17 bear inequitable/unlawful cost responsibility (as described above), but would
18 also be burdened by the requirement to hold solicitations in order to dispose of
19 procurement not required to meet bundled service customers' needs, likely at a
20 significant loss. This needless encumbrance of resources and impediment to
21 LSE portfolio planning would serve no valid purpose and is contrary to the
22 public interest.

23 **D. Existing Resource-Specific Time Limits for Cost Allocation Violate the** 24 **Indifference Requirement**

25 As discussed above, the statutory requirement to prevent cost shifting
26 between bundled service customers and departing load customers is not
27 time-limited and applies regardless of resource type (e.g., renewable,
28 conventional, etc.). Put simply, the Commission's obligation to allocate costs in
29 order to preserve indifference applies so long as resources procured to serve
30 customers who subsequently depart bundled service remain in the utility's
31 portfolio. Thus, there is no statutory support for establishing different rules or
32 cost allocation periods for different resources.

33 Under the current PCIA methodology, the Commission has established a
34 presumption that the costs of certain resources will be allocated for a limited

1 period rather than for the total period of utility cost responsibility. Specifically,
2 the Commission has singled out energy storage resources and post-2002 UOG
3 as being subject to a 10-year limit on cost allocation. To satisfy its obligation to
4 ensure customer indifference, the Commission must eliminate these arbitrary
5 term limits on recovery periods and treat all resources equally for purposes of
6 cost allocation. Clearly the public interest is not served by bundled service
7 customers making multi-decades-long commitments for certain resources, while
8 departing load customers are permitted to avoid cost responsibility for those
9 same resources after 10 years.

10 **1. Energy Storage**

11 In Decision (D.) 14-10-045, the Commission authorized recovery
12 through the PCIA of above-market costs of certain energy storage projects
13 procured on behalf of bundled service customers from customers who
14 subsequently depart utility bundled service.² It pointed out the need for a
15 methodology to determine above-market costs of energy storage
16 procurement and directed the Joint Utilities, in consultation with affected
17 parties, to propose a PCIA methodology or “Joint IOU Protocol” for
18 determining above-market costs of energy storage at the time approval was
19 sought for energy storage project contracts.³ In light of the nascent state of
20 the energy storage market and need for further development of the
21 methodology for establishing above-market costs of energy storage projects,
22 the Commission concluded that for the purpose of the first energy storage
23 solicitation, PCIA cost recovery for energy storage contracts would be
24 limited to 10 years. The Commission left the door open to reconsideration of
25 the 10-year limit, however, observing that “[t]he Commission may consider
26 other venues such as workshops or Order Instituting Rulemaking to help
27 resolve outstanding issues involving PCIA treatment for subsequent [energy
28 storage] solicitations or the extension of PCIA treatment to the life of the
29 contracts terms beyond 10 years.”⁴

2 Certain other energy storage resources are eligible for recovery through mechanisms other than the PCIA.

3 D.14-10-045, p. 46.

4 *Id.* at p. 47.

1 In D.16-01-032, the Commission again considered the 10-year limitation
2 on allocation of energy storage project costs through the PCIA. It noted that
3 “[e]ligibility for PCIA treatment supports the ‘indifference principle’ affirmed in
4 D.14-10-045,” but observed that the concerns identified in D.14-10-045—
5 namely, the lack of an approved PCIA methodology for determining above-
6 market energy storage project costs and an insufficient showing of the
7 existence of stranded costs—had not yet been resolved.⁵ The Commission
8 further concluded that at that time, there existed “no new information to
9 justify changing our prior determination regarding the Investor-Owned
10 Utility’s (IOU) request to extend our authorization of the use of the PCIA
11 from the current [10] year limitation, to the life of the contract.”⁶ The
12 Commission thus deferred resolution of the request for extension of the
13 PCIA for market/“bundled” energy storage contracts beyond 10 years,
14 indicating that it would address the issue as part of its consideration of the
15 Joint IOU Protocol for accounting for storage resources in the PCIA.

16 When the Commission addressed the Joint IOU Protocol in
17 D.16-09-004, however, the question of the reasonableness of the 10-year
18 PCIA cost allocation limit for energy storage projects was removed from the
19 scope of the proceeding. The Commission approved a method for
20 incorporating the costs and value of energy storage contracts serving the
21 Generation/Market function into the calculation of PCIA rates,⁷ but it
22 continued the 10-year cost allocation limit presumption with no explanation.
23 Thus, the Commission has not yet squarely addressed the merits of a
24 10-year cost allocation limit for energy storage.

25 As noted above, the need for a methodology to determine above-market
26 costs of energy storage procurement was addressed by the Commission in
27 D.16-09-004, but in any event, the Joint Utilities’ PMM proposal provides a
28 means to quantify the actual above-market costs of energy storage
29 (i.e., actual contract costs minus actual realized market revenues). Thus,
30 there are no remaining impediments to fair and complete cost allocation to

5 D.16-01-032, pp. 48-49.

6 *Id.* at p. 49.

7 D.16-09-004, pp. 16-23, Conclusion of Law 8.

1 all benefitting customers for energy storage resources. To ensure
2 compliance with the requirement for customer indifference, the cost recovery
3 period for energy storage resources should span the length of the contract.
4 To find otherwise would violate the plain language of the relevant statutes.
5 There is no justifiable rationale for requiring remaining bundled service
6 customers alone to bear the costs of energy storage resources that were
7 procured to serve all bundled service customers at the time of the resource
8 commitment.

9 **2. Post-2002 Utility Owned Fossil Generation**

10 Similar to energy storage, the Commission has adopted a presumption
11 of a 10-year limit on allocation to departing load customers of the above-
12 market costs of post-2002 UOG. In D.03-12-059, the Commission approved
13 Southern California Edison Company's acquisition of its Mountainview
14 Generating Station (Mountainview) facility. In the decision, the Commission
15 noted the concern raised by The Utility Reform Network (TURN) that given
16 the regulatory uncertainty regarding, among other things, the status of DA
17 and CCA, approval of the acquisition placed bundled service customers at
18 "serious risk of 'rate shock.'"⁸ In order to protect bundled service customers,
19 TURN proposed that "the Commission condition the approval of Edison's
20 application on the requirement that all customers currently ineligible for
21 direct access will be obligated to pay for any stranded costs related to
22 Mountainview *for at least the first 10 years of its life.*"⁹ Thus, the 10-year
23 allocation period adopted in D.03-12-059, which was later broadened to
24 apply generally to post-2002 UOG, was originally intended to protect
25 bundled service customers from the alternative outcome (advocated by DA
26 providers) of departing load customers entirely avoiding costs associated
27 with the resource.¹⁰

28 In D.04-12-048, the Commission indicated its intent to allow utilities to
29 recover the net costs of procurement commitments "from all customers,

8 D.03-12-059, p. 32.

9 *Id.* (emphasis added).

10 See *id.* at pp. 35-36, Finding of Fact 22.

1 including departing customers.”¹¹ While it adopted a 10-year cost allocation
2 limit for post-2002 UOG, pointing to D.03-12-059 as precedent, it recognized
3 that the 10-year limit on cost allocation should not be applied as an absolute
4 and that circumstances could exist to justify a longer allocation period.¹² As
5 support for the 10-year cost allocation limit, the Commission relied on
6 assumptions regarding emerging capacity and energy markets, reasoning
7 that credits against resource costs would mean that the costs of these UOG
8 resources would not be above-market indefinitely.¹³

9 In D.08-09-012, the Commission addressed the 10-year cost recovery
10 limitation, electing to keep the presumption in place.¹⁴ The Commission
11 reasoned that the utilities could adjust their load forecasts and resource
12 portfolios over time to mitigate the impacts of load loss to DA and CCAs,
13 and that the impacts of departing load could be minimized.¹⁵ The
14 Commission noted that it could in fact be beneficial to extend the time that a
15 resource remained in the total portfolio if it put downward pressure on total
16 portfolio costs, and reiterated its finding in D.04-12-048 that circumstances
17 could exist to justify extending the cost allocation period for post-2002 UOG
18 resources beyond 10 years.¹⁶

19 The predictions relied upon by the Commission to justify application of
20 the 10-year cost allocation presumption have not borne out. The state has
21 not developed a capacity market. Thus, a market does not exist that would
22 provide additional revenues to compensate for the full capacity value of
23 post-2002 UOG resources. Likewise, energy and ancillary service revenues
24 are not sufficient to “minimize” any above-market costs of such resources.
25 The Commission did not anticipate the current 50 percent Renewables
26 Portfolio Standard (RPS) as outlined in Senate Bill 350. The introduction of
27 a significantly increased RPS has resulted in the introduction of thousands

¹¹ D.14-12-048, p. 60.

¹² *Id.* at pp. 61, 63.

¹³ *Id.* at p. 60.

¹⁴ D.08-09-012, p. 52.

¹⁵ *Id.* at pp. 54-55.

¹⁶ *Id.* at p. 55.

1 of megawatts of additional capacity and fundamentally changed the role and
2 economics of fossil resources.

3 Likewise, the level of potential load departure that the Joint Utilities face
4 today is substantially higher than any load departure contemplated at the
5 time the 10-year limit was adopted. At that time, the assumption was that
6 the Joint Utilities would be able to “adjust” their portfolios with no impact on
7 costs to bundled service customers. Even then, this assumption was
8 questionable at best. Adjusting the portfolio for small amounts of load loss
9 spread over many years is very different than today’s situation where more
10 than half the load could depart in just a few years.

11 Thus, it is clear that the assumptions relied upon to support imposition of
12 the 10-year limit on allocating costs of post-2002 UOG do not apply in the
13 current environment. The existing approach of arbitrarily cutting off
14 allocation of above-market costs to departing load customers at the 10-year
15 point, regardless of the life of the resource, improperly shifts costs to
16 bundled service customers. As such, it violates the plain language of the
17 statute and the Commission’s obligation to allocate costs in order to
18 preserve customer indifference. The statutory requirement to prevent cost
19 shifting between bundled service customers and departing load customers is
20 clear and unambiguous. It is not limited in time or specific to any given
21 resource type (i.e., renewable, conventional, etc.). The Commission’s
22 obligation to preserve customer indifference applies so long as resources
23 procured to serve departing load customers remain in the utility’s portfolio.
24 Thus, there is no reasonable basis for establishing different rules or cost
25 allocation periods for post-2002 UOG resources.

26 To ensure that costs are not shifted to remaining bundled service
27 customers, post-2002 UOG resources must be treated in the same manner
28 as all other Commission-approved resources subject to the PCIA/alternate
29 cost allocation method. All included resources have been approved by the
30 Commission as being “just and reasonable.” Thus, no distinction in terms of
31 cost allocation period should be made. Indeed, to find otherwise would be
32 inequitable and inconsistent with the Commission’s statutory obligation to
33 maintain customer indifference to departing load.

**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY**

CHAPTER 6

**SHOULD THE COMMISSION REQUIRE FORECASTING OF THE
PCIA OR AN ALTERNATIVE COST ALLOCATION METHOD FOR
A SPECIFIC FUTURE PERIOD?
(SCOPING MEMO ISSUE 8)**

PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
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CHAPTER 6
SHOULD THE COMMISSION REQUIRE FORECASTING OF THE PCIA OR AN
ALTERNATIVE COST ALLOCATION METHOD FOR A SPECIFIC FUTURE
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CHAPTER 6**

**SHOULD THE COMMISSION REQUIRE FORECASTING OF THE
PCIA OR AN ALTERNATIVE COST ALLOCATION METHOD FOR A
SPECIFIC FUTURE PERIOD?
(SCOPING MEMO ISSUE 8)**

A. Introduction

The Joint Utilities recognize the need for all Load-Serving Entities (LSE) to have access to information necessary to develop their individual resource portfolios. The Joint Utilities agree with the California Public Utilities Commission (CPUC or Commission) that there is a need for transparency regarding the going-forward cost allocation method, within the bounds of statutory and Commission requirements regarding protection of confidential market-sensitive procurement information. Guiding Principle 2 set forth in the Scoping Memo addresses this balance, providing that the adopted cost allocation method “should be transparent and verifiable, including the most open and easily accessible treatment of input data, while maintaining confidentiality of information that should remain confidential.”¹ Accordingly, the Joint Utilities support development of a standardized methodology that allows Community Choice Aggregators (CCA) and Energy Service Providers (ESP) to develop forecasts that maximize the use of public data on the attributes and costs allocated to them under the Joint Utilities’ Proposal, while maintaining confidentiality protections necessary to both shield remaining bundled service customers from the potential harm caused by disclosure of bundled service customers’ market-sensitive procurement information to other market participants, and to protect the integrity of California’s competitive energy markets.

As discussed in more detail below, for attribute allocation under the Joint Utilities’ Proposal, LSEs will generally require information necessary to forecast

¹ Scoping Memo, pp. 13-14.

1 the quantity and composition of Resource Adequacy (RA) products, the quantity
2 and composition of Renewable Portfolio Standard (RPS)-eligible energy, and net
3 costs. For allocation of costs, LSEs will require a forecast of net costs and sales
4 revenues. LSEs might also find value in knowing the total amount of RA that is
5 anticipated to be available for sale by each utility. Given the need to protect
6 bundled service customers' confidential market-sensitive procurement
7 information from disclosure, the Joint Utilities propose below a forecasting
8 approach that relies on publicly-available information and aggregated data in
9 order to develop a forecasting methodology that is consistent with the
10 requirements of Public Utilities Code Section 454.5(g) and Decision
11 (D.) 06-06-066, *et seq.*

12 The forecasting methodology proposed by the Joint Utilities was developed
13 in accordance with the following principles:

- 14 • Data should be provided in a manner that will allow each LSE to develop
15 an annual forecast based on its own expectations of market prices;
- 16 • Data must be provided in a manner that complies with Section 454.5(g)
17 and the Commission's confidentiality rules;
- 18 • Public data should be used to the greatest extent possible; and
- 19 • If confidential data are required, such data should be aggregated.

20 **B. The Adopted Forecasting Methodology Must Protect Bundled Service**
21 **Customers' Market-Sensitive Procurement Information**

22 Section 454.5(g) requires the Commission to protect bundled service
23 customers' market-sensitive electric procurement information:

24 The commission shall adopt appropriate procedures to ensure the
25 confidentiality of any market sensitive information submitted in an
26 electrical corporation's proposed procurement plan or resulting from or
27 related to its approved procurement plan, including, but not limited to,
28 proposed or executed power purchase agreements, data request
29 responses, or consultant reports, or any combination, provided that the
30 Office of Ratepayer Advocates and other consumer groups that are
31 nonmarket participants shall be provided access to this information
32 under confidentiality procedures authorized by the commission.

33 The Commission adopted rules implementing Section 454.5(g) in its
34 confidentiality Rulemaking, (R.) 05-06-040. In doing so, the Commission made
35 clear that "[c]onfidentiality protections are essential to avoid a repetition of the

1 energy market crisis [of 2000-2001].”² It stressed the importance of “guard[ing]
2 against the release of information that can lead to more opportunities for market
3 manipulation,” noting that “Californians are still paying for the energy crisis that
4 commenced in 2000.”³

5 In D.06-06-066, the Commission identified certain electric procurement
6 information as being “market-sensitive” and found that Section 454.5(g)
7 mandates that such information be protected from disclosure. It adopted two
8 matrices—one applicable to IOU data, the other to the data of ESPs—that address
9 certain categories of procurement data and specify the confidentiality treatment
10 to be afforded to each. To the extent information matches a Matrix category, it is
11 entitled to the protection the Matrix provides for that category of information. In
12 addition, the Commission has made clear that information must be protected
13 where “it matches a Matrix category exactly ... or consists of information from
14 which that information may be easily derived.”⁴ To ensure consistency with
15 Section 454.5(g) and the Commission’s confidentiality rules, the forecasting
16 methodology developed by the Joint Utilities leverages public and aggregated
17 information in order to avoid the risks inherent in disclosure of bundled service
18 customers’ market-sensitive procurement data.

19 **C. Proposed Forecasting Methodology**

20 The Joint Utilities propose that by March 31 of each year, each utility will file
21 an information-only Tier 1 advice letter providing a non-binding forecast for each
22 vintage of its bundled service portfolio for the subsequent ten calendar year
23 period (e.g., in the March 2019 advice letter, each IOU would provide a forecast
24 for 2020-2029) for items discussed further below.^{5,6} The Joint Utilities propose
25 the March 31 date because it will allow for inclusion of the previous year’s

2 D.06-06-066, as modified by D.07-05-032, p. 4.

3 *Id.* at pp. 16, 18.

4 *Administrative Law Judge’s Ruling on San Diego Gas & Electric Company’s April 3, 2007 Motion to File Data Under Seal*, issued May 4, 2007 in R.06-05-027, p. 2 (emphasis added).

5 The forecast for the current year would have been included as part of the Joint Utilities’ respective Energy Resource Recovery Account Forecast filings.

6 The granularity of the forecasts may be adjusted subject to CPUC requirements for planning proceedings such as the Integrated Resource Plan proceeding.

1 operations and revenues. Each year's forecast would: (i) update values from
2 the previous year's forecast to reflect changes due to contract termination,
3 expirations, sales contract performance and/or any new contracts; and (ii) add
4 one additional year to the forecast. Forecasts will be based on the portfolio
5 characteristics and rules in place at the time the forecast is prepared.⁷ It is
6 important for parties to be mindful of the fact that forecasts are inherently
7 uncertain, particularly for extended time periods and especially in outer years –
8 assumptions will change over time. While the Joint Utilities will make a good
9 faith effort to produce accurate forecasts based on the best then-available
10 information, by definition such forecasts will inevitably differ from actual market
11 results. In addition, the Joint Utilities' forecasts will not include speculation as to
12 the impact of potential changes in applicable regulatory rules or requirements,
13 any one or more of which could materially affect market and cost results going
14 forward. Ultimately, it will be up to each LSE to make its own assessment of the
15 potential long-term values and costs regarding the allocated portfolio attributes,
16 using its own assumptions about future market conditions and potential
17 regulatory changes.

18 Green Allocation Method (GAM) Forecast: Under the Joint Utilities'
19 proposed GAM, there will be an allocation of the renewable attributes and RA
20 associated with the resources in this portfolio, as well as a charge for the net
21 costs (based on resource costs minus energy and Ancillary Service market
22 revenues). The GAM forecast would include the following:

- 23 • Renewable Energy Credit Allocation: Expected energy deliveries from
24 all RPS-eligible resources;
- 25 • RA Allocation: Available RA (system, local and flexible) based on
26 current Commission rules and contract/plant performance; and
- 27 • Net Cost: In order to develop net cost, each utility will provide a forecast
28 of its costs. Because of the high proportion of fixed price, must-take,
29 renewable generation in the Joint Utilities' portfolios, in general, the
30 gross costs are relatively predictable. The utility will also provide the
31 previous year's market revenues, which is useful in informing an

⁷ For example, forecasted RA will be based on the current net qualifying capacity of each resource. However, RA rules and actual RA capacity may change over time.

1 estimate of going-forward net costs. LSEs can then apply their own
2 assumption as to future market revenues (based on their own
3 assumptions about future market prices) in order to estimate the
4 net costs.

5 Portfolio Monetization Mechanism (PMM) Forecast: No attributes will be
6 allocated from this portion of the Joint Utilities' portfolios. Instead, CCA and ESP
7 customers will pay a departing load charge based on the difference between
8 forecast costs and revenues, with a subsequent true-up for actual costs and
9 revenues. The PMM forecast would include the following:

- 10 • Net Cost: Aggregate forecast of portfolio costs less forecast
11 market revenues;⁸
- 12 • Energy: Forecast of expected energy production from the portfolio; and
- 13 • RA Monetization: Total amount of RA sold and total revenues realized
14 from RA sales in the past year and a forecast of RA that will be made
15 available for sale in each of the future years based on the current level of
16 load departure.

⁸ Development of forecasted market revenues and energy will require use of an agreed-upon forecast of market prices. The Joint Utilities propose that parties work together to determine what source to use for this purpose.

**PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 7
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SOUTHERN CALIFORNIA EDISON COMPANY**
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4 **CHAPTER 7**
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6 **A. Introduction**

7 This chapter presents two proposals. First, to further the goal of ensuring
8 bundled service customer indifference to departing load, the Joint Utilities
9 propose that the California Public Utilities Commission (CPUC or Commission)
10 approve the recovery of the difference between rates under the Current
11 Methodology and rates using the methodology adopted in this proceeding for the
12 period between the first implementation date of the charge under the adopted
13 methodology and either January 1, 2019, in the case where the Joint Utilities'
14 Proposal is adopted but there is a delay in implementation beyond January 1,
15 2019, or January 1, 2018, in the case where the revised methodology approved
16 is different than the Joint Utilities' Proposal.

17 Second, the Joint Utilities propose to recover the costs of certain mandated
18 procurement, conducted irrespective of bundled service customer load and in
19 support of state policy goals, from all customers, rather than from a subset of
20 customers on a vintaged basis.

21 **B. Preserving Bundled Service Customer Indifference Pending**
22 **Implementation of a Revised PCIA or Alternative Cost Allocation**
23 **Methodology**

24 The schedule for this proceeding anticipates that a final decision will be
25 issued in August 2018, and that the Joint Utilities will be able to implement the
26 revised PCIA or alternative cost allocation methodology by January 1, 2019.
27 However, if the adopted methodology reflects the Joint Utilities' Proposal
28 described in Chapter 4 of this testimony, and if the schedule in the proceeding is
29 delayed such that implementation of the methodology occurs after January 1,
30 2019, the Joint Utilities request that the new methodology be applied
31 retroactively to January 1, 2019. If instead the adopted methodology is a
32 modified benchmark proposal, with or without a true-up to actual costs and

1 actual market revenues, the Joint Utilities request the methodology be applied
2 retroactively to January 1, 2018, irrespective of any delays in the schedule.

3 The distinction in the requested retroactivity periods is based on the Joint
4 Utilities' recognition that under the Joint Utilities' Proposal, it would be
5 impractical to retroactively allocate Resource Adequacy (RA) from resources
6 subject to the Green Allocation Mechanism (GAM) or RA from resources subject
7 to the Portfolio Monetization Mechanism (PMM) auction. Instead, retroactive
8 application of the Joint Utilities' Proposal will require proxy values to be used to
9 monetize the RA value of the attributes. The Joint Utilities propose using the
10 Commission's most recent RA Report for the value of RA as a "next best"
11 substitute for the allocation or auction value of RA capacity, as would be
12 required under the Joint Utilities' GAM and PMM proposals, respectively. The
13 use of an RA benchmark price is undesirable for a number of reasons as set
14 forth in the Joint Utilities' testimony, but it would be the most representative
15 benchmark price and its limitations would be constrained to a one-time true-up.
16 Because Renewable Energy Credits (REC) can be allocated more than one year
17 after they are generated, the Joint Utilities' Proposal to allocate RECs can be
18 effectuated retroactive to January 1, 2019.

19 If the Joint Utilities' Proposal is adopted and made effective on a date later
20 than January 1, 2019, the under-collected amount for the period of time
21 impacted by the procedural delay will be the difference between the Joint
22 Utilities' Proposal rate that would have been in effect on January 1, 2019, and
23 the rate that is in effect as a result of the procedural delay.

24 However, if the adopted methodology is based on a modified benchmark
25 mechanism, the revised rate could be calculated by substituting the revised
26 benchmark, based on actual or proxy market prices, and actual recorded costs,
27 if applicable. There would be no practical impediment to implementing this
28 revised calculation retroactively to January 1, 2018.

29 To effectuate the retroactive application of the adopted methodology, the
30 Joint Utilities request authority to create a subaccount to their respective Energy
31 Resource Recovery Account balancing accounts to track PCIA billed revenues,
32 by vintage, actual costs, by vintage, and market revenues by vintage, for the
33 PCIA-eligible resource costs dating back to January 1, 2018. Once a decision in
34 this proceeding is issued, using the actual recorded costs and market revenues,

1 if applicable, by vintage, in combination with the adopted methodology, the
2 Joint Utilities would recalculate what the revised vintaged rates would have been
3 under the adopted methodology. The difference between the revised rates and
4 the rates that were in place in 2018 and 2019 (if there is a procedural delay),
5 multiplied by the billed sales would determine the under- or over-collection
6 amount to be amortized in rates effective either January 1, 2019 or
7 January 1, 2020.

8 The Commission has the authority to make the new departing load rate
9 retroactive to address the ongoing cost shifts, and, as discussed, the Joint
10 Utilities submit that the appropriate date for such a retroactive adjustment is
11 either January 1, 2019 for the Joint Utilities' Proposal, or January 1, 2018, if the
12 Current Methodology is updated or replaced with market price benchmarks or
13 market price indices. If there is a delay in implementation beyond January 1,
14 2019, the Joint Utilities propose to amortize the under- or over-collection in their
15 respective 2020 revised PCIA revenue requirements. If there is no
16 implementation delay but the mechanism approved is a modified benchmark,
17 with or without true-up to actual costs, the Joint Utilities request they be allowed
18 to amortize the under- or over-collection dating from January 1, 2018 in the 2019
19 revised PCIA revenue requirements.

20 The retroactive cost recovery request proposed by the Joint Utilities is
21 similar to a request made by various parties in the Direct Access (DA)
22 Reopening Order Instituting Investigation, Rulemaking 07-05-025, when the
23 Commission evaluated the PCIA mechanism in advance of the re-opening of DA
24 service pursuant to Senate Bill 695 (2009). The Commission approved the
25 retroactive application of the updated PCIA methodology developed in that
26 proceeding in D.11-12-018.¹

27 **C. Costs Incurred for Procurement Mandated of the Joint Utilities Irrespective**
28 **of Load and in Support of State Policy Goals Should Be Recovered From**
29 **All Benefitting Customers**

30 As discussed throughout this testimony, state law prohibits cost shifting
31 between bundled service customers and departing load customers. However,
32 significant cost shifts are occurring not only between bundled service and

¹ Decision (D.) 11-12-018, Ordering Paragraphs 39, 40 and 41.

1 departing customers, but also between different vintages of departing load
2 customers as a result of procurement mandated by the Commission to further
3 numerous state policy objectives, the costs of which are currently borne only by
4 a subset of customers. The Commission has imposed these mandates on the
5 Joint Utilities irrespective of any need for the underlying procurement to serve
6 their remaining bundled service customers' load.

7 The resulting cost shifts occur as a function of the "vintaging" rules under the
8 Current Methodology. The term "vintaging" refers to the process of grouping
9 departing load customers based on the date those customers left utility bundled
10 service for an alternate service provider. Departing load customers are held
11 responsible for generation costs incurred for their vintage, and for the costs of
12 resources that do not have a vintage. For example, if an IOU procured a
13 resource in January 2015, only those customers that took service from the IOU
14 as of July 1, 2015 or after are required to contribute to the costs of that resource.
15 All customers that departed bundled service prior to that date (i.e., July 1, 2015)
16 pay nothing for the resource. Resources that are effectively subject to a
17 "vintage" include: (1) post-2002 UOG costs; and (2) post-2002 contracts.

18 Currently, resources included in the PCIA calculation methodology that are
19 recovered from non-exempt departed load include: (1) legacy Qualifying
20 Facilities (QF); (2) irrigation district and water agency contracts; and (3) legacy
21 nuclear and hydro-electric UOG costs. These resources are referred to as
22 non-vintaged resources since the costs are included in all total portfolio
23 indifference calculations for all vintage portfolios.

24 Current programs subject to vintaging that are unrelated to load and that are
25 recoverable under the PCIA include the following:

TABLE 7-1
IOU MANDATED PROCUREMENT PROGRAMS INDEPENDENT OF LOAD^(a)

CPUC Procurement Program	State Legislative Requirement	Total IOU MW Allocation	Resources to Be Procured
Renewable Auction Mechanism (RAM)	No	<u>RAM</u> : 1,000 MW <u>PV Program</u> : 1,100 MW (mix of UOG and PPAs)	<u>RAM</u> : Eligible renewables over 3 MW and up to 20 MW <u>PV Program</u> : Solar PV between 1-20 MW
Renewable Market Adjusting Tariff (ReMAT)	Yes, SB 32	750 MW	Eligible renewables up to 3 MW from three categories: As-Available Peaking (generally solar PV) As-Available Non-Peaking (generally small hydro, wind) Baseload
Bioenergy Market Adjusting Tariff (BioMAT)	Yes, SB 1122	250 MW	Bioenergy facilities up to 3 MW from three categories: Biogas from wastewater, municipal waste, food processing, or co-digestion Biogas from dairy or agriculture Biogas or biomass using sustainable forest management
PURPA (Non-CHP)	No	PURPA (Non-CHP): Unlimited	PURPA (Non-CHP): Any QF under 20 MW
AB 1969 Feed-in Tariff	Yes, AB 1969	478.4 MW	Eligible renewables, up to 1.5 MW 250 MW carve-out for eligible renewable generation from water and wastewater facilities

(a) The table is not a comprehensive list of all procurement programs (e.g., does not include energy efficiency programs) or procurement recovered through alternate cost recovery mechanisms.

1 The programs listed above, all of which were developed to support specific
2 state policy objectives, such as reducing greenhouse gas emissions, require the
3 Joint Utilities to procure favored resources without consideration of bundled
4 service load requirements or whether there is otherwise a need for the resources
5 to bolster electric system reliability for all customers. Because all customers
6 benefit equally from these policy-directed programs, all customers should
7 contribute equitably to their costs.

1 The need to address the inherent cost shift associated with these programs
2 is urgent, as increased customer departures concentrate recovery of incremental
3 and mandated policy-based procurement on a constantly-shrinking customer
4 base.² Consider, for example, a scenario where the IOU has an ongoing
5 procurement obligation for one or more of the procurement programs listed in
6 Table 7-1 and 80 percent of the IOU's load departs. This scenario is not
7 hyperbolic: Commission staff predicts that up to 85 percent of retail load may be
8 served by sources other than the Joint Utilities in the next decade.³ In that
9 instance, the 20 percent of customers remaining with the IOU would be required
10 to pay 100 percent of the costs of the incremental mandated procurement.
11 Requiring the remaining bundled service customers to pay for 100 percent of the
12 costs for resources that are not needed to meet bundled service load, but
13 instead were developed to support various state policy objectives, would be
14 unjust. These customers will necessarily experience a cost increase as the cost
15 of these programs will be recovered from a smaller subset of customers.

16 To ensure bundled service customer indifference and indifference between
17 vintaged portfolios, the costs of these programs must be recovered from *all*
18 benefitting customers—and not just from bundled service and vintaged departing
19 load customers—through the removal of the vintaging construct. The Joint
20 Utilities therefore propose that the vintaging methodology be revised to remove
21 vintaging associated with mandated procurement conducted independent of load
22 requirements so that all customers pay their equitable share of the costs
23 associated with these procurement programs.

2 These mandated procurement programs comprise a significant portion of the Joint Utilities' current procurement given their long positions generally, as discussed in Chapter 1 of this testimony. The costs of these mandated programs are well above the current market prices for other renewable resources. For example, the average contract price of BioMAT contracts executed by PG&E in 2017 was \$197 megawatt-hour (MWh) (on a post time-of-delivery basis); the average contract price of ReMAT contracts executed by PG&E in 2017 was \$80 MWh (on a post time-of-delivery basis). As noted in Chapter 1, solar resources in 2016 were generally priced at or below \$50/MWh with a few priced at approximately \$30/MWh.

3 See CPUC May 2017 Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*, p. 3.

**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
APPENDIX A
STATEMENTS OF QUALIFICATIONS**

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF FONG WAN

Q 1 Please state your name and business address.

A 1 My name is Fong Wan, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Senior Vice President (SVP) of Energy Policy and Procurement. In this position, I am responsible for gas and electric supply planning and policies, wholesale market design, quantitative analysis, and commodity and resource procurement and settlements.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from Columbia University, in 1984, with a Bachelor of Science degree in Chemical Engineering and from the University of Michigan, in 1986, with a Master's degree in Business Administration.

From 1986-1988, I worked as a Business Analyst with Exxon U.S.A. I began work with PG&E in 1988 as a Financial Analyst in the financial planning and analysis area. I was promoted to Senior Financial Analyst in 1989 and to Manager in 1991. In this area, I worked on recommendations involving capital structure and dividend policies, as well as various capital, acquisition, and divestiture analyses.

From 1992-1993, I was on a special assignment working on the de-contracting of Canadian gas supply contracts. In this capacity, I oversaw financial and economic analyses and participated in contract negotiations with suppliers.

In 1994, I joined the Product and Sales Department in California Gas Transmission. I was promoted to Director of the department in 1995, where I was responsible for the sales of interstate and intrastate gas transmission capacity and gas storage-related services. I also participated in the development of Gas Accord.

In 1996, I transferred as director to the Power Market Planning Department and the Energy Trading Department. Here, I participated in market structure activities involving the California Independent System

1 Operator and Power Exchange and oversaw electric supply planning and
2 trading activities.

3 In 1997, I left PG&E and joined PG&E Corporation's Energy Trading
4 subsidiary of the National Energy Group, in Bethesda Maryland. I was
5 promoted to VP of Structured Trading in 1999 and my responsibilities
6 encompassed all complex, structured transactions at Energy Trading.

7 In 1999, I joined AltaGas Inc., in Calgary, Alberta. At AltaGas, I was
8 Senior VP and Chief Operating Officer, overseeing all trading, acquisition,
9 strategy and planning, operations, and engineering activities for this
10 mid-stream gas company.

11 In 2000, I rejoined PG&E Corporation as VP of Risk Initiative in
12 San Francisco. I participated in PG&E's Plan of Reorganization and advised
13 on power procurement issues.

14 In 2004, I rejoined PG&E as VP of Power Contracts and Electric
15 Resource Development. I oversaw all existing power contracts, including
16 qualifying facility, renewable generation, and irrigation district contracts. In
17 addition, I was also responsible for acquiring all long-term supply needs via
18 contracts or generation ownership.

19 In 2006, I was named VP of Energy Procurement.

20 In 2008, I assumed my current position as Senior VP of Energy Policy
21 and Procurement.

22 Q 4 What is the purpose of your testimony?

23 A 4 I am sponsoring the following prepared testimony in the Power Charge
24 Indifference Adjustment Order Instituting Rulemaking proceeding:

- 25 • Chapter 1, "Introduction"; and
- 26 • Public and Confidential Appendix G, "PG&E 2017 Resource
27 Adequacy Sales."

28 Q 5 Does this conclude your statement of qualifications?

29 A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOSEPH T. LAWLOR

Q 1 Please state your name and business address.

A 1 My name is Joseph T. Lawlor, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 Since mid-2015, I have held the position of Director, Portfolio Management, in the Energy Policy and Procurement Department of PG&E. In that capacity, my team buys and sells resource adequacy, greenhouse gas, and non-renewable energy products.

Q 3 Please summarize your educational and professional background.

A 3 I have a Master's degree in Business Administration from the University of San Francisco and a Bachelor of Science degree from San Francisco State University. In my 26 years with PG&E, I have primarily held positions associated with Energy Procurement and California Independent System Operator Wholesale Market Design.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following prepared testimony in the Power Charge Indifference Adjustment Order Instituting Rulemaking proceeding:

- Chapter 3, "Proposals for Going-Forward IOU Portfolio Optimization";
- Appendix F1, "Joint Utilities Resource Lists and Summary Tables" (PG&E); and
- Confidential Appendix H, "PG&E 2018 Multi-year Resource Adequacy Request for Bids Results."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARGOT C. EVERETT

Q 1 Please state your name and business address.

A 1 My name is Margot C. Everett, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E or the Company).

A 2 I am the Senior Director responsible for the Rates and Regulatory Analytics Department. This department consists of: Rate Design; Load Forecasting; and Rate Data Analytics. Department responsibilities include:

- Designing electric and gas rates;
- Supporting rates-related cases, such as the Gas Cost Allocation Proceeding, General Rate Case Phase 2, and Rate Design Window;
- Providing data analytics and analysis and systems support;
- Analyzing customer: sales; load; rates; usage; and billing information.
- Developing the Company's electric and gas annual load forecasts, hourly load forecasts, peak day forecasts, and performing load research analyses, including developing the necessary analyses to comply with California Energy Commission requirements on load research;
- Analyzing customer load data and providing data analytics to support rate design and customer programs;
- Working with Lines of Business to develop rate and customer programs policy and case strategies;
- Managing Tariffs and Advice Letter filings;
- Forecasting, revenue requirements and rates;
- Managing regulatory operations; and
- Managing annual electric and gas true-up advice filings.

Q 3 Please summarize your educational and professional background.

A 3 I received a Master of Science Degree in Applied Economics from the University of California, Santa Cruz in 1985. I have over 30 years of experience in the energy industry with roles in: Regulatory Affairs; Risk Management and Compliance; Demand-Side Management; and Wholesale Power Contracts. My utility experience includes: PG&E; PacifiCorp;

1 PPM Energy; and Constellation Energy. I also have experience with energy
2 consultants Energetics and Hagler Bailley.

3 Q 4 What is the purpose of your testimony?

4 A 4 I am sponsoring the following prepared testimony in the Power Charge
5 Indifference Adjustment Order Instituting Rulemaking proceeding:

6 • Chapter 4, “Proposals for Alternatives to the PCIA to Uphold Statutory
7 Requirements and Meet the Guiding Principles of the Proceeding”:
8 – Section D, “Cost Recovery and Rate Design”;

9 • Chapter 7, “Other Issues”;

10 • Appendix C, “PCIA OIR Workshop 2 Joint Utilities Presentation”;

11 • Appendix D, “Billed Revenues”; and

12 • Appendix E, “Joint Utilities Proposal – Illustrative Example.”

13 Q 5 Does this conclude your statement of qualifications?

14 A 5 Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF COLIN E. CUSHNIE

- Q. Please state your name and business address for the record.
- A. My name is Colin E. Cushnie, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.
- Q. Briefly describe your present responsibilities at the Southern California Edison Company.
- A. I am a Vice President, responsible for managing the Energy Procurement & Management Operating Unit at Edison. My organization's responsibilities include contracting for wholesale energy supply, including renewables and energy storage; energy solicitations and valuations; energy contract management and financial settlements, and energy market operations, including the bidding and scheduling of SCE's utility-owned and contracted resources into organized wholesale energy markets.
- Q. Briefly describe your educational and professional background.
- A. I earned a Bachelor of Arts Degree in both Economics and Business Administration from Whittier College in 1986. I was hired by Edison in January 1987 and held various positions related to the procurement of material, equipment, and services until October 1993. Beginning in October 1993, I held positions of increased responsibility related to natural gas and electrical energy planning, energy procurement, and energy markets and energy procurement regulatory support. I assumed my current position in August 2014.
- Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Chapter 4, Sections A, B and C and Appendices C and E, as identified in the Tables of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF RANBIR SEKHON

Q. Please state your name and business address for the record.

A. My name is Ranbir Sekhon, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Director of the Portfolio Planning & Analysis department of Southern California Edison's (SCE's) Power Supply organization.

Q. Briefly describe your educational and professional background.

A. I graduated from Queen Mary College, University of London in May of 1998 with a Bachelors of Science Degree in Mathematics and Computing with First Class Honors. Prior to joining SCE I worked briefly for ABN Amro in their corporate finance department and for nine years as a Management Consultant for PA Consulting Group. During my time with PA I reached the rank of Principal Consultant and was responsible for managing teams of consultants on various consulting projects. Six of my nine years with PA was spent working with global energy sector clients on engagements ranging from Energy Transaction and Risk Management (ETRM) systems implementation to Business Process and Quantitative Model development. I joined SCE as Manager of Portfolio Planning & Management in August 2007 and have held various roles responsible for monthly risk and resource adequacy reporting to CPUC ,analytical model development, managing all valuation processes related to renewable, alternative and conventional procurement and developing analytical models to support SCEs hedging program. I have previously testified before the commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Chapter 2, Chapter 3 and Appendices C and F2, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

WITNESS QUALIFICATIONS

My name is Robert B. Anderson. My business address is 8330 Century Park Court, San Diego, California, 92123.

I am employed by San Diego Gas & Electric Company (“SDG&E”) as Director – Resource Planning. My responsibilities mainly include electric resource planning. I have been employed by SDG&E since 1980, and have held a variety of positions in resource planning, corporate planning, power plant management, and gas planning and operations. I have a BS in Mechanical Engineering and a MBA - Finance. I am a registered professional engineer in Mechanical Engineering in California.

I have previously testified before this Commission.

WITNESS QUALIFICATIONS

My name is Kendall K. Helm and my business address is 8330 Century Park Court, San Diego, California 92123. I am the Director of Origination and Portfolio Design in the Electric Fuel and Procurement Department of San Diego Gas and Electric. I have been with the Sempra Energy family of companies since 2012. Prior to taking my current position at SDG&E, I was the Director of Investor Relations at Sempra Energy. I have also worked as Manager of Corporate Economics for Sempra Energy, where I provided research on the company's valuation, capital structure and corporate strategy. Prior to joining the Sempra Energy companies, I was Senior Economist for International Affairs and Trade at the U.S. Government Accountability Office, where I reported to Congress on topics relating to climate change, energy export promotion, and international competitiveness. I received a bachelor's degree in economics and international studies from the University of Denver and a Ph.D. in economics from American University. I have not previously testified before the California Public Utilities Commission. This concludes my prepared direct testimony.

WITNESS QUALIFICATIONS

My name is Emily C. Shults. My business address is 8330 Century Park Court, San Diego, California 92123. I am employed by SDG&E as Vice President – Energy Procurement and have been in my current position since August 2015. My responsibilities include overseeing the company's electric and gas procurement, operations and trading, settlements, generation, and resource planning. Prior to my current role and responsibilities, I served as Director – Construction Services. In that role, I was responsible for the work of third party contractors on SDG&E's transmission and distribution system in the roles of construction, vegetation management, and aviation services. I joined SDG&E in April 2015 and have deep experience in all aspects of origination, trading, portfolio optimization, and settlements. During my thirteen year career with the non-utility Sempra Energy family of companies, I served as managing director, director gas and power trading, director gas and power marketing, manager of origination and portfolio optimization and various other roles. Prior to joining Sempra, I worked with the John Zink Company, Williams Energy Marketing and Trading and Deloitte and Touche LLP. I hold a Bachelor's degree in accounting from the University of Tulsa. I have previously testified before the California Public Utilities Commission.

**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
APPENDIX B
PAM TESTIMONY (A.17-04-018)**

Application No.: A.17-04-XXX
Exhibit No.: Joint IOUs-01
Witnesses: Fong Wan
Kendall Helm
Colin Cushnie
Ranbir Sekhon
Margot Everett
Cynthia Fang
Akbar Jazayeri
Emily Shults



(U 338-E)

***JOINT UTILITIES' DIRECT TESTIMONY IN
SUPPORT OF APPLICATION FOR APPROVAL OF
THE PORTFOLIO ALLOCATION
METHODOLOGY FOR ALL CUSTOMERS***

Before the

Public Utilities Commission of the State of California

Rosemead, California
April 25, 2017

Joint IOUs-01: Joint Utilities’ Direct Testimony In Support Of Application For Approval Of The Portfolio Allocation Methodology For All Customers

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Acronym List

Acronym	Definition
A.	Application
BioMAT	Bioenergy Market Adjusting Tariff
BPP	bundled procurement plan
CEC	California Energy Commission
CAISO	California Independent System Operator
Commission or CPUC	California Public Utilities Commission
CCA	Community Choice Aggregator
CTC	Competition Transition Charge
CRR	congestion revenue rights
CAM	Cost Allocation Mechanism
CRS	Cost Responsibility Surcharge
D.	Decision
DOE	Department of Energy
DWR	Department of Water Resources
DA	Direct Access
ERRA	Energy Resource Recovery Account
ESP	Energy Service Provider
GTSR	Green Tariff Shared Renewables
HPC	Historical Procurement Charge
IE	Independent Evaluator
Investor-Owned Utility	IOU
kWh	kilowatt-hour
LCD	Least-Cost Dispatch
LSE	load serving entities
LTPP	long term procurement plan
MPB	Market Price Benchmark
MWh	megawatt-hour
NQC	Net Qualifying Capacity
ORA	Office of Ratepayer Advocates
O&M	Operations and Maintenance
PG&E	Pacific Gas and Electric Company
PAC	Portfolio Allocation Charge

Acronym List

Acronym	Definition
PAM	Portfolio Allocation Methodology
PAMBA	Portfolio Allocation Methodology Balancing Account
PCIA	Power Charge Indifference Adjustment
PRG	Procurement Review Group
PCC	Product Content Category
P.U. Code	Public Utilities Code
R.	Rulemaking
RDW	Rate Design Windows
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard
RUC	residual unit commitment
RA	Resource Adequacy
R.	Rulemaking
SDG&E	San Diego Gas & Electric Company
SONGS	San Onofre Nuclear Generating Station
SB	Senate Bill
SCE	Southern California Edison Company
SOC 4	Standard of Conduct 4
TURN	The Utility Reform Network
UOG	Utility-Owned Generation
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

I.

INTRODUCTION

Over the past fifteen years, California’s energy market has been fundamentally transformed. With the Legislature’s guidance through the statutes that it has enacted, and the California Public Utilities Commission’s (“Commission” or “CPUC”) approval and oversight, Pacific Gas and Electric Company (“PG&E”), Southern California Edison Company (“SCE”), and San Diego Gas & Electric Company (“SDG&E”) (the “Joint Utilities”) have collectively entered into hundreds of long-term contracts for renewable energy. Those long-term contracts have directly led to the building of thousands of megawatts of renewable energy generation resources, contributed to significant price reductions for renewable energy resources currently available in the market, and have supported California’s rise as one of the world’s green energy leaders. In addition, the Joint Utilities have entered into agreements for other generating resources, or built or contracted for utility-owned generating resources, that ensure that all Californians are able to enjoy reliable and affordable electricity service.

Although these contracts and resources directly or indirectly benefit all Californians, the contracts are between the Joint Utilities and the resource owners. Those costs must be paid, irrespective of how many of the Joint Utilities’ customers choose to take service from other electricity providers.

The Joint Utilities support customers’ right to choose their electricity supplier, provided that exercising this choice does not cause cost shifts or rate increases to customers who continue to take procurement service from a utility. The Legislature, as an express condition of authorizing retail choice, required that procurement costs incurred on behalf of utility customers cannot be bypassed when those customers choose to depart utility service for another provider. This is reflected in California Public Utilities Code (P.U. Code) Sections 365.2, 366.2 and

1 366.3,¹ among others, which prohibit cost shifting or cost increases to remaining bundled service
2 customers as a result of departing or migrating load, and, correspondingly, require that departing
3 load customers not pay costs that were not incurred on their behalf.² These statutes protect all
4 customers by providing that costs must be appropriately allocated to those on whose behalf they
5 were incurred.

6 This Commission has interpreted these statutes to require that customers on utility
7 bundled service remain “indifferent” to the departure of other customers (*i.e.*, they are neither
8 better off nor worse off as a result of another customer’s choice).³ Unfortunately, the current
9 methodology intended to protect bundled service customers from increased costs due to
10 departing load is deficient because it is based on hypothetical, projected market outcomes. A
11 forecast-based methodology cannot ensure customer indifference to departing load. The

¹ All statutory references in this Testimony are to the California Public Utilities Code unless otherwise noted.

² See *e.g.*, Cal. Pub. Util. Code (“P.U. Code”) §366.2(a)(4) (“The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.”); §366.2(d)(1) (“It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.”); §365.2 (“The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.”); §366.1(d)(1) (“It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the department’s power purchase costs, as well as power purchase contract obligations incurred as of January 1, 2003, that are recoverable from electrical corporation customers in commission-approved rates. It is the further intent of the Legislature to prevent any shifting of recoverable costs between customers.”); §366.3 (“Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.”).

³ The “indifference requirement” also requires that all benefitting customers pay for their pro-rata share of all other relevant resources in the Joint Utilities’ portfolios procured or built on their behalf, including but not limited to Utility-Owned Generation (“UOG”) and resources necessary for system or local reliability reasons.

1 shortcomings of the current approach will become more significant as greater levels of customers
2 depart utility procurement service, which is happening now and accelerating.⁴

3 The Joint Utilities file this Application to propose a new methodology that results in an
4 equitable and transparent allocation of energy and capacity benefits and costs, based on actual
5 market results, to more effectively protect customers from cost shifts and increases as a result of
6 departing load, as required by Sections 365.2, 366.2 and 366.3.

⁴ See October 7, 2016 Motion of the City of Lancaster, Marin Clean Energy, and Sonoma Clean Power for Official Notice in R.16-02-007, which forecasts approximately 13,000 GWh of CCA load statewide by 2018 and identifies an additional 19 cities and counties that have passed resolutions or “taken affirmative, formal steps to launch a CCA program within the 2017-2018 timeframe.”

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II.

EXECUTIVE SUMMARY

Over the past decade and a half, the Legislature, the Commission, utilities and other load-serving entities (“LSEs”) such as Community Choice Aggregators (“CCAs”) and Energy Service Providers (“ESPs”), customer advocacy groups such as the Office of Ratepayer Advocates (“ORA”) and The Utility Reform Network (“TURN”), and numerous interested parties have sought to establish rules and processes that implement customer choice in electricity procurement with programs like Direct Access (“DA”) and CCA. Because utility procurement costs are passed through to customers with no mark-up, the Joint Utilities’ interests are simply to ensure appropriate cost allocation between groups of customers. A foundational requirement to enabling customer choice is that utility bundled service customers remain indifferent to load departure by recovering from departing load customers costs of resources procured on their behalf. This has been no easy undertaking given the complexities of the energy markets and the varied resource types in the utility generation portfolios, and the Joint Utilities appreciate that the Commission had limited information to uphold the indifference requirement at the time that it established the “above-market” cost allocation⁵ mechanism that is currently in effect (the “Current Methodology”).

Despite these efforts, it has become patently clear in the last few years that the current Commission-approved method of recovering costs from departing load customers is broken, and that the cost shift from departing load customers to remaining bundled service customers is increasing. It is imperative that the Commission act immediately to remedy the insufficient cost allocation mechanism, prevent further cost-shifting, and provide certainty on cost responsibilities and benefits for communities that are evaluating customer choice programs.

⁵ In this Testimony, “cost allocation” refers to the recovery of generation-related costs from departing load customers.

1 Currently, the Commission relies on a method to allocate costs to departing load
2 customers based on an estimate of the above-market costs for resources procured prior to their
3 departure from bundled utility procurement service. Basing cost allocation on the share of costs
4 estimated to be above-market essentially assumes the utilities can sell excess resources resulting
5 from customer departure “at market,” thereby leaving only the above-market costs to be
6 recovered. Since the Commission first adopted the Current Methodology, more accurate and
7 transparent means of allocating procurement costs among customers of different procurement
8 service providers (or LSEs) have been developed that result in far more accurate and transparent
9 outcomes. Now is the time for the Commission to replace the existing estimated above-market
10 cost allocation mechanism with a cost allocation approach that is based on actual market results,
11 thus truly protecting all customers, bundled service and departing load alike, from cost shifting.

12 Accordingly, in this Application, the Joint Utilities propose a new approach to allocate
13 bundled service generation portfolio costs and benefits to all customers – bundled service and
14 departing load – that replaces the current method of approximating and recovering above-market
15 costs from departing load customers. The Joint Utilities’ proposal, the Portfolio Allocation
16 Methodology (“PAM”), is accurate, equitable, transparent, scalable, and actually implements
17 state law requirements that no cost shifting take place between bundled service and departing
18 load customers as a result of customer choice.

19 The PAM will completely replace the Current Methodology. As described in more detail
20 in the following chapters, the PAM will allocate a pro-rata share of recorded net costs of each
21 utility’s generation portfolio to departing load customers on whose behalf the portfolio was
22 procured or built, on a “vintaged-portfolio” basis.⁶ Departing load customers will only pay the
23 “net” costs because the total portfolio costs will be offset by the energy and ancillary services

⁶ A portfolio’s “vintage” refers to the fact that departing load customers are only responsible for resources procured while they received utility bundled procurement service. Thus, a “vintage” represents the resources that were under contract or otherwise in a utility’s portfolio at the time the customers departed. The Commission has recently reaffirmed and clarified a vintaging methodology, which is described in more detail below.

1 revenues realized by the portfolio resources in the energy markets. In addition, under PAM,
2 departing load customers' LSEs will receive a pro-rata allocation of attributes from those
3 resources, including Resource Adequacy ("RA"), Renewable Energy Credits ("RECs"), and any
4 future attributes if appropriate.⁷ Symmetrically, bundled service customers will pay their pro-
5 rata share of the recorded net costs as part of their bundled service generation rates, and the Joint
6 Utilities will retain or use the remaining bundled service customers' pro-rata allocation of RA
7 and REC attributes for their benefit.

8 Just as the Joint Utilities currently do for their bundled service customers, portfolio costs
9 and market revenues will be forecasted under PAM, but then later "trued up" to reflect actual,
10 realized resource costs and market revenues. This approach will eliminate the contentious and
11 inaccurate process of forecasting above-market costs, and annually applying those ever-changing
12 values to the Joint Utilities' respective portfolios, with no true-ups. PAM will also be more
13 transparent, so that LSEs and their customers can thoroughly review the costs and benefits that
14 are allocated as part of each vintaged portfolio. In these regards, PAM will ensure that the
15 statutory indifference requirement is upheld, namely: That all customers pay their equitable share
16 of costs, that costs are not shifted among customers (in either direction), and that customers who
17 do not (or cannot) depart utility bundled service do not pay procurement costs that were incurred
18 on behalf of departing load customers.⁸

19 PAM will be implemented through the Joint Utilities' respective Energy Resource
20 Recovery Account ("ERRA") Forecast proceedings. Once approved, the Joint Utilities propose
21 that PAM would take effect no sooner than one year from Commission approval through the next
22 ERRA Forecast proceeding (*e.g.*, if approved in December 2017, PAM would be presented in the
23 IOUs' 2019 ERRA Forecast proceedings filed in 2018, with PAM rates in effect as of January 1,

⁷ In certain situations, it may not be appropriate to allocate an attribute depending on the regulations and/or rules creating the attribute, such as energy storage attributes. *See* discussion below in footnote 54.

⁸ *See e.g.* Cal. Pub. Util. Code §§ 365.2, 366.2(f)(2), and 366.3.

1 2019). Given the rapid expansion of customer choice programs in California, the time for the
2 Commission to act is now to protect remaining bundled service customers from cost increases as
3 required by law, ensure that future cost-shifting between remaining bundled service and
4 departing load customers does not occur as required by law, and to provide planning certainty for
5 communities considering CCA.

6 The remainder of this Testimony provides background information on the Legislature's
7 and the Commission's regulatory framework governing utility electricity procurement and efforts
8 regarding cost allocation and protecting customers, discusses the problems with the Current
9 Methodology, and provides a detailed discussion of the PAM proposal.

1 **III.**

2 **OVERALL PROCUREMENT POLICY GUIDING PRINCIPLES AND PROCUREMENT**

3 **HISTORY**

4 Following the 2000-2001 Energy Crisis, the Legislature and the Commission established
5 the regulatory framework for the Joint Utilities to resume electricity procurement, beginning
6 January 1, 2003. Section 454.5(d)(2) and (3) provided for a utility procurement framework that
7 would:

8 Eliminate the need for after-the-fact reasonableness reviews of an electrical
9 corporation's actions in compliance with an approved procurement plan, including
10 resulting electricity procurement contracts, practices, and related expenses. However,
11 the commission may establish a regulatory process to verify and assure that each
12 contract was administered in accordance with the terms of the contract, and contract
13 disputes which may arise are reasonably resolved [and] [e]nsure timely recovery of
14 ... procurement costs incurred pursuant to an approved procurement plan.

15 Consistent with this statutory directive, the Joint Utilities have submitted their respective
16 bundled procurement plans ("BPPs") as part of the long term procurement plan ("LTPP")
17 proceedings for Commission review and approval.² The Joint Utilities' BPPs establish policies
18 and cost recovery for electricity purchases, ensure that the utilities maintain a set amount of
19 electric capacity for what they will need to serve their customers (plus a reserve margin), and
20 implement the approved long-term energy planning process. The Joint Utilities implement their
21 respective Commission-approved BPPs through various procurement methods and practices,
22 including competitive solicitations, bilateral negotiations, and participation in various markets.

23 The Joint Utilities are also required to submit annual Renewables Portfolio Standard
24 ("RPS") plans for Commission approval. These RPS plans cover the rigorous standards required
25 for RPS procurement, including, but not limited to, a determination of whether or not additional
26 renewable procurement is needed to meet the RPS targets by a specific date and a solicitation
27 protocol. In addition to the utility-scale renewable resources procured pursuant to the utilities'
28 approved RPS plans, the Commission also requires the utilities to procure RPS-eligible resources

² See e.g. Decision ("D.") 15-10-031 (approving 2014 BPPs).

1 through various siloed mandated programs such as the Renewable Auction Mechanism
2 (“RAM”), Renewable Market Adjusting Tariff (“ReMAT”), and the Bioenergy Market Adjusting
3 Tariff (“BioMAT”).

4 As a measure of oversight for procurement of all resource types for each utility’s bundled
5 customer portfolio, the Commission created two entities: the Procurement Review Group
6 (“PRG”) and the Independent Evaluator (“IE”). The PRG is comprised of non-market
7 participants, including the Commission’s Energy Division, consumer advocacy groups,
8 environmental groups and other parties. Its purpose is to review and consult on each utility’s
9 procurement process and most proposed contracts. The Commission also requires that an IE
10 participate in a utility’s competitive solicitation process for electric procurement, utility-built
11 projects, utility turnkey projects, and bilaterally-negotiated contracts. The purpose of the IE is to
12 increase fairness and transparency of the electric procurement contract selection process. Once a
13 bid makes it through the rigorous solicitation, evaluation, and selection standards, it is then
14 submitted to the Commission, which must determine if the contract is just and reasonable. Any
15 interested party is free to intervene and comment on the merits of a contract.

16 While the Joint Utilities have procured resources pursuant to the procurement process
17 described above, or through Commission-mandated programs, the RPS procurement done in the
18 first several years of the RPS program was extremely costly (compared to today’s market prices).
19 This early procurement of renewable energy generation resources, which ultimately contributed
20 to the rapid decrease in market prices that are accessible to CCAs and ESPs today, constitutes the
21 majority of the above-market portfolio costs that have contributed to the recent increases in the
22 departing load rates resulting from the Current Methodology. It is at least partially because of
23 the Joint Utilities’ early RPS procurement that current market prices are low (and therefore why
24 those early-procured renewable resources are now so much above-market).

25 Every one of the Joint Utilities’ contracts was approved by this Commission as just and
26 reasonable, and various statutes mandate that the customers on whose behalf the contracts were

1 signed pay the costs for those contracts in a manner that does not shift costs. Indeed, as the
2 Commission noted less than six months ago in D.16-12-038:

3 Contracts signed by PG&E were reviewed and approved by the Commission and
4 were found to be just and reasonable at the time they were entered into. This early
5 contracting, as required by legislation and approved by the Commission, served its
6 intended purpose and promoted the development of a robust renewable resource
7 market. Californians now enjoy lower renewable energy costs in part due to these
8 early contracts. These early contracts were entered into on behalf of all customers of
9 PG&E at the time, and departing customers should pay their share of the costs rather
10 than shifting them to bundled customers.¹⁰

¹⁰ D.16-12-038, p. 11.

1 IV.

2 **CURRENT METHODOLOGY** ¹¹

3 **A. Introduction**

4 For more than a decade, the California Legislature has consistently enacted laws intended
5 to ensure the equitable allocation of electricity procurement costs among the Joint Utilities’
6 bundled electric service customers and customers who depart bundled electric service to receive
7 service from another procurement service provider. Most recently, in Senate Bill (“SB”) 350,
8 codified in Section 366.3, the Legislature provided:

9 Bundled retail customers of an electrical corporation [i.e., a utility] shall not
10 experience any cost increase as a result of the implementation of a community choice
11 aggregator program. The commission shall also ensure that departing load does not
12 experience any cost increases as a result of an allocation of costs that were not
13 incurred on behalf of the departing load.

14 The Legislature enacted a comparable statute to address the situation where an electric
15 service customer departs to receive DA service from an ESP.¹²

16 These statutes are based on principles of cost causation and their requirements are self-
17 evident: When a customer chooses to receive service from another procurement service
18 provider, that customer’s choice should not increase the costs for, or otherwise detrimentally
19 impact, the remaining bundled service customers, nor should that customer be required to pay for
20 costs not incurred on its behalf. This prohibition against cost shifting as a result of customers
21 departing bundled service is at the heart of all statutory provisions on departing load cost
22 allocation. Because the Joint Utilities procure generation portfolios on behalf of all then-bundled
23 service customers, including those that later decide to take service from another procurement

¹¹ Through various decisions, the Commission also determined or altered the portfolio of the Joint Utilities’ resources whose above-market costs were included in various components of the Current Methodology. In this section, the Joint Utilities focus on the various iterations of the market price benchmark (“MPB”) adopted by the Commission.

¹² Cal. Pub. Util. Code § 365.2.

1 service provider, it is axiomatic that all of those customers must pay their share of costs to avoid
2 cost shifting as a result of departing load.

3 Since the 2000-2001 Energy Crisis, the Commission has implemented these statutory
4 requirements with regulatory decisions that embrace what is known as the “indifference
5 principle.” The indifference principle seeks to implement the statutory requirement that bundled
6 service customers remain financially indifferent to the impact of departing load. The Legislature
7 has enacted, and the Commission has implemented, a number of “nonbypassable charges” to
8 ensure that the indifference principle is maintained in the context of departing load. For
9 example, when the California electric industry was originally restructured in 1997, the
10 Legislature adopted Sections 367 - 369, which require that all customers share in any
11 “uneconomic” procurement costs, including contracted and utility-owned resources, resulting
12 from deregulation. The Commission implemented this statute through the ongoing Competition
13 Transition Charge (“CTC”), which is set using the Current Methodology and collected from all
14 utility distribution customers.¹³ In addition, the Legislature required the Commission to adopt a
15 nonbypassable charge to recover other procurement-related costs that are incurred on behalf of
16 customers that depart utility bundled service for a DA or CCA program.¹⁴ The Commission
17 implemented this requirement through the nonbypassable Power Charge Indifference Adjustment
18 (“PCIA”) rate. Together, the PCIA and CTC rates (using the Current Methodology) attempt to
19 recover the above-market costs of the Joint Utilities’ respective generation portfolios from
20 departing load customers.¹⁵

¹³ For PG&E and SDG&E, the above-market costs, as quantified using the Current Methodology, are collected from all customers through the CTC. For SCE, those above-market costs are collected from departing load customers through the CTC and from bundled service customers through their generation rates.

¹⁴ See e.g. Cal. Pub. Util. Code §§ 366.2(d), (e)(2) and (f).

¹⁵ Today, about 5% of the costs collected pursuant to the Current Methodology are CTC-related; the remaining 95% are PCIA-related.

1 More recently, the Legislature enacted statutes that require the costs for resources that
2 provide system-wide or local reliability benefits, or facilitate the integration of renewable energy
3 resources, be allocated to all customers that benefit from these resources, including end-use retail
4 customers of the Joint Utilities, CCAs, and ESPs.¹⁶ The Commission implemented system and
5 local reliability cost allocation through the Cost Allocation Mechanism (“CAM”), which has
6 proven largely effective in fairly allocating procurement costs and benefits to all benefitting
7 customers; the CAM is the conceptual basis for the PAM, which is proposed to replace the
8 Current Methodology.

9 Replacing the Current Methodology (and its resulting PCIA and CTC rates) with PAM is
10 a critical step in ensuring indifference in the face of the current and anticipated significant load
11 departures to alternative procurement service providers. The Current Methodology is out-of-date
12 and unable to produce results based on actual market conditions. The Current Methodology was
13 conceived during a time when levels of departing load were rather modest, and as detailed
14 below, even if modified, the Current Methodology breaks down further with increasing levels of
15 departing load.

16 Attempting to “fix” the inputs to the Current Methodology is not the answer. The
17 Current Methodology is premised on market proxies which often do not reflect actual market
18 outcomes. Nor does the Current Methodology employ a true-up mechanism to reflect actual
19 market outcomes. It was put in place before more sophisticated mechanisms, such as CAM,
20 were conceived and successfully implemented. It is not reasonable to try to “fix” a mechanism
21 that is inherently inconsistent with State law; any cost-allocation mechanism that relies on
22 administratively-set benchmarks ultimately will result in cost shifting to or from remaining
23 bundled service customers depending on actual market outcomes.

24 The Current Methodology has also been the subject of endless litigation and disputes, and
25 it is ill-designed to effectively manage currently-anticipated levels of departing load. Instead, the

¹⁶ Cal. Pub. Util. Code §§ 365.1, 454.52.

1 Commission should replace it with the PAM, which is a transparent, accurate, equitable, and
2 scalable mechanism that will appropriately allocate costs and benefits at all levels of departing
3 load in a manner that always ensures customer indifference, as required by California law.

4 Indeed, when the Commission adopted the Current Methodology for use in determining
5 departing load customers' cost responsibility for generation procured or built after the Energy
6 Crisis, it acknowledged that:

7 If, due to future changing circumstances, the processes adopted by this decision for
8 determining the [PCIA and CTC] become unworkable, unbalanced, or unfair, parties
9 may propose and request, for our consideration, modifications to the form of the
10 [PCIA and CTC] or the manner in which [it] should be determined or calculated.¹⁷

11 As will be described throughout this Testimony, circumstances have changed; the Current
12 Methodology has become unworkable, unbalanced, and unfair; and a complete replacement to
13 the Current Methodology is now necessary.

14 **B. Need for Reform**

15 The Current Methodology has undergone a number of modifications since it was first
16 adopted by the Commission under the rubric of the Cost Responsibility Surcharge ("CRS") in
17 2002.¹⁸ The central driver for these modifications has been a desire on the part of the
18 Commission and the parties to more accurately determine and apportion the above-market costs
19 of these resources.

20 The Joint Utilities' generation rates, set annually in their respective EERRA Forecast
21 proceedings, recover the total resource costs (less the "Indifference Rate" payments by
22 departing load customers) from bundled service customers. For departing load customers,
23 an "Indifference Rate" is determined using the Current Methodology to approximate their
24 pro-rata share of above-market costs, and recovered through the CTC and the PCIA. To
25 approximate the above-market costs, the Indifference Rate starts with the forecast costs of

¹⁷ D.08-09-012 p. 58.

¹⁸ See D.02-11-022 (adopting the initial CRS).

1 the utility generation portfolio and subtracts an estimate (proxy) of the revenue those
2 resources could garner in the market using forecasts of energy prices and administratively-
3 determined benchmarks, which collectively comprise the Market Price Benchmark
4 (“MPB”). These values are not trued-up after the fact. Thus, the Indifference Rate is the
5 result of a forecast of portfolio costs that is inevitably inaccurate and an imprecise proxy of
6 theoretical market outcomes.

7 Proxies – by their nature – do not reflect actual market conditions and therefore shift
8 costs in one direction or the other. Despite numerous Commission modifications, the
9 Commission-adopted MPBs are much higher than actual realized market prices, particularly for
10 renewable and RA values.¹⁹ These discrepancies – which have resulted in cost shifts to
11 remaining bundled service customers – were less consequential (although still prohibited by
12 statute) when the level of departing load was stable and relatively modest. However, with the
13 recently realized and expected increases in departing load in the immediate future from CCA
14 expansion (not to mention the potential reopening of DA), these discrepancies will cause
15 increasingly large cost shifts to remaining bundled service customers, which is prohibited by law
16 and plainly inequitable.

17 **C. History and Description of the Current Methodology**

18 In D.02-11-022, the Commission first established the CRS to recover from departing load
19 customers their share of the “(1) costs incurred by Department of Water Resources (“DWR”) on
20 behalf of customers in the service territories of the three IOUs (“DWR Power Charge”), and (2)
21 costs incurred by each of the IOUs for their own resources and contracts (CTC).”²⁰ The method
22 adopted for calculating these components of CRS was known as the “DA In – DA Out
23 methodology” which used a production cost model to determine the increase in the average

¹⁹ See Figure IV-1.

²⁰ D.02-11-022, p. 3. The adopted CRS also included the Historical Procurement Charge (“HPC”) for
SCE’s Departing Load customers to recover the procurement costs SCE incurred prior to DWR
assuming the responsibility to procure energy for the Joint Utilities’ customers.

1 generation cost to the bundled service customers as the result of some customers switching to
2 DA service, and the CRS applicable to those DA customers to keep the average bundled service
3 generation rate at the same level.

4 Due to the complexity and lack of transparency in this methodology, especially as related
5 to the market-clearing prices used in the modelling process, a working group established by the
6 assigned Administrative Law Judge in Rulemaking (“R.”) 02-01-011 proposed the Current
7 Methodology for calculating the CTC and PCIA using a MPB that was comprised of a forward
8 market energy price and a negotiated capacity adder on a \$/MWh basis. The Commission
9 adopted this proposed methodology in D.06-07-030.²¹ The Commission ordered that the
10 working group be reconvened in August 2006 to discuss and propose a capacity adder for 2007
11 and beyond.²² However, due to the lack of a functioning and transparent capacity market or a
12 suitable public index, the working group proposed to continue the use of a negotiated capacity
13 adder until such a market was developed.²³

14 The last and most recent decision to modify the MPB to arrive at its current structure was
15 D.11-12-018. In that decision the Commission decided that because a larger portion of the Joint
16 Utilities’ respective portfolios will consist of relatively more expensive renewable resources
17 procured to comply with RPS, it is reasonable to augment the MPB with an “RPS adder.” Again,
18 because of the lack of a robust and transparent renewable market or suitable public index at the
19 time, the Commission adopted an administratively-set benchmark based on the average price of
20 the Joint Utilities’ newly delivering (but not newly executed) contracts (weighted at 68%) and

²¹ Although the methods for calculating the CRS were determined and adopted by the Commission in R.02-11-011, they were also adopted for calculation of CCAs’ CRS in R.03-10-003 (*see* D.04-12-046 and D.07-01-025).

²² D.06-07-030, p. 13.

²³ D.07-01-030, pp. 3-4. This decision also updated the line loss factors used in the calculation of MPB and modified the forward energy prices used in the calculation of MPB to reflect the availability of published prices for both on- and off-peak future power deliveries.

1 the average price of voluntary green pricing programs spread throughout the Western Electricity
2 Coordinating Council (“WECC”) geographical footprint (weighted at 32%).²⁴

3 In the same decision, due to the lack of a transparent market price for RA capacity and
4 having relied on negotiated numbers for many years, the Commission adopted a capacity adder
5 equal to the going-forward costs of a simple combined-cycle combustion turbine as estimated by
6 the California Energy Commission (“CEC”) and updated biannually.²⁵

7 These efforts by the Commission and interested parties over the last 15 years have
8 resulted in the Current Methodology, under which:

- 9 1) The forecast costs of the total portfolio of generation resources for each vintage are
10 determined;
- 11 2) The value of the energy and capacity provided by those resources is approximated using
12 the MPB as described above;
- 13 3) This value is subtracted from the forecast costs to determine the above-market costs of
14 the total portfolio, which are then allocated to various rate groups based on their
15 contributions to the highest 100 hours of system load to establish an Indifference Rate;
- 16 4) Similar calculations are performed to approximate the above-market costs of resources
17 identified in P.U. Code § 367²⁶ to calculate the CTC, which is then subtracted from the
18 Indifference Rate to residually determine the PCIA;²⁷ and,
- 19 5) The Indifference Rate is set annually in each utility’s ERRRA Forecast proceeding on an
20 estimated basis and is not subject to a true-up.²⁸

²⁴ Specifically, as described in D.11-12-018, the RPS adder is to be calculated as the weighted average of Department of Energy (“DOE”) data for premiums paid by customers under voluntary green pricing programs (32%) and the premium paid by the Joint Utilities for renewable resources delivered in the year when the CRS is calculated and the prior year (68%).

²⁵ *Id.*, p. 30.

²⁶ Pursuant to Cal. Pub. Util. Code § 367(e)(2), bundled service customers “shall not experience rate increases as a result of the allocation of transition costs.” Those transition costs include the costs of “Old World” generation resources, as identified in P.U. Code § 367(a)(1)-(6).

²⁷ See D.06-07-030, pp. 13-16 and pp. 27-28.

1 **D. Reliance on Administratively-Set Benchmarks is Fundamentally Flawed and Does**
2 **Not Result in Indifference**

3 As the above section describes, the Commission has consistently sought to update the
4 MPB to better reflect the market prices for various attributes of the Joint Utilities' portfolios. In
5 doing so, the Commission has expressed a desire to rely on prices from transparent and liquid
6 markets when such markets for portfolio attributes exist.²⁹ To date, the Commission has relied
7 on administratively-set price inputs as proxies for market value. Unfortunately, these efforts
8 have not been successful and have resulted in convoluted and heavily-inflated MPBs. At best,
9 benchmarks are "educated guesses" about future market outcomes, and when administratively
10 set, they may become even more disconnected from actual market conditions. Consistent with
11 State law and policy, PAM replaces the "guess work" with actual market outcomes and protects
12 bundled service customers by ensuring customer indifference at any level of departing load.

13 **1. Flaws in the Existing MPB Result in Cost Shifts**

14 The values of the current administratively-set RPS and RA benchmarks are
15 materially overstated. In other words, current market prices for these attributes are much lower
16 than the benchmarks. The RA value is overstated because it is set equal to the going-forward
17 cost of a combustion turbine, at a time when there is excessive capacity available in the market.
18 RA capacity can generally be procured at prices much lower than the administratively-set
19 benchmark price. The RPS value is overstated because the costs of recently delivering resources
20 are based on contracts negotiated and executed several years prior, when prices were much
21 higher than they are today. Furthermore, the premiums associated with the voluntary green

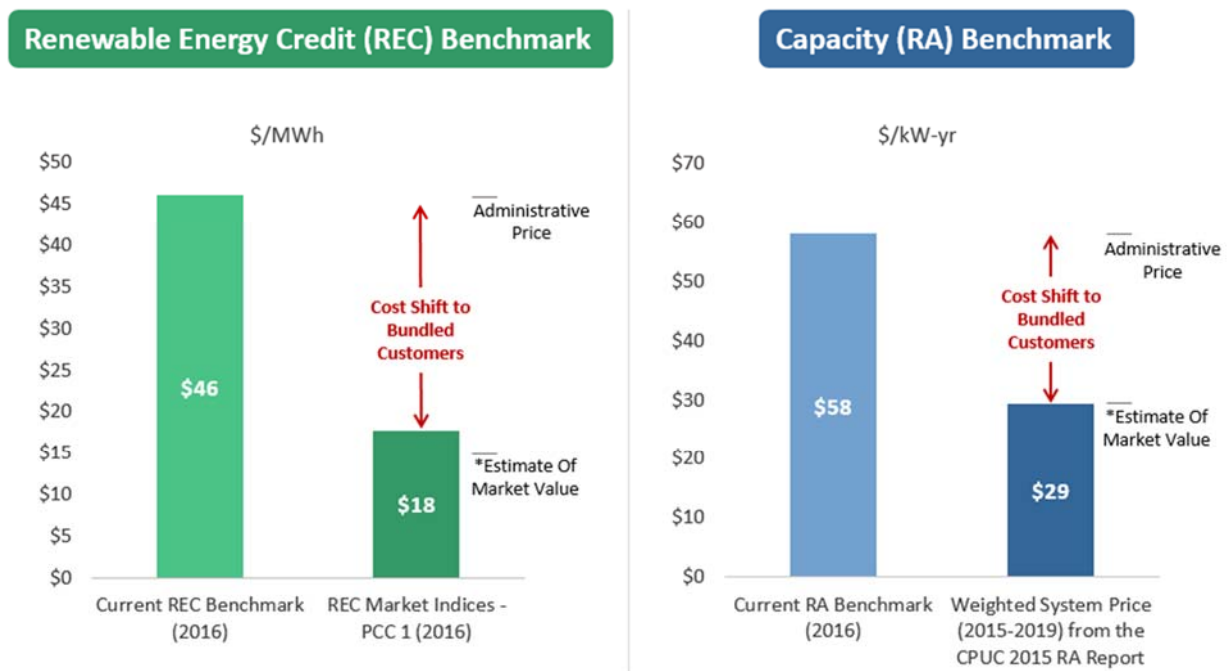
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²⁸ Although these costs were subject to a true-up when the Commission first adopted this methodology, the true-up was later eliminated due to parties seeking more certainty and simplicity in the calculation of CTC and the PCIA. See D.08-09-012, p. 69.

²⁹ See e.g. D.11-12-018, p. 24 (discussing Commission's desire to use market information for renewable energy adder when information becomes available).

pricing programs are inflated as they include administrative costs of these programs. Figure IV-1 demonstrates the magnitude of the overstated benchmarks:

Figure IV-1³⁰
Comparison of 2016 Current Methodology Benchmarks to Public and Market Information



Because the Current Methodology defines departing load customers' cost responsibility as the difference between the costs of the utility generation portfolio and its market value, as determined using the administratively-set benchmark, any variance between the administratively-set benchmarks and current market prices for those products results in an improperly-calculated market value that shifts costs between bundled service and departing load customers. The estimates shown in Figure IV-1 are based strictly on public and readily-available market

³⁰ The REC Market Indices PCC 1 information are derived from a blend of RECs index numbers as well as broker quotes. The RA estimates are based on publicly available information in the CPUC's 2015 Resource Adequacy Report and available at <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452221> (p.20).

1 information, and reflect a conservative estimate of the current, substantial costs that are being
2 shifted from departing load customers to bundled service customers.

3 During the Commission-ordered PCIA Working Group process³¹ and over the
4 past few years, the Joint Utilities have expressed concerns that the MPB is overstated and not
5 reflective of the actual market value of the Joint Utilities' generation portfolios.³² Other parties
6 have disagreed. With PAM, the Commission does not need to adjudicate who is "right," or be
7 satisfied with an inadequate approximation of indifference—deficiencies which become more
8 problematic as departing load increases. Under PAM, estimation and forecasting are replaced
9 with after-the-fact actual energy market results to determine the vintaged portfolios' net costs.
10 PAM also uses actual customer demand to facilitate a pro-rata allocation of the value of those
11 same portfolios (i.e., their "attributes") to all vintaged customers.³³ Compared to the Current
12 Methodology, PAM is more transparent, based on actual portfolio costs and revenues, accurately
13 allocates benefits and net costs of the Joint Utilities' portfolios to bundled service and departing
14 load customers (and their LSEs), and will achieve a far superior implementation of the
15 statutorily-mandated indifference requirement.

16 **2. Existing REC Benchmarks Are Volatile, Not Transparent, and Do Not**
17 **Accurately Reflect Market Prices**

18 Some CCA and DA parties have expressed concerns that the Indifference Rate
19 resulting from the Current Methodology is volatile, making it difficult to forecast and plan. As
20 shown in the charts below, the volatility and uncertainty in current departing load CTC and PCIA

³¹ Pursuant to D.16-09-044, the Joint Utilities participated in a PCIA Working Group with interested parties.

³² See e.g. February 16, 2016 filings by PG&E, SCE, and SDG&E in response to Energy Division's Questions for March 8, 2016 Workshop (A.14-05-024, Phase 2).

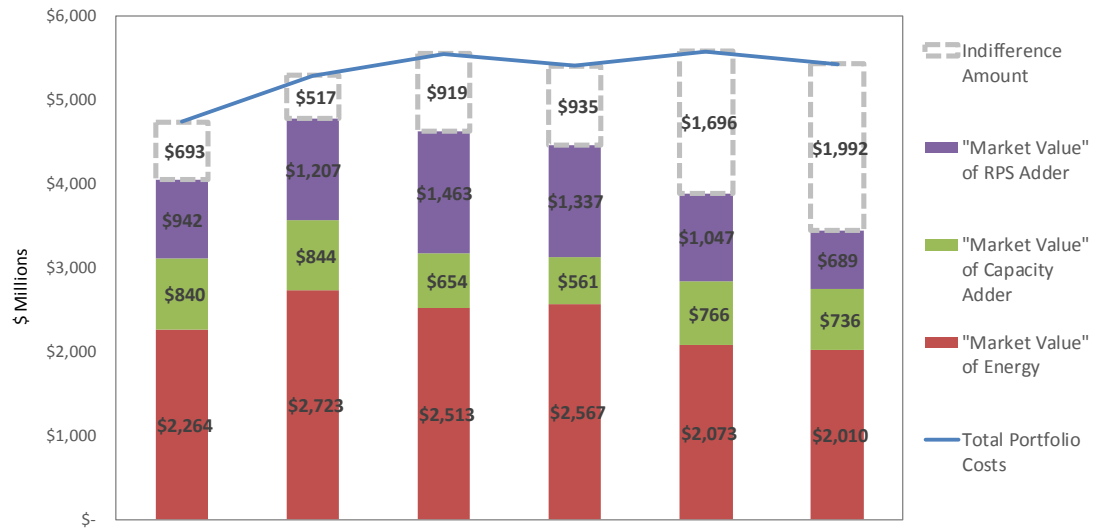
³³ For attributes such as Resource Adequacy which must be used prior to market results, PAM uses the latest forecasts reasonably available to make a pro-rata allocation to all load serving entities ("LSEs") based on each LSE's load share ratio.

1 rates is largely driven by the volatility³⁴ and lack of transparency in the RPS adder (or “REC
2 Benchmark”). The REC Benchmark has fluctuated significantly since its introduction in 2012,
3 and is based largely on confidential RPS contract-pricing data that is finalized and validated by
4 the Commission’s Energy Division in October of each year.³⁵

³⁴ Assume that the average cost of the resources in the utility portfolio for a given year (Year 1) is \$100/MWh, and assume that the market price benchmark for that portfolio is \$90/MWh. The Indifference Rate for that year is thus \$10/MWh, or \$0.01/kWh (\$100/MWh - \$90/MWh). Now assume the following year, the average cost of the same resources in the same utility portfolio stays at \$100/MWh, but that the market price benchmark drops to \$80/MWh. In Year 2, the Indifference Rate is now \$20/MWh or \$0.02/kWh (\$100/MWh - \$80/MWh). Thus the Indifference Rate is increased by 100% simply due to a change in the market price benchmark of 11%.

³⁵ See Resolution E-4475.

Figure IV-2
2012 – 2017 Indifference Calculation for PG&E's 2012 Vintage³⁶



Includes Line Losses to Customer Meter	2012	2013	2014	2015	2016	2017
REC Benchmark (\$/MWh)	\$63.94	\$63.78	\$69.76	\$61.15	\$47.75	\$33.54
Total RPS Energy (MWh)	14,735	18,926	20,968	21,866	21,672	20,558
Capacity Benchmark (\$/kW-Year)	\$50.17	\$50.17	\$50.17	\$50.17	\$58.26	\$58.26
Total Net Qualifying Capacity (MW)	16,740	16,823	13,036	11,174	13,140	12,637
Energy Benchmark (\$/MWh)	\$35.23	\$41.27	\$41.39	\$43.73	\$34.87	\$37.33
Total Energy (MWh)	64,259	65,992	60,725	58,701	59,437	53,857

The decline in the RPS adder component of the MPB is a function of steadily decreasing renewable energy prices, but it has not kept pace with the larger decline in actual market prices. As described above, the RPS adder is, in large part, set using the average cost of newly-delivering renewable utility contracts. Because the utilities' newly-delivering renewable resources are the result of contracts that were executed several years prior to the commencement of deliveries, the RPS adder lags actual market prices for new contract resources. As a result, the RPS adder has persistently overstated the market value of the Joint Utilities' renewable energy portfolios, which results in impermissible cost shifts to remaining bundled service customers. Therefore, even though the Indifference Rate for departing load customers has been justifiably

³⁶ 1) Indifference Calculation excludes Franchise Fees and Uncollectibles and includes Ongoing CTC;
2) All energy (MWh) and benchmark prices (\$/MWh) are at the Customer Metered level and reflect an average of 6% line losses from Generation to Load level.

1 increasing, its rate of increase has not sufficiently protected remaining bundled service customers
2 from unlawful cost shifts. It should be noted that departing load customers (through their CCAs
3 and ESPs) can now procure RPS-eligible resources on the open market at prices significantly less
4 than they otherwise would have been paying absent this earlier utility procurement that helped
5 transform the market, but remaining bundled service customers must still pay the fixed (high)
6 costs of the early RPS contracts.³⁷ The Legislature and the Commission implemented the
7 statutory indifference requirement precisely to prohibit the cost-shifting consequences that would
8 result if departing load customers were permitted to avoid some of these unavoidable historical
9 costs.

10 That cost-shift will only continue to increase if not addressed now. Looking
11 ahead, under the Current Methodology, the RPS adder component of the MPB is likely to
12 continue to diverge from market conditions. As the Joint Utilities have indicated in their recent
13 RPS plans, they have little to no need for incremental renewable procurement in the near
14 future.³⁸ This would result in an RPS benchmark that will be set based on a limited set of
15 resources – most, if not all, of which will be procured pursuant to state-mandated “carve-out”
16 programs³⁹ and thus much more expensive than the current prices for market-based, large-scale
17 renewable resource procurement. This will result in greater inflation of the RPS adder that does
18 not reflect the actual market value of RPS resources. A significant portion of the Joint Utilities’
19 CTC- and PCIA-eligible portfolios are comprised of renewable resources; thus, the Indifference
20 Rate is and will continue to be largely driven by an unreliable and inflated RPS adder.
21 Administratively-set benchmarks should not be used at all, when instead they can be replaced
22 with a mechanism like the PAM which can allocate both the portfolio benefits (e.g., the RPS
23 attribute) and actual net costs on a load share basis to each customer and its LSE.

³⁷ D.16-12-038, p. 11.

³⁸ D.16-12-044 (approving 2016 RPS Plans).

³⁹ Examples include feed-in tariff programs such as ReMAT and BioMAT.

1 The Current Methodology also inhibits transparency of its calculations and
2 results. The current RPS adder relies on confidential utility contract data, which limits the ability
3 of the Joint Utilities to disclose forecast changes in their current Indifference Rates to CCA and
4 DA entities, as they are market participants. The RPS adder data sources are not only highly
5 variable, not representative of actual market conditions, and non-transparent, they are also the
6 major underlying cause of the current and growing cost shifts between bundled service and
7 departing load customers. There should be no question that the use of actual market outcomes
8 and resource attributes is the most effective means to ensure customer indifference.

9 **E. Need for a Methodology that Can Scale**

10 The Current Methodology implicitly assumes that the Joint Utilities' excess remaining
11 RA, RECs, and other potential portfolio attributes after load departs can either be sold at the
12 MPB value or used to offset future procurement. While this assumption is flawed even when
13 small amounts of load departs (as discussed above), the flaws are amplified with large amounts
14 of load departure. In that situation – which the State may soon face based on projections of
15 departing load provided by CCAs -- the Joint Utilities would need to liquidate the excess
16 resources in the bundled service portfolio and will likely be unable to sell their portfolios and
17 their attributes at prices anywhere near the MPB because the market will be very long with
18 excess bundled service portfolio attributes. Indeed, even a more accurate market-based index, if
19 one existed, would be unable to capture the effects of such a scenario given the magnitude of the
20 Joint Utilities' portfolios. Therefore, as the level of departing load increases, the current “above-
21 market construct” will result in an ever-decreasing number of remaining bundled service
22 customers absorbing an increasing level of above-market portfolio costs. This systematic cost
23 shift to remaining bundled service customers is inherently inequitable, unsustainable, and
24 incompatible with the indifference requirement clearly specified by law. Instead of
25 contemplating further revisions to inputs of the MPB, PAM offers a structure that robustly
26 ensures customer indifference at any level of departing load.

1 Second, allocating the attributes of the Joint Utilities' respective portfolios to all LSEs
2 that serve departing load would enable those LSEs to scale their operations and plan to serve
3 their load in a manner that optimizes the existing utility resources which were procured to also
4 serve the departing load customers. This will ensure greater societal efficiencies in achieving the
5 State's clean energy policy goals and mandates, including the requirement that 65 percent of
6 each LSE's RPS compliance requirement be met with long-term RPS energy deliveries starting
7 in 2021.⁴⁰ Absent such an allocation of attributes, as the level of departing load increases, there
8 will be a glut of those attributes in the market resulting in inefficient market outcomes and an
9 underutilization of resources previously procured by the Joint Utilities to serve their then-
10 bundled service customers.

⁴⁰ See Cal. Pub. Util. Code § 399.13(b).

V.

DESCRIPTION OF PORTFOLIO ALLOCATION METHODOLOGY

The fundamental goal of PAM is to ensure that customers who depart from bundled service receive their pro-rata share of the benefits from – and pay their pro-rata share of the costs of – resources that were procured or built on their behalf. To be consistent with California law, PAM is designed to ensure that cost shifting does not occur between customers who remain on utility bundled service and customers that are served by an alternative procurement service provider. This fundamental goal is mandated by statute and PAM is the most effective method for achieving it at all levels of departing load.⁴¹

A. PAM Overview and How It Protects All Customers

PAM will replace the Current Methodology, which is based on administratively-set benchmarks, with an allocation-of-portfolio-resources approach that ensures all customers receive the actual and full value of the resources that were procured or built on their behalf, and correspondingly, pay the actual and commensurate costs for those resources. Additionally, PAM is methodologically similar to the CAM adopted by the Commission in D.06-07-029,⁴² whereby the benefits of the generation resources (*e.g.*, enhanced system reliability and capacity that is applied towards each LSE’s RA requirements) are shared equitably by all customers, and the “net costs,” defined as the total cost of the resource minus the revenues associated with the dispatch of the resource, are also shared equitably by all customers.⁴³

Under PAM, the costs recovered from departing load customers will equal the actual incurred costs (*e.g.*, contract costs owed to the generators, UOG capital costs, fuel costs, and California Independent System Operator (“CAISO”) charges), less the actual revenues received from the markets for those resources (*e.g.*, energy and ancillary services revenue). While the

⁴¹ *Id.*, §365.2 and §366.2.

⁴² Many of the detailed mechanics of the methodology were refined and adopted in D.07-09-044 and D.15-11-041.

⁴³ D.06-07-029, p. 7.

1 initial rates will be set in the Joint Utilities’ respective annual ERRA Forecast proceedings based
2 on a forecast of costs and offsetting market revenues (forecast net resource costs), those rates
3 will be trued-up annually based on actual portfolio performance and market settlement data
4 (actual net resource costs), as well as billed revenues received from customers.⁴⁴ This method
5 mirrors the process used to set bundled service generation rates and New System Generation
6 rates,⁴⁵ and most importantly, ensures that all customers pay their pro-rata share of the net
7 resource costs for which they are responsible. Furthermore, net resource costs will be reviewed
8 and validated annually in each utility’s ERRA Compliance proceeding to ensure that the utility
9 prudently managed its resources pursuant to the Commission’s Standard of Conduct 4 (“SOC 4”)
10 Least-Cost Dispatch (“LCD”) requirements. This is the same review the Commission currently
11 conducts for the Joint Utilities’ bundled service customers’ portfolios in the annual ERRA
12 Compliance proceedings, and under PAM the utilities will continue to be required by SOC 4 to
13 efficiently dispatch the portfolio for all customers, both bundled service and departing load. In
14 the ERRA Compliance proceedings, the Commission will also continue to scrutinize the Joint
15 Utilities’ prudent contract administration obligations (on behalf of all customers under PAM).

16 PAM also establishes a process for an equitable and efficient allocation of all of the
17 attributes (value) of the resources in the utilities’ portfolios, including the value of the energy and
18 ancillary services (which will be realized through the market revenues that are used to offset the
19 resource costs), and direct assignment of RECs, RA, and any future benefits that may come into
20 existence with policy or market development, as appropriate.⁴⁶ As described in more detail
21 below, LSEs will receive relevant portfolio data to allow them to develop their own long-term
22 forecasts of the portfolio attributes that will be allocated to them. They will also realize the
23 annual energy attributes of the portfolio (*i.e.*, the market revenues) as an offset to costs

⁴⁴ A description of the cost true-up process is described in further detail in Section VI.A.

⁴⁵ New System Generation rates collect the costs of all CAM-eligible resources from all delivery service (*i.e.*, bundled service and departing load) customers.

⁴⁶ See footnote 7.

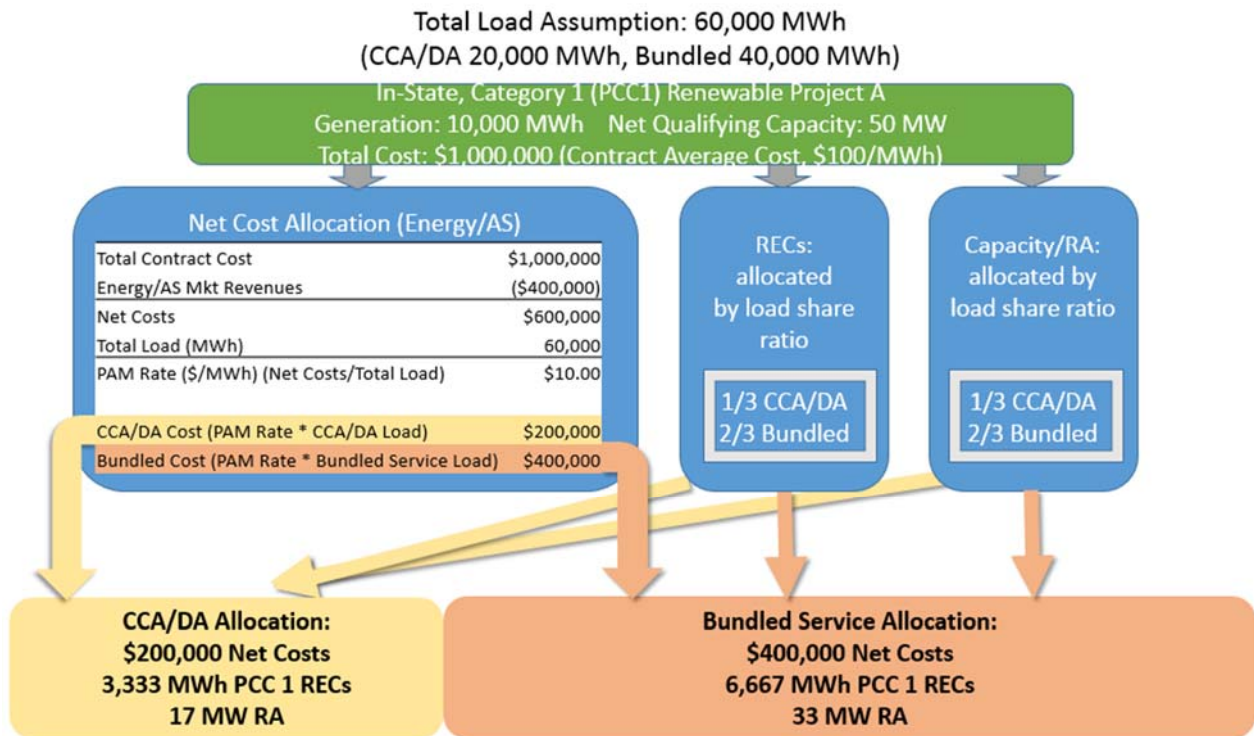
1 embedded in the PAM rate.⁴⁷ This is symmetrical to the way that bundled service customers’
2 generation rates are set. The long-term planning information can also be used by LSEs to build
3 out or rebalance their residual generation portfolios.⁴⁸ Actual REC and RA allocations will take
4 place quarterly and monthly, respectively, and will reflect actual load (for REC allocation) and
5 peak load shares (for RA allocation)⁴⁹ to ensure alignment between actual revenues received
6 from customers and benefit allocations. Moreover, these ongoing allocations will reduce ESPs’
7 and CCAs’ future need for RA and RPS procurement, thereby serving as a long-term hedge
8 against fluctuations in the prices for those products (again, symmetrical to the functions those
9 resources serve for bundled service customers).

⁴⁷ The Joint Utilities’ RPS contracts are largely fixed-price contracts. To the extent that market prices at any point exceed those contract-defined prices, the contracts will be “in the money” in the energy markets, and all customers will equitably benefit from the resulting market revenues. *See* Figure V-4.

⁴⁸ As will be described in further detail in Sections D and E of this chapter, LSEs will be able to use the PAM-allocated attributes as compliance instruments to meet their RPS and RA obligations and can, if needed to reduce long positions, enter into sales of resources in their own portfolios. Additionally, the PAM-allocated attributes reduce LSEs’ residual needs and provide a hedge against fluctuations in REC and RA prices.

⁴⁹ Load and peak load share in this context means the individual CCA’s or ESP’s portion of sales and peak demand, respectively, which accounts for reductions in load due to distributed generation and energy efficiency and increases in load due to electric vehicle charging. Load and peak load shares are calculated regularly on a vintaged basis. *See* Appendix A for an illustrative example.

Figure V-3
High Level Overview of PAM Cost and Benefit Allocation^{50 51}



PAM will also include a “vintaging” process, identical to what is used in the Current Methodology,⁵² to ensure that customers are held responsible for only the resources that were procured on their behalf. If a customer decides to depart bundled service, that customer will neither be allocated benefits nor costs for resources procured after its departure.

⁵⁰ Example scenario and illustrative of a one-resource allocation only. Actual PAM allocations will occur for all resources on a resource-specific basis.

⁵¹ The figure is intended to provide a high-level overview of the PAM proposal and does not detail the true-up process.

⁵² Pursuant to D.08-09-012, resources are assigned to a vintaged portfolio based on the year the generation resource commitment is made (*i.e.*, contract execution date or Commission approval for UOG) and customers are assigned to a vintage based on their departure date. Specifically, customers who depart before June 30 of a given year are assigned to the prior year’s vintage. The Commission clarified the vintaging rules for customers served by a CCA in D.16-09-044, and the Joint Utilities are not proposing any changes to the vintaging rules in this Application.

1 There are several advantages to PAM compared to the Current Methodology. First and
2 foremost, PAM protects all customers through a transparent process that uses actual market
3 results rather than hypothetical, administratively-set market proxies. PAM will replace an
4 “estimation” construct that relies on inaccurate and contentious administratively-set MPBs with
5 actual and verifiable net resource costs, including a true-up process, and a direct allocation of the
6 full benefits of the resources. PAM results in both departing load customers and remaining
7 bundled service customers paying the same net cost, on a per-kWh basis, for each resource for
8 which they are collectively responsible.

9 In addition, given PAM’s reliance on long-term contract information and actual market
10 data, predictability and transparency of the rates are improved. Long-term contracts have
11 predictable costs, and accordingly portfolio managers can forecast around the resulting, more-
12 predictable, costs, revenues and benefits.- Indeed, long-term renewable contracts, which
13 comprise the majority of the PAM-eligible portfolio, have little to no variable operating costs
14 and a “fixed price” per MWh of generated energy. CCAs and ESPs can use this predictable
15 resource-specific data, along with their own forward energy price curve forecasts, to develop
16 their own forecasts of future rates.

17 Finally, the resources that will be subject to PAM are all resources that were approved by
18 the Commission and procured to meet then-bundled service load requirements consistent with
19 State policy directives. By allocating to customers their pro-rata share of these resources’
20 attributes, customers take with them the inherent value of actions taken to support the State’s
21 regulatory and public policy, and pay their equitable pro-rata share of the costs of those actions
22 taken on their behalf.

23 **B. Resources Subject to PAM**

24 The resources that will be subject to PAM (PAM-eligible resources) include all resources
25 eligible for recovery under the Current Methodology (*i.e.*, all CTC- and PCIA-eligible
26 resources). In addition, as discussed in Chapter VII of this testimony, the Joint Utilities propose
27 to eliminate the 10-year cost allocation period limit for UOG fossil fuel resources acquired

1 through a procurement process after 2002, as adopted in D.04-12-048 and D.08-09-012, and
2 make these UOG resources PAM-eligible. PAM-eligible resources, which have been approved
3 by the Commission or procured through rules adopted by the Commission in the Joint Utilities’
4 LTPPs, RPS Plans,⁵³ and Energy Storage Plans were procured or built on behalf of then-bundled
5 service customers, and any forecast bundled service load growth, to meet bundled service load
6 requirements or the State’s policy directives, and their costs and benefits should be allocated to
7 all customers for whom they were procured.

8 All costs associated with the PAM-eligible resources will be included in the calculation
9 of the net costs of the PAM-eligible resources. These direct resource costs, and any associated
10 indirect resource costs, are currently included in the “Total Portfolio Costs” used in the Current
11 Methodology to calculate the PCIA and CTC rates and are described in further detail in
12 Appendix D.

13 **1. PAM-Eligible Contracts**

14 The PAM-eligible portfolio will include all RPS-eligible, non-RPS-eligible, and
15 energy storage contracts⁵⁴ included in the Current Methodology. As will be described in further
16 detail in Chapter VI, the net costs of contracts that are currently recovered through the CTC rate
17 will be recovered through a modified CTC rate component based on the PAM methodology,⁵⁵
18 and the net costs of resources that are currently recovered through the PCIA rate will be

⁵³ Resources procured through approved RPS Plans include those procured through utility-scale RFOs, feed-in tariff solicitations, and approved bilateral transactions.

⁵⁴ Because of the way the Commission has defined the energy storage targets in the Energy Storage Procurement Framework and Design Program for the Joint Utilities and CCAs/ESPs (a relatively higher megawatt target for the Joint Utilities and a relatively lower percentage of load target for CCAs and ESPs), for energy storage resources the Joint Utilities would only transfer RA attributes to other LSEs under PAM. The Joint Utilities would not transfer any of the MW capacity to meet the LSE-specific energy storage procurement targets. If the Commission redefines the energy storage compliance obligations, the Joint Utilities would propose the appropriate modifications to PAM to reflect that change.

⁵⁵ Inclusion of the CTC-eligible resources in the portfolio of resources used to determine the full cost responsibility of departing load customers is consistent with the Total Portfolio Approach adopted for calculating the Indifference Rate (*i.e.*, sum of CTC and PCIA) in D.06-07-030.

recovered through a new Portfolio Allocation Charge (“PAC”) rate component. As will be discussed further in Chapter VII, the Joint Utilities propose that all contracts be considered PAM-eligible for their entire terms⁵⁶ (identical to the treatment of PCIA-eligible RPS contracts under the Current Methodology), including energy storage contracts.

2. PAM-Eligible Utility Owned Generation (UOG)

In addition, PAM will apply to all UOG not subject to another cost allocation treatment.⁵⁷ UOG was approved by the Commission, based on the same justifications as contracted generation, at a time when departing load customers were still bundled service customers. The UOG resources were identified as being either the lowest-cost, best-fit solution at the time they were built or were needed to carry out a specific policy directive. There is no reason why UOG should be treated differently than contracted generation for purposes of PAM. Indeed, to arbitrarily exclude resources based on who owns them is unlawful because it does not protect remaining bundled service customers from increased costs associated with departing load.

The Joint Utilities propose in this Application that cost allocation for UOG resources be consistent between “Legacy” (i.e., pre-2002) and post-2002 UOG resources. As the Commission noted in D.08-09-012, “bundled customer indifference will only be maintained if all resources are included in the portfolio used to calculate the related charges...therefore, the use of the total portfolio and the inclusion of the [Legacy] resources in that portfolio is the appropriate approach to use for the duration of [new world generation] cost [allocation].”⁵⁸ Consistent with that conclusion and the existing treatment of Legacy UOG under the Current Methodology, the Joint Utilities propose that both Legacy and post-2002 UOG resources be considered PAM-

⁵⁶ Pursuant to D.04-12-048, all non-renewable contracts are subject to the 10-year cost allocation period.

⁵⁷ For example, the costs for SCE’s five UOG peaker plants are CAM-eligible, so those resources would not be subject to PAM treatment.

⁵⁸ D.08-09-012 at p.51.

1 eligible until the last of the long-term contracts associated with those customers' vintaged
2 portfolios expires, with the caveat that the Joint Utilities specifically reserve the right to seek
3 Commission approval of future UOG cost allocation should circumstances so warrant.⁵⁹ ⁶⁰ As
4 explained in more detail in Chapter 7 of the Joint Utilities' Testimony, the ten-year cost
5 allocation limitation is discriminatory and unreasonable because it results in treating similarly
6 situated resources differently. Instead of imposing an arbitrary cost allocation limitation, UOG
7 and other resources currently subject to the ten-year cost allocation limit should receive similar
8 cost allocation treatment and thus the costs for these resources should be recovered through PAM
9 until the last of the long-term contracts associated with those customers' vintages expire so that
10 all resources are treated similarly.

11 **3. Resources Ineligible for PAM**

12 PAM will exclude any current or new resources such as system reliability-,
13 emergency-, and policy-based procurement that the Commission determines are eligible for
14 broad cost allocation. Additionally, the Commission and the Legislature have previously

⁵⁹ For example, if a utility experiences an expectedly-large load departure after the presumptive cost-recovery period ends but before the UOG resource is retired, it may become necessary to revisit the cost-recovery issue to preserve bundled service customer indifference as mandated by state law. In such a situation, the Joint Utilities reserve their rights to seek appropriate relief at the Commission.

⁶⁰ For 2001 vintage customers, the issue of whether those customers should continue to pay the PCIA (which would be replaced with the PAC) now that the last of their relevant long-term contracts (specifically the Department of Water Resources contracts) have expired is currently before the Commission in the Joint Utilities' 2017 ERRRA Forecast Phase 2 proceedings (A.16-04-018 for SDG&E, A.16-05-001 for SCE, and A.16-06-003 for PG&E, which are anticipated to be consolidated). Consistent with the Joint Utilities' proposal in this proceeding, those 2001 vintage customers should no longer be responsible for PCIA (or PAC), with the caveat that the Joint Utilities specifically reserve the right to seek Commission approval of future UOG cost allocation should circumstances so warrant. In fact, one such particular scenario is currently before the Commission in the 2017 ERRRA Forecast Phase 2 proceedings, specifically regarding ongoing cost recovery from 2001 vintage departing load customers related to SCE's and SDG&E's retired San Onofre Nuclear Generating Station (SONGS). This issue is known as the DA Consensus Ratemaking Proposal (approved by the Commission in D.14-05-003 and D.14-05-022). SCE and SDG&E view that issue as settled and final, but to the extent that departing load customer groups dispute that Commission-approved cost allocation mechanism, it should continue to be litigated in the 2017 ERRRA Forecast Phase 2 proceedings.

1 concluded that all customers, including departing load customers, bear responsibility for the cost
2 of the Joint Utilities' procurement of biomass resources in response to the Governor's emergency
3 proclamation on tree mortality.⁶¹ As such, the Joint Utilities do not propose any changes to
4 current cost allocation mechanisms associated with these existing programs.

5 The PAM will also exclude any short-term contracts or transactions less than one
6 year in length. Exclusion of such resources is consistent with the Current Methodology.⁶²

7 **C. Market Revenues for Energy and Ancillary Services**

8 The Joint Utilities propose that, instead of allocating to each LSE its customers'
9 estimated share of the energy-related (*e.g.*, energy and ancillary services) benefits from the
10 PAM-eligible resources, the PAM-eligible resources be bid or sold into energy and ancillary
11 services markets and the actual revenues they generate be allocated to all customers for whom
12 the resources were procured.⁶³ The actual revenues received from the energy and ancillary
13 services markets (*i.e.*, the energy benefits) will be netted against the cost of the resources to
14 reduce the costs of the resources ("net costs").⁶⁴ This approach is both consistent with CAM, in
15 which the Joint Utilities use market revenues to reduce the costs of the CAM-eligible portfolio,
16 and ensures that the energy benefits of the PAM portfolio, including any energy price hedge
17 value, are shared equitably by all customers.

18 Under PAM, the Joint Utilities will continue to manage the PAM-eligible resources and
19 bid or sell them into energy markets if the utility is the Scheduling Coordinator ("SC").⁶⁵
20 However, instead of using those market revenues to offset the costs of meeting the bundled

⁶¹ See Cal. Pub. Util. Code §399.20.3(f); CPUC Resolution E-4805 (2016).

⁶² D.11-12-018, Finding of Fact (FOF) 24 and Conclusion of Law (COL) 3.

⁶³ Currently, most market revenues are realized from participation in CAISO markets, but the PAM proposal would account for all market revenue, including long-term sales.

⁶⁴ Additional work with the CEC will be required to ensure that energy associated with PAM resources is accounted for in the Power Content Label calculation.

⁶⁵ Resources for which the utility is not the SC will continue to be offered into the energy markets by the responsible party.

1 service customers' generation requirements as is currently done, the Joint Utilities will use the
2 revenues received from participation in the energy markets⁶⁶ to directly offset the costs of the
3 resource, resulting in a reduced net cost to bundled service and departing load customers. This
4 proposal eliminates the enormous complexity that would be involved in attempting to allocate a
5 pro-rata share of the energy to all LSEs—a process which would require LSEs to submit
6 inter-SC trades for their small slices of power from numerous resources with the respective
7 resources' SCs—and is reasonable given the Joint Utilities' obligation to realize market revenues
8 by abiding by SOC 4's LCD principle,⁶⁷ which requires that "[t]he utilities ... prudently
9 administer all contracts and generation resources and dispatch the energy in a least-cost
10 manner."⁶⁸

11 Additionally, the Joint Utilities' proposal ensures that the customers who are responsible
12 for the costs of the resource receive the energy price benefit that the resource provides,
13 regardless of their current LSE. This aspect of PAM will provide the same energy price
14 protection to departing load customers as will be received by remaining bundled service
15 customers. A simple example is shown in Figure V-4, below. Because the majority of the Joint
16 Utilities' resources are fixed-price long-term contracts, each LSE is hedged against price
17 fluctuations in the energy market by the amount of fixed price energy that represents their load
18 share ratio of the utility's portfolio. In the example below, the utility contract provides a fixed
19 cost of \$60/MWh regardless of whether the spot price is higher (\$80/MWh in Scenario 2) or
20 lower (\$40/MWh in Scenario 1) than the contract price of \$60/MWh.

⁶⁶ The energy market revenues include all energy, residual unit commitment ("RUC") or ancillary service payments from the day-ahead and real-time markets net of any charges that result from participation in the energy markets. An example of these charges is CAISO deviation charges for a resource that generates above or below its scheduled output.

⁶⁷ SOC 4, which articulates the LCD principles, was initially adopted in D.02-10-062 and is further discussed in D.02-12-069, D.02-12-074, D.03-06-076, D.05-01-054, and D.15-05-057.

⁶⁸ Compliance with these LCD principles is audited annually in each utility's respective ERRA Compliance proceeding.

Figure V-4
Illustrative Example of Energy Price Hedge

Item	Contract Cost	Market Revenues/Costs	Net Cost
CAISO Price Scenario 1			
PAM RPS Delivery (1 MWh)	60.00	-40.00	20.00
<u>Corresponding Load (1 MWh)</u>		<u>40.00</u>	<u>40.00</u>
Total Cost			60.00
CAISO Price Scenario 2			
PAM RPS Delivery (1 MWh)	60.00	-80.00	-20.00
<u>Corresponding Load (1 MWh)</u>		<u>80.00</u>	<u>80.00</u>
Total Cost			60.00

D. Renewable Energy Credit (REC) Allocation Process

The Western Renewable Energy Generation Information System (“WREGIS”) creates one REC for each whole megawatt-hour (“MWh”) of electricity that was generated from a qualified renewable energy source.⁶⁹ The REC allocation process under PAM will result in a proportionate sharing of RECs among the LSEs on a vintaged basis. The Joint Utilities propose to allow a utility to allocate a portion of its total PAM-eligible REC portfolio (including previously generated excess RECs before load departed)⁷⁰ to a CCA or ESP based on the LSE’s load share, and that REC allocations not disrupt the content categorization of the RECs in the allocated portfolio, nor the underlying contract tenors for the RECs in the allocated portfolio.

⁶⁹ See Cal. Pub. Util. Code §399.12(h), and also note that WREGIS issues one REC for each whole MWh generated, any fraction of a MWh of renewable energy generation is carried over into the next month.

⁷⁰ Under PAM, to the extent the utility banked RECs before customers departed bundled service, a proportionate share of RECs banked on behalf of those customers prior to their departure will be allocated to the CCA or ESP. The RECs will be transferred to the CCA or ESP ratably over the term spanning the latest delivering contract in their vintaged portfolio(s).

1 **1. Proposed REC Attribute Language to Enable REC Allocation under PAM**

2 As will be described in further detail below, the Joint Utilities propose to allocate
3 a portion of their total PAM-eligible REC portfolios⁷¹ to a CCA or ESP under PAM. This
4 proposal is designed to ensure that both bundled service and departing load customers do not
5 experience cost shifts. In the past, parties have expressed some concern that allocating a PCC 1
6 REC⁷² would result in the REC being classified as PCC 3,⁷³ decreasing the value of this benefit.
7 Additionally, there may be questions regarding whether the full long-term compliance benefits of
8 RECs transferred to other entities via PAM will count toward the transferee’s long-term RPS
9 compliance requirements.

10 In this proceeding, the Joint Utilities are requesting that the Commission clarify
11 D.11-12-052, which did not anticipate or address the issue of RECs allocated pursuant to
12 approved allocation mechanisms, and confirm that RECs transferred under PAM and any other
13 Commission-approved allocation mechanisms retain their original PCC attributes because they
14 will continue to be delivered on behalf of the customers that are paying for the RPS product (i.e.,
15 there is no change to the underlying RPS contract or customer responsibility to pay for the RPS-
16 eligible product). Specifically, the Joint Utilities request a finding that RECs transferred
17 pursuant to Commission-mandated allocation mechanisms do not, by virtue of that allocation,
18 become “unbundled RECs” as that term is used in Section 399.16(b)(3) and in D.11-12-052.

⁷¹ The total volume of renewable energy credits within the portfolio of an electrical corporation for a single quarter (Q1: Jan-Mar, Q2: Apr-Jun, Q3: Jul, Sep, Q4: Oct-Dec).

⁷² PCC 1 refers to the category of RPS-eligible procurement described in Cal. Pub. Util. Code § 399.16(b)(1). The Commission has implemented that section and described the PCCs more fully in D.11-12-052.

⁷³ PCC 3 refers to the category of RPS-eligible procurement described in Cal. Pub. Util. Code § 399.16(b)(3), and, as implemented by the Commission in D.11-12-052, generally includes unbundled RECs that are procured separately from the associated energy.

1 Additionally, this Application requests that the Commission implement the
2 long-term procurement requirement in the RPS statute, as revised in 2015 by SB 350,⁷⁴ to the
3 extent necessary to clarify that RECs associated with either contracts between the procuring
4 utility and the generator for delivery terms of 10 years or more or the procuring utility's
5 ownership or ownership agreements for eligible renewable energy resources and subsequently
6 transferred to other LSEs under the PAM or another Commission-approved allocation
7 methodology count for the transferee as RECs from "its contracts of 10 years or more in
8 duration" or "its ownership or ownership agreements for eligible renewable energy resources."⁷⁵
9 These clarifications will allow other LSEs to realize the full benefits of renewable procurement
10 done on behalf of their customers and for which they are paying their proportional share of the
11 net costs.

12 **2. REC Allocation Basis and Mechanism for Transfer**

13 The quantity of RECs to be transferred to the CCA or ESP will be calculated
14 based on the actual generation of the renewable facilities within the vintaged portfolio and the
15 proportion of actual customer sales of the CCA or ESP during the previous quarter. The utility
16 will calculate the load share ratio during the REC certificate generation period so that the correct
17 amount of RECs can be transferred during the subsequent transfer window.⁷⁶ There will likely
18 be no need for a material true-up at the end of each year because RECs are created subsequently

⁷⁴ See Cal. Pub. Util. Code § 399.13(b) (requiring that, by January 1, 2021, at least 65 percent of a retail seller's procurement be from "its contracts of 10 years or more in duration or in its ownership or ownership agreements" for RPS-eligible resources). The Joint Utilities have historically categorized their contracts in reporting on RPS compliance as long-term (durations of 10 years or more) or short-term based upon the delivery term of contracts. The Commission has not yet implemented P.U. Code § 399.13(b) as revised by SB 350, but it has previously clarified that "repackaged contracts," meaning those entered into by one entity and then re-packaged and transferred to other entities to meet their long-term contracting needs, continue to count toward the RPS long-term requirements added by SB 2 (1X) (2011). See D.12-06-038, pp. 44-45.

⁷⁵ *Id.*

⁷⁶ "Transfer Window" denotes the 60-day period following the date upon which RECs from the prior quarter are available.

(i.e., 90 days following the month of generation), and the actual quantity of RECs as well as CCA or ESP sales will be known at the time the RECs are allocated.⁷⁷

All retail sellers in California, including CCAs and ESPs are already registered in WREGIS for the purpose of RPS compliance. Therefore, no further administrative setup will be needed.

3. REC Allocation Timing

A utility will transfer RECs to a CCA or ESP in WREGIS no later than 60 days following the end of the quarter in which they are created in WREGIS (“transfer window”). Transferring RECs on a quarterly basis is optimal for all parties involved as it minimizes administrative processing time and provides sufficient time for all parties to use their RECs for compliance or as part of other transactions as Q4 RECs will be provided to retail sellers prior to all reporting deadlines:

- All RECs used for compliance for the previous year must be reported to the CEC by July of the following year.⁷⁸
- All RECs used for compliance for the previous year must be reported to the CPUC by August of the following year.

4. REC Adjustments

There are occasional non-material adjustments in the WREGIS system based on meter issues or other unforeseen events. Typically, these issues involve a small amount of RECs

⁷⁷ The CEC verifies the RECs reported by all IOUs, CCAs, and ESPs, and the CPUC determines RPS compliance for all IOUs, CCAs, and ESPs. All IOUs, CCAs, and ESPs bear the same risk – the IOUs are not responsible for the results of these verification and compliance determination processes, and any disallowance or reclassification of any transferred RECs will not be subject to a true-up process.

⁷⁸ Retail sellers must request WREGIS to email the WREGIS RPS State Provincial Voluntary Compliance Report to the CEC and CPUC, along with attestation of these forms using the CEC RPS Online System. The CEC verifies the amounts of retired RECs are correct based on the generation amounts received by the generators and other methods, and works with the retail seller to resolve any discrepancies. Final RECs are posted by the CEC on the Verification Report, and findings are reported to the CPUC.

1 (even as small as one REC), and may require a true-up REC transfer to ensure equitable
2 treatment between the utility and a CCA or ESP.

3 In the event an adjustment occurs within WREGIS that requires a true-up, the
4 utility will determine how all of the adjusted RECs from a given quarter must be allocated based
5 on the CCA's or ESP's load share, and will then make this allocation during the next transfer
6 window. This true-up allocation process may require the utility to transfer additional RECs to a
7 CCA or ESP, or it may require a CCA or ESP to transfer RECs back to the utility.

8 **E. Resource Adequacy Allocation Process**

9 The RA attribute allocation methodology should ultimately align with the allocation of
10 costs, distribute the attributes in proportion to compliance requirements, and provide portfolio
11 predictability to the participating LSEs. Much of the Joint Utilities' PAM proposal relies on the
12 existing RA allocation framework and process used for CAM, with a few modifications to
13 accommodate the vintaged nature of PAM portfolios, equally distribute the risk exposure
14 associated with managing unit outages, and match the timing of RA program requirements to
15 allocations of RA.

16 The current CAM process requires the Joint Utilities to submit to the Commission a list
17 of their CAM-eligible resources ("Eligible Resource List"). This list identifies each resource's
18 CAISO ID, System, Local and Flex RA Net Qualifying Capacities ("NQC"), and other relevant
19 attributes, and is refreshed annually around August for the upcoming year's CAM allocation
20 ("Year Ahead CAM list"), and again quarterly for CAM System RA allocation updates
21 ("Quarterly CAM list"). The Joint Utilities propose to use the same CAM data template for
22 allocation RA under PAM, whereby each utility will submit to the Commission a list of PAM-
23 eligible resources with corresponding CAISO IDs, RA attribute designations and "portfolio
24 vintage" identifier based on the resource's contract execution date.⁷⁹ This "PAM resource list"

⁷⁹ For UOG, the portfolio vintage identifier will be based on the date the utility's initial UOG cost recovery application is approved.

will allow the Commission to identify the resources and corresponding attributes that are eligible for allocation in each of the Joint Utilities' vintaged portfolios. The year-ahead PAM list will be submitted with the year-ahead CAM list, and in addition to submitting quarterly updates as is the case for CAM, the Joint Utilities propose monthly allocation updates for PAM that account for changes in load forecasts. This monthly allocation update interval will allow the Commission to conduct monthly PAM RA allocations to ensure greater equity in the allocation of RA benefits to LSEs, as discussed in detail below.

1. RA Allocation Basis and Mechanism for Transfer

The Joint Utilities recommend using the same LSE-submitted load forecasts currently used to set the RA compliance requirements and corresponding CAM load share amounts to perform the PAM load share calculation. These forecasts include the year-ahead forecasts that set the requirements and Year-Ahead CAM allocations and monthly and mid-year load migration forecasts that update the requirements⁸⁰ and refresh the CAM allocations.⁸¹ These same forecasts provide the information required to calculate each LSE's share of the utility's vintaged PAM portfolios.

As described above, the PAM resource list will identify the portfolio vintage of each resource. Similar to the calculation of CAM load share within a utility service area, the Commission will be able to utilize the vintaged PAM resource lists and LSE-submitted load forecasts⁸² to calculate a load share amount, by vintaged portfolio, for each LSE whose customers are responsible for the net costs of that portfolio. This vintaged monthly load share amount, by LSE, will determine the RA attributes received through PAM.

⁸⁰ Annual system, local, and flex RA requirements are set using the year-ahead forecasts. System RA requirements are updated monthly to account for monthly load migrations, and local and flex RA requirements are updated mid-year.

⁸¹ CAM allocations and re-allocations rely on the same load forecast data used to set RA requirements. CAM allocations for system RA are updated quarterly, while CAM allocations for local and flex RA are updated mid-year.

⁸² The Joint Utilities may need to supply the Commission additional, more granular, load data to facilitate the allocations for LSEs with phased-in CCA service that spans multiple PAM vintages.

1 The mechanics of attribute transfer should follow that of the existing CAM
2 contracts accounting process whereby the IOU's RA requirement increases (*i.e.*, a PAM debit)
3 by the quantity of RA transferred to PAM participants, and a receiving LSE's RA requirement
4 decreases (*i.e.*, a PAM credit) by its peak load share of the PAM portfolio, resulting in a net zero
5 total RA requirement change among all entities receiving PAM RA allocations. This process is
6 conducted for System RA, Local RA, and Flex RA attributes. This process is well established in
7 CAM, and will result in the least amount of administrative burden in the transition to a PAM RA
8 attribute allocation.

9 **2. RA Allocation Timing**

10 Similar to the intent to utilize as much of the CAM process as possible for
11 resource identification, peak load share determination, and transfer of attributes, the Joint
12 Utilities propose to utilize the timing of the CAM allocation for PAM RA allocation, with the
13 exception of the month-ahead allocation described in section b, below. The allocations would
14 occur commensurate with all RA compliance requirement determinations, which are annually,
15 monthly, and a mid-year update.

16 **a) Year-Ahead Allocation**

17 Year-ahead System, Local, and Flex RA obligations are established for
18 each of the LSEs utilizing the Commission-jurisdictional LSE Load Forecast Template. This
19 process also establishes the CAM allocations, and would also set the PAM allocations. System,
20 Local, and Flex RA attributes would be allocated to the PAM entities at this time, and net
21 requirements (net of CAM and PAM credits and debits) would be provided to all LSEs. This
22 typically occurs around August for the upcoming year's RA compliance cycle.

23 **b) Month-Ahead Allocation**

24 The forecasts submitted on the Month Ahead Load Forecast Template,
25 which captures each LSE's forecast load migration amounts, sets each LSE's Month Ahead
26 System RA requirements. These Month Ahead requirements should trigger a reallocation of
27 PAM System RA among the LSEs that captures the load migration, as well as an allocation of

any PAM RA that has not already been allocated (e.g. newly delivering resources). This will ensure that the RA attributes follow the actual load, just as they would before the load departed. These requirements are typically established 30 days prior to the compliance showing deadline.

c) Mid-Year Local and Flex Update

The Commission employs a process to calculate a Local and Flex RA requirement update for the second half of the year for all LSEs. This is typically based on a load forecast submitted in March of that year, and also triggers a CAM re-allocation for Local and Flex attributes. This update should also trigger a PAM re-allocation of those same attributes because, as in the case of the Month Ahead allocation of System RA, the RA attributes should follow the actual load.

3. RA Adjustments for Replacement and Substitution

Because the Joint Utilities will be the entities responsible for submitting PAM resources on behalf of all LSEs in the RA compliance filings, the Joint Utilities will also be responsible for submitting replacements or substitutions,⁸³ if needed by CAISO, on behalf of those same LSEs. As such, the Joint Utilities must be assured recovery of any incremental costs associated with such a replacement or substitution. The RA attribute benefits from such replacements or substitutions will also be allocated to all LSEs during the monthly allocation process for non-outage related replacements or substitutions. The potential options for RA replacement or substitution include: (1) PAM- or CAM-eligible resources that are not fully utilized in the showing, (2) bundled service customer-only resources that are not fully utilized in the showing, (3) newly sourced resources from the market, or (4) via the then-existing CAISO mechanism for capacity replacement or substitution. In the event that a utility uses PAM- or CAM-eligible resources for substitution, there should be no incremental costs borne by the utility and therefore no incremental costs charged to the LSEs for this action. These resources are paid

⁸³ RA replacement or substitution needs could arise from planned outages, forced outages, de-rates of a resource's capacity, use-limitations, differences between CPUC and CAISO RA rules, delays in achieving commercial operations and/or related NQC, etc.

for by all benefitting customers, available for RA compliance, and are therefore justly utilized for substitution at no incremental cost. If the utility is unable to substitute with a PAM- or CAM-eligible resource, it must use its discretion whether to source the capacity from its unused bundled service customer resources or from the market (CAISO or third-party supplied).

Consistent with the methodology approved by the Commission for CAM substitutions, in the event that a bundled service customer resource is utilized for the replacement or substitution, then the utility's bundled service customers should be reimbursed for the RA at the weighted average RA capacity price by zone and month from the most recent Energy Division Resource Adequacy report. If the replacement or substitution is sourced from the market, either through a CAISO market mechanism or sourced directly from a third-party RA provider, then the actual costs incurred should be paid for by all benefitting LSEs in proportion to their peak load share.

4. Consideration for Imports

Contracts that deliver energy to a CAISO intertie can receive System RA credit only when coupled with an intertie allocation. These intertie allocations are made on a load share basis, and as load departs from bundled service, the utility's load share, and allocations, decrease. This creates the potential for "stranding" RA, causing a situation where the value of a contract is lowered due to a load departure. Under PAM, since LSEs will be obligated to pay their share of net costs for such a contract, they should also be afforded the opportunity to receive their share of RA. The Joint Utilities propose that a stakeholder process with the Joint Utilities, CCAs, ESPs, and the CAISO should convene to create a process that allows all PAM entities to receive their share of RA through a modified CAISO import allocation process.

F. Predictability and Transparency

The Joint Utilities recognize the need for all LSEs to be fully informed in the development of their portfolios, and this will require visibility into the costs and attributes inherent in their part of the PAM portfolio. Specifically, LSEs will need the information necessary to forecast the quantity and composition of RA, the quantity and composition of RPS-

1 eligible energy, and net costs. At the same time, Joint Utilities are required to keep certain
2 contract information confidential as required by the Commission's confidentiality rules and
3 contract confidentiality provisions. The Joint Utilities will continuously seek to provide the most
4 granular data while adhering to confidentiality obligations. In addition to providing ERRRA year-
5 ahead forecasts of costs, generation and RA, the Joint Utilities will provide contract level
6 information where possible, and aggregate data where necessary, to support the LSEs'
7 development of long term forecasts to meet their own planning needs.

8 The Joint Utilities recognize the need for a formal process to provide portfolio and
9 contract data to LSEs as a part of PAM, and anticipate that a detailed process will need to be put
10 in place that balances necessary transparency and planning certainty for LSEs; rules to protect
11 customers and market integrity; and contractual counter-party confidentiality obligations. To
12 that end, the Joint Utilities propose to open a second phase in this proceeding. In Phase 2, the
13 Joint Utilities will work with LSEs to develop proposals on this issue, including on the frequency
14 and format of the portfolio data that will be shared with LSEs to facilitate their portfolio
15 planning. The Joint Utilities anticipate that ESP and CCA representatives, and other interested
16 parties will actively engage in Phase 2, and the Joint Utilities are optimistic that the process will
17 be collaborative and productive given the need for all LSEs to have access to necessary
18 information to forecast their pro-rata share of the utility's energy portfolio.

19 **G. Impact of PAM on Incremental Procurement Costs in the Event of a Mass Return**

20 Because PAM allocates a proportionate share of the attributes to the LSE serving the
21 CCA or DA customers and allocates the net costs to the customers based on a vintaged portfolio
22 method, it ensures that costs and attributes of a vintaged portfolio are allocated equitably and that
23 all customers are treated the same. In addition to ensuring equity between customers, in the
24 event of a mass involuntary return⁸⁴ of CCA or DA customers to a utility's procurement service,
25 that proportionate share of attributes would also return with the customers, and therefore reduce

⁸⁴ Mass involuntary return is defined in Rule 22 of the Joint Utilities' tariffs.

1 the need for the utility to procure resources to serve the returned load, thereby mitigating some of
2 the exposure to the incremental procurement cost risk resulting from such mass return of
3 customers.

VI.

COST RECOVERY AND RATE DESIGN

In this chapter, the Joint Utilities describe the ratemaking and rate design mechanisms to implement PAM. These mechanisms ensure that all customers responsible for a particular vintaged portfolio pay the same rate toward the recovery of the net costs of that portfolio, and that forecast costs and revenues are trued up at the end of the year so that all customers, bundled service and departing load alike, pay for the actual net costs of the utility portfolio that was originally procured to serve them.

A. Cost Recovery

1. Background

As described in Chapter IV, under the Current Methodology, all resources in the Joint Utilities' generation portfolio⁸⁵ are used to meet bundled service customers' generation requirements, and the full costs,⁸⁶ including any that may be viewed as above-market, of those resources, are recorded in the ERRA. In addition to the full costs of those resources, which include contract costs, fuel costs, and variable Operations and Maintenance ("O&M") expenses as described in Appendix D (as debits), the ERRA also records the market revenues received for those resources' energy and ancillary services (as credits) and other costs of meeting the bundled service customers' energy requirements (as debits).⁸⁷

The total cost of "fuel and purchased power" is forecast on a year-ahead basis in the ERRA Forecast proceeding and bundled service generation rates are set based on this forecast. The Current Methodology utilizes that same forecast to determine the total Indifference

⁸⁵ This does not include any CAM-eligible resources.

⁸⁶ The capital and O&M revenue requirements for UOG are recorded in each utility's GRC-related balancing account (SCE—Base Revenue Requirement Balancing Account, PG&E—Utility Generation Balancing account, and SDG&E—Non-Fuel Generation Balancing Account) and the fuel and other variable operating costs for UOG are recorded in the ERRA.

⁸⁷ The difference between the market revenues received for the resources and the costs of meeting the bundled service energy requirements is often referred to as the "Net Open Position," or "Net Short."

1 Amount, on a vintaged basis, and to set the departing load Indifference Rate.⁸⁸ Revenues
2 collected from both bundled service customers' CTC and generation rates and departing load
3 customers' CTC and PCIA rates ("billed revenues") are recorded in the ERRA.⁸⁹ ⁹⁰ In other
4 words, the ERRA has traditionally been the primary account used to record all generation-related
5 costs—both the net costs associated with utility-owned and contracted resources and the costs of
6 market purchases. Revenues from departing load customers' CTC and PCIA rates, intended to
7 account for their "share" of the above-market costs of the utility-owned and contracted resources,
8 are credited to the ERRA to theoretically ensure that bundled service customers' generation rates
9 are not impacted by any customer's decision to depart bundled service.

10 But, as described in earlier chapters, the Current Methodology is not effective at
11 quantifying and recovering the above-market costs of the Joint Utilities' generation resource
12 portfolios. Additionally, although revenues collected from both bundled service and departing
13 load customers are recorded in the ERRA, any differences between forecast costs, actual costs
14 and billed revenues are solely assigned to the bundled service customers. As such, the Current
15 Methodology cannot ensure the protection of bundled service customers from increased costs
16 due to departing load. Although historically and currently that cost-shift results in bundled
17 service customers subsidizing departing load customers, in theory, the Current Methodology
18 could also result in cost shifts in the other direction. PAM eliminates cost shifting in either
19 direction as required by statute.

20 The following sections describe the Joint Utilities' proposed changes to the
21 existing cost recovery mechanisms that achieve indifference and provide transparency to that

⁸⁸ The Indifference Rate is defined as the sum of the CTC and PCIA rate components.

⁸⁹ For more detail on the current structure of ERRA, see SCE's Preliminary Statement YY, PG&E's Preliminary Statement CP, and SDG&E's ERRA Preliminary Statement.

⁹⁰ PG&E and SDG&E maintain CTC as a separate rate component applicable to both bundled and departing load customers and separate balancing accounts. SCE does not maintain a separate CTC rate component and balancing account and credits CTC billed revenues from departing load customers to its ERRA.

1 process. The Joint Utilities’ proposal, which tracks the actual net costs by vintage—based on
2 actual costs and market revenues, and actual billed revenues from customers — ensures that all
3 customers pay only the actual net costs of the resources that were procured on their behalf and
4 for which their LSEs receive benefits.

5 **2. Ratemaking Proposal**

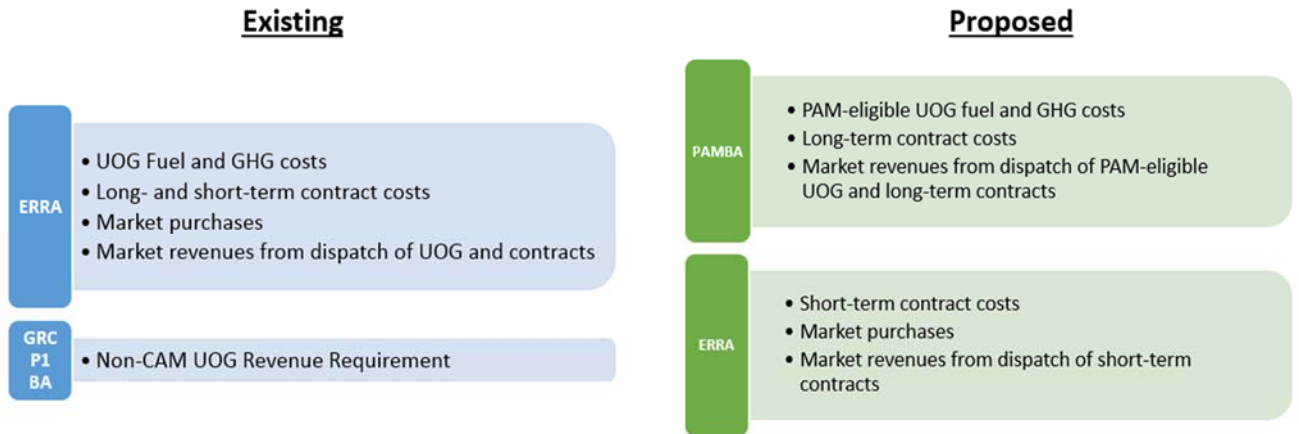
6 The Joint Utilities propose to modify the generation-related balancing accounts to
7 more clearly delineate the costs and the associated market revenues of long-term⁹¹ generation
8 resources entered into on behalf of then-bundled service customers, the benefits of which will be
9 shared with those customers, and the costs of meeting the residual requirements of the current
10 bundled service customers.

11 To accomplish this objective, the Joint Utilities propose to establish the Portfolio
12 Allocation Methodology Balancing Account (“PAMBA”) and modify the ERRA and GRC Phase
13 1 generation-related balancing accounts, as is described in detail below. The changes to the
14 ERRA and the GRC Phase 1 generation-related balancing accounts are necessary to ensure that
15 costs and revenues are not double counted and that any UOG-related base revenue requirements
16 eligible for recovery from both bundled service and departing load customers are also recorded
17 in the PAMBA instead of the Joint Utilities’ respective GRC Phase 1 generation-related
18 balancing accounts.

19 Figure VI-5, below, illustrates the mapping of the costs and market revenues
20 (billed revenues have been excluded for simplicity) under the existing and proposed cost
21 recovery structures.

⁹¹ Long-term is defined as greater than one-year.

Figure VI-5
Summary of Ratemaking Proposal



The net costs of the PAM-eligible resources will be forecast annually on a vintaged portfolio basis in each utility’s ERRA Forecast proceeding to determine the revenue requirement for each vintaged portfolio and set rates for the following year.⁹² However, as described below, actual costs, market revenues and billed revenues will be tracked by vintaged portfolio, and any over- or under-collections will be included in rates the following year.

a) PAMBA

The PAMBA will have a subaccount for each vintaged portfolio⁹³ for each year that records the costs (debits) and market revenues (credits) of all of the PAM-eligible contracts executed that year and the UOG approved by the Commission for cost recovery during that year, and will track the net costs that are the obligation of all customers who were bundled

⁹² Bundled service generation revenue requirements will thus be set by multiplying the CTC and PAC rates for each portfolio by the forecast bundled service kWh usage, and adding the result to the modified ERRA revenue requirement (*see* Section b “ERRA” below).

⁹³ In addition to subaccounts by year, the PAMBA may also include a single (non-vintaged) CTC subaccount that records the net costs of all CTC-eligible resources. Additionally, the PAMBA will include a single Legacy UOG subaccount (non-vintaged) that records the net costs of all Legacy UOG. *See* Figure VI-6 for additional information.

1 service customers that year—customers who are receiving the benefits of those resources (and on
2 whose behalf those resources were procured or built), as described in Chapter V.

3 For example, there will be a 2010 vintaged subaccount that will record the
4 costs and market revenues of all generation contracts executed in the calendar year 2010 and the
5 UOG approved by the Commission for cost recovery in 2010. Departing load customers who
6 leave after July 2010 (those with customer vintage 2010 or later) and current bundled service
7 customers are thus responsible for these costs. As such, they will be responsible for the net costs
8 recorded in that 2010 subaccount and all “prior” 2004-2009 subaccounts, including the non-
9 vintaged CTC and Legacy UOG⁹⁴ subaccounts. Conversely, customers who departed before
10 2010 were not bundled service customers at the time those contracts were executed or UOG was
11 approved by the Commission for cost recovery and would not be responsible for the net costs
12 recorded in that 2010 subaccount.⁹⁵ This is illustrated in Figure VI-6, below.

13 The billed revenues collected from bundled service and departing load
14 customers will also be recorded in the PAMBA (credit) on a vintaged basis, as is described in
15 further detail below. Any differences between the actual recorded net costs and the billed
16 revenues will be carried forward and included in bundled service and departing load customers’
17 rates in the following year, similar to what is done for bundled service customers’ generation
18 rates today. Each vintaged subaccount of the PAMBA will thus include the following monthly
19 debit and credit entries:

⁹⁴ Currently, Legacy UOG is considered a “non-vintaged” resource subject to PCIA and is thus included in the overall cost responsibility of all customers who pay PCIA. The Joint Utilities’ proposal to track net costs in a separate subaccount of PAMBA does not modify that aspect of the Current Methodology.

⁹⁵ As described above, subaccounts represent portfolios of generation resources based on the year those resources were procured or approved. Accordingly, there will be subaccounts for each year that incremental procurement takes place—regardless of whether or not any load departs that year.

1 Debits

- 2 1) Fuel and GHG costs associated with the PAM-eligible UOG resources in that
- 3 vintaged portfolio;
- 4 2) Recorded utility payments to the long-term contracted generation resource
- 5 counter-parties in that vintaged portfolio; and
- 6 3) GRC-derived base rate revenue requirement of the PAM-eligible UOG resources
- 7 in that vintaged portfolio

8 Credits

- 9 1) Market energy and ancillary service revenues associated with the contracted and
- 10 PAM-eligible UOG resources in that vintaged portfolio;
- 11 2) A portion of bundled service billed generation revenues equal to the incremental
- 12 rate for the particular vintaged portfolio multiplied by the actual bundled service
- 13 kWh usage; and
- 14 3) A portion of billed revenues from departing load customers equal to the
- 15 incremental rate for the particular vintaged portfolio multiplied by the actual kWh
- 16 usage of departing load customers responsible for the costs of that vintaged
- 17 portfolio.

18 Credits or Debits

- 19 1) Interest on any monthly over-or under-collection at the three-month commercial
- 20 paper rate

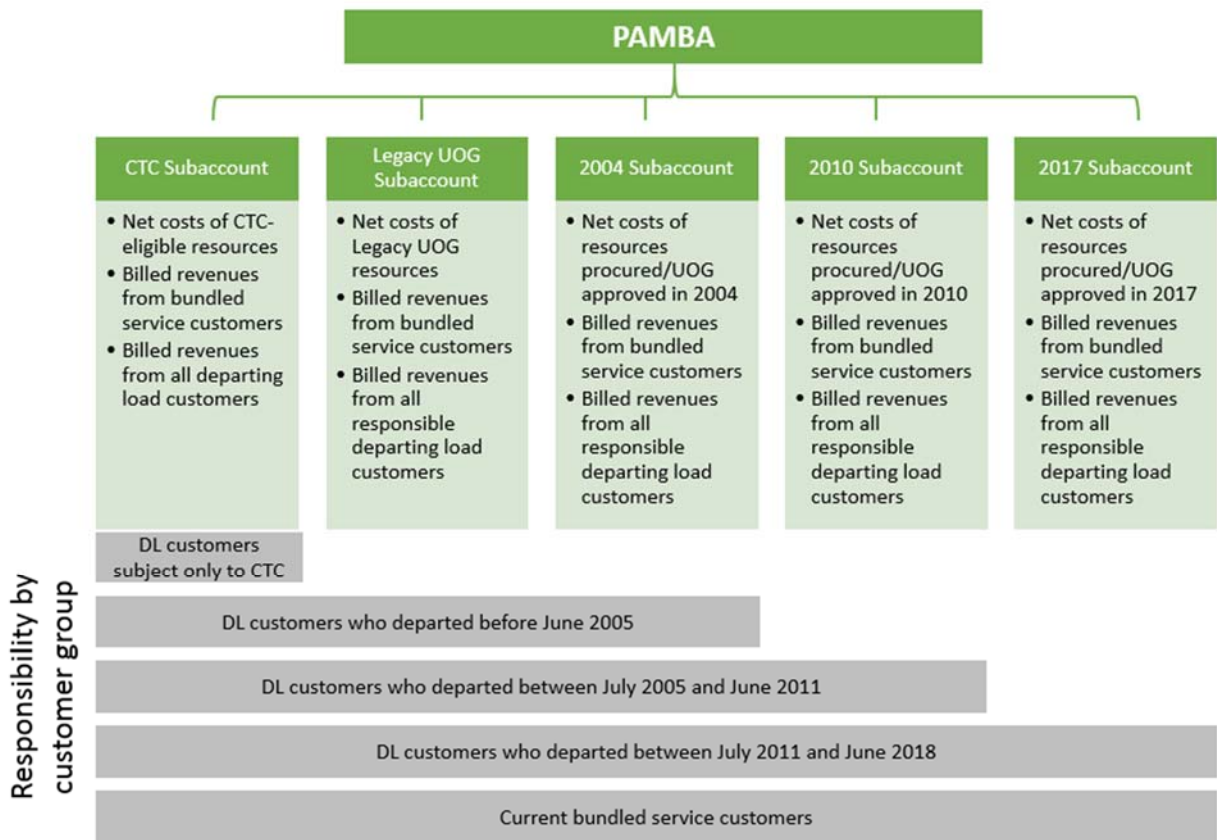
21 End-of-Year balances in each subaccount of PAMBA will be reflected in the vintaged rate in the

22 following year.⁹⁶

⁹⁶ The utilities may occasionally amortize any significant over- or under-collected balances over a longer period of time (*i.e.*, greater than 12 months) to reduce rate volatility for customers. This amortization will have a natural “smoothing” effect on the rates, thus partially mitigating the volatility that has been associated with the Current Methodology.

1 In other words, the PAMBA will record all costs and revenues that are
2 currently recorded in the ERRA except for the costs associated with payments to CAISO that are
3 attributable only to meeting bundled service energy requirements and the costs of any other
4 resources that are ineligible for PAM. Additionally, the PAMBA will also record the revenue
5 requirements of all PAM-eligible UOG resources, which are currently recorded in the Joint
6 Utilities' GRC Phase 1 balancing accounts. The following figure depicts the general structure of
7 PAMBA subaccounts and customers' responsibility for the balances of those subaccounts with
8 an illustrative assumption of 2005, 2011 and 2017 vintages of departing load.

**Figure VI-6
Proposed PAMBA Structure⁹⁷**



b) ERRA

The ERRA will be restructured to record the costs associated with wholesale market purchases (*i.e.*, the costs of meeting remaining bundled service customers' full energy requirements) and the fuel and purchased power costs of any resources that are ineligible for PAM and CAM. The responsibility for the costs recorded in the ERRA lie solely with then current bundled service customers.⁹⁸ Accordingly, the share of monthly bundled service billed

⁹⁷ SDG&E and PG&E currently maintain a standalone CTC account, and may elect to continue to record the CTC-eligible resources' net costs and billed revenues in that standalone account.

⁹⁸ Examples of this include the costs of short-term power purchases for terms of less than one year (*see* D.11-12-018, FOF 24 and COL 3), CAISO charges related to bundled service load, costs of incremental, short-term RA and REC attributes that are needed to meet bundled service load requirements.

1 generation revenues to cover these costs, as described below, will be recorded as a credit to the
2 ERRA.

3 c) **GRC Phase 1 Generation-Related Balancing Account**

4 The base rate revenue requirement for PAM-eligible UOG, as determined
5 in each utility's respective GRC proceeding, will now be recorded in the PAMBA, and will no
6 longer be recorded as a cost in the GRC Phase 1 generation-related balancing account.

7 Additionally, the portion of the monthly bundled service billed generation revenues that would
8 have been credited to the GRC Phase 1 balancing account towards the recovery of the PAM-
9 eligible UOG base revenue requirement will now be credited to the PAMBA.

10 **3. Determination of Billed Revenues to be Recorded in Each Balancing Account**

11 Billed revenues collected from bundled service customers' CTC and generation
12 rates and departing load customers' CTC and PAC rates will be directed into the various
13 accounts for which they are responsible. This process, which is done today to separate and direct
14 bundled service customers' generation billed revenues into the ERRA and GRC Phase 1
15 balancing accounts, is described in the Preliminary Statements of the Joint Utilities' tariffs⁹⁹ and
16 updated regularly to ensure that the correct amount of billed revenues, based on current revenue
17 requirements, is directed to each balancing account. The Joint Utilities propose to utilize this
18 same process to separate and direct billed revenues received from bundled service and departing
19 load customers to the appropriate balancing accounts. A description of the process is included in
20 Appendix D.

21 **4. ERRA Trigger**

22 Currently, the Joint Utilities are required to file an application with the
23 Commission to propose to adjust their bundled service generation rates when the under- or over-
24 collection in the ERRA balancing account exceeds 5% of the prior year's revenue that is

⁹⁹ See SCE's Preliminary Statement YY and ZZ, PG&E's Preliminary Statement I, and SDG&E's Preliminary Statements for ERRA and Non-Fuel Generation Balancing Account.

classified as generation for retail rates. The Joint Utilities propose to combine the balance in the modified ERRA and the bundled service customers' share of the balances in the PAMBA subaccounts (calculated based on the ratio of bundled service kWh usage to the total system kWh usage) for this purpose.

B. Applicability

As a general matter, the Joint Utilities propose to apply the new CTC and PAC rates to customers in the same manner as CTC and PCIA are applied today.¹⁰⁰ As discussed in the prior sections, the customer's LSE (*e.g.*, utility, ESP or CCA) will then receive an allocation of RECs and RA. However, there are some categories of customers whose departing load is not served by one of the LSEs described above. These categories include Customer Generation Departing Load (CGDL), New Municipal Departing Load, Transferred Municipal Departing Load, and for SCE and PG&E, customers that may be served by a Western Area Power Administration (WAPA) or a similarly situated entity. Where possible, the Joint Utilities propose to continue the process of allocating RA and REC benefits to these customers' LSEs. Where these benefits may not be allocated to the LSE, the Joint Utilities propose to monetize these benefits and reduce the PAC and/or CTC responsibility for the customer.

One such example is for CGDL.¹⁰¹ Pursuant to D.03-04-030, nearly all CGDL is subject to the CTC, and certain CGDL installed after February 2015 is subject to the 2001 vintage PCIA.¹⁰² The Joint Utilities recognize that, under PAM, it is impractical to allocate RECs and

¹⁰⁰ SCE currently charges its bundled service customers a composite generation rate that includes their CTC obligation. To increase the transparency of billed revenues to be credited to the CTC subaccount of PAMBA, SCE will unbundle its bundled service generation rates into the CTC and the remaining part. The CTC component will be the same for bundled service and departing load customers in the same rate group.

¹⁰¹ Pursuant to D.98-12-067, new or incremental load that is served by a Customer Generation unit is considered "departing load" if it does not pass the "physical test." The physical test "requires that new or incremental customer load be able to be 'islanded' to demonstrate that the direct transaction does not require the use of the utilities' systems. See D.98-12-067 at 24 and Resolution E-3600, dated March 13, 1999.

¹⁰² See SCE AL 3263-E and 3263-E-A, SDG&E AL 2778-E and 2778-E-A, and PG&E AL 4743-E and 4743-E-A.

1 RA to individual CGDL customers. Thus, the Joint Utilities propose that bundled service
2 customers “buy back” the RECs and RA that would have otherwise been allocated to the CGDL
3 customers. In other words, bundled service customers will purchase the RECs and RA from the
4 CTC-eligible portfolio that would have otherwise been allocated to the CGDL customers, and
5 those proceeds will be subtracted from the net costs to be collected from these customers.
6 However, the Joint Utilities propose that the consideration of how to set the appropriate
7 “purchase price” for the RECs and RA be deferred to a Tier 3 advice letter, to be filed upon
8 receiving a final decision resolving this Application.

9 The Joint Utilities have also identified an additional category of customers that will need
10 to be addressed. Pursuant to D.15-01-051, GTSR customers are subject to CTC and a vintaged
11 PCIA based on the date they elect to begin service on GTSR. The Joint Utilities acknowledge
12 that GTSR customers are responsible for the same generation-related above-market costs that are
13 the subject of this Application; however, GTSR customers are also responsible for other
14 generation-related costs that, together with the CTC and PCIA, are meant to ensure non-
15 participant indifference. In light of the fact that indifference as it relates to GTSR customers
16 consists of more than just the stranded costs associated with the new CTC and PAC rates, the
17 Joint Utilities propose that GTSR non-participant indifference, including the consideration of
18 how the new CTC and PAC rates should be applied, be considered once a final decision
19 resolving this Application is issued.

20 **C. Rate Design**

21 The following section describes the Joint Utilities’ proposal to allocate the forecast costs
22 of each PAMBA subaccount to rate groups (*e.g.*, residential, small commercial, agricultural, etc.)
23 and to set final rates. The Joint Utilities propose to recover the full net costs of all PAM-eligible
24 resources from bundled service customers through their new CTC and generation charges and
25 from departing load customers through their new CTC and PAC. As described in Chapter V,
26 PAM results in both departing load customers and bundled service customers paying the same
27 net costs, on a per-kWh basis, for each resource—a result that is wholly consistent with the Joint

1 Utilities' proposal to equitably allocate the benefits of the PAM-eligible resources to all
2 customers.

3 Today, vintaged Indifference Amounts, as determined using the Current Methodology,
4 are allocated to rate groups based on the contribution of each rate group¹⁰³ to the highest 100
5 hours of system load. This methodology is known as the "Top 100 hours" methodology. The
6 resulting allocation factors are used to allocate revenues to each rate group which are then
7 divided by the rate group's total forecast system sales to determine the indifference rate for that
8 vintaged portfolio.

9 The Joint Utilities recommend deferring the issue of potential changes to the revenue
10 allocation factors, which determine the allocation to individual rate groups to each utility's
11 respective GRC Phase 2 proceedings or Rate Design Windows ("RDWs"), where the issue of
12 cost allocation to rate groups is traditionally addressed on a holistic basis. Changes in allocation
13 factors would have implications to other parties who otherwise would not participate in this
14 proceeding but have interest in cost allocation issues. In addition, GRC Phase 2 proceedings also
15 contain the marginal costs studies that provide the basis for changing allocation factors.

16 As such, the Joint Utilities propose to continue to use the current, Commission-approved,
17 Top 100 hours revenue allocation factors to allocate the net costs, as calculated under PAM, to
18 individual rate groups unless and until a new allocator can be agreed upon or is adopted by the
19 Commission in each utility's GRC Phase 2 or RDW. Rate group-level net costs will be divided
20 by the rate group-level sales of only those customers responsible for that vintaged portfolio (and
21 not the rate group-level sales of all customers) to determine the applicable new CTC and PAC
22 rates.¹⁰⁴

¹⁰³ Both bundled service and departing load customers are included in each rate group.

¹⁰⁴ Consistent with the Cost Recovery testimony included above, vintaged PAC rates will be determined using the PAMBA subaccount revenue requirements. However, final PAC rates listed on customers' bills will reflect their cumulative PAC rate (*i.e.*, the sum of all of the incremental vintaged PAC rates for which they are responsible).

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VII.

ARBITRARY TIME LIMITS FOR COST ALLOCATION ARE NO LONGER
APPROPRIATE

This Application proposes a new method to determine departing load charges based upon realized resource costs and market revenues. This proposal completely replaces the Current Methodology which administratively estimates above-market costs of the resources that the Joint Utilities procured on behalf of their customers. Instead of estimating above-market costs, the method proposed in this Application results in all customers, both bundled service and those that depart to different procurement service providers, paying the same net costs on a pro-rata basis and being allocated an equivalent pro-rata share of all the attributes (benefits) of those resources on a vintaged portfolio basis.

This Application is being proposed to carry out the statutory requirement of preventing cost shifting between bundled service and departing load customers as a result of customer choice, and applies regardless of the type of resource (e.g. renewable, fossil, etc.) at issue. Moreover, the statutory requirement contains no time limitation. Instead, the statutory requirement applies so long as the costs were incurred on behalf of the departing load customers. Thus, there is no basis in statute for the Commission to set different rules and recovery periods for some resources as compared to others.

As part of implementing the Current Methodology, the Commission has made assumptions regarding the time needed for cost allocation periods. The Commission has also made assumptions about the time over which resources might be “above-market,” while in other cases, recognized that it does not have sufficient data to even make assumptions about what the above-market costs might be. With respect to certain resources, the Commission has established a presumption of a ten-year time limit on allocating costs to departing load customers. This most recently occurred in the storage proceeding, but also occurred in proceedings regarding post-2002 utility owned fossil generation. To satisfy the law and ensure customer indifference, the

1 Commission needs to eliminate these arbitrary term limits on recovery periods and treat all
2 resources equally under the PAM.

3 **A. Storage**

4 In D.14-10-045, the Commission ruled that energy storage projects would be subject to
5 PCIA, but did not reach a conclusion regarding the method for estimating the above-market
6 costs. The Commission also applied a 10-year limit due to its concerns about estimating the
7 above-market costs for a “nascent” market, and concerns about the existing PCIA benchmark
8 and lack of sufficient data as applied to energy storage. However, in doing so, the Commission
9 also contemplated that utilities could seek cost allocation over the life of the contract.

10 The Commission considered this 10-year limit again in D.16-01-032, in which it found
11 no new information to justify a change to its approach utilized in D.14-10-045, and again
12 deferred the issue to a later date; specifically, when the Commission considered the Joint IOU
13 Protocol for accounting for storage resources in the PCIA. However, when the Commission
14 addressed the Joint IOU Protocol in D.16-09-004, the length of the cost allocation was excluded
15 from the scope of the proceeding. With respect to the projects before it, the Commission
16 continued the 10-year presumption with no explanation. Thus, the Commission has not yet
17 squarely addressed the merits of a 10-year cost allocation for energy storage.

18 The PAM will eliminate the above-market cost construct entirely, and the need to
19 determine when the above-market costs associated with a given resource no longer exist. In fact,
20 the PAM by accounting for actual costs and benefits and by allocating all attributes, will
21 eliminate the need for the Commission to continually relook at what “value” storage may be
22 providing because the value is conveyed to all customers for whom the resource was originally
23 procured. Including storage resources in PAM for the life of their contracts also makes sense
24 because the Commission has resisted attempts to limit contract lengths to the current 10-year
25 PCIA recovery period.

1 To ensure customer indifference, storage resources should be included in the PAM and
2 the cost recovery period should span the length of the contract.¹⁰⁵ To do otherwise would be
3 inconsistent with State law which requires bundled service customer indifference to departing
4 load. There is no legal basis or equity consideration to require remaining bundled service
5 customers alone to bear the costs of energy storage resources that were procured to serve all
6 bundled service customers at the time of the resource commitment.

7 **B. Post-2002 Utility Owned Fossil Generation**

8 Another group of resources for which the Commission implemented a cost allocation
9 limit is post-2002 utility owned fossil generation. The 10-year presumption was adopted and
10 addressed in several decisions that are nearly a decade old. That presumption, however, was
11 never intended to be an absolute limit. The Commission recognized that changed circumstances
12 could necessitate the need to justify a longer nonbypassable recovery period. At that time, the
13 Commission made it clear that it was making assumptions about the above-market value of those
14 assets. Those assumptions are no longer reasonable. Described in greater detail below are the
15 decisions and assumptions built into the Commission's analysis, and the changed circumstances
16 that warrant a modification to the current approach. To ensure bundled service customer
17 indifference, post-2002 UOG resources should be treated under PAM in the same manner as
18 Legacy UOG. To do otherwise would be inconsistent with state law which requires bundled
19 service customer indifference to departing load.

20 In D.04-12-048, the Commission adopted a 10-year cost allocation period for UOG fossil
21 fuel resources acquired through a procurement process. The 10-year period commences upon
22 commercial operation of the UOG facility. The Commission intended for utilities to recover
23 above-market costs from departing load customers, yet the Commission assumed that emerging

¹⁰⁵ Consistent with the proposed treatment of Post-2002 Utility Owned Fossil Generation, the Joint Utilities propose that utility-owned storage resources that are not subject to broad cost allocation be considered PAM-eligible until the last of the long-term contracts associated with those customers' vintaged portfolios expires.

1 capacity and energy markets would result in credits against resource costs and, therefore, the
2 costs of these UOG resources would not be above-market indefinitely.¹⁰⁶ The Commission
3 recognized, however, that a 10-year limit might not be adequate,¹⁰⁷ and thus stated that the
4 utilities could justify a longer-term recovery period in applications for these resources. Further,
5 in D.08-09-012, the Commission again discussed issues associated with the 10-year cost
6 allocation period from departing load customers. The Commission stated its assumption that
7 utilities could adjust their load forecasts and portfolios to mitigate the impacts of DA and CCA.
8 The Commission further assumed that the impact of departing load could be minimized. The
9 Commission noted that it could be beneficial to extend the time that the resources remain in the
10 total portfolio because they could put downward pressure on total portfolio costs. The
11 Commission also reiterated its point in D.04-12-048 that the utilities are entitled to make a
12 specific factual showing to justify a longer cost allocation period for non-RPS resources, beyond
13 10 years.

14 In short, the Commission has never held that the 10-year period is an absolute limit on
15 allocating costs associated with UOG fossil resources to departing load customers. Instead, the
16 Commission recognized that the 10-year limit was based solely on market value and other
17 assumptions at the time, and has contemplated that the utilities may present specific facts and
18 circumstances to justify a longer cost allocation period.

19 Today, facts are very different than those the Commission first considered when
20 addressing this issue. The state has not developed a capacity market. Thus, a market does not
21 exist that would provide additional revenues to compensate for the full capacity value. Likewise,
22 the energy and ancillary service revenues are not sufficient to “minimize” any above-market
23 costs. The Commission did not anticipate the current 50% RPS as outlined in SB350. The
24 introduction of a significantly increased RPS has resulted in the introduction of thousands of

¹⁰⁶ See D.04-12-048, p. 60.

¹⁰⁷ *Id.*, pp. 61, 63.

1 megawatts of additional capacity and fundamentally changed the role and economics of fossil
2 resources.

3 Likewise, the level of potential load departure that the Joint Utilities face today is
4 substantially higher than any load departure considered at that time. At that time, the assumption
5 was that the Joint Utilities would be able to “adjust” their portfolios with no impact on costs to
6 bundled service customers. This assumption was questionable at best. Adjusting the portfolio
7 for small amounts of load loss spread over many years is very different than today’s situation
8 where more than half the load could depart in just a few years. Load reduction is also occurring
9 by the growth in behind the meter generation and increased energy efficiency standards and
10 programs. At the time the Commission made its decision around the 10-year limit, utilities’
11 loads were increasing and expected to continue to increase. Today, utilities’ loads may be
12 decreasing, even without any new departing load.

13 Fundamentally, the purpose of this application is to replace the current PCIA and its
14 outdated approach that relies on estimates of above-market costs with a mechanism that self-
15 adjusts for actual market value and load departure. The Commission’s decade-old determination
16 that a 10-year cost allocation window is sufficient can no longer be used to ensure bundled
17 service customer indifference. To ensure that costs are not shifted to remaining bundled service
18 customers, as well as to ensure departing load customers are allocated the benefits of prior
19 resource procurement, these post-2002 UOG resources must be treated like all other UOG
20 commitments. These resources were approved by the Commission as being “just and
21 reasonable,” exactly like all other resources subject to PAM. There is no logic to treating these
22 resources differently than other resource commitments under PAM. Indeed, to do otherwise
23 would be inconsistent with statutory requirements to maintain customer indifference to departing
24 load.

Appendix A
Illustrative Example

Illustrative Example

1. Simplifying Assumptions Used in Example

- IOU has four portfolios of resources (*i.e.*, there were only four tranches of generation resource procurement):
 - Pre-Restructuring Portfolio
 - 2009 Portfolio
 - 2014 Portfolio
 - 2017 Portfolio
- Three active groups (“vintages”) of departing load customers in the IOU service territory:
 - LSE X, whose customers departed in 2008
 - CCA Y, whose customers departed in 2010
 - CCA Z, whose customers departed in 2015
 - The IOU continues to serve its remaining bundled service customers
- Single year example for year X

Customer Responsibility for Each Portfolio					
Description	Forecasted Load (GWh)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio
LSE X (Departs in 2008)	1000	-	-	-	Yes
CCA Y (Departs in 2010)	3500	-	-	Yes	Yes
CCA Z (Departs in 2015)	1500	-	Yes	Yes	Yes
Remaining Bundled Service	4000	Yes	Yes	Yes	Yes

2. Forecast Load vs. Actual Load

Forecast of Load Share					
Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio	Forecast of Total System Load in Year X
FL1. Forecast Load Responsible for Each Portfolio (GWh)	4,000	5,500	9,000	10,000	10,000
FL2. Forecast Load Share (%) and Load (GWh) of LSE X (2008)	-	-	-	10%	1,000
FL3. Forecast Load Share (%) and Load (GWh) of LSE Y (2010)	-	-	39%	35%	3,500
FL4. Forecast Load Share (%) and Load (GWh) of CCA Z (2015)	-	27%	17%	15%	1,500
FL5. Forecast Load Share (%) and Load (GWh) of Bundled	100%	73%	44%	40%	4,000

Actual Load Share					
Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio	Actual Total System Load in Year X
AL1. Actual Load Responsible for Each Portfolio (GWh)	4,200	5,800	9,000	10,200	10,200
AL2. Actual Load Share (%) and Load (GWh) of LSE X (2008)	-	-	-	12%	1,200
AL3. Actual Load Share (%) and Load (GWh) of LSE Y (2010)	-	-	36%	31%	3,200
AL4. Actual Load Share (%) and Load (GWh) of CCA Z (2015)	-	28%	18%	16%	1,600
AL5. Actual Load Share (%) and Load (GWh) of Bundled	100%	72%	47%	41%	4,200

- Customers are responsible for all portfolios procured prior to their departure – e.g., customers who depart in 2015 are responsible for the 2014, 2009, and Pre-Restructuring portfolios
- Customers' "share" of each portfolio will be the proportion of their actual load to the actual load of all customers responsible for that portfolio

3. Forecast Portfolio vs. Actual Portfolio

Forecast of Costs, Market Revenues, and Generation					
Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio	Total
FP1. Forecast Costs (\$M)	\$100	\$220	\$175	\$275	\$770
FP2. Forecast Market Revenues (\$M)	(\$60)	(\$120)	(\$90)	(\$175)	(\$445)
FP3. Forecast Net Costs (\$M)	\$40	\$100	\$85	\$100	\$325
FP4. Forecast RECs (GWh)	500	2,000	2,000	1,500	6,000
FP5. Net Qualifying Capacity (MW)	200	650	500	700	2,050

Actual Costs, Market Revenues, and Generation					
Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio	Total
AP1. Actual Costs (\$M)	\$80	\$200	\$160	\$290	\$730
AP2. Actual Market Revenues (\$M)	(\$50)	(\$125)	(\$100)	(\$200)	(\$475)
AP3. Actual Net Costs (\$M)	\$30	\$75	\$60	\$90	\$255
AP4. Actual RECs Generated (GWh)	600	2,100	1,900	1,300	5,900
AP5. Net Qualifying Capacity (MW)	200	650	500	700	2,050

- Portfolios are “incremental” – e.g., the 2014 Portfolio only includes the resources executed (or UOG approved) between January 1, 2014 and December 31, 2014
- Costs, market revenues, and generation are forecast annually in the ERRA Forecast proceeding; however, customers will only be responsible for the actual net costs and REC allocations will be based on actual RECs generated

4. REC Allocations

- Forecasts of future REC allocations can be developed by multiplying forecast load share (lines FL 2-5) by the forecast number of RECs in each vintaged portfolio (line FP4)
- Actual REC allocations will be determined by multiplying actual load share (lines AL 2-5) by the actual number of RECs (line AP4)
 - Accounts for variation in load share throughout the year
 - Accounts for actual RECs produced by each resource
- Allocated RECs will retain their current designation (e.g., Portfolio Content Category 1, long-term, etc.)
- REC allocations will occur 90 days after the RECs are generated

Actual REC Allocations						
Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio	Total RECs Allocated
1. AP4	Actual RECs Generated	600	2,100	1,900	1,300	5,900
2. AL2*(1)	RECs Allocated to LSE X (Departs in 2008)	-	-	-	153	153
3. AL3*(1)	RECs Allocated to CCA Y (Departs in 2010)	-	-	676	408	1,083
4. AL4*(1)	RECs Allocated to CCA Z (Departs in 2015)	-	579	338	204	1,121
5. AL5*(1)	RECs Allocated to Remaining Bundled Service	600	1,521	887	535	3,543

5. RA Allocation Overview

- RA is allocated on a forecast basis, based on peak load share as calculated by the Energy Division – see next page
 - IOUs provide capacity MWs of eligible resources to Energy Division in July of each year for the Year Ahead RA process for the following compliance year
 - ED then allocates to LSEs their respective portion of the allocation based on the LSEs' forecasted peak load ratio shares by month
- IOUs will provide additional monthly updates of PAM-eligible resources to ED to facilitate re-allocation of RA
 - Monthly updates will reflect MW variability such as resource on-line dates
 - Re-allocation of PAM-eligible RA should coincide with monthly RA requirement adjustment process, capture changes in load, and be based on updated monthly forecasted peak load share ratios
- In lieu of directly allocating RA Net Qualifying Capacity, IOUs will absorb a portion of each LSE's RA obligation, commensurate with the RA that would have been allocated to them
 - *E.g.*, If LSE X's PAM RA allocation is 15 MW, LSE X's RA obligation is reduced by 15 MW, and the IOU's RA obligation is increased by 15 MW
 - Process is consistent with existing CAM framework

6. RA Allocations

Forecast of Q1 Peak Load and Peak Load Share of Each Portfolio						
Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio	Total Peak Load
1.	Peak Load Responsible for Each Portfolio (MW)	1,200	1,700	2,700	2,885	2,885
2.	Forecast Peak Load Share (%) and Peak Load (MW) LSE X (2008)	-	-	-	6%	185
3.	Forecast Peak Load Share (%) and Peak Load (MW) LSE Y (2010)	-	-	37%	35%	1,000
4.	Forecast Peak Load Share (%) and Peak Load (MW) CCA Z (2015)	-	29%	19%	17%	500
5.	Forecast Peak Load Share (%) and Peak Load (MW) Bundled	100%	71%	44%	42%	1,200
Q1 Allocation of RA						
Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre- Restructuring Portfolio	Total RA Allocated
6. FP5	Total Net Qualifying Capacity in Each Portfolio (MW)	200	650	500	700	2,050
7. (2)*(6)	RA Allocated to LSE X (Departs in 2008) (MW)	-	-	-	45	45
8. (3)*(6)	RA Allocated to CCA Y (Departs in 2010) (MW)	-	-	185	243	428
9. (4)*(6)	RA Allocated to CCA Z (Departs in 2015) (MW)	-	191	93	121	405
10. (5)*(6)	RA Allocated to Remaining Bundled Service (MW)	200	459	222	291	1,172

- Forecast peak load (lines 2-5) and PAM-eligible NQC (line FP5) will be updated monthly
 - Monthly updates to forecast peak loads are also used to adjust LSEs' monthly RA requirements, if necessary (existing process)
- Actual RA allocations will be done monthly on a forecast basis and will be determined by multiplying forecast peak load share (lines 2-5) by the NQC of the portfolio (line FP5)

7. Cost Recovery and True Up Process

- Costs and revenues are "true-up"

- Actual costs (AP3) are compared to forecasted costs (FP3) to true-up costs
- Recorded revenues (equal to actual sales (AL1) times applicable rate) are compared to forecasted revenues (forecasted sales (FL1) times applicable rate) to true-up revenues
- Any over- or under-collections will be subtracted or added, respectively, to the following year's forecast net costs

True-Up - Costs					
Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre-Restructuring Portfolio
1. FP3	Forecast Net Costs (\$M)	\$40	\$100	\$85	\$100
2. AP3	Actual Net Costs (\$M)	\$30	\$75	\$60	\$90
3. (2)-(1)	(Over)/Under-Collection of Costs (\$M)	\$ (10.00)	\$ (25.00)	\$ (25.00)	\$ (10.00)
True-Up - Revenue					
Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre-Restructuring Portfolio
4. FL1.	Forecast Load Responsible for Portfolio (GWh)	4,000	5,500	9,000	10,000
5. (1)/(4)	Rate for Vintaged Portfolio (\$/kWh)	\$0.01000	\$0.01818	\$0.00944	\$0.01000
6. (4)*(5)	Forecasted Revenues (\$M)	\$40	\$100	\$85	\$100
7. AL1.	Actual Load Responsible for Each Portfolio (GWh)	4,200	5,800	9,000	10,200
8. (7)*(5)	Actual Revenues Received from Customer (\$M)	\$42	\$105	\$85	\$102
9. (6)-(8)	(Over)/Under-Collection of Revenues (\$M)	\$ (2.00)	\$ (5.45)	\$ -	\$ (2.00)
Total True-Up					
Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre-Restructuring Portfolio
10. (3)+(9)	Total Over/Under Collectin in Bal. Acct (\$M)	(\$12.00)	(\$30.45)	(\$25.00)	(\$12.00)

8. Rate Design – Residential Example

- Rates will be calculated using current PCIA rate design methodology
 - Rates are set by based on each rate group's current allocators^{1/} and retail sales
 - Each vintaged portfolio will have its own rate group-specific rates
 - Incremental rates for each vintaged portfolio are set in the ERRR Forecast proceeding setting the revenue requirement to the forecast of net costs of that vintaged portfolio
- As with the PCIA, Customers will pay a total rate that reflects their total obligation of all vintages prior to their departure year – e.g., Customer who departs in 2015 will pay total costs of Pre-Restructuring, 2009, and 2014 portfolios

		Residential Rates			
Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre-Restructuring Portfolio
		a.	b.	c.	d.
1.	Residential Allocation Factor	45%	45%	45%	45%
2. FP3	Forecast Net Costs	\$40	\$100	\$85	\$100
3. (1)*(2)	Residential Share of Net Costs	\$18	\$45	\$38	\$45
4.	Forecast Residential Load Responsible (GWh)	1,600	2,200	3,600	4,000
5. (3)/(4)	Residential Rate by Vintaged Portfolio (\$/kWh)	\$0.01125	\$0.02045	\$0.01063	\$0.01125

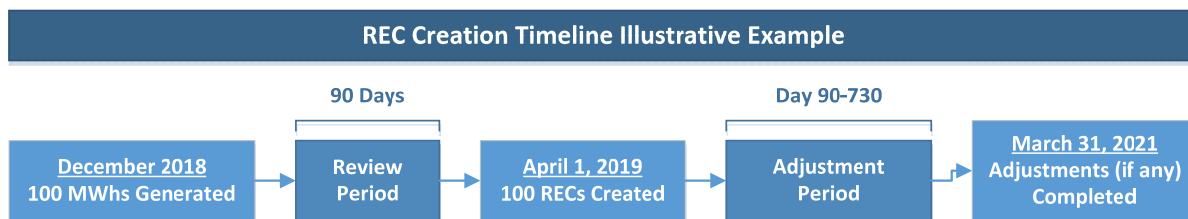
Residential Rates by Vintage		
Eq.	Description (Unit)	Residential Rate by Vintaged Portfolio (\$/kWh)
6. 5.d.	Pre-Restructuring Vintage	\$0.01125
7. (6)+5.c	Vintage 2009	\$0.02188
8. (7)+5.b	Vintage 2014	\$0.04233
9. (8)+5.a	Vintage 2017	\$0.05358

Appendix B
REC Overview

REC Overview

Senate Bill 1078 (2002) created the California RPS Program, and required the CEC to design and implement a tracking and verification system for renewable energy output. This system is referred to as the WREGIS. It is an independent, renewable energy registry and tracking system for the Western Interconnect Region that tracks renewable energy generation from units that register in the system by using verifiable data, and creates RECs for each whole megawatt-hour (“MWh”) of electricity that was generated from a qualified renewable energy source¹⁰⁸ using the following process:

REC Creation Timeline Illustrative Example



The purpose of WREGIS is to ensure against the double-counting of RECs, and it also facilitates REC transfers, enables permanent retirement of RECs, assists regulators with the implementation of their renewable energy programs, and brings transparency to REC markets.

Any party who signs the WREGIS usage agreements, pays all required participation fees, and has not previously had a WREGIS account terminated for cause or for convenience, can register as an account holder in WREGIS. In addition, any generator considered “renewable” by any state, province or program in the WECC region can register with WREGIS for the issuance of RECs. WREGIS Account Holders have two options regarding the RECs held in their account, they may:

1. Transfer them to accounts of other registered WREGIS Account Holders.

¹⁰⁸ See Cal. Pub. Util. Code 399.12(h), and also note that WREGIS issues one REC for each whole MWh generated, any fraction of a MWh of renewable energy generation is carried over into the next month.

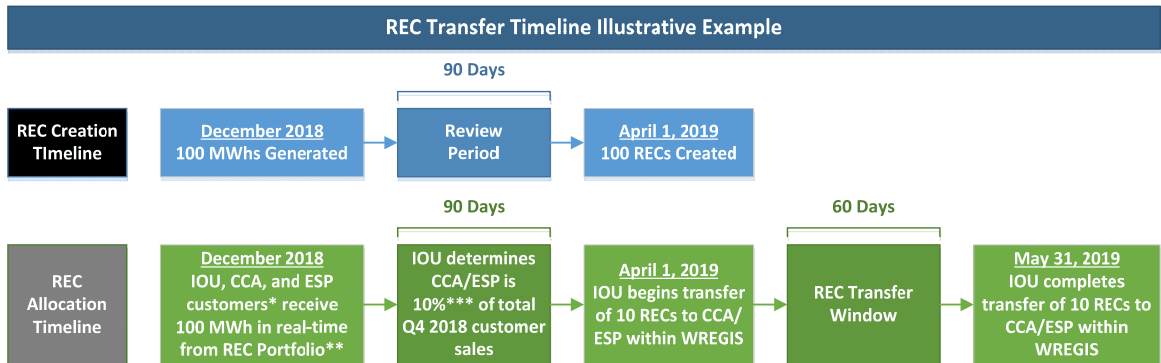
2. Retire them to show compliance with state/provincial programs by moving them from an “active” subaccount to a “retirement” subaccount.

WREGIS also issues the state/provincial/voluntary report that is used by regulatory agencies to verify compliance with state mandates. The CEC is responsible for the certification of electrical generation facilities as eligible renewable energy resources, and it also verifies all renewable energy deliveries using the report generated by WREGIS, the final results of which are transmitted to the CPUC. The CPUC implements and administers the RPS program for its jurisdictional retail sellers (including electrical corporations, CCAs, and ESPs), and as a part of this process has developed a compliance report spreadsheet for retail sellers to report their annual progress towards the RPS program requirements.¹⁰⁹ The CPUC uses this compliance report, submitted in August of each year per D.12-06-038, in combination with the CEC’s verification report to determine compliance with RPS program requirements.

The following is an illustrative example of how the proposed transfer process of RECs would work under the PAM proposal:

¹⁰⁹ RECs used for compliance with California’s RPS Program must be retired within 36 months from month/year of generation and reported to the CPUC on the annual compliance report.

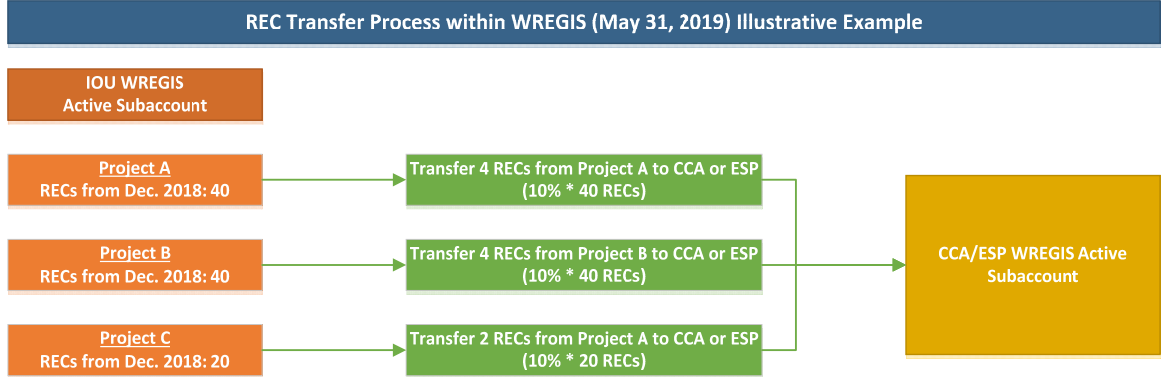
REC Transfer Timeline & REC Transfer Process within WREGIS (May 31, 2019) Illustrative Examples



*CCA and ESP customers are those that left bundled service with the electrical corporation. "In real-time" denotes "as generated."

**For illustrative purposes, the REC Portfolio is composed of Projects A, B, and C, see example transfer process below.

***10% is for illustrative purposes only.



Appendix C
Billed Revenues

Billed Revenues

1. Billed revenues from departing load customers' CTC and PAC rates

Revenues collected from departing load customers' CTC rates will be recorded in the CTC subaccount of the PAMBA.

Revenues collected from departing load customers' PAC rates will need to be directed to the subaccounts for which they are responsible. For example, as described in Section A.2.a in Chapter VI, customers who depart in 2010 are responsible for the net costs recorded in the CTC subaccount and the 2001-2010 subaccounts, and their total, cumulative PAC rate will represent the sum of the 2001-2010 PAC rates. Although the departing load customers' bills will include a single PAC rate that is the sum of the incremental PAC rates for which they are responsible, the billed revenues collected from those customers will be allocated to each subaccount by multiplying their total recorded usage by the applicable (incremental) PAC rate.

2. Billed revenues from bundled service customers' CTC and generation rates

Revenues collected from bundled service customers' CTC rates will be recorded in the CTC subaccount of the PAMBA.

Revenues collected from bundled service customers' generation rates will need to be directed to the accounts (and subaccounts) for which they are responsible. Unlike departing load customers, bundled service customers continue to be responsible for the costs recorded in the ERRA and the generation-related GRC Phase 1 balancing account. As such, their billed revenues will need to be allocated between PAMBA and ERRA. This is done by allocating the product of the bundled service customers' total recorded usage and the ERRA rate specified in each utility's respective Preliminary Statement¹¹⁰ to ERRA and the product of the bundled service customers' total recorded usage by CTC and each subaccount PAC rate to the appropriate PAMBA subaccount.

¹¹⁰ See SCE's Preliminary Statement YY and ZZ, PG&E's Preliminary Statement I, and SDG&E's Preliminary Statements for ERRA and Non-Fuel Generation Balancing Account.

Appendix D
PAM-Eligible Costs

PAM-Eligible Costs

1. Contract Costs

All costs that are associated with the management of the resources will be included in the PAM calculation of net costs. This includes costs that are specified in the CPUC-approved contracts, such as capacity payments, O&M payments (both fixed and variable), energy payments, and costs associated with performance requirements, including both performance penalties and bonuses, as well as other costs associated with the dispatch of the resources, such as fuel costs, GHG compliance instruments, and CAISO grid management costs.

2. UOG Costs

In determining the UOG costs included in the PAM calculation of net costs, the Joint Utilities propose to include the full capital recovery and O&M costs as authorized in the utilities' most recent GRCs,¹¹¹ and the costs of all fuel and GHG compliance instruments. Inclusion of these UOG resource costs in the PAM net cost calculation is consistent with the inclusion of these costs in the Current Methodology.^{112 113}

3. Indirect Costs

In addition to the costs directly attributable to certain resources described above, there are also indirect costs that the Joint Utilities incur on a portfolio basis (for example, hedging costs). The CPUC has authorized each utility to conduct a set amount of advance hedging to provide stability to customer costs.¹¹⁴ Consistent with the Current Methodology, all

¹¹¹ It is in the GRC that the Commission reviews the utilities' O&M expenses as well as forecast capital expenditures.

¹¹² See D.06-07-030 p.12.

¹¹³ Although costs associated with decommissioning generation resources are generally included in the depreciation reserves for those assets and recovered through GRC-adopted generation base rates, those reserves may not be sufficient to cover the cost of retiring the assets. The Joint Utilities reserve the right to seek recovery through a separate application of any additional decommissioning/retirement costs for UOG if necessary.

¹¹⁴ D.15-10-31 (Decision approving 2014 BPPs)

hedging costs associated with hedging contracts that exceed one year in duration will be included in the PAM net cost calculation.

4. Excluded Costs and Revenues

The following costs will be excluded from the PAM net cost calculation. First, the revenue or cost from congestion revenue rights (“CRRs”) will be excluded. CRRs are allocated to load serving entities based on load share; thus CRR revenues or costs should accrue to only the customers that the utility provides bundled procurement service. In addition, if the Joint Utilities enter into purchases of CRRs, these purchases will be paid for exclusively by bundled service customers. Long-term CRRs, which have nine-year terms, are automatically re-allocated by CAISO from load-losing entities to load-gaining entities, and, therefore, any long-term CRRs remaining with the Joint Utilities will be associated with bundled load only. The Joint Utilities also propose that if a utility enters into any gas storage contracts, the associated costs and benefits remain with bundled service customers.

Appendix E
Witness Qualifications

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF FONG WAN

Q 1 Please state your name and business address.

A 1 My name is Fong Wan, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Senior Vice President (VP) of Energy Policy and Procurement. In this position, I am responsible for gas and electric supply planning and policies, wholesale market design, quantitative analysis, power plant development, and commodity procurement and settlements.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from Columbia University, in 1984, with a bachelor of science degree in chemical engineering and from the University of Michigan, in 1986, with a master's degree in business administration.

From 1986-1988, I worked as a business analyst with Exxon U.S.A. I began work with PG&E in 1988 as a financial analyst in the financial planning and analysis area. I was promoted to senior financial analyst in 1989 and to manager in 1991. In this area, I worked on recommendations involving capital structure and dividend policies, as well as various capital, acquisition, and divestiture analyses.

From 1992-1993, I was on a special assignment working on the de-contracting of Canadian gas supply contracts. In this capacity, I oversaw financial and economic analyses and participated in contract negotiations with suppliers.

In 1994, I joined the Product and Sales Department in California Gas Transmission. I was promoted to director of the department in 1995, where I was responsible for the sales of interstate and intrastate gas transmission capacity and gas storage-related services. I also participated in the development of Gas Accord.

In 1996, I transferred as director to the Power Market Planning Department and the Energy Trading Department. Here, I participated in market structure activities involving the California Independent System Operator and Power Exchange and oversaw electric supply planning and trading activities.

1 In 1997, I left PG&E and joined PG&E Corporation's Energy Trading subsidiary of
2 the National Energy Group, in Bethesda Maryland. I was promoted to VP of Structured
3 Trading in 1999 and my responsibilities encompassed all complex, structured
4 transactions at Energy Trading.

5 In 1999, I joined AltaGas Inc., in Calgary, Alberta. At AltaGas, I was Senior VP
6 and Chief Operating Officer, overseeing all trading, acquisition, strategy and planning,
7 operations, and engineering activities for this mid-stream gas company.

8 In 2000, I rejoined PG&E Corporation as VP of Risk Initiative in San Francisco. I
9 participated in PG&E's Plan of Reorganization and advised on power procurement
10 issues.

11 In 2004, I rejoined PG&E as VP of Power Contracts and Electric Resource
12 Development. I oversaw all existing power contracts, including qualifying facility,
13 renewable generation, and irrigation district contracts. In addition, I was also
14 responsible for acquiring all long-term supply needs via contracts or generation
15 ownership.

16 In 2006, I was named VP of Energy Procurement.

17 In 2008, I assumed my current position as Senior VP of Energy Policy and
18 Procurement.

19 Q 4 What is the purpose of your testimony?

20 A 4 I am sponsoring the following testimony in Joint IOUs' Portfolio Allocation
21 Methodology Case:

- 22 – Chapter 1, "Introduction."
- 23 – Chapter 2, "Executive Summary."

24 Q 5 Does this conclude your statement of qualifications?

25 A 5 Yes, it does.
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SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF COLIN E. CUSHNIE

Q. Please state your name and business address for the record.

A. My name is Colin E. Cushnie, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Vice President, responsible for managing the Energy Procurement & Management Operating Unit at Edison. My organization's responsibilities include conducting energy-related solicitations and related valuation and risk management activities; contracting for wholesale supply, including renewables and energy storage; energy contract management and settlements, and energy procurement market operations, including bidding and schedule of wholesale electric supply into energy markets.

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Arts Degree in both Economics and Business Administration from Whittier College in 1986. I was hired by Edison in January 1987 and held various positions related to the procurement of material, equipment, and services until October 1993. Beginning in October 1993, I held positions of increased responsibility related to natural gas and electrical energy planning, energy procurement, and energy markets and energy procurement regulatory support. I assumed my current position in August 2014.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Chapter 4 of Exhibit No. Joint IOUs-01, as identified in the Tables of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

1 Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best
2 judgment?

3 A. Yes, it does.

4 Q. Does this conclude your qualifications and prepared testimony?

5 A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF RANBIR SEKHON

Q. Please state your name and business address for the record.

A. My name is Ranbir Sekhon, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Director of the Portfolio Planning & Analysis department of Southern California Edison's (SCE's) Power Supply organization.

Q. Briefly describe your educational and professional background.

A. I graduated from Queen Mary College, University of London in May of 1998 with a Bachelor of Science Degree in Mathematics and Computing with First Class Honors. Prior to joining SCE I worked briefly for ABN Amro in their corporate finance department and for nine years as a Management Consultant for PA Consulting Group. During my time with PA I reached the rank of Principal Consultant and was responsible for managing teams of consultants on various consulting projects. Six of my nine years with PA was spent working with global energy sector clients on engagements ranging from Energy Transaction and Risk Management (ETRM) systems implementation to Business Process and Quantitative Model development. I joined SCE as Manager of Portfolio Planning & Management in August 2007 and have held various roles responsible for monthly risk and resource adequacy reporting to CPUC ,analytical model development, managing all valuation processes related to renewable, alternative and conventional procurement and developing analytical models to support SCEs hedging program. I have previously testified before the commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Chapter 5 of Exhibit Joint IOUs-1, as identified in the Table of Contents thereto.

1 Q. Was this material prepared by you or under your supervision?
2 A. Yes, it was.
3 Q. Insofar as this material is factual in nature, do you believe it to be correct?
4 A. Yes, I do.
5 Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best
6 judgment?
7 A. Yes, it does.
8 Q. Does this conclude your qualifications and prepared testimony?
9 A. Yes, it does.

10

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARGOT C. EVERETT

Q 6 Please state your name and business address.

A 6 My name is Margot C. Everett, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 7 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E or the Company).

A 7 I am the senior director responsible for the Rates and Regulatory Analytics Department. This department consists of Rate Design, Load Forecasting, Regulatory Analytics, Revenue Forecasting and Tariffs. Department responsibilities include:

- Designing electric and gas rates.
- Supporting rates-related cases, such as the General Rate Case Phase 2 and Rate Design Window.
- Providing data analytics and analysis and systems support.
- Analyzing customer sales, load, rates, usage, and billing information.
- Developing the Company's electric and gas annual load forecasts, hourly load forecasts, peak day forecasts, and performing load research analyses, including developing the necessary analyses to comply with California Energy Commission requirements on load research.
- Analyzing customer load data and providing data analytics to support rate design and customer programs.
- Developing revenue and rate forecasts.
- Filing Advice Letters and filing and maintaining tariffs.

Q 8 Please summarize your educational and professional background.

A 8 I received a Master of Science degree in applied economics from the University of California, Santa Cruz in 1985 and a Bachelor of Arts in Economics from the same university in 1983. I have over 30 years of experience in the energy industry with roles in Regulatory Affairs, Risk Management and Compliance, Demand-Side Management, and Wholesale Power Contracts. My utility experience includes PG&E, PacifiCorp, PPM Energy and Constellation Energy and I also have experience with energy consultants Energetics and Hagler Bailly.

1 Q 9 What is the purpose of your testimony?
2 A 9 I am sponsoring the following testimony and workpapers in the Joint IOUs' Portfolio
3 Allocation Methodology Case:
4 – Chapter 6, "Cost Recovery and Rate Design."
5 – Workpapers supporting Chapter 6, "Cost Recovery and Rate Design."
6 Q 10 Does this conclude your statement of qualifications?
7 A 10 Yes, it does.

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In 1993, I graduated from the University of California at Berkeley with a Bachelor of Science in Political Economics of Natural Resources. I also attended the University of Minnesota where I completed all coursework required for a Ph.D. in Applied Economics.

I have previously submitted testimony before the California Public Utilities Commission and the Federal Energy Regulatory Commission regarding SDG&E's electric rate design and other regulatory proceedings. In addition, I have previously submitted testimony and testified before the Minnesota Public Utilities Commission on numerous rate and policy issues applicable to the electric and natural gas utilities.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF AKBAR JAZAYERI

Q. Please state your name and business address for the record.

A. My name is Akbar Jazayeri, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities for the Southern California Edison Company.

A. I am a consultant assisting SCE in development of the ratemaking and rate design mechanisms to implement the Portfolio Allocation Methodology.

Q. Briefly describe your educational and professional background.

A. I earned a Ph.D. degree in economics from the University of Southern California (USC).

As a research assistant at USC, I was involved in modeling industrial and commercial demand for electricity by time-of-use. My Ph.D. thesis concentrated on developing a new econometric approach to modeling peak load pricing policies. I was employed by Southern California Edison Company between May 1982 and April 2013.

I joined SCE as a market analyst in the Conservation and Load Management Department. My areas of responsibility included evaluation of load impacts and persistence of various conservation measures and analysis of appliance choice by residential customers.

Starting in 1984, I worked as a load research analyst for two years. In this position, I was involved in sample design and estimation of load profiles for various customer classes, research in alternative sample design methodologies, and evaluation of load characteristics of cogenerating customers. I then worked as a Regulatory Specialist for two and one-half years. In that capacity, I coordinated the estimation of present and marginal cost revenues and I was involved in various rate design functions. I held various supervisory and management positions in the Revenues and Tariffs Division prior to assuming the position of Director of Revenue and Tariffs Division in the Regulatory

1 Policy and Affairs (RP&A) Department in March 2001. In that capacity, I oversaw all
2 California Public Utilities Commission jurisdictional ratemaking, revenue requirements,
3 revenue forecasting, load research, pricing and tariff functions. I also directed the
4 activities of the Federal Energy Regulatory Commission (FERC) Rates and Regulation
5 Section of the RP&A Department. I was promoted to the position of Vice President of
6 Regulatory Operations in 2006 and served in that position until I retired in April 2013. In
7 that capacity I maintained the responsibilities of Director of Revenue and Tariffs and
8 assumed the responsibility of ensuring Company's compliance with State and Federal
9 regulatory mandates including compliance with Federal Critical Infrastructure Protection
10 (CIP) standards. I also led the Company's efforts on legislative bills with impact on its
11 revenues and rate structures. After retiring from SCE I worked as a Senior Manager for
12 Ernst & Young LLP between January 2015 and June 2016 providing ratemaking and
13 other regulatory services to power and utilities clients. I have previously testified before
14 this Commission.

15 Q. What is the purpose of your testimony in this proceeding?

16 A. The purpose of my testimony in this proceeding is to sponsor Chapter 6 of Exhibit No.
17 Joint IOUs-01.

18 Q. Was this material prepared by you or under your supervision?

19 A. Yes, it was.

20 Q. Insofar as this material is factual in nature, do you believe it to be correct?

21 A. Yes, I do.

22 Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best
23 judgment?

24 A. Yes, it does.

25 Q. Does this conclude your qualifications and prepared testimony?

26 A. Yes, it does.
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**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY**

APPENDIX C

PCIA OIR WORKSHOP 2 JOINT UTILITIES PRESENTATION

PCIA Rulemaking Workshop 2

Joint Utilities' Presentation

January 16, 2017

Outline

Introduction

- OIR guiding principles and legal requirements
- Review of the IOUs' ongoing cost responsibilities

Flaws in the Current Methodology

- Review of historical context
- Mathematical proof of what is required for indifference
- Impact of using administratively-set benchmarks on bundled service rates
- Impact of using administratively-set benchmarks on procurement decisions

Descriptions and Data-Based Comparison of Potential Solutions

- Direct allocation of portfolio costs and benefits to CCAs and ESPs
- Current methodology with "true-up" of benchmarks
- Buy-out of obligation
- Assignment of IOU contracts to CCAs and LSEs

Conclusion

- Matrix of Results

Principles for Going-Forward Solutions

Scoping Memo Section 2.1

- Bundled IOU customers should be neither worse off nor better off as a result of customers departing the IOU for other energy providers (“bundled customer indifference”)
- Transparent and verifiable, including the most open and easily accessible treatment of input data, while maintaining confidentiality of market-sensitive data that must remain confidential
- Reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon
- Flexible enough to maintain its accuracy and stability if the number of departing customers changes significantly
- Not create unreasonable obstacles for customers of non-IOU energy providers
- Consistent with California energy policy goals and mandates

Public Utilities Code Sections 365.2 and 366.3

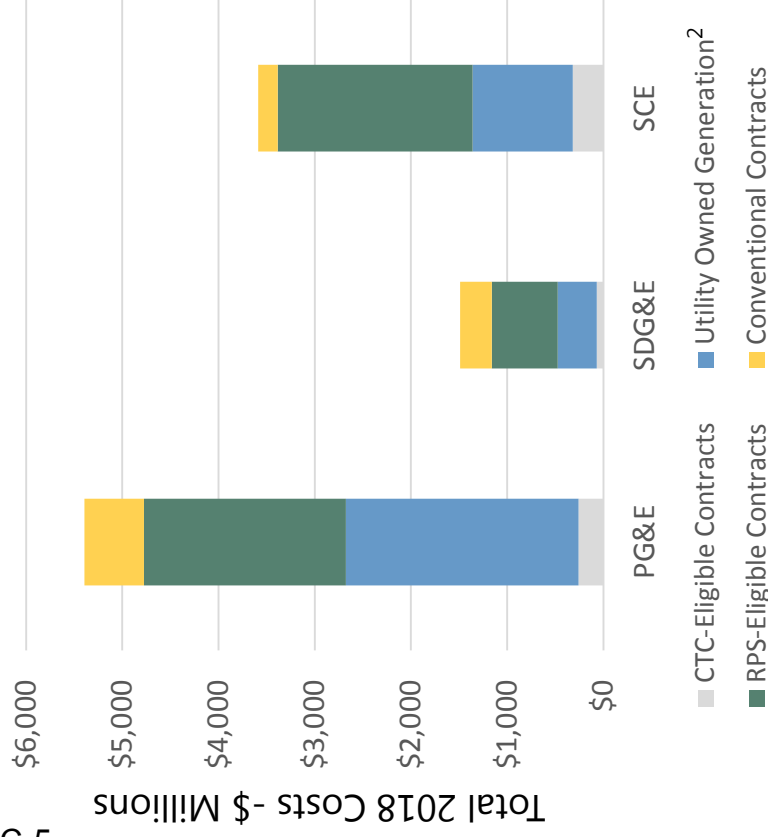
The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of:

- retail customers of an electrical corporation electing to receive service from other providers (365.2).
- the implementation of a community choice aggregator program (366.3).

The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load (366.3).

Historical IOU Generation Portfolio “Snapshot”¹

AppC-5



- Historical IOU portfolios were procured/built for all “then-bundled service” customers consistent with 366.3

- All resources were built/procured pursuant to CPUC approval or an approved procurement plan, selected using the “least cost and best fit” criteria, and approved by the Commission through a rigorous regulatory process that involved numerous stakeholders

- Historical portfolio obligations “taper down” as contracts expire

- RPS-eligible contracts typically range between 10 and 25 years in length
- Most conventional contracts expire within the next five years
- Utilities have proposed that PCIA (or its successor)-recovery for UOG ends when all contracts in the vintage portfolio expire

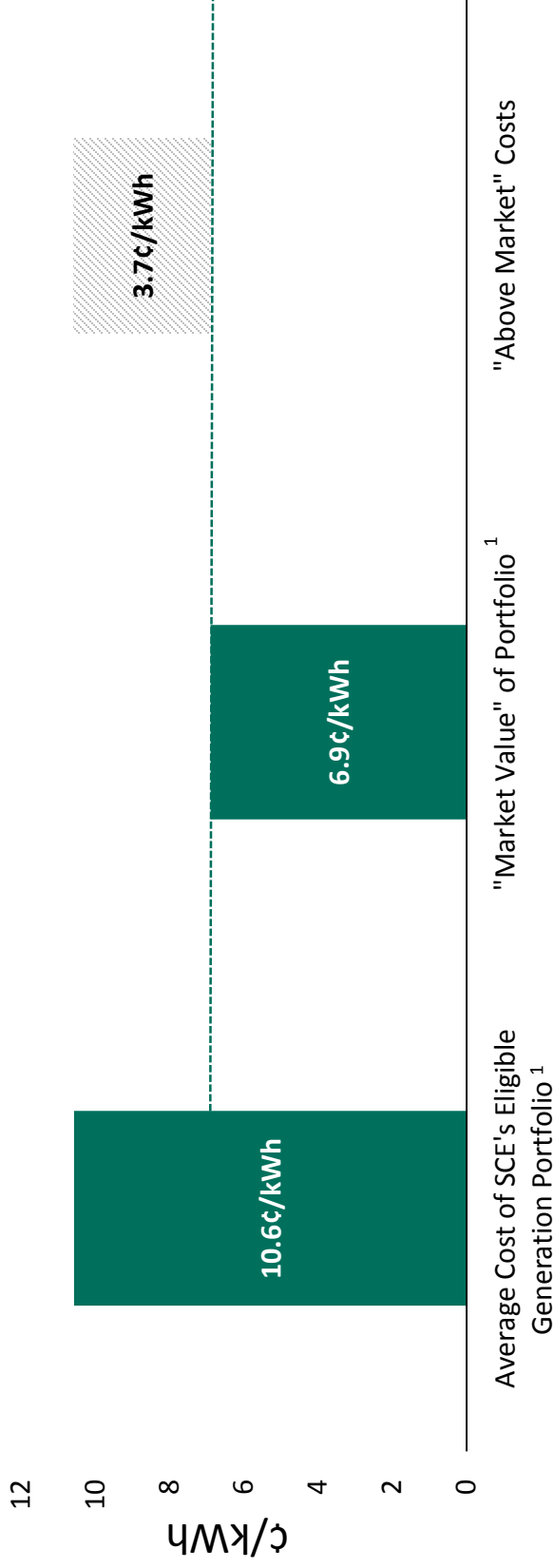
- 1 Customers are only responsible for the resources that were procured/built prior to their departure. Snapshot is based on each IOU’s current portfolio of online resources, and does not include the forecast costs of signed resources that are not yet online (PG&E: ~\$46M; SDG&E: ~\$20M; SCE: ~\$300M), nor does it include CAM costs
- 2 SONGS Settlement Revenue Requirement is included in SCE and SDGE’s UOG category

Review of Current Methodology

Akbar Jazayeri, SCE

Current Cost Responsibility Framework

AppC-7



- Customers who depart bundled service for a different "Load Serving Entity" (LSE) currently leave their share of the IOU's historical generation portfolio with the IOU
- Any "above-market" costs, as determined using the Commission-prescribed methodology, of resources procured prior to a customer's departure are the responsibility of that customer

¹ Average cost and "market value" based on SCE's 2018 ERRA Forecast November Update

Historical Context for Current Methodology

AppC-8

- The Current Methodology has significantly evolved over time in efforts to:
 - Reduce administrative burden and increase transparency¹
 - Reflect the current market value of the utilities' generation portfolio in light of evolving market conditions and new regulatory requirements²
- The administrative and formula-based approaches for establishing the Renewable and Capacity benchmarks were adopted as interim solutions, and were to be replaced once markets and/or public indices for those products became available³
 - There is continued disagreement on the accuracy and efficacy of the Renewable and Capacity benchmarks
- The Current Methodology was established at a time when there was a limited and capped amount of departing load

1 D.06-07-030; D.08-09-012

2 D.06-07-030; D.11-12-018; Resolution E-4475

3 D.11-12-018 at p. 24 for Renewables and p. 30 for Capacity

Definitions

- kWh_B = Bundled Service Usage
- kWh_{DL} = Departing Load Usage
- C_P = Portfolio Cost Subject to PCIA
- G_P = Output of Portfolio Subject to PCIA
- R_1 = Bundled Service Rate (associated with PCIA-eligible portfolio)¹ Prior to Load Departure
- R_2 = Bundled Service Rate (associated with PCIA-eligible portfolio)¹ After Load Departure
- MPB = Administratively-set Market Price Benchmark
- P_{act} = Actual Price Utility Obtains from Selling Departing Load Customers' Share of G_P
- IR = Indifference Rate

1 Inclusion of the IOU's net short position in the formulas would not result in significantly different results (See backup slides)

Formulas

AppC-10

- $R_1 = \frac{C_P}{kWh_B + kWh_{DL}}$

– **Bundled Service Rate Before Departures:** Portfolio Cost ÷ Load Responsible for Portfolio

- $IR = \frac{C_P - (MPB \times G_P)}{kWh_B + kWh_{DL}} = R_1 - \frac{(MPB \times G_P)}{kWh_B + kWh_{DL}}$

– **Indifference Rate:** (Portfolio Cost – Portfolio's Market Value at MPB) ÷ Load Responsible for Portfolio

– **Indifference Rate:** Bundled Service Rate Before Departures – (Portfolio Market Value at MPB ÷ Load Responsible for Portfolio)

- $R_2 = \frac{C_P - (P_{act} \times \frac{kWh_{DL} \times G_P}{kWh_B + kWh_{DL}}) - (IR \times kWh_{DL})}{kWh_B}$

– **Bundled Service Rate After Departure:** (Portfolio Cost – Revenues received by IOU for the sale of the Departing Load customers' share of Portfolio – PCIA and CTC paid by Departing Load customers) ÷ Remaining Bundled Service Load

- $R_2 - R_1 = \frac{kWh_{DL}}{kWh_B} \times \frac{G_P}{kWh_B + kWh_{DL}} \times [MPB - P_{act}]$

Observations about the Current Methodology

- Bundled service customer indifference is achieved when $R_2 = R_1$, which only occurs if $MPB = P_{act}$
 - This **requires** a true-up of the administratively-set MPB to the actual price obtained from selling departing load customers' share of G_p in the market
 - $R_2 > R_1$ (i.e., bundled service rates increase as a result of departing load) when $MPB > P_{act}$ (current situation from the Joint Utilities' perspective)
 - $R_2 < R_1$ (i.e., bundled service rates decrease as a result of departing load) when $MPB < P_{act}$ (current situation from departing load advocates' perspective)
- If MPB is different from P_{act} then harm or benefit to bundled service customers increases as kWh_{DL} increases and when G_p serves a larger portion of system load
- Current methodology resulted in acceptable outcomes when kWh_{DL} was small and frozen and MPB/P_{act} did not include RPS and RA components

Customer Bill Impact of Using "Benchmarks"¹

$$\text{Bundled Service Customer Bill Impact} = \frac{(\$/\text{MWh difference btwn benchmark and actual}) \times (\text{Portfolio MWh/Vintage Load Responsible for Portfolio}) \times \text{Departing Load (MWh)}}{\text{Remaining Bundled Service Customer Load (MWh)}}$$

% Difference Between Benchmark and Actual²

30%

% Load Departures	Impact of Understated Benchmark (¢/kWh)	Impact of Overstated Benchmark (¢/kWh)	% Impact on Generation Bill (2018 SCE)
20%	-0.20	0.20	(+/-) 3%
30%	-0.35	0.35	(+/-) 5%
40%	-0.54	0.54	(+/-) 7%
50%	-0.81	0.81	(+/-) 11%
60%	-1.22	1.22	(+/-) 16%
70%	-1.90	1.90	(+/-) 25%
80%	-3.25	3.25	(+/-) 43%
90%	-7.32	7.32	(+/-) 96%
99%	-80.51	80.51	(+/-) 1056%

Any difference between the benchmark and "actual" market value (in either direction) currently is reflected in bundled service customers' bills because there is no "true-up"

- 1 Correction to December 5, 2017 equation noted in **bold** and reflected in calculation
- 2 Data is based on SCE's 2018 ERRA Forecast values

Additional Observation: Current Methodology is Contrary to Least Cost Best Fit (LCBF) Procurement Principles

- The current use of a “flat” RA benchmark (\$58.27/kW-year, or \$4.86/kW-month) is contrary to LCBF procurement on behalf of customers, because it applies the same RA benchmark to all RA MW, regardless of whether or not it is meeting a customer need

For Example

- Assume the utility customers have a 100 MW short position in August only
 - The utility as the procurement agent for its bundled service customers would run an RFO to procure the needed capacity and per Commission oversight apply LCBF principals to the procurement
- The following bids are received in the RFO
 - Year Round offer of 100 MW @ \$2/kW-month
 - August only offer of 100 MW @ \$25/kW-month

Offers	Description	Contract payments
1	Year Round offer of 100 MW @ \$2/kW-mon	=100MW *1000kW/MW x \$2 x 12 month = \$2,400,000
2	August only offer of 100 MW @ \$25/kW-mon	=100MW *1000kW/MW x \$25 x 1 month = \$2,500,000

Additional Observation: Current Methodology is Contrary to Least Cost Best Fit (LCBF) Procurement Principles Cont.

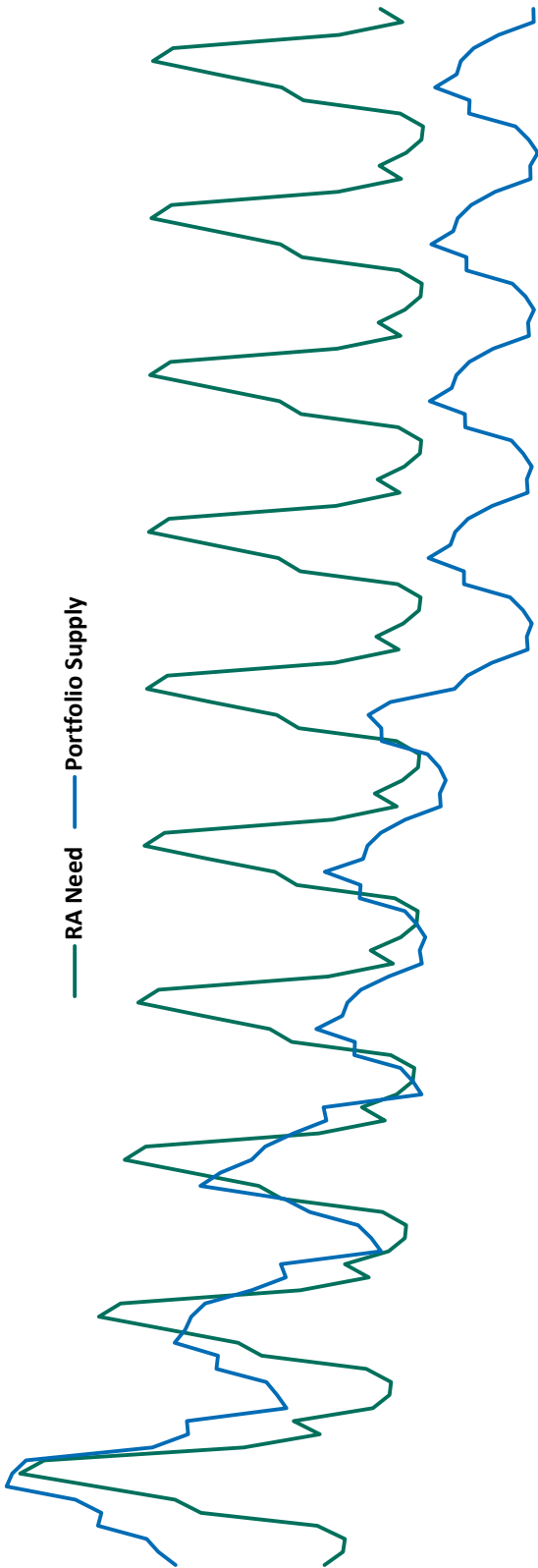
- Under LCBF principles the lowest cost offer to meet the identified need would be Offer 1 at a total cost of \$2.4M
 - Qualitatively from a best fit perspective this offer also provides additional hedge value at no cost for non-August months for RA substitution
 - The additional RA procured in non-August months has little to no RA value from the customer perspective
- However, under the current PCIA methodology, if load were to depart then utility customers would be required to credit departing customers at a rate of \$4.86/kW-month for all RA MW-months

Offers	PCIA Credit
1	$= 100\text{MW} \times 1000\text{kW/MW} \times (\$4.86) \times 12 \text{ months}$ $= \mathbf{\$5,832,000}$
2	$= 100\text{MW} \times 1000\text{kW/MW} \times (\$4.86) \times 1 \text{ month}$ $= \mathbf{\$486,000}$

- If this were incorporated into the selection decision then the utility as agent for customers would procure Offer 2 and not Offer 1 leading to a higher cost (\$2.5M) for customers at the outset contrary to LCBF

Resource Adequacy Needs

AppC-15



Any portfolio supply (blue line) that is above the RA need (green line) has little to no RA value to customers

Jan-18	Apr-18	Jul-18	Oct-18	Jan-19	Apr-19	Jul-19	Oct-19	Jan-20	Apr-20	Jul-20	Oct-20	Jan-21	Apr-21	Jul-21	Oct-21	Jan-22	Apr-22	Jul-22	Oct-22	Jan-23	Apr-23	Jul-23	Oct-23	Jan-24	Apr-24	Jul-24	Oct-24	Jan-25	Apr-25	Jul-25	Oct-25	Jan-26	Apr-26	Jul-26	Oct-26	Jan-27	Apr-27	Jul-27	Oct-27
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Review of “Potential Options”

Ranbir Sekhon

Description of Portfolio Allocation

- IOUs continue to manage the historical generation portfolios on behalf of the customers the portfolios were procured for
- All customers (bundled service and departing load) receive their share of the portfolio benefits
 - Energy and ancillary services benefits will be monetized by the IOU, and market revenues will be used to offset the costs of the resources
 - Resource Adequacy (RA) will be allocated to the customers' LSEs using the existing Cost Allocation Mechanism (CAM) process, and will reduce the LSEs' RA obligation
 - Renewable Energy Credits (RECs) will be transferred to the LSEs' WREGIS account and can be used to meet the LSEs' RPS requirements
 - Contingent upon CPUC approval that allocated RECs retain their Portfolio Content Category and long-term contracting designations
- All customers are responsible for their share of the portfolio "net costs"
 - Initial rates will be based on a forecast of annual costs and market revenues and set in the annual ERRA Forecast proceeding
 - Actual costs, market revenues, and revenues received from customers will be recorded in a balancing account and "trued-up" in the following year's rates.

Key Takeaways:

- All customers (bundled service and departing load customers) contribute the same \$/kWh towards the recovery of the resource costs for which they are responsible
- Customers and their LSEs receive the pro-rata share of the portfolios that were procured on their behalf with a methodology that is fully scalable

Description of Current Methodology with “True-Up”

- Customers who depart bundled service continue to leave their share of the IOU’s historical generation portfolio with the IOU
- Portfolio costs, output, and market value set on a forecast basis and “trued-up” the following year based on actual market outcomes—this would **require** the following:
 - Readily-available market-index for RPS and RA
 - Robust, liquid, and transparent market for RPS and RA products
 - Recognition of depth of market concerns for RA and RPS, value trends to zero when there is no need
- RPS and RA procurement data from all entities, not just IOUs, will be required given potential load-share of non-IOU LSEs
 - All market sensitive data must be provided to third party to preserve market integrity given that all LSEs will be transacting with each other
- True-ups can create significant rate volatility and limit the ability to accurately forecast total generation costs

Description of Other Alternatives (Buy-Out and Assignment)

Both options require a one-time calculation of the Net Present Value (NPV) of the historical generation portfolio (based on mutually agreeable long-term forecast of its market value)

NPV Calculation

- Reach agreement on forward energy prices to derive energy value (liquid markets available)
- Reach agreement on forward RA prices to derive RA Capacity value (no liquid markets)
- Reach agreement on forward renewables prices to derive renewables value (no liquid markets)
- Reach agreement on potential risk adjustments to account for uncertainty in market outcomes

Buy-Out

- LSE's buy-out amount would be equal to its pro-rata share of the historical portfolio NPV
- LSE's share of the utility portfolio will remain with the IOU

Contract Assignment

- Mutually-agreeable assignment of specific IOU contract(s) to the LSE; assigned contracts must have an NPV equal to the LSE's pro-rata share of the historical portfolio NPV
- Transfer of all rights and obligations from the IOU to the LSE
 - LSE assumes contract and resource management, as well as payment obligations, going forward
 - IOU, and its bundled service customers, would not have any further rights or obligations in those contracts for the period after the assignment, to the extent legally possible
- Requires approval from the contract's counterparty
- LSE's assumption of the IOU contract(s) relieves its customers of their cost responsibility for the remainder of the IOU's historical portfolio
- Must determine how to address special circumstances (e.g., unexpected terminations of either transferred or left-behind contracts)

Data-Based Comparison of Solutions

Ranbir Sekhon, SCE

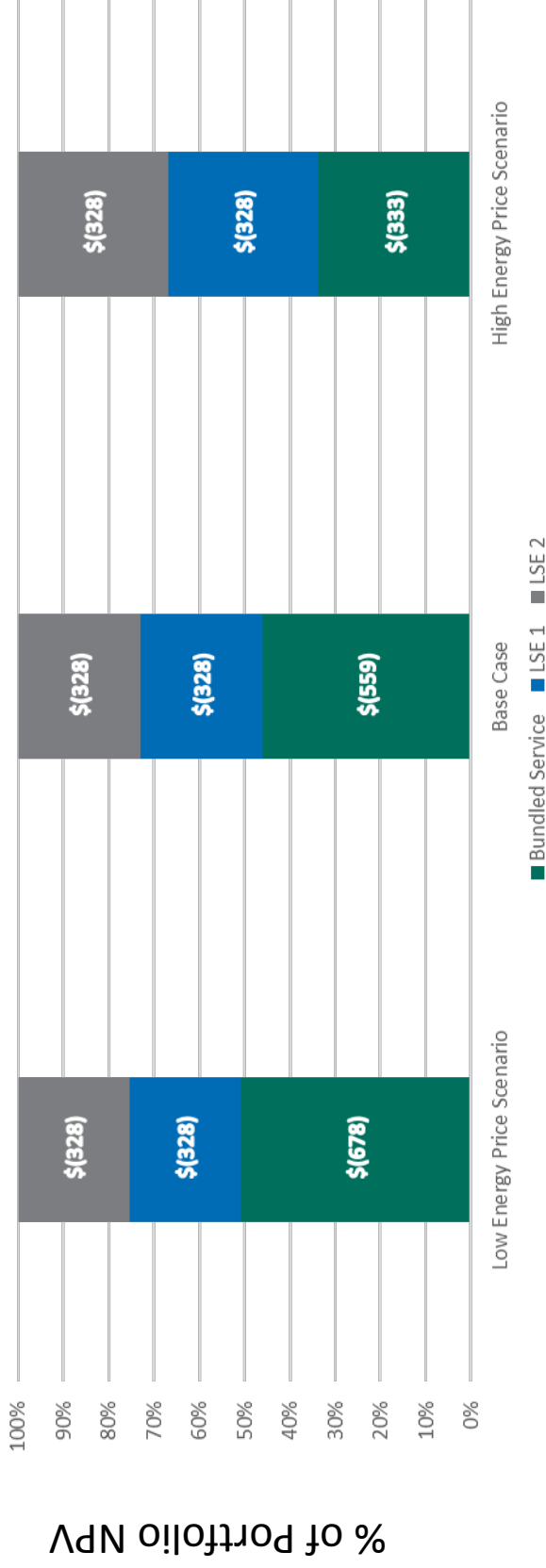
Simplified Portfolio Assumptions

Resource	Capacity (MW)	Length	NPV - \$M
RPS Contract 1	150	12	\$ (251)
RPS Contract 2	150	12	\$ (322)
RPS Contract 3	38	12	\$ (77)
RPS Contract 4	20	12	\$ (35)
RPS Contract 5	20	12	\$ (35)
Gas Fired Toll 1	500	5	\$ (85)
Gas Fired Toll 2	520	7	\$ (131)
Gas Fired Toll 3	520	7	\$ (131)
SRAC 1	38	12	\$ (51)
SRAC 2	38	1	\$ (2)
SRAC 3	37	6	\$ (9)
SRAC 4	49.8	1.3	\$ (4)
RA Only 1	238	3	\$ (16)
RA Only 2	54	4	\$ (2)
RA Only 3	250	8	\$ (65)
Total			\$ (1,216)

- Assume 3 LSEs – Determination of buy-out amount and/or contracts to be assigned is based on each LSE's share of the calculated portfolio NPV of \$1,216M
 - IOU: 46% load share
 - LSE 1: 27% load share; \$328M
 - LSE 2: 27% load share; \$328M
- Actual market outcomes will differ from forecasts used to determine the initial NPV – must test each option's efficacy at various "scenarios"
 - 5th and 95th percentile scenarios reflect high and low scenarios for energy prices only
 - Flat price assumed for RPS and RA throughout analysis given lack of liquid/transparent markets
 - Portfolio NPV at the 5th Percentile energy price: \$1,335M
 - Portfolio NPV at the 95th Percentile energy price: \$990M
- Indifference for all customers is achieved when each LSE's share of the NPV is the same in all potential outcomes/scenarios

Model Results of Buy-Out Option

AppC-22



- LSE 1 and 2 make a one-time payment of \$328M based on an initial NPV calculation using the base case energy price forecast¹
- The LSE's "share" of the portfolio NPV changes based on actual market conditions
 - All customers indifferent if actual market conditions = base case assumed during NPV calculation
 - LSE 1 and 2 customers "win" in low-priced scenario
 - Bundled service customers "win" in high-priced scenario
- Because forecasts do not accurately predict future market prices, customer indifference is not achieved in a Buy-Out construct

¹ Renewables valued assuming a flat \$10/MWh REC and RA valued at \$25/kW-Year (shaped by month)

Model Results of Contract Assignment

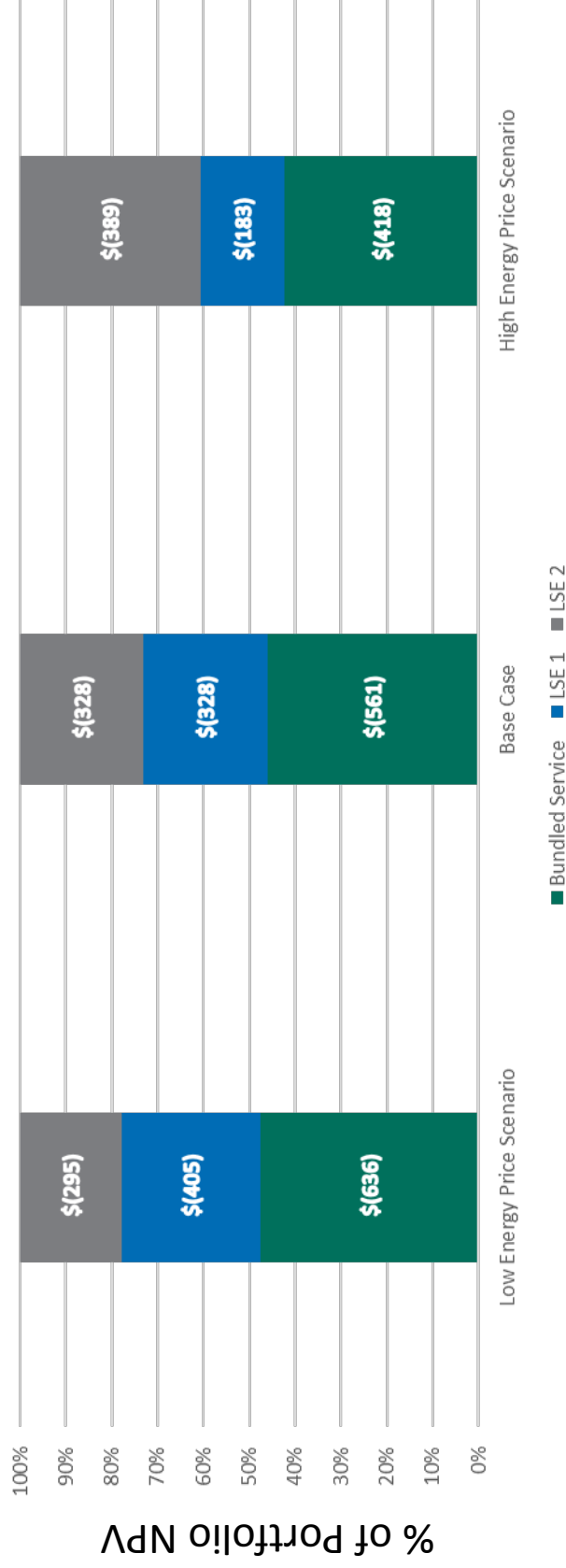
AppC-23

Key	NPV (Base)
Bundled Service	\$ (561)
LSE 1	\$ (328)
LSE 2	\$ (328)

Resource	NPV (Low)	NPV (Base)	NPV (High)
RPS Contract 1	\$ (311)	\$ (251)	\$ (138)
RPS Contract 2	\$ (382)	\$ (322)	\$ (209)
RPS Contract 3	\$ (93)	\$ (77)	\$ (45)
RPS Contract 4	\$ (43)	\$ (35)	\$ (21)
RPS Contract 5	\$ (42)	\$ (35)	\$ (20)
Gas Fired Toll 1	\$ (85)	\$ (85)	\$ (85)
Gas Fired Toll 2	\$ (131)	\$ (131)	\$ (131)
Gas Fired Toll 3	\$ (131)	\$ (131)	\$ (131)
SRAC 1	\$ (25)	\$ (51)	\$ (100)
SRAC 2	\$ (1)	\$ (2)	\$ (4)
SRAC 3	\$ (4)	\$ (9)	\$ (17)
SRAC 4	\$ (2)	\$ (4)	\$ (6)
RA Only 1	\$ (16)	\$ (16)	\$ (16)
RA Only 2	\$ (2)	\$ (2)	\$ (2)
RA Only 3	\$ (65)	\$ (65)	\$ (65)
Total	\$ (1,335)	\$ (1,216)	\$ (990)

Model Results of Contract Assignment

AppC-24

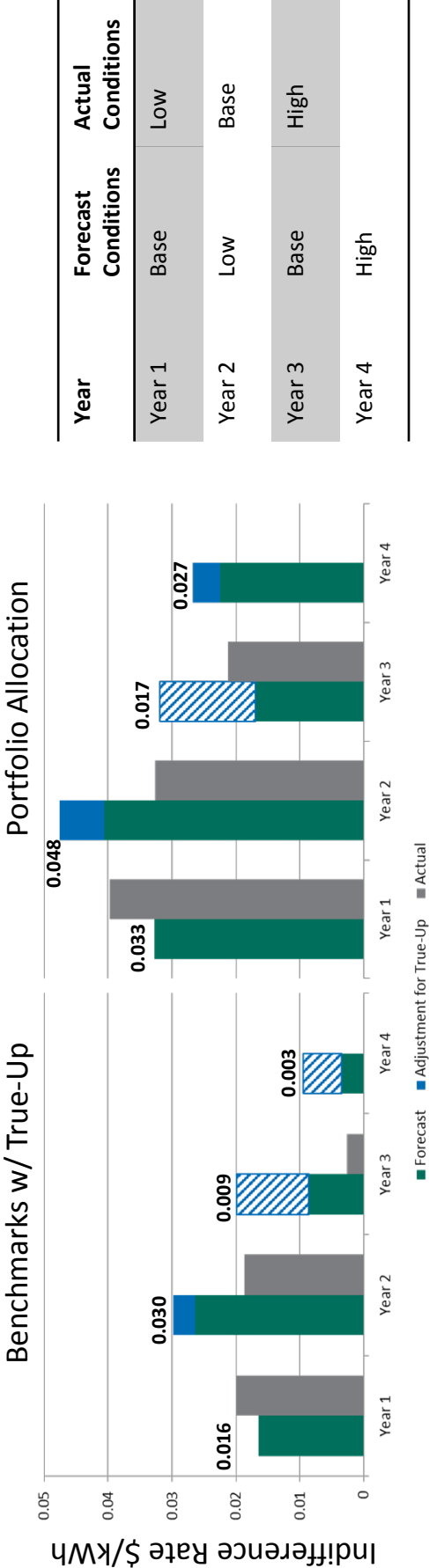


- Contracts assigned to LSE 1 have initial NPV of \$328M (27.0%)
 - Contracts assigned to LSE 2 have initial NPV of \$328M (26.9%)¹
 - The LSE's "share" of the portfolio NPV changes based on how their assigned contracts fare during actual market conditions
 - All customers indifferent if actual market conditions = base case assumed during NPV calculation
 - LSE 2 customers "win" in varying degrees in low-priced scenario
 - Bundled service and LSE 1 "win" in varying degrees in high priced scenario
- ¹ Allocated NPV between LSEs may not precisely match load share due to "lumpiness" of contract quantities, price and expiration

Comparison of Current Methodology with True-Up vs. Portfolio Allocation Methodology

AppC-25

- All vintaged over- or under-collections are shared by IOU and ESP/CCA customers
 - Portfolio Allocation Methodology requires annual true-up of actual portfolio costs and energy and ancillary services revenue
 - Benchmarks with True-Up requires additional true-up of REC and RA benchmarks (agreement on actuals – which could mean zero value)
- True-up of REC and RA benchmarks introduce additional volatility
 - Limited data sources available for use on a forecast basis
 - Significant variance between forecast and actual benchmark expected given depth of market concerns



Matrix of Results (IOU Perspective)

Guiding Principle	Criteria	Current Method (No Update)	Buy-Out of Obligation	Contract Assignment	Benchmark Method with “True-Up”	Portfolio Allocation
Maintains customer indifference	At all price scenarios				✓ ¹	✓
Transparent and Verifiable	All inputs and calculations are transparent and verifiable	✓ ²	✓	✓	✓ ²	✓
Reasonably Predictable Outcomes that Promote Certainty and Stability	Certainty on the costs and resulting rates		✓			✓
Scalable	At any level of load departure				✓ ¹	✓
Does not create unreasonable obstacles for customers of non-IOU providers	Does not impede CCA expansion or formation	✓			✓	✓
Consistent with California energy policy goals and mandates	No “double procurement”			✓		✓

1

Requires agreement on process to true up RA and REC value without liquid or transparent markets

2

Market data used for benchmarks must be aggregated by a non-market participant third party

Matrix of Results

Guiding Principle	Criteria	Current Method (No Update)	Buy-Out of Obligation	Contract Assignment	Benchmark Method with “True-Up”	Portfolio Allocation
Maintains customer indifference						
Transparent and Verifiable						
Reasonably Predictable Outcomes that Promote Certainty and Stability						
Scalable						
Does not create unreasonable obstacles for customers of non-IOU providers						
Consistent with California energy policy goals and mandates						

Appendix

Formulas with Net Short costs included

- $R_1 = \frac{C_P + (NS \times P_1)}{kWh_B + kWh_{DL}}$

– **Added Net Short position (NS) x Price Paid by the IOU to fill it (P₁)**

- $IR = \frac{C_P - (MPB \times G_P)}{kWh_B + kWh_{DL}} = \frac{C_P}{kWh_B + kWh_{DL}} - \frac{(MPB \times G_P)}{kWh_B + kWh_{DL}}$

– **Net short costs are not included in the Indifference Rate Calculation**

- $R_2 = \frac{C_P + (NS \times P_1) - \left(\text{Pact} \times \frac{kWh_{DL} \times G_P}{kWh_B + kWh_{DL}} \right) - (IR \times kWh_{DL})}{kWh_B}$

– **Bundled Service Rate After Departure:** (PCIA-eligible Portfolio Cost + cost of filling the Net Short position – Revenues received by IOU for the sale of the Departing Load customers' share of PCIA-eligible Portfolio – PCIA and CTC paid by Departing Load customers) ÷ Remaining Bundled Service Load

- $R_2 - R_1 = \frac{kWh_{DL}}{kWh_B} \times \frac{G_P}{kWh_B + kWh_{DL}} \times [MPB - P_{act} + (P_1 \times \frac{NS}{G_P})]$

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APPENDIX D
BILLED REVENUES

Billed Revenues

1. Billed revenues from departing load customers' CTC and PAC rates

Revenues collected from departing load customers' CTC rates will be recorded in the CTC subaccount¹ of the PABA-GAM and PABA-PMM sub-accounts.

Revenues collected from departing load customers' PAC rates will need to be directed to the subaccounts for which they are responsible. For example, as described in Section D.1 in Chapter 4, customers who depart in 2010 are responsible for the net costs recorded in the CTC subaccount and the 2001-2010 subaccounts, and their total, cumulative PAC rate will represent the sum of the 2001-2010 GAM and PMM rates. Although the departing load customers' bills will include a single PAC rate that is the sum of the incremental GAM and PMM rates for which they are responsible, the billed revenues collected from those customers will be allocated to each subaccount by multiplying their total recorded usage by the applicable (incremental) GAM and PMM rate.

2. Billed revenues from bundled service customers' CTC and generation rates

Revenues collected from bundled service customers' CTC rates will be recorded in the CTC subaccount of the PABA-GAM and PABA-PMM sub-accounts.

Revenues collected from bundled service customers' generation rates will need to be directed to the accounts (and subaccounts) for which they are responsible. Unlike departing load customers, bundled service customers continue to be responsible for the costs recorded in the ERRA and any other generation-related bundled service customer-only balancing accounts. As such, their billed revenues will need to be allocated between PABA and ERRA. This is done by allocating the product of the bundled service customers' total recorded usage and the ERRA rate specified in each utility's respective Preliminary Statement² to ERRA, and the product of the bundled service customers' total recorded usage by CTC and each subaccount GAM and PMM rate to the appropriate PABA subaccount.

¹ As described in testimony, SDG&E may elect to maintain its standalone CTC balancing account in lieu of creating CTC-subaccounts in the PABA.

² See SCE's Preliminary Statement YY and ZZ, PG&E's Preliminary Statement I, and SDG&E's Preliminary Statements for ERRA and Non-Fuel Generation Balancing Account.

**PACIFIC GAS AND ELECTRIC COMPANY
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APPENDIX E

JOINT UTILITIES PROPOSAL – ILLUSTRATIVE EXAMPLE

1. Simplifying Assumptions Used in Example

- IOU has four portfolios of GAM-eligible resources and four portfolios of PMM-eligible (i.e., there were four tranches of generation resources, in the GAM and PMM, respectively)
- GAM
 - Pre-Restructuring Portfolio
 - 2009 Portfolio
 - 2014 Portfolio
 - 2017 Portfolio
- PMM
 - Pre-Restructuring Portfolio
 - 2009 Portfolio
 - 2014 Portfolio
 - 2017 Portfolio
- Three active groups (“vintages”) of departing load customers in the IOU service territory:
 - LSE X, whose customers departed in 2008
 - CCA Y, whose customers departed in 2010
 - CCA Z, whose customers departed in 2015
 - The IOU continues to serve its remaining bundled service customers
- Single year example for year X

Customer Responsibility for Each Vintaged Portfolio					
Description	Forecasted Load (GWh)	2017 GAM & PMM Portfolios	2014 GAM & PMM Portfolios	2009 GAM & PMM Portfolios	Pre-restruct. GAM & PMM Portfolios
LSE X (Departs in 2008)	1000	-	-	-	Yes
CCA Y (Departs in 2010)	3500	-	-	Yes	Yes
CCA Z (Departs in 2015)	1500	-	Yes	Yes	Yes
Remaining Bundled Service	4000	Yes	Yes	Yes	Yes

2. Forecast Load vs. Actual Load

Forecast of Load Share					
Description (Unit)	2017 GAM and PMM Portfolios	2014 GAM and PMM Portfolios	2009 GAM and PMM Portfolios	Pre-restruct. GAM and PMM Portfolios	Forecast of Total System Load in Year X
FL1. Forecast Load Responsible for Each Portfolio (GWh)	4,000	5,500	9,000	10,000	10,000
FL2. Forecast Load and Load Share of LSE X (GWh)	-	-	-	10%	1,000
FL3. Forecast Load and Load Share of CCA Y (GWh)	-	-	39%	35%	3,500
FL4. Forecast Load and Load Share of CCA Z (GWh)	-	27%	17%	15%	1,500
FL5. Forecast of Remaining Bundled Service Load (GWh)	100%	73%	44%	40%	4,000

Actual Load Share					
Description (Unit)	2017 GAM and PMM Portfolios	2014 GAM and PMM Portfolios	2009 GAM and PMM Portfolios	Pre-restruct. GAM and PMM Portfolios	Actual Total System Load in Year X
AL1. Actual Load Responsible for Each Portfolio (GWh)	4,200	5,800	9,000	10,200	10,200
AL2. Actual Load and Load Share of LSE X (GWh)	-	-	-	12%	1,200
AL3. Actual Load and Load Share of CCA Y (GWh)	-	-	36%	31%	3,200
AL4. Actual Load and Load Share of CCA Z (GWh)	-	28%	18%	16%	1,600
AL5. Actual of Remaining Bundled Service Load (GWh)	100%	72%	47%	41%	4,200

Forecast Peak Load and Peak Load Share of Each Portfolio					
Description (Unit)	2017 GAM and PMM Portfolios	2014 GAM and PMM Portfolios	2009 GAM and PMM Portfolios	Pre-restruct. GAM and PMM Portfolios	Total Peak Load
PL1. Peak Load Responsible for Each Portfolio (MW)	1,200	1,700	2,700	2,885	2,885
PL2. Forecast Peak Load and Share of LSE X (MW)	-	-	-	6%	185
PL3. Forecast Peak Load and Share of CCA Y (MW)	-	-	37%	35%	1,000
PL4. Forecast Peak Load and Share of CCA Z (MW)	-	29%	19%	17%	500
PL5. Forecast Peak Load and Share of Bundled Service (MW)	100%	71%	44%	42%	1,200

- Customers are responsible for all portfolios procured prior to their departure – e.g., customers who depart in 2015 are responsible for the 2014, 2009, and Pre-Restructuring portfolios
- Customers' "share" of each portfolio will be the proportion of their actual load to the actual load of all customers responsible for that portfolio

3. Forecast vs. Actual GAM Portfolio Costs, Mkt. Rev, and RECs

Forecast of GAM Costs, Market Revenues, and Generation					
Description (Unit)	2017 GAM Portfolio	2014 GAM Portfolio	2009 GAM Portfolio	Pre-restruct. GAM Portfolio	Total
FGP1. Forecast Costs (\$M)	\$80	\$176	\$140	\$220	\$616
FGP2. Forecast Market Revenues (\$M)	(\$48)	(\$96)	(\$72)	(\$140)	(\$356)
FGP3. Forecast Net Costs (\$M)	\$32	\$80	\$68	\$80	\$260
FGP4. Forecast RECs (GWh)	500	2,000	2,000	1,500	6,000
FGP5. Net Qualifying Capacity (MW)	200	650	500	700	2,050

Actual GAM Costs, Market Revenues, and Generation					
Description (Unit)	2017 GAM Portfolio	2014 GAM Portfolio	2009 GAM Portfolio	Pre-restruct. GAM Portfolio	Total
AGP1. Actual Costs (\$M)	\$64	\$160	\$128	\$232	\$584
AGP2. Forecast Market Revenues (\$M)	(\$40)	(\$68)	(\$80)	(\$144)	(\$332)
AGP3. Actual Net Costs (\$M)	\$24	\$92	\$48	\$88	\$252
AGP4. Actual RECs Generated (GWh)	600	2,100	1,900	1,300	5,900
AGP5. Net Qualifying Capacity (MW)	200	650	500	700	2,050

- Portfolios are “incremental” – *e.g.*, the 2014 Portfolio only includes the resources executed (or UOG approved) between January 1, 2014 and December 31, 2014
- Costs, market revenues, and generation are forecast annually in the ERRA Forecast proceeding; however, customers will only be responsible for the actual net costs and REC allocations will be based on actual RECs generated

4. GAM REC Allocation

Eq.	Description (Unit)	Actual REC Allocations				Total RECs Allocated
		2017 GAM Portfolio	2014 GAM Portfolio	2009 GAM Portfolio	Pre-restruct. GAM Portfolio	
1. AGP4	Actual RECs Generated	600	2,100	1,900	1,300	5,900
2. AL2*(1)	RECs Allocated to LSE X	-	-	-	153	153
3. AL3*(1)	RECs Allocated to CCA Y	-	-	676	408	1,083
4. AL4*(1)	RECs Allocated to CCA Z	-	579	338	204	1,121
5. AL5*(1)	RECs Allocated to Remaining Bundled Service	600	1,521	887	535	3,543

- Forecasts of future REC allocations can be developed by multiplying forecast load share (lines FL 2-5) by the forecast number of RECs in each vintaged portfolio (line FP4)
- Actual REC allocations will be determined by multiplying actual load share (lines AL 2-5) by the actual number of RECs generated (line AP4)
 - Accounts for variation in load share throughout the year
 - Accounts for actual RECs produced by each resource
- Allocated RECs will retain their current designation (e.g., Portfolio Content Category 1, long-term, etc.)
- REC allocations will occur 90 days after the RECs are generated

5. GAM RA Allocation

		Allocation of GAM RA				
Eq.	Description (Unit)	2017 GAM Portfolio	2014 GAM Portfolio	2009 GAM Portfolio	Pre-restruct. GAM Portfolio	Total RA Allocated
1. AGP5	Total NQC in Each Portfolio (MW)	200	650	500	700	2,050
2. PL2*(1)	RA Allocated to LSE X	-	-	-	45	45
3. PL3*(1)	RA Allocated to CCA Y	-	-	185	243	428
4. PL4*(1)	RA Allocated to CCA Z	-	191	93	121	405
5. PL5*(1)	RA Allocated to Remaining Bundled Service (MW)	200	459	222	291	1,172

- Forecast peak load (slide 1) and GAM-eligible NQC (line FP5) will be updated monthly
 - Monthly updates to forecast peak loads are also used to adjust LSEs' monthly RA requirements, if necessary (existing process)
- Actual RA allocations will be done monthly on a forecast basis and will be determined by multiplying forecast peak load share by the NQC of the portfolio (line FP5)

6. Forecast vs. Actual PMM Portfolio Costs and Mkt. Revenues

	Forecast of PMM Costs, Market Revenues, and Generation					
	Description (Unit)	2017 PMM Portfolio	2014 PMM Portfolio	2009 PMM Portfolio	Pre-restruct. PMM Portfolio	Total
FPP1.	Forecast Costs (\$M)	\$20	\$40	\$35	\$55	\$150
FPP2.	Forecast Energy and A/S Market Revenues (\$M)	(\$15)	(\$30)	(\$23)	(\$44)	(\$111)
FPP3.	Forecast Net Costs (\$M) (FPP1 + FPP2)	\$5	\$10	\$13	\$11	\$39
FPP4.	Net Qualifying Capacity (MW)	50	160	125	175	510
FPP5.	Forecast RA Market Revenues (FPP4 x 0.5 x \$37.20/kW-Year) (\$M)	(\$1)	(\$3)	(\$2)	(\$3)	(\$9)
FPP6.	Forecast Above Market Costs (FPP3 + FPP5) (\$M)	\$4	\$7	\$10	\$8	\$29
	Actual PMM Costs, Market Revenues, and Generation					
	Description (Unit)	2017 PMM Portfolio	2014 PMM Portfolio	2009 PMM Portfolio	Pre-restruct. PMM Portfolio	Total
APP1.	Actual Costs (\$M)	\$17	\$45	\$42	\$60	\$164
APP2.	Actual Energy and A/S Market Revenues (\$M)	(\$15)	(\$31)	(\$35)	(\$50)	(\$131)
APP3.	Actual Net Costs (\$M)	\$2	\$14	\$7	\$10	\$33
APP4.	Net Qualifying Capacity (MW)	50	160	125	175	510
APP5.	Actual RA Market Revenues (see next page)	(\$1)	(\$4)	(\$3)	(\$4)	(\$12)
APP6.	Actual Above Market Costs (APP3 + APP5) (\$M)	\$1	\$10	\$4	\$6	\$21

- Above-market costs are defined as costs less energy and A/S revenues less RA market revenues (*i.e.*, net costs less RA market revenues)
- Similar to the GAM example, costs, energy and A/S market revenues, and RA market revenues are forecast annually in the ERRA proceeding; however, customers will only be responsible for the actual above-market costs of the PMM portfolio
 - RA market revenues are forecast in the following manner: Multiply the NQC of the portfolio by the CPUC RA Report Price and adjust based on a historical rate of sales factor (50% in this example for illustrative purposes)

7. PMM Portfolio RA Monetization

Determination of RA to be Monetized						
Eq.	Description (Unit)	2017 PMM Portfolio	2014 PMM Portfolio	2009 PMM Portfolio	Pre-restruct. PMM Portfolio	Total RA
1. APP4	Total Net Qualifying Capacity in Each Portfolio (MW)	50	160	125	175	510
2. PL3*(1)	RA to be Monetized on behalf of LSE X (MW)	-	-	-	11	11
3. PL4*(1)	RA to be Monetized on behalf of CCA Y	-	-	46	61	107
4. PL5*(1)	RA to be Monetized on behalf of CCA Z	-	47	23	30	101
5. (2)+(3)+(4)	Total RA to be Monetized through RA RFO	-	47	69	102	219
6. (5)*(6)	RA Allocated to Remaining Bundled Service	50	113	56	73	291

PMM RA Monetization Process ^{1/}						
Eq.	Description (Unit)	2017 PMM Portfolio	2014 PMM Portfolio	2009 PMM Portfolio	Pre-restruct. PMM Portfolio	Total
12. (10)	Total RA to be Monetized through PMM RA RFO (MW)	-	47	69	102	219
13. -\$24 x (12)	PMM RA RFO Proceeds (\$M)	\$0	(\$1)	(\$2)	(\$2)	(\$5)
14. (11)	RA Allocated to Remaining Bundled Service (MW)	50	113	56	73	291
15. -\$24 x (14)	Imputed Market Revenues from Bundled Service PMM RA (\$M)	(\$1)	(\$3)	(\$1)	(\$2)	(\$7)
16. (13)+(15)	Actual RA Market Revenues (\$M)	(\$1)	(\$4)	(\$3)	(\$4)	(\$12)

1/ Assumes a single RA product. Each RA product in the PMM portfolio will have an annual PMM RA value, which is defined as the total revenues received for a given RA product divided by the total quantity of the RA product offered in the PMM RA RFO

- Quantity of RA offered for sale is 219 MW (assumes no bundled service long position is offered)
- Assume 175 MW RA is sold (out of the 219 MW offered) and the total proceeds of the sale is equal to \$5.25M
 - Annual PMM RA value is determined to be \$24/kW-Year (\$5.25M/219 MW)
- Imputed market revenues from bundled service customers is equal to the RA that is allocated to them multiplied by the Annual PMM RA Value

8. Cost Recovery--True-Up Process^{1/}

True-Up - Costs and Market Revenues					
Eq.	Description (Unit)	2017 GAM & PMM Portfolios	2014 GAM & PMM Portfolios	2009 GAM & PMM Portfolios	Pre-restruct. GAM & PMM Portfolios
1.	FGP3 Forecast GAM Net Costs (\$M)	\$32	\$80	\$68	\$80
2.	FPP6 Forecast PMM Above-Market Costs (\$M)	\$4	\$7	\$10	\$8
3.	AGP3 Actual GAM Net Costs (\$M)	\$24	\$92	\$48	\$88
4.	APP6 Actual PMM Above-Market Costs (\$M)	\$1	\$10	\$4	\$6
5.	(3)+(4)-(1)-(2) (Over) /Under-Collection of Costs (\$M)	(\$11)	\$15	(\$26)	\$6
True-Up - Billed Revenue					
Eq.	Description (Unit)	2017 GAM & PMM Portfolios	2014 GAM & PMM Portfolios	2009 GAM & PMM Portfolios	Pre-restruct. GAM & PMM Portfolios
6.	FL1. Forecast Load Responsible for Portfolio (GWh)	4,000	5,500	9,000	10,000
7.	[(1)+(2)]/(4) GAM+PMM Rate for Vintaged Portfolio (\$/kWh)	\$0.00902	\$0.01582	\$0.00869	\$0.00880
8.	(6)*(7) Forecasted Billed Revenues (\$M)	\$36	\$87	\$78	\$88
9.	AL1. Actual Load Responsible for Each Portfolio (GWh)	4,200	5,800	9,000	10,200
10.	(9)*(7) Actual Billed Revenues Received from Customers (\$M)	\$38	\$92	\$78	\$90
11.	(8)-(10) (Over) /Under-Collection of Billed Revenues (\$M)	(\$2)	(\$5)	\$0	(\$2)
Total True-Up ^{2/}					
Eq.	Description (Unit)	2017 GAM & PMM Portfolios	2014 GAM & PMM Portfolios	2009 GAM & PMM Portfolios	Pre-restruct. GAM & PMM Portfolios
12.	(5)+(11) Total (Over) /Under Collectin in Bal. Acct (\$M)	(\$13)	\$10	(\$26)	\$4

1/ Reflects the recording of all GAM and PMM entries in a single account for simplicity.

2/ "True-Up" results can also be calculated by adding together lines 3 and 4 (total actual costs and market revenues) and subtracting line 10 (actual billed revenues). As described in the Cost Recovery section of direct testimony, only the actual costs, market revenues, and billed

- Actual costs and market revenues are compared to forecasted costs and market revenues to true-up costs and market revenues (lines 1-5)
- Recorded billed revenues (actual sales (AL1) times applicable rate) are compared to forecasted billed revenues (forecasted sales (FL1) times applicable rate) to true-up billed revenues received from customers
- Any over- or under-collections will be subtracted or added, respectively, to the following year's forecast net costs

9. Rate Design -- Residential Example

Residential Rates					
Eq.	Description (Unit)	2017 GAM & PMM Portfolios	2014 GAM & PMM Portfolios	2009 GAM & PMM Portfolios	Pre- restruct. GAM & PMM Portfolios
		a.	b.	c.	d.
1.	Residential Allocation Factor	45%	45%	45%	45%
2.	FGP3 + FPP6 Forecast PMM and GAM Revenue Requirement	\$36	\$87	\$78	\$88
3.	(1)*(2) Residential Share of Rev. Req.	\$16	\$39	\$35	\$40
4.	Forecast Residential Load Responsible (GWh)	1600	2200	3600	4000
5.	(3)/(4) Residential Rate by Vintaged Portfolio (\$/kWh)	\$0.01014	\$0.01780	\$0.00977	\$0.00990
Residential Rates by Vintage					
Eq.	Description (Unit)	Final Residential Rates by Vintage (\$/kWh)			
6.	5.d. Pre-restruct. Vintage	\$0.00990			
7.	(6)+5.c Vintage 2009	\$0.01967			
8.	(7)+5.b Vintage 2014	\$0.03747			
9.	(8)+5.a Vintage 2017	\$0.04762			

- Vintaged "revenue requirements" (*i.e.*, Forecast GAM net costs and forecast PMM above-market costs) will be allocated to rate groups using generation revenue allocators (as determined in each IOU's GRC Phase 2)
- Rate group-level revenue requirement will be divided by the rate group-level forecasted sales of customers responsible for the vintaged portfolio to determine the rate group-level rates
- As shown in lines 6-9, customers will pay a total rate that reflects their total obligation of all vintages prior to their departure year – e.g., Customer who departs in 2015 will pay total costs of Pre-Restructuring, 2009, and 2014 portfolios

**PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
APPENDIX F
JOINT UTILITIES RESOURCE LISTS AND SUMMARY TABLES**

**Appendix F1
PG&E Summary Table**

Line		Contract Type <i>(refer to Column M "RPS Eligibility" and Column O "Contract/Solicitation Type" of PG&E/SCE/SDG&E ALJ Standard Data Matrix)</i>	Allocation Proposal	Joint Utility Vintaging Proposal	Contract Capacity (MW) <i>(Maximum Contract Capacity or Nameplate Capacity for UOG)</i>	2019 Forecasted Total Costs (\$)	RECs
1	RPS + Large Hydro	RAM, QF Standard Contract (if RPS-eligible), QF CHP, ReMAT, BioMAT, AB 1969	GAM	Non-Vintaged	688	\$164,025,035	1,856,153
2		Irrigation District/ Water Agency, PPA – Bilateral, PPA – Solicitation, Shape + Firm Only, PV, UOG (if RPS-eligible or UOG), Conventional	GAM	Vintaged	10,783	\$2,711,667,629	28,303,369
3	Nuclear + Fossil + Energy Storage	QF Standard Contract (non-RPS)	PMM	Non-Vintaged	796	\$174,717,198	N/A
4		Tolling, UOG (non-RPS/non-hydro), Energy Storage					
5		RA, Tolling, UOG, Energy Storage	PMM	Vintaged	6,380	\$2,135,970,151	N/A

Notes:

- (1) UOG pumped storage is included with the GAM Vintage category
- (2) PG&E does not have any BioRAM contracts that are not eligible for TM-NBC, therefore no BioRAM resources are included in the table above
- (3) PG&E has one Resource Adequacy contract which expires after 2018, but PG&E is not the SC for the contract. Therefore, only costs associated with the RA contract are included in the table above, not the contract capacity
- (4) 2019 Total Costs was based on the ALJ Matrix data, provided to parties on March 2, 2018
- (5) REC estimates are based on the 2019 Forecasted Energy Volumes for RPS eligible resources from the ALJ Matrix data, provided to parties on March 2, 2018. 1 REC = 1 MWh of energy produced

Appendix F1
PG&E Green Allocation Methodology Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
1	GAM	01P219	USWND4_2_UNITS	Waste Management Renewable Energy	Biogas		Ongoing CTC - Pre-1996
2	GAM	01W119	NEWARK_1_QF	Donald R. Chenoweth	Wind		Ongoing CTC - Pre-1996
3	GAM	04H061QPA5	INDVLY_1_UNITS	Indian Valley Hydro	Small Hydro		PCIA - 2017
4	GAM	04H134	IGNACO_1_QF	John Neerhout Jr.	Small Hydro		Ongoing CTC - Pre-1996
5	GAM	04S142	IGNACO_1_QF	Villa Sorriso Solar	Solar PV	Fixed	Ongoing CTC - Pre-1996
6	GAM	06N168	MONTPH_7_UNITS	Solano Irrigation District (SID)	Small Hydro		Ongoing CTC - Pre-1996
7	GAM	06W146C	USWNRD_2_UNITS	EDF Renewable Windfarm V, Inc. (70 MW - C)	Wind		Ongoing CTC - Pre-1996
8	GAM	06W146D	USWNRD_2_UNITS	EDF Renewable Windfarm V, Inc. (70 MW - D)	Wind		Ongoing CTC - Pre-1996
9	GAM	08C078	MOSSLD_1_QF	City of Watsonville	Biogas		Ongoing CTC - Pre-1996
10	GAM	08H013	METCLF_1_QF	Santa Clara Valley Water Dist.	Small Hydro		Ongoing CTC - Pre-1996
11	GAM	10H007	TBLMTN_6_QF	Gansner Hydroelectric Project	Small Hydro		Ongoing CTC - Pre-1996
12	GAM	10H010	TBLMTN_6_QF	Five Bears Hydroelectric	Small Hydro		Ongoing CTC - Pre-1996
13	GAM	10H013	FORKBU_6_UNIT	Hypower, Inc.	Small Hydro		Ongoing CTC - Pre-1996
14	GAM	10H059	TBLMTN_6_QF	James B. Peter	Small Hydro		Ongoing CTC - Pre-1996
15	GAM	10H090	TBLMTN_6_QF	James Crane Hydro	Small Hydro		Ongoing CTC - Pre-1996
16	GAM	12H007	KANAKA_1_UNIT	STS Hydropower (Kanaka)	Small Hydro		Ongoing CTC - Pre-1996
17	GAM	12H010	DEADCK_1_UNIT	Deadwood Creek	Small Hydro		Ongoing CTC - Pre-1996
18	GAM	13H001QPA	COVERD_2_MCKHY1	El Dorado Hydro (Montgomery Creek)	Small Hydro		PCIA - 2017
19	GAM	13H013	COVERD_2_QFUNTS	Snow Mountain Hydro (Cove)	Small Hydro		Ongoing CTC - Pre-1996
20	GAM	13H016	SPBURN_7_SNOWMT	Snow Mountain Hydro (Burney Creek)	Small Hydro		Ongoing CTC - Pre-1996
21	GAM	13H024	OLSEN_2_UNIT	Olsen Power Partners	Small Hydro		Ongoing CTC - Pre-1996
22	GAM	13H035	VOLTA_7_QFUNTS	Snow Mountain Hydro (Ponderosa Bailey Creek)	Small Hydro		Ongoing CTC - Pre-1996
23	GAM	13H042	PIT5_7_QFUNTS	Nelson Creek Power Inc.	Small Hydro		Ongoing CTC - Pre-1996
24	GAM	13H047	MALCHQ_7_UNIT 1	Malacha Hydro	Small Hydro		Ongoing CTC - Pre-1996
25	GAM	13H120	TBLMTN_6_QF	Lofton Ranch	Small Hydro		Ongoing CTC - Pre-1996
26	GAM	13H123	CTNWDP_1_QF	Hat Creek Hereford Ranch	Small Hydro		Ongoing CTC - Pre-1996
27	GAM	13H125QPA	CLOVER_2_UNIT	Hydro Partners (Clover Creek)	Small Hydro		PCIA - 2016
28	GAM	13H130	TBLMTN_6_QF	Steve & Bonnie Tetrick	Small Hydro		Ongoing CTC - Pre-1996
29	GAM	15H005	HAYPRS_6_QFUNTS	EIF Haypress (Lwr)	Small Hydro		Ongoing CTC - Pre-1996
30	GAM	15H006	HAYPRS_6_QFUNTS	EIF Haypress (Mdl)	Small Hydro		Ongoing CTC - Pre-1996
31	GAM	15H012	RIOOSO_1_QF	Eagle Hydro	Small Hydro		Ongoing CTC - Pre-1996
32	GAM	15H068	RIOOSO_1_QF	Charcoal Ravine	Small Hydro		Ongoing CTC - Pre-1996
33	GAM	15H069	RIOOSO_1_QF	Swiss America	Small Hydro		Ongoing CTC - Pre-1996
34	GAM	15H072	RIOOSO_1_QF	Wright Ranch Hydroelectric	Small Hydro		Ongoing CTC - Pre-1996
35	GAM	16H030	TESLA_1_QF	Schaads Hydro	Small Hydro		Ongoing CTC - Pre-1996
36	GAM	16H033	TESLA_1_QF	Rock Creek Water District	Small Hydro		Ongoing CTC - Pre-1996
37	GAM	16P054	THMENG_1_UNIT 1	Thermal Energy Dev. Corp.	Biomass		Ongoing CTC - Pre-1996
38	GAM	18C001	CSTRVL_7_QFUNTS	Monterey One Water	Biogas		Ongoing CTC - Pre-1996
39	GAM	19H055	FTSWRD_7_QFUNTS	Tom Benninghoven	Small Hydro		Ongoing CTC - Pre-1996

Appendix F1
PG&E Green Allocation Methodology Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
40	GAM	25H073	RIOBRV_6_UNIT 1	Olcese Water District	Small Hydro		Ongoing CTC - Pre-1996
41	GAM	25H149	MCCALL_1_QF	Orange Cove Irrigation Dist.	Small Hydro		Ongoing CTC - Pre-1996
42	GAM	25H150	MCCALL_1_QF	Kings River Hydro Co.	Small Hydro		Ongoing CTC - Pre-1996
43	GAM	25W105	INTTRB_6_UNIT	International Turbine Research	Wind		Ongoing CTC - Pre-1996
44	GAM	33B103	FORBST_7_UNIT 1	SFWP Woodleaf/Forbestown	Large Hydro		PCIA - 2009
45	GAM	33B103	WDLEAF_7_UNIT 1	SFWP Woodleaf/Forbestown	Large Hydro		
46	GAM	33B110	CHICPK_7_UNIT 1	Nevada Irrigation District-Chicago Park	Large Hydro		PCIA - 2012
47	GAM	33R008	ETIWND_6_MWDETI	Etiwanda - Metropolitan Water District (MWD)	Small Hydro		Ongoing CTC - Pre-1996
48	GAM	33R013-AR	BRDSLD_2_MTZUMA	Montezuma Wind Energy Center	Wind		PCIA - 2010
49	GAM	33R015	BRDSLD_2_SHILO1	Shiloh I Wind Project	Wind		PCIA - 2005
50	GAM	33R016	ELNIDP_6_BIOMASS	EI Nido Biomass Facility	Biomass		PCIA - 2005
51	GAM	33R017	CHWCHL_1_BIOMAS	Chowchilla Biomass Facility	Biomass		PCIA - 2005
52	GAM	33R030	N/A	Klondike Wind Power III Project	Wind		PCIA - 2007
53	GAM	33R030TR1	N/A	Avangrid Renewables (S&F for Klondike III)	Wind		PCIA - 2007
54	GAM	33R032-AR	MENBIO_6_RENEW1	CalRenew-1	Solar PV	Fixed	PCIA - 2015
55	GAM	33R033	BRDSLD_2_SHILO2	Shiloh II Wind Project	Wind		PCIA - 2007
56	GAM	33R038	WADHAM_6_UNIT	Wadham Energy LP	Biomass		PCIA - 2008
57	GAM	33R045	RATL_PCG2_T004004	Rattlesnake Road Wind Power Project	Wind		PCIA - 2008
58	GAM	33R046AB	RIOOSO_1_QF	Buckeye Hydroelectric Project	Small Hydro		PCIA - 2008
59	GAM	33R047AB	N/A	Tunnel Hill Hydroelectric Project	Small Hydro		PCIA - 2008
60	GAM	33R052	CAVLSR_2_RSOLAR	High Plains Ranch II	Solar PV	1 Axis	PCIA - 2008
61	GAM	33R053AB	SISQUC_1_SMARIA	Santa Maria II	Biogas		PCIA - 2008
62	GAM	33R054	N/A	Klondike IIIA	Wind		PCIA - 2008
63	GAM	33R054TR1	N/A	Bonneville Power Administration (S&F for Klondike IIIa)	Wind		PCIA - 2008
64	GAM	33R056	TOPAZ_2_SOLAR	Topaz Solar Farm	Solar PV	Fixed	PCIA - 2008
65	GAM	33R058	HATRDG_2_WIND	Hatchet Ridge	Wind		PCIA - 2008
66	GAM	33R060	COPMTN_2_CM10	CM10	Solar PV	Fixed	PCIA - 2008
67	GAM	33R061AB	N/A	Castelanelli Bros. Biogas	Biogas		PCIA - 2009
68	GAM	33R063	IVANPA_1_UNIT1	Ivanpah Unit 1	Solar Thermal		PCIA - 2009
69	GAM	33R064	IVANPA_1_UNIT3	Ivanpah Unit 3	Solar Thermal		PCIA - 2009
70	GAM	33R073	AVSOLR_2_SOLAR	AV Solar Ranch One	Solar PV	Fixed & 1 Axis	PCIA - 2009
71	GAM	33R074	KELYRG_6_UNIT	SFWPA - Sly Creek / Kelly Ridge	Small Hydro		PCIA - 2009
72	GAM	33R075	BIOMAS_1_UNIT 1	Woodland Biomass	Biomass		PCIA - 2009
73	GAM	33R076AB	N/A	Ortigalita Power Company	Biomass		PCIA - 2009
74	GAM	33R077AB	HIGGNS_7_QFUNTS	Combie North	Small Hydro		PCIA - 2009
75	GAM	33R078	NEENCH_6_SOLAR	Alpine Solar Project	Solar PV	Fixed	PCIA - 2010
76	GAM	33R079	COPMTN_2_SOLAR1	CM48	Solar PV	Fixed	PCIA - 2009
77	GAM	33R082	MTNPOS_1_UNIT	Mt. Poso	Biomass		PCIA - 2009
78	GAM	33R083	N/A	Vantage Wind Energy Center	Wind		PCIA - 2009
79	GAM	33R084	AGUCAL_5_SOLAR1	Agua Caliente Solar Project	Solar PV	Fixed	PCIA - 2009
80	GAM	33R088	CAVLSR_2_BSOLAR	High Plains Ranch III	Solar PV	1 Axis	PCIA - 2010
81	GAM	33R089-AR	SANDLT_2_SUNITS	Mojave Solar Project	Solar Thermal		PCIA - 2009
82	GAM	33R090	GENESI_2_STG	Genesis Solar Energy Project	Solar Thermal		PCIA - 2009
83	GAM	33R093	ADLIN_1_UNITS	Geysers	Geothermal		PCIA - 2009
84	GAM	33R095	N/A	Powerex (S&F for Vantage Wind)	Wind		PCIA - 2009
85	GAM	33R096AB	HIGGNS_1_COMBIE	Combie South	Small Hydro		PCIA - 2009
86	GAM	33R099	COGNAT_1_UNIT	DTE Stockton	Biomass		PCIA - 2009
87	GAM	33R100	GRSCRK_6_BGCKWW	Big Creek Waterworks	Small Hydro		PCIA - 2009
88	GAM	33R101AB	HATLOS_6_LSCRK	Snow Mountain Hydro (Lost Creek 1)	Small Hydro		PCIA - 2009
89	GAM	33R102AB	HATLOS_6_LSCRK	Snow Mountain Hydro (Lost Creek 2)	Small Hydro		PCIA - 2009
90	GAM	33R107AB	N/A	SGE Site 1	Small Hydro		PCIA - 2009
91	GAM	33R108-AR	FTSWRD_6_TRFORK	Norman Ross Burgess - Three Forks Water Power Project	Small Hydro		PCIA - 2010
92	GAM	33R118	ALPSLR_1_SPSSLR	Alpaugh 50	Solar PV	1 Axis	PCIA - 2010
93	GAM	33R119	ALPSLR_1_NTHSLR	Alpaugh North	Solar PV	1 Axis	PCIA - 2010
94	GAM	33R120	ATWELL_1_SOLAR	Atwell Island	Solar PV	Fixed	PCIA - 2010
95	GAM	33R121	WAUKNA_1_SOLAR	Corcoran	Solar PV	1 Axis	PCIA - 2010
96	GAM	33R122	OLIVEP_1_SOLAR	White River	Solar PV	1 Axis	PCIA - 2010
97	GAM	33R123	AVENAL_6_AVPARK	Avenal Park	Solar PV	Fixed	PCIA - 2009
98	GAM	33R124	AVENAL_6_SUNCTY	Sun City Project	Solar PV	Fixed	PCIA - 2009
99	GAM	33R125	AVENAL_6_SANDDG	Sand Drag	Solar PV	Fixed	PCIA - 2009
100	GAM	33R127AB	N/A	T&G Hydro	Small Hydro		PCIA - 2010
101	GAM	33R132	SUNSHN_2_LNDFL	Sunshine Landfill	Biogas		PCIA - 2010
102	GAM	33R133	PEABDY_2_LNDFL1	Potrero Hills Landfill	Biogas		PCIA - 2010
103	GAM	33R135	N/A	Halkirk I Wind Project	Wind		PCIA - 2010

Appendix F1
PG&E Green Allocation Methodology Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
104	GAM	33R136	N/A	Blackspring Ridge IA	Wind		PCIA - 2010
105	GAM	33R137	N/A	Blackspring Ridge IB	Wind		PCIA - 2010
106	GAM	33R138	DSRTSN_2_SOLAR1	Desert Center Solar Farm	Solar PV	Fixed	PCIA - 2010
107	GAM	33R139AB	POTTER_7_VECINO	Vecino Vineyards	Small Hydro		PCIA - 2010
108	GAM	33R140	ELDORO_7_UNIT 1	El Dorado Irrigation District	Small Hydro		PCIA - 2010
109	GAM	33R141AB	RIOOSO_1_QF	NID Scotts Flat	Small Hydro		PCIA - 2010
110	GAM	33R142	BRODIE_2_WIND	Coram Brodie	Wind		PCIA - 2010
111	GAM	33R144	MSOLAR_2_SOLAR1	Mesquite Solar 1	Solar PV	Fixed	PCIA - 2010
112	GAM	33R145	BRDSLD_2_SHLO3A	Shiloh III Wind Project	Wind		PCIA - 2010
113	GAM	33R146AB	N/A	Blake's Landing	Biogas		PCIA - 2010
114	GAM	33R148	MNDOTA_1_SOLAR1	North Star Solar	Solar PV	1 Axis	PCIA - 2010
115	GAM	33R151	USWPJR_2_UNITS	Vasco Wind Energy Center	Wind		PCIA - 2010
116	GAM	33R152	BRDSLD_2_MTZUM2	Montezuma II Wind Energy Center	Wind		PCIA - 2010
117	GAM	33R154AB	WFRESN_1_SOLAR	La Joya Del Sol #1	Solar PV	1 Axis	PCIA - 2011
118	GAM	33R160	KANSAS_6_SOLAR	Kansas South	Solar PV	1 Axis	PCIA - 2011
119	GAM	33R161	JAYNE_6_WLSLR	Westlands Solar Farms	Solar PV	1 Axis	PCIA - 2011
120	GAM	33R162	ARVINN_6_ORION1	Orion Solar	Solar PV	1 Axis	PCIA - 2011
121	GAM	33R163	JAWBNE_2_NSRWWD	North Sky River Energy Center	Wind		PCIA - 2011
122	GAM	33R164AB	TIWSSL_6_SOLAR	Nickel 1	Solar PV	Fixed	PCIA - 2011
123	GAM	33R165AB	PEORIA_1_SOLAR	Fresh Air Energy IV, LLC - Sonora 1	Solar PV	1 Axis	PCIA - 2011
124	GAM	33R166	COPMT2_2_SOLAR2	Copper Mountain Solar 2	Solar PV	Fixed	PCIA - 2011
125	GAM	33R167	BRDSLD_2_SHLO3B	Shiloh IV	Wind		PCIA - 2011
126	GAM	33R169AB	N/A	Cox Ave Hydro	Small Hydro		PCIA - 2011
127	GAM	33R171AB	REEDLY_6_SOLAR	Terzian	Solar PV	1 Axis	PCIA - 2011
128	GAM	33R174AB	ELCAP_1_SOLAR	Helton	Solar PV	1 Axis	PCIA - 2011
129	GAM	33R177AB	N/A	Christensen	Solar PV	1 Axis	PCIA - 2011
130	GAM	33R178AB	N/A	Rogers	Solar PV	1 Axis	PCIA - 2011
131	GAM	33R180AB	N/A	Fitzjarrell	Solar PV	1 Axis	PCIA - 2011
132	GAM	33R184AB	LOCKFD_1_BEARCK	Bear Creek Solar Project	Solar PV	1 Axis	PCIA - 2011
133	GAM	33R185AB	SANLOB_1_LNDFIL	Toro SLO Landfill	Biogas		PCIA - 2011
134	GAM	33R187AB	N/A	Alvares 2041	Solar PV	1 Axis	PCIA - 2011
135	GAM	33R188AB	N/A	Stroing	Solar PV	1 Axis	PCIA - 2011
136	GAM	33R190AB	N/A	Cotton	Solar PV	1 Axis	PCIA - 2011
137	GAM	33R191AB	N/A	Jarvis	Solar PV	1 Axis	PCIA - 2011
138	GAM	33R195AB	N/A	Jardine	Solar PV	1 Axis	PCIA - 2011
139	GAM	33R197AB	N/A	Smotherman	Solar PV	1 Axis	PCIA - 2011
140	GAM	33R198AB	N/A	Buzzelle	Solar PV	1 Axis	PCIA - 2011
141	GAM	33R201AB	LIVEOK_6_SOLAR	Harris	Solar PV	1 Axis	PCIA - 2011
142	GAM	33R202AB	N/A	Scherz	Solar PV	1 Axis	PCIA - 2011
143	GAM	33R204AB	N/A	Hill	Solar PV	1 Axis	PCIA - 2011
144	GAM	33R205AB	COCOSB_6_SOLAR	Oakley Executive Solar Project	Solar PV	Fixed	PCIA - 2011
145	GAM	33R206AB	PIT1_6_FRIVRA	Ignite Solar Holdings 1 - Fall River Mills Solar Project A	Solar PV	1 Axis	PCIA - 2011
146	GAM	33R207AB	MCARTH_6_FRIVRB	Ignite Solar Holdings 1 - Fall River Mills Solar Project B	Solar PV	1 Axis	PCIA - 2011
147	GAM	33R210AB	HOLSTR_1_SOLAR	Enerparc CA1	Solar PV	Fixed	PCIA - 2011
148	GAM	33R214AB	KNGBRG_1_KBSLR1	Kingsburg 1	Solar PV	Fixed	PCIA - 2011
149	GAM	33R215AB	KNGBRG_1_KBSLR2	Kingsburg 2	Solar PV	Fixed	PCIA - 2011
150	GAM	33R216AB	N/A	Kingsburg 3	Solar PV	Fixed	PCIA - 2011
151	GAM	33R230AB	WRGHTP_7_AMENGY	Wolfen Bypass	Small Hydro		PCIA - 2011
152	GAM	33R231AB	WRGHTP_7_AMENGY	San Luis Bypass	Small Hydro		PCIA - 2011
153	GAM	33R232AB	LOCKFD_1_KSOLAR	Kettleman Solar Project	Solar PV	1 Axis	PCIA - 2011
154	GAM	33R233AB	TMPLTN_2_SOLAR	Vintner Solar Project	Solar PV	1 Axis	PCIA - 2011
155	GAM	33R237AB	CLOVDL_1_SOLAR	Cloverdale Solar FSEC 1	Solar PV	Fixed	PCIA - 2011
156	GAM	33R240AB	TBLMTN_6_QF	South Sutter Water	Small Hydro		PCIA - 2011
157	GAM	33R243	CONTRL_1_CASAD3	Mammoth G3	Geothermal		PCIA - 2012
158	GAM	33R244	ACACIA_6_SOLAR	West Antelope	Solar PV	1 Axis	PCIA - 2012
159	GAM	33R245	PLAINV_6_BSOLAR	Western Antelope Blue Sky Ranch A	Solar PV	1 Axis	PCIA - 2012
160	GAM	33R246	NZWIND_6_CALWWD	Wind Resource I	Wind		PCIA - 2012
161	GAM	33R247AB	TESLA_1_QF	Calaveras PUD-Hydro #1	Small Hydro		PCIA - 2012
162	GAM	33R248AB	TESLA_1_QF	Calaveras PUD-Hydro #2	Small Hydro		PCIA - 2012
163	GAM	33R249AB	TESLA_1_QF	Calaveras PUD-Hydro #3	Small Hydro		PCIA - 2012
164	GAM	33R250AB	BANGOR_6_HYDRO	Browns Valley Irrigation District	Small Hydro		PCIA - 2012
165	GAM	33R251AB	TESLA_1_QF	Jackson Valley Irrigation District	Small Hydro		PCIA - 2012
166	GAM	33R253	BOWMN_6_HYDRO	Nevada Irrigation District (NID) - Dutch Flat / Rollins / Bowman	Small Hydro		PCIA - 2012
167	GAM	33R254	SPIAND_1_ANDSN2	SPI Biomass Portfolio	Biomass		PCIA - 2012
168	GAM	33R259	HENRTS_1_SOLAR	Henrietta Solar	Solar PV	1 Axis	PCIA - 2012
169	GAM	33R260AB	DAVIS_1_SOLAR1	Yolo County Grassland #3	Solar PV	1 Axis	PCIA - 2012
170	GAM	33R261AB	DAVIS_1_SOLAR2	Yolo County Grassland #4	Solar PV	1 Axis	PCIA - 2012
171	GAM	33R267	KNTSTH_6_SOLAR	Kent South	Solar PV	1 Axis	PCIA - 2012
172	GAM	33R272	SKERN_6_SOLAR1	Algonquin SKIC 20 Solar	Solar PV	1 Axis	PCIA - 2012
173	GAM	33R274	OLIVEP_1_SOLAR2	White River Solar 2	Solar PV	1 Axis	PCIA - 2012
174	GAM	33R275	CONTRL_1_CASAD1	Mammoth G1	Geothermal		PCIA - 2012
175	GAM	33R276	ARBWD_6_QF	Wind Resource II	Wind		PCIA - 2012

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176	GAM	33R278	CUMBIA_1_SOLAR	Columbia Solar Energy	Solar PV	1 Axis	PCIA - 2012
177	GAM	33R279	VICTOR_1_SOLAR2	Alamo Solar, LLC	Solar PV	1 Axis	PCIA - 2012
178	GAM	33R280	CORCAN_1_SOLAR1	CID Solar PV Project	Solar PV	1 Axis	PCIA - 2012
179	GAM	33R281AB	HOLSTR_1_SOLAR2	Ecos Energy - Hollister Project	Solar PV	1 Axis	PCIA - 2012
180	GAM	33R282AB	MERCED_1_SOLAR2	Ecos Energy - Merced Solar Project	Solar PV	1 Axis	PCIA - 2012
181	GAM	33R283	OLDRIV_6_BIOGAS	ABEC Bidart-Old River	Biogas		PCIA - 2012
182	GAM	33R284	TUPMAN_1_BIOGAS	ABEC Bidart-Stockdale	Biogas		PCIA - 2012
183	GAM	33R285AB	MERCED_1_SOLAR1	Ecos Energy - Mission Solar	Solar PV	1 Axis	PCIA - 2013
184	GAM	33R288	OLDRIV_6_SOLAR	Old River One	Solar PV	1 Axis	PCIA - 2013
185	GAM	33R291	7STDRD_1_SOLAR1	Shafter Solar	Solar PV	1 Axis	PCIA - 2013
186	GAM	33R292	MRLSDS_6_SOLAR1	Morelos del Sol	Solar PV	1 Axis	PCIA - 2013
187	GAM	33R294AB	N/A	APEX 646-460	Solar PV	1 Axis	PCIA - 2013
188	GAM	33R295AB	KERMAN_6_SOLAR1	Fresno Cogeneration - Fresno Solar South	Solar PV	1 Axis	PCIA - 2013
189	GAM	33R296AB	KERMAN_6_SOLAR2	Fresno Cogeneration - Fresno Solar West	Solar PV	1 Axis	PCIA - 2013
190	GAM	33R300AB	N/A	Greenlight - Sirius Solar Project	Solar PV	1 Axis	PCIA - 2013
191	GAM	33R301AB	N/A	PCWA- Lincoln Metering and Hydroelectric Station	Small Hydro		PCIA - 2013
192	GAM	33R302AB	TX-ELK_6_SOLAR1	Greenlight - Castor Solar Project	Solar PV	1 Axis	PCIA - 2013
193	GAM	33R304AB	N/A	GreenLight- Peacock Solar Project	Solar PV	1 Axis	PCIA - 2013
194	GAM	33R307AB	HENRTA_6_SOLAR1	imMOD0- Lemoore 1	Solar PV	Fixed	PCIA - 2013
195	GAM	33R315AB	BKRFLD_2_SOLAR1	Bakersfield 111	Solar PV	1 Axis	PCIA - 2013
196	GAM	33R316AB	N/A	2154 Foote	Solar PV	1 Axis	PCIA - 2013
197	GAM	33R318AB	N/A	2192 Ramirez	Solar PV	1 Axis	PCIA - 2013
198	GAM	33R322	RTREE_2_WIND2	Rising Tree Wind Farm II	Wind		PCIA - 2013
199	GAM	33R323	KEKAWK_6_UNIT	Kekawaka Creek Hydroelectric Facility	Small Hydro		PCIA - 2013
200	GAM	33R324	LAMONT_1_SOLAR3	Woodmere Solar Farm	Solar PV	1 Axis	PCIA - 2013
201	GAM	33R329	FLOWD2_2_FPLWWD	Diablo Winds	Wind		PCIA - 2013
202	GAM	33R333RM	VOLTA_6_DIGHYD	Digger Creek Hydro	Small Hydro		PCIA - 2013
203	GAM	33R334RM	N/A	Cedar Flat	Small Hydro		PCIA - 2013
204	GAM	33R335RM	FULTON_1_QF	Clover Leaf	Small Hydro		PCIA - 2013
205	GAM	33R336RM	FULTON_1_QF	McFadden Hydroelectric Facility	Small Hydro		PCIA - 2013
206	GAM	33R337RM	CSTOGA_6_LNDFIL	Clover Flat LFG	Biogas		PCIA - 2013
207	GAM	33R338RM	S_RITA_6_SOLAR1	NDP1	Solar PV	Fixed	PCIA - 2013
208	GAM	33R339RM	PUTHCR_1_SOLAR1	Putah Creek Solar Farms	Solar PV	1 Axis	PCIA - 2013
209	GAM	33R340RM	ALLGNY_6_HYDRO1	Salmon Creek Hydroelectric Project	Small Hydro		PCIA - 2013
210	GAM	33R341RM	BRDGLV_7_BAKER	Baker Creek Hydroelectric Project	Small Hydro		PCIA - 2013
211	GAM	33R342RM	CEDRCK_6_UNIT	Water Wheel Ranch	Small Hydro		PCIA - 2013
212	GAM	33R347RM	LOWGAP_1_SUPHR	Mill Sulphur Creek Project	Small Hydro		PCIA - 2014
213	GAM	33R350RM	ORLND_6_SOLAR1	2184 Gruber	Solar PV	1 Axis	PCIA - 2014
214	GAM	33R353RM	N/A	2105 Hart	Solar PV	1 Axis	PCIA - 2014
215	GAM	33R355RM	STOREY_7_MDRCHW	Site 980 (Madera Chowchilla)	Small Hydro		PCIA - 2014
216	GAM	33R356RM	STOREY_2_MDRCH2	Site 1174 (Madera Chowchilla)	Small Hydro		PCIA - 2014
217	GAM	33R357RM	STOREY_2_MDRCH4	Site 1923 (Madera Chowchilla)	Small Hydro		PCIA - 2014
218	GAM	33R358RM	STOREY_2_MDRCH3	Site 1302 (Madera Chowchilla)	Small Hydro		PCIA - 2014
219	GAM	33R362	GLDFGR_6_SOLAR2	Portal Ridge Solar C Project	Solar PV	1 Axis	PCIA - 2015
220	GAM	33R363	OROLOM_1_SOLAR1	CED Oro Loma Solar Project A	Solar PV	1 Axis	PCIA - 2015
221	GAM	33R364	SEGS_1_SR2SL2	Sunray 2	Solar PV	1 Axis	PCIA - 2015
222	GAM	33R365	AVENAL_6_AVSLR1	Avenal Solar Project A	Solar PV	1 Axis	PCIA - 2015
223	GAM	33R366	OROLOM_1_SOLAR2	CED Oro Loma Solar Project B	Solar PV	1 Axis	PCIA - 2015
224	GAM	33R368	AVENAL_6_AVSLR2	Avenal Solar Project B	Solar PV	1 Axis	PCIA - 2015
225	GAM	33R373RM	PLACVL_1_RCKCRE	Rock Creek	Small Hydro		PCIA - 2015
226	GAM	33R374	FRESHW_1_SOLAR1	CED Corcoran Solar 3	Solar PV	1 Axis	PCIA - 2015
227	GAM	33R375	PAIGES_6_SOLAR	Westside Solar	Solar PV	1 Axis	PCIA - 2015
228	GAM	33R376	GIFFEN_6_SOLAR1	Aspiration Solar G	Solar PV	1 Axis	PCIA - 2015
229	GAM	33R377RM	BUCKCK_2_HYDRO	Lassen Station Hydro	Small Hydro		PCIA - 2015
230	GAM	33R378RM	N/A	Goose Valley Hydro	Small Hydro		PCIA - 2015
231	GAM	33R397RM	N/A	2207 Ritchie	Solar PV	1 Axis	PCIA - 2016
232	GAM	33R401RM	DAIRLD_1_MD1SL1	Madera 1	Solar PV	1 Axis	PCIA - 2016
233	GAM	33R402RM	TBLMTN_6_QF	Mini Hydro	Small Hydro		PCIA - 2016
234	GAM	33R403RM	LOWGAP_7_QFUNTS	Matthews Dam Hydro	Small Hydro		PCIA - 2016
235	GAM	33R405BIO	DIXNLD_1_LNDFL	Zero Waste Energy Development Company	Biogas		PCIA - 2016
236	GAM	33R407RM	TBLMTN_6_QF	Arbuckle Mountain Hydro	Small Hydro		PCIA - 2017
237	GAM	33R408RM	PIT5_7_QFUNTS	Grasshopper Flat	Small Hydro		PCIA - 2017
238	GAM	33R409RM	RNDMTN_2_SLSPHY1	Silver Springs	Small Hydro		PCIA - 2017
239	GAM	33R415RM	TBD	Eagle Solar	Solar PV	1 Axis	PCIA - 2017
240	GAM	33R416BIO	TBD	San Luis Obispo AD	Biogas		PCIA - 2017
241	GAM	33R417RM	VOLTA_7_QFUNTS	Sutters Mill Hydroelectric Plant	Small Hydro		PCIA - 2017
242	GAM	33R418RM	FROGTN_1_UTICAA	Angels Powerhouse	Small Hydro		PCIA - 2017
243	GAM	33R419	TBD	RE Gaskell West 3	Solar PV	1 Axis	PCIA - 2017
244	GAM	33R420	TBD	RE Gaskell West 4	Solar PV	1 Axis	PCIA - 2017
245	GAM	33R421	TBD	RE Gaskell West 5	Solar PV	1 Axis	PCIA - 2017
246	GAM	33R422BIO	GANSO_1_WSTBM1	ABEC #2 LLC	Biogas		PCIA - 2017

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247	GAM	33R423BIO	OLDRIV_6_LKVBM1	ABEC #3 LLC	Biogas		PCIA - 2017
248	GAM	33R424BIO	OLDRIV_6_CESDBM	ABEC #4 LLC	Biogas		PCIA - 2017
249	GAM	26R001X	N/A	PG&E AT&T Park Solar Arrays	UOG - Solar	Fixed	Other
250	GAM	26R002X	N/A	PG&E SF Service Center Solar Array 1	UOG - Solar	Fixed	Other
251	GAM	26R003X	N/A	PG&E SF Service Center Solar Array 2	UOG - Solar	Fixed	Other
252	GAM	PGEALTA	BNNIEN_7_ALTAPH	PGE Alta	UOG - Hydro		Pre-2002
253	GAM	PGEALCH1	BALCHS_7_UNIT 1	PGE Balch 1	UOG - Hydro		Pre-2002
254	GAM	PGEALCH2	BALCHS_7_UNIT 2	PGE Balch 2	UOG - Hydro		Pre-2002
255	GAM	PGEALCH2	BALCHS_7_UNIT 3	PGE Balch 2	UOG - Hydro		Pre-2002
256	GAM	PGEBELDEN	BELDEN_7_UNIT 1	PGE Belden	UOG - Hydro		Pre-2002
257	GAM	PGEBUCKSCREEK	BUCKCK_7_PL1X2	PGE Bucks Creek	UOG - Hydro		Pre-2002
258	GAM	PGE BUTTVL	BUTTVL_7_UNIT 1	PGE Butt Valley	UOG - Hydro		Pre-2002
259	GAM	PGE CARIBOU1	CARBOU_7_UNIT 1	PGE Caribou 1	UOG - Hydro		Pre-2002
260	GAM	PGE CARIBOU1	CARBOU_7_PL2X3	PGE Caribou 1	UOG - Hydro		Pre-2002
261	GAM	PGE CARIBOU2	CARBOU_7_PL4X5	PGE Caribou 2	UOG - Hydro		Pre-2002
262	GAM	PGE CENTERVILLE	CNTRVL_6_UNIT	PGE Centerville	UOG - Hydro		Pre-2002
263	GAM	PGE CHILIBAR	N/A	PGE Chili Bar	UOG - Hydro		Pre-2002
264	GAM	PGE COLCANYN	N/A	PGE Coal Canyon	UOG - Hydro		Pre-2002
265	GAM	PGE COLEMAN	COLEMN_2_UNIT	PGE Coleman	UOG - Hydro		Pre-2002
266	GAM	PGE COWCREEK	COWCRK_2_UNIT	PGE Cow Creek	UOG - Hydro		Pre-2002
267	GAM	PGE CRANE VALLEY	CRNEVL_6_CRNVA	PGE Crane Valley	UOG - Hydro		Pre-2002
268	GAM	PGE CRESTA	CRESTA_7_PL1X2	PGE Cresta	UOG - Hydro		Pre-2002
269	GAM	PGE DEERCREEK	DEERC_6_UNIT 1	PGE Deer Creek	UOG - Hydro		Pre-2002
270	GAM	PGE DESABLA	DSABLA_7_UNIT	PGE De Sabla	UOG - Hydro		Pre-2002
271	GAM	PGE DRUM1	DRUM_7_PL1X2	PGE Drum 1	UOG - Hydro		Pre-2002
272	GAM	PGE DRUM1	DRUM_7_PL3X4	PGE Drum 1	UOG - Hydro		Pre-2002
273	GAM	PGE DRUM2	DRUM_7_UNIT 5	PGE Drum 2	UOG - Hydro		Pre-2002
274	GAM	PGE DUTCHFLAT1	DUTCH1_7_UNIT 1	PGE Dutch Flat 1	UOG - Hydro		Pre-2002
275	GAM	PGE ELECTRA	ELECTR_7_PL1X3	PGE Electra	UOG - Hydro		Pre-2002
276	GAM	PGE HAAS	HAASPH_7_PL1X2	PGE Haas	UOG - Hydro		Pre-2002
277	GAM	PGE HALSEY	HALSEY_6_UNIT	PGE Halsey	UOG - Hydro		Pre-2002
278	GAM	PGE HAMILTON	HMLTBR_6_UNITS	PGE Hamilton Branch	UOG - Hydro		Pre-2002
279	GAM	PGE HAT1	HATCR1_7_UNIT	PGE Hat 1	UOG - Hydro		Pre-2002
280	GAM	PGE HAT2	HATCR2_7_UNIT	PGE Hat 2	UOG - Hydro		Pre-2002
281	GAM	PGE HELMSGEN	HELMGP_7_UNIT 1	HelmsGen	UOG - Hydro		Pre-2002
282	GAM	PGE HELMSGEN	HELMGP_7_UNIT 2	HelmsGen	UOG - Hydro		Pre-2002
283	GAM	PGE HELMSGEN	HELMGP_7_UNIT 3	HelmsGen	UOG - Hydro		Pre-2002
284	GAM	PGE HELMSPUMP	N/A	HelmsPump	UOG - Hydro		Pre-2002
285	GAM	PGE INSKIP	INSKIP_2_UNIT	PGE Inskip	UOG - Hydro		Pre-2002
286	GAM	PGE JBBBLACK	BLACK_7_UNIT 1	PGE J. B. Black	UOG - Hydro		Pre-2002
287	GAM	PGE JBBBLACK	BLACK_7_UNIT 2	PGE J. B. Black	UOG - Hydro		Pre-2002
288	GAM	PGE KERCKHOFF1	KERKH1_7_UNIT 3	PGE Kerckhoff 1	UOG - Hydro		Pre-2002
289	GAM	PGE KERCKHOFF1	KERKH1_7_UNIT 1	PGE Kerckhoff 1	UOG - Hydro		Pre-2002
290	GAM	PGE KERCKHOFF2	KERKH2_7_UNIT 1	PGE Kerckhoff 2	UOG - Hydro		Pre-2002
291	GAM	PGE KERN	KRNCNY_6_UNIT	PGE Kern Canyon	UOG - Hydro		Pre-2002
292	GAM	PGE KILARC	KILARC_2_UNIT 1	PGE Kilarc	UOG - Hydro		Pre-2002
293	GAM	PGE KINGSRIVER	KINGRV_7_UNIT 1	PGE Kings River	UOG - Hydro		Pre-2002
294	GAM	PGE LIMESADL	CLRKRD_6_LIMESD	PGE Lime Saddle	UOG - Hydro		Pre-2002
295	GAM	PGE NARROWS1	NAROW1_2_UNIT	PGE Narrows 1	UOG - Hydro		Pre-2002
296	GAM	PGE NEWCASTLE	NWCSTL_7_UNIT 1	PGE Newcastle	UOG - Hydro		Pre-2002
297	GAM	PGE OAKFLAT	BUCKCK_7_OAKFLT	PGE Oak Flat	UOG - Hydro		Pre-2002
298	GAM	PGE PHOENIX	PHOENX_1_UNIT	PGEoenix	UOG - Hydro		Pre-2002
299	GAM	PGE PIT1	PIT1_7_UNIT 1	PGE Pit 1	UOG - Hydro		Pre-2002
300	GAM	PGE PIT1	PIT1_7_UNIT 2	PGE Pit 1	UOG - Hydro		Pre-2002
301	GAM	PGE PIT3	PIT3_7_PL1X3	PGE Pit 3	UOG - Hydro		Pre-2002
302	GAM	PGE PIT4	PIT4_7_PL1X2	PGE Pit 4	UOG - Hydro		Pre-2002
303	GAM	PGE PIT5	PIT5_7_PL1X2	PGE Pit 5	UOG - Hydro		Pre-2002
304	GAM	PGE PIT5	PIT5_7_PL3X4	PGE Pit 5	UOG - Hydro		Pre-2002
305	GAM	PGE PIT6	PIT6_7_UNIT 1	PGE Pit 6	UOG - Hydro		Pre-2002
306	GAM	PGE PIT6	PIT6_7_UNIT 2	PGE Pit 6	UOG - Hydro		Pre-2002
307	GAM	PGE PIT7	PIT7_7_UNIT 1	PGE Pit 7	UOG - Hydro		Pre-2002
308	GAM	PGE PIT7	PIT7_7_UNIT 2	PGE Pit 7	UOG - Hydro		Pre-2002
309	GAM	PGE POTTER	POTTER_6_UNITS	PGE Potter Valley	UOG - Hydro		Pre-2002
310	GAM	PGE POW	POEPH_7_UNIT 1	PGE Poe	UOG - Hydro		Pre-2002
311	GAM	PGE POW	POEPH_7_UNIT 2	PGE Poe	UOG - Hydro		Pre-2002
312	GAM	PGE PVUOG_PY1_FP	SCHNDR_1_FIVPTS	PGE Five Points	UOG - Solar	Fixed	2010
313	GAM	PGE PVUOG_PY1_ST	STROUD_6_SOLAR	PGE Stroud	UOG - Solar	Fixed	2010
314	GAM	PGE PVUOG_PY1_WS	SCHNDR_1_WSTSD	PGE Westside	UOG - Solar	Fixed	2010
315	GAM	PGE PVUOG_PY2_CA	CANTUA_1_SOLAR	PGE Cantua	UOG - Solar	Fixed	2011
316	GAM	PGE PVUOG_PY2_GI	GIFFEN_6_SOLAR	PGE Giffen	UOG - Solar	Fixed	2011
317	GAM	PGE PVUOG_PY2_HU	HURON_6_SOLAR	PGE Huron	UOG - Solar	Fixed	2011

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318	GAM	PGEPUOG_PY3_GA	GATES_2_SOLAR	PGE Gates	UOG - Solar	Fixed	2012
319	GAM	PGEPUOG_PY3_GU	GUERNS_6_SOLAR	PGE Guernsey	UOG - Solar	1 Axis	2012
320	GAM	PGEPUOG_PY3_WG	GATES_2_WSOLAR	PGE West Gates	UOG - Solar	Fixed	2012
321	GAM	PGEROCKCREEK	RCKCRK_7_UNIT 1	PGE Rock Creek	UOG - Hydro		Pre-2002
322	GAM	PGEROCKCREEK	RCKCRK_7_UNIT 2	PGE Rock Creek	UOG - Hydro		Pre-2002
323	GAM	PGEROCKCREEKRPS	N/A	PGE Rock Creek RPS	UOG - Hydro		Pre-2002
324	GAM	PGESALTSPRINGS1	SALTSP_7_UNITS	PGE Salt Springs 1	UOG - Hydro		Pre-2002
325	GAM	PGESALTSPRINGS2	SALTSP_7_UNITS	PGE Salt Springs 2	UOG - Hydro		Pre-2002
326	GAM	PGESANJOAQU1	WISHON_6_UNITS	PGE San Joaquin 1A	UOG - Hydro		Pre-2002
327	GAM	PGESANJOAQU2	CRNEVL_6_SJQN 2	PGE San Joaquin 2	UOG - Hydro		Pre-2002
328	GAM	PGESANJOAQU3	CRNEVL_6_SJQN 3	PGE San Joaquin 3	UOG - Hydro		Pre-2002
329	GAM	PGESOUTH	SOUTH_2_UNIT	PGE South	UOG - Hydro		Pre-2002
330	GAM	PGESPAULDING1	SPAULD_6_UNIT12	PGE Spaulding 1	UOG - Hydro		Pre-2002
331	GAM	PGESPAULDING2	SPAULD_6_UNIT12	PGE Spaulding 2	UOG - Hydro		Pre-2002
332	GAM	PGESPAULDING3	SPAULD_6_UNIT 3	PGE Spaulding 3	UOG - Hydro		Pre-2002
333	GAM	PGESPRINGGAP	SPRGAP_1_UNIT 1	PGE Spring Gap	UOG - Hydro		Pre-2002
334	GAM	PGESTANISLAUS	STANIS_7_UNIT 1	PGE Stanislaus	UOG - Hydro		Pre-2002
335	GAM	PGETIGERCREEK	TIGRCK_7_UNITS	PGE Tiger Creek	UOG - Hydro		Pre-2002
336	GAM	PGETOADTOWN	TOADTW_6_UNIT	PGE Toadtown	UOG - Hydro		Pre-2002
337	GAM	PGETULE	SPRGVL_2_TULE	PGE Tule River	UOG - Hydro		Pre-2002
338	GAM	PGEVACADIXON	VACADX_1_SOLAR	Vaca-Dixon Solar (PG&E)	UOG - Solar	Fixed	2010
339	GAM	PGEVOLTA1	VOLTA_2_UNIT 1	PGE Volta 1	UOG - Hydro		Pre-2002
340	GAM	PGEVOLTA2	VOLTA_2_UNIT 2	PGE Volta 2	UOG - Hydro		Pre-2002
341	GAM	PGEWESTPOINT	WESTPT_2_UNIT	PGE West Point	UOG - Hydro		Pre-2002
342	GAM	PGEWISE1	WISE_1_UNIT 1	PGE Wise 1	UOG - Hydro		Pre-2002
343	GAM	PGEWISE2	WISE_1_UNIT 2	PGE Wise 2	UOG - Hydro		Pre-2002
344	GAM	PGEWISHON	WISHON_6_UNITS	PGE A_G Wishon	UOG - Hydro		Pre-2002
345	GAM	2011 RPS RFO	various	various	Solar PV	1 Axis	PCIA - 2012
346	GAM	2012 RPS RFO	various	various	Solar PV	1 Axis	PCIA - 2013
347	GAM	GTSR Program	various	various	Solar PV	various	PCIA - 2016
348	GAM	PV and RAM	various	various	Solar PV	1 Axis	PCIA - 2016

Note: Biomass resources, Burney Forest Products and Wheelabrator Shasta are not PCIA eligible as of April 2018 and have been moved to a TM memo account. Therefore, they are not included in the table above.

Appendix F1
PG&E Portfolio Monetization Mechanism Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
1	PMM	01C045	CROKET_7_UNIT	Crockett Cogeneration	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
2	PMM	01C061	UNOCAL_1_UNITS	Phillips 66	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
3	PMM	01C089	CLRMTH_1_QF	Stanford Energy Group	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
4	PMM	01C108	STAUFF_1_UNIT	Eco Services Operations LLC	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
5	PMM	01C199	CLRMTH_1_QF	Satellite Senior Homes	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
6	PMM	01C201	NEWARK_1_QF	Hayward Area Rec & Park Dist.	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
7	PMM	01C245	CLRMTH_1_QF	Orinda Senior Village	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
8	PMM	02C041	SRINTL_6_UNIT	SRI International	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
9	PMM	02C047	MISSIX_1_QF	Arden Wood Benevolent Assoc.	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
10	PMM	02C048	MISSIX_1_QF	1080 Chestnut Corp.	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
11	PMM	02C058	MISSIX_1_QF	Nihonmachi Terrace	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
12	PMM	04C130	IGNACO_1_QF	Greater Vallejo Recreation District	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
13	PMM	04C140	FULTON_1_QF	Airport Club	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
14	PMM	08C071	PSWEET_7_QFUNTS	County Of Santa Cruz (Water St. Jail)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
15	PMM	08C097	MLPTAS_7_QFUNTS	City of Milpitas	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
16	PMM	12C020	GRNLF1_1_UNITS	Greenleaf Unit #1	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
17	PMM	12C021	GRNLF2_1_UNIT	Greenleaf Unit #2	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
18	PMM	12C026	YUBACT_1_SUNSWT	Yuba City Cogen Partners	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
19	PMM	12C085	TBLMTN_6_QF	Yuba City Racquet Club	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
20	PMM	18C006	BASICE_2_UNITS	Calpine King City Cogen	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
21	PMM	24B001FHP	TXMCKT_6_UNIT	Chevron U.S.A. - McKittrick	Natural Gas Combustion Turbine		PCIA - 2015
22	PMM	25C002	CHEVCD_6_UNIT	Chevron U.S.A. (Taft/Cadet)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
23	PMM	25C003	CHEVCY_1_UNIT	Chevron U.S.A. (Cymric)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
24	PMM	25C055	CHEVCO_6_UNIT 1	Chevron U.S.A. (Coalinga)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
25	PMM	25C092	AGRICO_7_UNIT	Fresno Cogeneration Partners, LP	Natural Gas Combustion Turbine		Non-CTC - Pre-2002
26	PMM	25C164	KINGCO_1_KINGBR	PE - KES Kingsburg	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
27	PMM	25C246	VEDDER_1_SEKERN	Chevron U.S.A. (SE Kern River)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
28	PMM	25C248	DISCOV_1_CHEVRN	Chevron U.S.A. (Eastridge)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
29	PMM	25C249	CHEVCO_6_UNIT 2	Aera Energy (Coalinga)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
30	PMM	25C293	FELLOW_7_QFUNTS	Sentinel Peak Resources (Dome) (FKA Freeport McMoran Oil and Gas)	Natural Gas Combustion Turbine		Ongoing CTC - Pre-1996
31	PMM	33B074	PNCHPP_1_PL1X2	Midway Peaking	Natural Gas Combustion Turbine		PCIA - 2006
32	PMM	33B075	RUSCTY_2_UNITS	Calpine Russell City Energy Center	Combined Cycle		PCIA - 2008
33	PMM	33B076	PNCHEG_2_PL1X4	Panoche Energy Center	Natural Gas Combustion Turbine		PCIA - 2006
34	PMM	33B092	KELSO_2_UNITS	Mariposa	Natural Gas Combustion Turbine		PCIA - 2009
35	PMM	33B097	LMBEPK_2_UNITA2	Calpine Peakers Replacement & Extension	Natural Gas Combustion Turbine		PCIA - 2009
36	PMM	33B099	LECEF_1_UNITS	Calpine Los Esteros Upgrade	Combined Cycle		PCIA - 2009
37	PMM	33B101	SCHLTE_1_PL1X3	AltaGas Tracy Repowering PPA	Combined Cycle		PCIA - 2009

Appendix F1
PG&E Portfolio Monetization Mechanism Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
38	PMM	33B108	GWFPWR_1_UNITS	Alta Gas San Joaquin Hanford Facility	Natural Gas Combustion Turbine		PCIA - 2011
39	PMM	33B109	HENRTA_6_UNITA1	GWF Henrietta	Natural Gas Combustion Turbine		PCIA - 2011
40	PMM	40S001	TBD	Golden Hills Energy Storage	Lithium Ion		PCIA - 2015
41	PMM	40S004	TBD	Henrietta D Energy Storage	Zinc / Air Battery		PCIA - 2015
42	PMM	PGECOLUSA	COLUSA_2_PL1X3	Colusa	UOG - Fossil		2008
43	PMM	PGEDIABLO1	DIABLO_7_UNIT 1	Diablo 1	UOG - Nuclear		Pre-2002
44	PMM	PGEDIABLO2	DIABLO_7_UNIT 2	Diablo 2	UOG - Nuclear		Pre-2002
45	PMM	PGEFUELCELL_Bloom	DALYCT_1_FCELL	Bloom	UOG - Fuel Cell		2010
46	PMM	PGEFUELCELL_UTC1	DALYCT_1_FCELL	UTC_Unit_1	UOG - Fuel Cell		2010
47	PMM	PGEFUELCELL_UTC2	CASTVL_2_FCELL	UTC_Unit_2	UOG - Fuel Cell		2010
48	PMM	PGEGATEWAY	GATWAY_2_PL1X3	Gateway	UOG - Fossil		2006
49	PMM	PGEHUMBOLDT	HUMBPP_1_UNITS3	NewHumboldt	UOG - Fossil		2009
50	PMM	PGEHUMBOLDT	HUMBPP_6_UNITS	Humboldt Bay Generating Station 1	UOG - Fossil		2009
51	PMM	UOG_HBGS_FUEL	N/A	HBGS Distillate Fuel Cost	UOG - Fossil		2009
52	PMM	33B229P01	SGREGY_6_SANGER	Algonquin Power Sanger LLC	N/A		PCIA - 2016

Appendix F2
SCE Summary Table

Line		Contract Type (refer to Column “ <u>RPS Eligibility</u> ” and Column “ <u>Contract Type/Solicitation</u> ” of R1706026 SCE Standard Data Matrix)	Allocation Proposal	Joint Utility Vintaging Proposal	Contract Capacity (MW) (Maximum Contract Capacity or Nameplate Capacity for UOG)	2019 Forecasted Total Costs (\$000) ¹	2019 Forecasted Total RECs ²
1	RPS + Large Hydro	Standard Offer Contract (NEG, SO1, SO2 SO3, ISO4, QF-SOC), Tariff (Re-MAT, CREST, WATER,), RAM (RAM5, RAM20), Technology Mandate (PVSC, PV10)	GAM	Non-Vintaged	1,995	313,705	4,170,322
2		PPA (ERR, RSC5, RSC20, Exchange, Bilateral, RA RFO), UOG	GAM	Vintaged	11,601	2,220,393	22,445,550
3	Fossil, Nuclear + Energy Storage	Standard Offer Contract (NEG, SO1, SO2, SO3, ISO4)	PMM	Non-Vintaged	311	40,070	N/A
4		PPA (All-Source RFO, Bilateral, RA RFO), UOG	PMM	Vintaged	8,186	519,894	N/A

¹ 2019 Forecasted Total Costs was based on the R1706026 SCE Standard Data Matrix, provided to parties on March 2, 2018

² REC estimates are based on the 2019 Forecasted Energy Volumes for RPS eligible resources from the R1706026 SCE Standard Data Matrix, provided to parties on March 2, 2018. 1 REC = 1 MWh of energy produced

Appendix F2
SCE Green Allocation Methodology Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
1	GAM	1007	SPRGVL_2_QF	Royal Farms	Biomass	other	CTC Eligible
2	GAM	1009	MESAS_2_QF	L.A. Co. Sanitation Dist CSD 2610	Biomass	other	CTC Eligible
3	GAM	1038	RAMON_2_SCEDYN	Desert View Power, Inc.	Biomass	other	CTC Eligible
4	GAM	1087	SPRGVL_2_QF	Royal Farms #2	Biomass	other	CTC Eligible
5	GAM	1099	CHINO_2_QF	Inland Empire Utilities Agency	Biomass	other	CTC Eligible
6	GAM	1210	GOLETA_6_TAJIGS	MM Tajiguas Energy LLC	Biomass	other	2009
7	GAM	1221	SAUGUS_2_TOLAND	Ventura Regional Sanitation District	Biomass	other	2009
8	GAM	1225	VALLEY_7_BADLND	Riverside County Waste Management Dept	Biomass	other	2009
9	GAM	1238	SNMALF_6_UNITS	Republic Services of Sonoma County Energy Producers, Inc.	Biomass	other	2015
10	GAM	2804	ELLIS_2_QF	Orange County Sanitation District	Cogeneration	other	2009
11	GAM	3004	RAMON_2_SCEDYN	Del Ranch Company (Niland #2)	Geothermal	other	CTC Eligible
12	GAM	3009	RAMON_2_SCEDYN	Elmore Company	Geothermal	other	CTC Eligible
13	GAM	3011	CONTRL_1_OXBOW	Terra-Gen Dixie Valley, LLC	Geothermal	other	CTC Eligible
14	GAM	3021	RAMON_2_SCEDYN	Second Imperial Geothermal Co.	Geothermal	other	CTC Eligible
15	GAM	3025	RAMON_2_SCEDYN	Salton Sea Power Generation Co #3	Geothermal	other	CTC Eligible
16	GAM	3026	RAMON_2_SCEDYN	CE Leathers Company	Geothermal	other	CTC Eligible
17	GAM	3027	CONTRL_1_QF	Mammoth Pacific L P II (MP2)	Geothermal	other	CTC Eligible
18	GAM	3028	RAMON_2_SCEDYN	Salton Sea Power Generation Co #2	Geothermal	other	CTC Eligible
19	GAM	3030	BLM_2_UNITS	Coso Energy Developers	Geothermal	other	CTC Eligible
20	GAM	3050	RAMON_2_SCEDYN	Salton Sea Power Generation Co #4	Geothermal	other	CTC Eligible
21	GAM	3103	NAVYII_2_UNITS, CALGEN_1_UNITS	Coso Clean Power, LLC	Geothermal	other	2009
22	GAM	3108	RAMON_2_SCEDYN	ORNI 18, LLC	Geothermal	other	2009
23	GAM	4004	CONTRL_1_QF	Hi Head Hydro Incorporated	Small Hydro	other	CTC Eligible
24	GAM	4008	CONTRL_1_QF	Desert Power Company	Small Hydro	other	CTC Eligible
25	GAM	4014	VISTA_6_QF	San Bernardino MWD	Small Hydro	other	CTC Eligible
26	GAM	4026	DEVERS_1_QF	Desert Water Agency (Snow Creek)	Small Hydro	other	CTC Eligible
27	GAM	4029	RHONDO_2_QF	LA CO Flood Control District	Small Hydro	other	CTC Eligible
28	GAM	4030	VESTAL_6_QF	Daniel M. Bates	Small Hydro	other	CTC Eligible

Appendix F2
SCE Green Allocation Methodology Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
29	GAM	4034	VESTAL_6_QF	Central Hydroelectric Corp.	Small Hydro	other	CTC Eligible
30	GAM	4039	RECTOR_2_QF	Kaweah River Power Authority	Small Hydro	other	CTC Eligible
31	GAM	4051	GOLETA_2_QF	Montecito Water District	Small Hydro	other	CTC Eligible
32	GAM	4054	BARRE_2_QF	City of Santa Ana	Small Hydro	other	CTC Eligible
33	GAM	4058	SAUGUS_6_QF	United Water Conservation District	Small Hydro	other	CTC Eligible
34	GAM	4071	CONTRL_1_QF	Deep Springs College	Small Hydro	other	CTC Eligible
35	GAM	4076	SNCLRA_6_QF	Camrosa County Water District	Small Hydro	other	CTC Eligible
36	GAM	4100	ETIWND_2_QF	San Bernardino MWD (Unit 3)	Small Hydro	other	CTC Eligible
37	GAM	4202	N/A	Bishop Tungsten Development, LLC	Small Hydro	other	2012
38	GAM	4205	N/A	California Water Service Company	Small Hydro	other	2013
39	GAM	4206	N/A	Isabella Fish Flow Hydroelec Proj LLC	Small Hydro	other	2012
40	GAM	4207	PADUA_6_QF	Monte Vista Water District	Small Hydro	other	2012
41	GAM	4208	SPRGVL_2_TULESC	Lower Tule River Irrigation District	Small Hydro	other	2012
42	GAM	4209	N/A	White Mountain Ranch, LLC	Small Hydro	other	2012
43	GAM	4210	MOORPK_6_QF	Calleguas MWD - Conejos	Small Hydro	other	2012
44	GAM	4213	TKOPWR_6_HYDRO	TKO Power, LLC (South Bear Creek)	Small Hydro	other	2015
45	GAM	4216	N/A	City of Santa Barbara	Small Hydro	other	2013
46	GAM	4222	GOLETA_2_QF	Goleta Water District	Small Hydro	other	2013
47	GAM	4225	GARNET_2_HYDRO	Desert Water Agency	Small Hydro	other	2015
48	GAM	4252	SNCLRA_2_SPRHYD	Calleguas Municipal Water District	Small Hydro	other	2013
49	GAM	4255	SAUGUS_6_QF	Calleguas Municipal Water District	Small Hydro	other	2013
50	GAM	4316	CHINO_2_QF	WALNUT VALLEY WATER DISTRICT	Small Hydro	other	2016
51	GAM	4352	MOORPK_6_QF	Calleguas MWD (Santa Rosa)	Small Hydro	other	2015
52	GAM	5019	KRAMER_1_SEGS37	Luz Solar Partners Ltd. V	Solar	other	CTC Eligible
53	GAM	5020	KRAMER_1_SEGS37	Luz Solar Partners Ltd. VI	Solar	other	CTC Eligible
54	GAM	5021	KRAMER_1_SEGS37	Luz Solar Partners Ltd. VII	Solar	other	CTC Eligible
55	GAM	5050	KRAMER_2_SEGS89	Luz Solar Partners Ltd. VIII	Solar	other	CTC Eligible

Appendix F2
SCE Green Allocation Methodology Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
56	GAM	5051	KRAMER_2_SEGS89	Luz Solar Partners Ltd. IX	Solar	other	CTC Eligible
57	GAM	5207	BLYTHE_1_SOLAR1	NRG Solar Blythe LLC	Solar	fixed solar	2009
58	GAM	5208	IVANPA_1_UNIT2	Solar Partners I, LLC	Solar	other	2009
59	GAM	5217	DSRTSN_2_SOLAR2	Desert Sunlight 250, LLC	Solar	fixed solar	2009
60	GAM	5218	DSRTSL_2_SOLAR1	Desert Stateline LLC	Solar	fixed solar	2009
61	GAM	5240	GLDTWN_6_SOLAR	RE Rio Grande, LLC	Solar	tracking solar	2009
62	GAM	5247	RSMSLR_6_SOLAR2	RE Rosamond Two LLC	Solar	tracking solar	2009
63	GAM	5249	VICTOR_1_SOLAR1	RE Victor Phelan Solar One LLC	Solar	tracking solar	2009
64	GAM	5252	GLOW_6_SOLAR	TA High Desert LLC	Solar	tracking solar	2009
65	GAM	5277	N/A	Temescal Canyon RV, LLC	Solar	fixed solar	2011
66	GAM	5283	WAUKNA_1_SOLAR2	CED Corcoran Solar 2, LLC	Solar	tracking solar	2011
67	GAM	5284	PRIMM_2_SOLAR1	Silver State Solar Power South, LLC	Solar	tracking solar	2011
68	GAM	5297	LAMONT_1_SOLAR1	Regulus Solar, LLC	Solar	tracking solar	2010
69	GAM	5298	ADOBEE_1_SOLAR	Adobe Solar, LLC	Solar	tracking solar	2010
70	GAM	5369	DELAMO_2_SOLRC1	Golden Springs Develop Co., LLC (Bldg C)	Solar	fixed solar	2010
71	GAM	5370	DELAMO_2_SOLRD	Golden Springs Develop. Co, LLC (Bldg D)	Solar	fixed solar	2010
72	GAM	5371	WALNUT_2_SOLAR	Industry Metrolink PV 1, LLC	Solar	fixed solar	2010
73	GAM	5394	CHINO_2_SASOLR	SS San Antonio West LLC	Solar	fixed solar	2010
74	GAM	5396	LITLRK_6_SEPV01	SEPV1, LLC	Solar	tracking solar	2010
75	GAM	5397	DEVERS_1_SEPV05	SEPV2, LLC	Solar	tracking solar	2010
76	GAM	5408	BUCKWD_1_NPALM1	North Palm Springs Investments, LLC 5408	Solar	tracking solar	2010
77	GAM	5411	GARNET_1_SOLAR	North Palm Springs Investments, LLC 5411	Solar	tracking solar	2010
78	GAM	5412	SLSTR1_2_SOLAR1	Solar Star California XIX, LLC	Solar	tracking solar	2010
79	GAM	5413	SLSTR2_2_SOLAR2	Solar Star California XX, LLC	Solar	tracking solar	2011
80	GAM	5415	SLST13_2_SOLAR1	Solar Star California XIII, LLC	Solar	tracking solar	2011
81	GAM	5434	N/A	One Miracle Property, LLC	Solar	fixed solar	2011
82	GAM	5439	VICTOR_1_CREST	Powhatan Solar Power Generation Station	Solar	tracking solar	2011
83	GAM	5440	VICTOR_1_CREST	Otoe Solar Power Generation Station	Solar	fixed solar	2011

Appendix F2
SCE Green Allocation Methodology Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
84	GAM	5442	VICTOR_1_CREST	Navajo Solar Power Generation Station 1	Solar	tracking solar	2011
85	GAM	5447	DELSUR_6_DRYFRB	FTS Master Tenant 1, LLC (LDFRB)	Solar	tracking solar	2010
86	GAM	5459	VICTOR_1_VDRYFA	Victor Dry Farm Ranch A, LLC	Solar	fixed solar	2010
87	GAM	5460	VICTOR_1_VDRYFB	Victor Dry Farm Ranch B, LLC	Solar	fixed solar	2010
88	GAM	5463	PLAINV_6_SOLARC	Central Antelope Dry Ranch C, LLC	Solar	fixed solar	2010
89	GAM	5468	PLAINV_6_NLRSR1	North Lancaster Ranch, LLC	Solar	fixed solar	2010
90	GAM	5469	PLAINV_6_SOLAR3	Sierra Solar Greenworks, LLC	Solar	fixed solar	2010
91	GAM	5476	DELSUR_6_SOLAR1	American Solar Greenworks, LLC	Solar	tracking solar	2010
92	GAM	5477	VICTOR_1_EXSLRA	Expressway Solar A, LLC	Solar	fixed solar	2012
93	GAM	5478	VICTOR_1_EXSLRB	FTS Master Tenant 1 (ESB)	Solar	fixed solar	2012
94	GAM	5485	VESTAL_2_SOLAR1	Nicolis, LLC	Solar	tracking solar	2010
95	GAM	5488	GARNET_1_SOLAR2	Garnet Solar Pwr Gen Station 1, LLC	Solar	tracking solar	2010
96	GAM	5490	VESTAL_2_SOLAR2	Tropico, LLC	Solar	tracking solar	2010
97	GAM	5493	GLDTWN_6_COLUM3	RE Columbia 3 LLC	Solar	tracking solar	2010
98	GAM	5494	BLKCRK_2_SOLAR1	McCoy Solar, LLC	Solar	tracking solar	2011
99	GAM	5496	RDWAY_1_CREST	Industry Solar Power Generation Station	Solar	tracking solar	2011
100	GAM	5509	N/A	Newberry Solar 1 LLC	Solar	tracking solar	2011
101	GAM	5510	N/A	USDA Forest Service San Dimas Technology	Solar	fixed solar	2011
102	GAM	5512	LITLRK_6_SOLAR4	Little Rock - Pham Solar, LLC	Solar	tracking solar	2014
103	GAM	5517	N/A	L-8 Solar Project, LLC	Solar	fixed solar	2011
104	GAM	5518	N/A	Heliocentric, LLC	Solar	fixed solar	2011
105	GAM	5520	OASIS_6_CREST	Treen Solar 1, LLC	Solar	tracking solar	2012
106	GAM	5521	OASIS_6_CREST	Treen Solar 2, LLC	Solar	tracking solar	2012
107	GAM	5522	OASIS_6_CREST	Annie Power, LLC	Solar	tracking solar	2012
108	GAM	5523	OASIS_6_CREST	J Ram Solar 1, LLC	Solar	tracking solar	2012
109	GAM	5524	OASIS_6_CREST	J Ram Solar 2, LLC	Solar	tracking solar	2012
110	GAM	5525	OASIS_6_CREST	J Ram Solar 3, LLC	Solar	tracking solar	2012
111	GAM	5536	DELSUR_6_CREST	Sandra Energy, LLC	Solar	tracking solar	2012
112	GAM	5539	OASIS_6_CREST	Dreamer Solar, LLC	Solar	tracking solar	2012
113	GAM	5541	VICTOR_1_CREST	Drew Energy, LLC	Solar	tracking solar	2012
114	GAM	5549	SHUTLE_6_CREST	Voyager Solar 1, LLC	Solar	tracking solar	2012
115	GAM	5550	SHUTLE_6_CREST	Voyager Solar 2, LLC	Solar	tracking solar	2012
116	GAM	5551	SHUTLE_6_CREST	Voyager Solar 3, LLC	Solar	tracking solar	2012
117	GAM	5559	OASIS_6_CREST	Becca Solar, LLC	Solar	tracking solar	2012
118	GAM	5560	RDWAY_1_CREST	Toro Power 1, LLC	Solar	tracking solar	2012

Appendix F2
SCE Green Allocation Methodology Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
119	GAM	5561	RDWAY_1_CREST	Toro Power 2, LLC	Solar	tracking solar	2012
120	GAM	5562	N/A	Radiance Solar 5 LLC	Solar	fixed solar	2012
121	GAM	5563	N/A	Radiance Solar 4 LLC	Solar	fixed solar	2012
122	GAM	5568	DEVERS_1_SOLAR1	Highlander Solar 1	Solar	tracking solar	2012
123	GAM	5569	DEVERS_1_SOLAR2	Highlander Solar 2	Solar	tracking solar	2012
124	GAM	5570	DELSUR_6_CREST	Summer Solar C2, LLC	Solar	fixed solar	2012
125	GAM	5571	DELSUR_6_CREST	Summer Solar D2, LLC	Solar	fixed solar	2012
126	GAM	5572	DELSUR_6_CREST	Summer Solar A2 LLC	Solar	fixed solar	2012
127	GAM	5573	DELSUR_6_CREST	Summer Solar B2, LLC	Solar	fixed solar	2012
128	GAM	5574	DELSUR_6_CREST	FTS Master Tenant 1 LLC (Rodeo Solar C2)	Solar	fixed solar	2012
129	GAM	5578	DELSUR_6_CREST	FTS Master Tenant 1 LLC (Rodeo Solar D2)	Solar	fixed solar	2012
130	GAM	5585	VICTOR_1_CREST	Expressway Solar C2, LLC	Solar	fixed solar	2012
131	GAM	5587	SPRGVL_2_CREST	Tulare PV I, LLC (Exeter 1)	Solar	fixed solar	2012
132	GAM	5588	SPRGVL_2_CREST	Tulare PV I, LLC (Exeter 2)	Solar	fixed solar	2012
133	GAM	5589	SPRGVL_2_CREST	Tulare PV I, LLC (Exeter 3)	Solar	fixed solar	2012
134	GAM	5590	SPRGVL_2_CREST	Tulare PV I, LLC (Lindsay 1)	Solar	fixed solar	2012
135	GAM	5591	SPRGVL_2_CREST	Tulare PV I, LLC (Lindsay 3)	Solar	fixed solar	2012
136	GAM	5592	SPRGVL_2_CREST	Tulare PV I, LLC (Lindsay 4)	Solar	fixed solar	2012
137	GAM	5597	RECTOR_2_CREST	Tulare PV I, LLC (Ivanhoe 1)	Solar	fixed solar	2012
138	GAM	5598	RECTOR_2_CREST	Tulare PV I, LLC (Ivanhoe 2)	Solar	fixed solar	2012
139	GAM	5599	RECTOR_2_CREST	Tulare PV I, LLC (Ivanhoe 3)	Solar	fixed solar	2012
140	GAM	5600	SPRGVL_2_CREST	Tulare PV I, LLC (Porterville 1)	Solar	fixed solar	2012
141	GAM	5601	SPRGVL_2_CREST	Tulare PV I, LLC (Porterville 2)	Solar	fixed solar	2012
142	GAM	5602	SPRGVL_2_CREST	Tulare PV I, LLC (Porterville 5)	Solar	fixed solar	2012
143	GAM	5603	RECTOR_2_CREST	Sequoia PV 1, LLC (Tulare 1)	Solar	fixed solar	2012
144	GAM	5604	RECTOR_2_CREST	Sequoia PV 1, LLC (Tulare 2)	Solar	fixed solar	2012
145	GAM	5605	LNCSTR_6_CREST	Kettering 1	Solar	fixed solar	2012
146	GAM	5606	LNCSTR_6_CREST	Kettering 2	Solar	fixed solar	2012
147	GAM	5607	LNCSTR_6_CREST	Division 1	Solar	fixed solar	2012
148	GAM	5609	LNCSTR_6_CREST	Division 2	Solar	fixed solar	2012
149	GAM	5610	LNCSTR_6_CREST	Division 3	Solar	fixed solar	2012

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Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
150	GAM	5617	N/A	Ecos Energy, LLC (Diamond Valley Solar)	Solar	fixed solar	2013
151	GAM	5618	N/A	Marinos Ventures LLC	Solar	tracking solar	2012
152	GAM	5619	RECTOR_2_CREST	Sequoia PV 1 LLC (Farmersville 1)	Solar	fixed solar	2012
153	GAM	5620	RECTOR_2_CREST	Sequoia PV 1 LLC (Farmersville 2)	Solar	fixed solar	2012
154	GAM	5621	VICTOR_1_LVSLR1	Lone Valley Solar Park I, LLC	Solar	tracking solar	2012
155	GAM	5622	VICTOR_1_LVSLR2	Lone Valley Solar Park II, LLC	Solar	tracking solar	2012
156	GAM	5626	ARVINN_6_ORION2	Orion Solar II, LLC	Solar	tracking solar	2012
157	GAM	5627	TWISL_6_SOLAR1	Coronal Lost Hills, LLC	Solar	tracking solar	2012
158	GAM	5628	VEGA_6_SOLAR1	Vega Solar, LLC	Solar	tracking solar	2012
159	GAM	5629	LITLRK_6_SOLAR2	FTS Master Tenant 2, LLC (SEPV18)	Solar	tracking solar	2014
160	GAM	5630	ADMEST_6_SOLAR	RE Adams East LLC	Solar	tracking solar	2012
161	GAM	5631	RECTOR_2_CREST	Sequoia PV 1 LLC (Farmersville 3)	Solar	fixed solar	2012
162	GAM	5645	SPRGVL_2_CREST	Sequoia PV 3 LLC (Porterville 6)	Solar	fixed solar	2012
163	GAM	5646	SPRGVL_2_CREST	Sequoia PV 3 LLC (Porterville 7)	Solar	fixed solar	2012
164	GAM	5649	CORONS_2_SOLAR	SunE W12DG-C, LLC	Solar	fixed solar	2012
165	GAM	5650	VICTOR_1_SLRHES	DG Solar Lessee, LLC - Hesperia	Solar	fixed solar	2012
166	GAM	5652	ETIWND_2_CHMPNE	California PV Energy, LLC	Solar	fixed solar	2012
167	GAM	5653	CHINO_2_JURUPA	California PV Energy, LLC	Solar	fixed solar	2012
168	GAM	5656	VICTOR_1_CREST	DG Solar Lessee, LLC (Duncan Rd North)	Solar	tracking solar	2012
169	GAM	5657	VICTOR_1_CREST	DG Solar Lessee, LLC (Duncan Rd South)	Solar	tracking solar	2012
170	GAM	5659	VICTOR_1_CREST	Victor Mesa Linda B2 LLC	Solar	fixed solar	2012
171	GAM	5660	VICTOR_1_CREST	Victor Mesa Linda C2 LLC	Solar	fixed solar	2012
172	GAM	5661	VICTOR_1_CREST	Victor Mesa Linda D2 LLC	Solar	fixed solar	2012
173	GAM	5662	VICTOR_1_CREST	Victor Mesa Linda E2 LLC	Solar	fixed solar	2012
174	GAM	5667	RECTOR_2_CREST	Sequoia PV 2, LLC (Hanford 1)	Solar	fixed solar	2012
175	GAM	5668	RECTOR_2_CREST	Sequoia PV 2, LLC (Hanford 2)	Solar	fixed solar	2012
176	GAM	5675	DEVERS_2_DHSPG1	CES DHS Solar, LLC (DHS Solar 1)	Solar	tracking solar	2012
177	GAM	5676	DEVERS_2_DHSPG2	CES DHS Solar, LLC (DHS Solar 2)	Solar	tracking solar	2012

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Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
178	GAM	5690	VICTOR_1_CREST	DG Solar Lessee, LLC (White Rd N)	Solar	tracking solar	2013
179	GAM	5691	VICTOR_1_CREST	DG Solar Lessee, LLC (White Rd C)	Solar	tracking solar	2013
180	GAM	5692	VICTOR_1_CREST	Mitchell Solar, LLC	Solar	tracking solar	2012
181	GAM	5693	VICTOR_1_CREST	Rudy Solar, LLC	Solar	tracking solar	2012
182	GAM	5694	VICTOR_1_CREST	Madelyn Solar, LLC	Solar	tracking solar	2012
183	GAM	5695	VICTOR_1_CREST	DG Solar Lessee, LLC (White Rd S)	Solar	tracking solar	2013
184	GAM	5700	RDWAY_1_CREST	CF SBC Master Tenant One LLC (Adelanto 1)	Solar	fixed solar	2013
185	GAM	5701	RDWAY_1_CREST	CF SBC Master Tenant One LLC (Adelanto 2)	Solar	fixed solar	2013
186	GAM	5702	N/A	Venable Solar, LLC (North)	Solar	fixed solar	2013
187	GAM	5703	N/A	Venable Solar, LLC (South)	Solar	fixed solar	2013
188	GAM	5715	OASIS_6_CREST	PsomasFMG Lancaster Solar CREST, LLC	Solar	tracking solar	2013
189	GAM	5716	OASIS_6_CREST	PsomasFMG Lancaster Solar CREST, LLC	Solar	tracking solar	2013
190	GAM	5740	OASIS_6_SOLAR1	Morgan Lancaster I, LLC	Solar	tracking solar	2013
191	GAM	5745	PMDLET_6_SOLAR1	SEPV Palmdale East, LLC	Solar	tracking solar	2013
192	GAM	5753	PMPJCK_1_SOLAR1	Pumpjack Solar I, LLC	Solar	tracking solar	2013
193	GAM	5755	CATLNA_2_SOLAR2	Catalina Solar 2, LLC	Solar	tracking solar	2013
194	GAM	5756	MNDOTA_1_SOLAR2	Citizen Solar B, LLC	Solar	fixed solar	2013
195	GAM	5757	WLDWD_1_SOLAR1	Wildwood Solar I, LLC	Solar	tracking solar	2013
196	GAM	5758	VICTOR_1_SOLAR4	Adelanto Solar, LLC	Solar	tracking solar	2013
197	GAM	5759	LAMONT_1_SOLAR5	67RK 8 ME LLC	Solar	tracking solar	2013
198	GAM	5767	LITLRK_6_SOLAR1	Lancaster Little Rock C LLC	Solar	fixed solar	2013
199	GAM	5774	OASIS_6_SOLAR2	NRG Solar Oasis LLC	Solar	tracking solar	2013
200	GAM	5777	ATWEL2_1_SOLAR1	CED Atwell Island West, LLC	Solar	tracking solar	2013
201	GAM	5778	MOJAVW_2_SOLAR	SEPV Mojave West, LLC	Solar	tracking solar	2013
202	GAM	5781	ADERA_1_SOLAR1	ADERA SOLAR, LLC	Solar	fixed solar	2013
203	GAM	5785	VALLEY_5_SOLAR1	Kona Solar LLC	Solar	fixed solar	2014
204	GAM	5786	CHINO_2_SOLAR2	Kona Solar LLC	Solar	fixed solar	2014
205	GAM	5787	PADUA_2_SOLAR1	Kona Solar LLC	Solar	fixed solar	2014
206	GAM	5791	ETIWND_2_SOLAR2	SunE Solar XVI Lessor, LLC	Solar	fixed solar	2014
207	GAM	5795	ETIWND_2_SOLAR1	DG Solar Lessee II, LLC - E Philadelphia	Solar	fixed solar	2014

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Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
208	GAM	5796	CENTER_2_SOLAR1	DG Solar Lessee II, LLC - Pico Rivera	Solar	fixed solar	2014
209	GAM	5799	DELAMO_2_SOLAR1	Golden Springs Develop. Co, LLC (Bldg H)	Solar	fixed solar	2014
210	GAM	5800	DELAMO_2_SOLAR2	Golden Springs Develop. Co, LLC (Bldg M)	Solar	fixed solar	2014
211	GAM	5801	VICTOR_1_SOLAR3	Adelanto Solar II, LLC	Solar	tracking solar	2014
212	GAM	5822	TORTLA_1_SOLAR	Longboat Solar, LLC	Solar	tracking solar	2014
213	GAM	5823	SKERN_6_SOLAR2	Algonquin SKIC 10 Solar, LLC	Solar	tracking solar	2014
214	GAM	5827	PMPJCK_1_SOLAR2	Rio Bravo Solar I, LLC	Solar	tracking solar	2014
215	GAM	5828	PMPJCK_1_RB2SLR	Rio Bravo Solar II, LLC	Solar	tracking solar	2014
216	GAM	5829	WLDWD_1_SOLAR2	Wildwood Solar II, LLC	Solar	tracking solar	2014
217	GAM	5834	GARLND_2_GASLRA	RE Garland A, LLC	Solar	tracking solar	2014
218	GAM	5835	CEDUCR_2_SOLAR1	CED Ducor 1, LLC	Solar	tracking solar	2014
219	GAM	5836	CEDUCR_2_SOLAR2	CED Ducor 2, LLC	Solar	tracking solar	2014
220	GAM	5837	CEDUCR_2_SOLAR4	CED Ducor 4, LLC	Solar	tracking solar	2014
221	GAM	5838	CEDUCR_2_SOLAR3	CED Ducor 3, LLC	Solar	tracking solar	2014
222	GAM	5874	DELAMO_2_SOLAR4	Golden Springs Building F, LLC	Solar	fixed solar	2015
223	GAM	5875	DELAMO_2_SOLAR3	Golden Springs Development Company, LLC	Solar	fixed solar	2015
224	GAM	5876	DELAMO_2_SOLAR5	Golden Springs Development Company, LLC	Solar	fixed solar	2015
225	GAM	5877	DELAMO_2_SOLAR6	Freeway Springs, LLC	Solar	fixed solar	2015
226	GAM	5878	ETIWND_2_SOLAR5	Golden Solar, LLC	Solar	fixed solar	2015
227	GAM	5880	MSOLAR_2_SOLAR2	Mesquite Solar 2, LLC	Solar	tracking solar	2015
228	GAM	5885	DRACKR_2_SOLAR2	Blythe Solar II, LLC	Solar	tracking solar	2015
229	GAM	5888	GARLND_2_GASLR	RE Garland, LLC	Solar	tracking solar	2015
230	GAM	6053	DEVERS_1_QF	Difwind Farms Limited V	Wind	wind	CTC Eligible
231	GAM	6063	VINCNT_2_QF	Desert Winds I PPC Trust	Wind	wind	CTC Eligible
232	GAM	6065	JAWBNE_2_SRWND	Sky River Partnership (Wilderness I)	Wind	wind	CTC Eligible
233	GAM	6066	JAWBNE_2_SRWND	Sky River Partnership (Wilderness II)	Wind	wind	CTC Eligible
234	GAM	6067	JAWBNE_2_SRWND	Sky River Partnership (Wilderness III)	Wind	wind	CTC Eligible
235	GAM	6090	DEVERS_1_QF	Alta Mesa Pwr Purch Contract Trust	Wind	wind	CTC Eligible
236	GAM	6092	ANTLPE_2_QF	Ridgetop Energy, LLC (II)	Wind	wind	CTC Eligible

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Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
237	GAM	6095	DEVERS_1_QF	Dutch Energy	Wind	wind	CTC Eligible
238	GAM	6102	VINCNT_2_QF	Victory Garden Phase IV Partner - 6102	Wind	wind	CTC Eligible
239	GAM	6103	VINCNT_2_QF	Victory Garden Phase IV Partner - 6103	Wind	wind	CTC Eligible
240	GAM	6104	VINCNT_2_QF	Victory Garden Phase IV Partner - 6104	Wind	wind	CTC Eligible
241	GAM	6105	VINCNT_2_QF	Terra-Gen 251 Wind, LLC (Monolith X)	Wind	wind	CTC Eligible
242	GAM	6106	VINCNT_2_QF	Terra-Gen 251 Wind, LLC (Monolith XI)	Wind	wind	CTC Eligible
243	GAM	6107	VINCNT_2_QF	Terra-Gen 251 Wind, LLC (Monolith XII)	Wind	wind	CTC Eligible
244	GAM	6108	VINCNT_2_QF	Terra-Gen 251 Wind, LLC (Monolith XIII)	Wind	wind	CTC Eligible
245	GAM	6113	VINCNT_2_QF	Desert Winds II Pwr Purch Trst	Wind	wind	CTC Eligible
246	GAM	6114	VINCNT_2_QF	Desert Wind III PPC Trust	Wind	wind	CTC Eligible
247	GAM	6304	BLAST_1_WIND	Mountain View Power Partners IV, LLC	Wind	wind	2009
248	GAM	6305	TIFFNY_1_DILLON	Dillon Wind LLC	Wind	wind	2009
249	GAM	6307	WNDSTR_2_WIND	Windstar Energy, LLC	Wind	wind	2009
250	GAM	6314	ALTA4A_2_CPCW1	Alta Wind I, LLC	Wind	wind	2009
251	GAM	6315	ALTA4B_2_CPCW2	Alta Wind II, LLC	Wind	wind	2009
252	GAM	6316	ALTA4B_2_CPCW3	Alta Wind III, LLC	Wind	wind	2009
253	GAM	6317	ALTA3A_2_CPCE4	Alta Wind IV, LLC	Wind	wind	2009
254	GAM	6318	ALTA3A_2_CPCE5	Alta Wind V, LLC	Wind	wind	2009
255	GAM	6319	ALTA4B_2_CPCW6	Mustang Hills, LLC	Wind	wind	2010
256	GAM	6320	ALT6DN_2_WIND7	Pinyon Pines Wind I, LLC	Wind	wind	2010
257	GAM	6321	ALTA3A_2_CPCE8	Alta Wind VIII, LLC	Wind	wind	2010
258	GAM	6322	ALT6DS_2_WIND9	Pinyon Pines Wind II, LLC	Wind	wind	2010
259	GAM	6323	ALTA6E_2_WIND10	Alta Wind X, LLC	Wind	wind	2011
260	GAM	6324	ALTA6B_2_WIND11	Alta Wind XI, LLC	Wind	wind	2011
261	GAM	6330	SCE1_MALIN500_I_F_CSFNO1	North Hurlburt Wind, LLC	Wind	wind	2009
262	GAM	6331	SCE1_MALIN500_I_F_CSFSO1	South Hurlburt Wind, LLC	Wind	wind	2009
263	GAM	6332	SCE1_MALIN500_I_F_CSFHB1	Horseshoe Bend Wind, LLC	Wind	wind	2009
264	GAM	6333	MTWIND_1_UNIT 1, MTWIND_1_UNIT 2	Mountain View Power Partners, LLC	Wind	wind	2009
265	GAM	6334	N/A- out of state	Goshen Phase II LLC	Wind	wind	2009
266	GAM	6355	MIDWD_2_WIND2	Coram Energy LLC	Wind	wind	2014

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Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
267	GAM	6358	GARNET_2_WIND4	San Geronio WestWinds II - Windustries	Wind	wind	2014
268	GAM	6366	ANTLPE_2_QF	Mogul Energy Partnership I, LLC	Wind	wind	2012
269	GAM	6367	MIDWD_6_WNDLND	Windland Refresh 1, LLC	Wind	wind	2013
270	GAM	6391	FLOWD_2_WIND1	Cameron Ridge II	Wind	wind	2014
271	GAM	6397	MIDWD_2_WIND1	Windland Refresh 2, LLC	Wind	wind	2014
272	GAM	6452	GARNET_2_WIND5	Yavi Energy, LLC (Eastwind)	Wind	wind	2015
273	GAM	6456	CAPWD_1_QF	Edom Hills Project 1, LLC	Wind	wind	2015
274	GAM	3117	ADLIN_1_UNITS, SMUDGO_7_UNIT 1, GYS5X6_7_UNITS, GYS7X8_7_UNITS, GEYS11_7_UNIT11, GEYS12_7_UNIT12, GEYS13_7_UNIT13, GEYS14_7_UNIT14, GEYS16_7_UNIT16, GEYS17_7_UNIT17, GEYS18_7_UNIT18, SANTFG_7_UNITS, GEYS20_7_UNIT20	Geysers Power Company, LLC	Geothermal	other	2014
275	GAM	3118	ADLIN_1_UNITS, SMUDGO_7_UNIT 1, GYS5X6_7_UNITS, GYS7X8_7_UNITS, GEYS11_7_UNIT11, GEYS12_7_UNIT12, GEYS13_7_UNIT13, GEYS14_7_UNIT14, GEYS16_7_UNIT16, GEYS17_7_UNIT17, GEYS18_7_UNIT18, SANTFG_7_UNITS, GEYS20_7_UNIT20	Geysers Power Company, LLC	Geothermal	other	2015
276	GAM	4226	N/A	Desert Water Agency (Snow Creek)	Small Hydro	other	2016
277	GAM	5226	TBD	Caliente Springs, LLC	Solar	fixed solar	2015
278	GAM	5245	GASKW1_2_GW1SR1	Re Gaskell West 1 LLC	Solar	tracking solar	2015
279	GAM	5246	TRNQL8_2_AZUSR1	Great Valley Solar 3, LLC	Solar	tracking solar	2015
280	GAM	5251	TBD	Milestone Wildomar, LLC	Solar	fixed solar	2016
281	GAM	5258	TBD	Green Beanworks C, LLC	Solar	tracking solar	2016
282	GAM	5261	TBD	Windhub Solar A, LLC	Solar	tracking solar	2016
283	GAM	5262	TBD	Antelope DSR 3, LLC	Solar	tracking solar	2016
284	GAM	5263	TBD	American Kings, LLC	Solar	other	2016

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Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
285	GAM	5264	TBD	Maverick Solar, LLC	Solar	other	2016
286	GAM	5268	TBD	Green Beanworks D, LLC	Solar	tracking solar	2016
287	GAM	5405	GALE_1_SR3SR3	Sunray Energy 3 LLC	Solar	tracking solar	2015
288	GAM	5414	TBD	Neenach Solar 1B South, LLC	Solar	tracking solar	2016
289	GAM	5519	LITLRK_6_SOLAR3	One Ten Partners, LLC	Solar	tracking solar	2016
290	GAM	5625	OASIS_6_SOLAR3	US Topco Energy, Inc (Soccer Center)	Solar	fixed solar	2014
291	GAM	5744	MIRLOM_2_LNDFL	PVN Milliken, LLC	Solar	fixed solar	2014
292	GAM	5747	TBD	AVS Phase 2, LLC	Solar	tracking solar	2016
293	GAM	5748	ROSMND_6_SOLAR	Lancaster WAD B, LLC (REMAT)	Solar	tracking solar	2015
294	GAM	5762	DELSUR_6_BSOLAR	Central Antelope Dry Ranch B LLC	Solar	tracking solar	2015
295	GAM	5788	REDMAN_2_SOLAR	Antelope Valley Solar, LLC	Solar	tracking solar	2014
296	GAM	5804	COPMTN_2_SOLAR1	Copper Mountain Solar 4, LLC	Solar	tracking solar	2014
297	GAM	5805	TBD	88FT 8me LLC	Solar	tracking solar	2014
298	GAM	5808	TBD	93LF 8me LLC	Solar	tracking solar	2014
299	GAM	5810	TBD	41MB 8me LLC	Solar	tracking solar	2014
300	GAM	5811	TBD	RE Tranquillity LLC	Solar	tracking solar	2014
301	GAM	5814	TBD	North Rosamond Solar, LLC	Solar	fixed solar	2015
302	GAM	5816	TBD	Panoche Valley Solar, LLC	Solar	tracking solar	2014
303	GAM	5817	KRAMER_1_SEGSR3	Luz Solar Partners Ltd. III	Solar	other	2015
304	GAM	5818	KRAMER_1_SEGSR4	Luz Solar Partners Ltd. IV	Solar	other	2015
305	GAM	5819	KRAMER_1_KJ5SR5	Luz Solar Partners Ltd. V	Solar	other	2015
306	GAM	5826	GLDFGR_6_SOLAR1	Portal Ridge Solar B, LLC	Solar	tracking solar	2014
307	GAM	5833	JACMSR_1_JACSR1	JACUMBA SOLAR, LLC	Solar	fixed solar	2014
308	GAM	5882	TBD	Sun Streams, LLC	Solar	other	2015
309	GAM	5883	TBD	Willow Springs Solar, LLC	Solar	other	2015
310	GAM	5884	TBD	Sunshine Valley Solar, LLC	Solar	other	2015
311	GAM	5886	TBD	Valentine Solar, LLC	Solar	other	2015
312	GAM	5889	TBD	Blythe Solar III, LLC	Solar	tracking solar	2015
313	GAM	6368	BEKWJS_5_BV1SCEDYN	Broadview Energy KW, LLC	Wind	wind	2015
314	GAM	6369	ELCABO_5_ECWSCEDYN	EI Cabo Wind LLC	Wind	wind	2015
315	GAM	6372	TULEWD_1_TULWD1	Tule Wind LLC	Wind	wind	2015
316	GAM	6379	BEJNLS_5_BV2SCEDYN	Broadview Energy JN, LLC	Wind	wind	2015
317	GAM	6380	TBD	Voyager Wind I, LLC	Wind	wind	2015
318	GAM	1245	RECTOR_7_TULARE	MM Tulare Energy, LLC	Biomass	other	2017

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Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
319	GAM	4235	PADUA_6_QF	Three Valleys Municipal Water District (Fulton)	Small Hydro	other	2017
320	GAM	4237	PADUA_6_QF	Three Valleys Municipal Water District (Williams)	Small Hydro	other	2017
321	GAM	5178	TBD	Green Beanworks B, LLC	Solar	tracking solar	2017
322	GAM	5890	TBD	CalCity Solar I, LLC	Solar	tracking solar	2017
323	GAM	3106	CONTRL_1_OXBOW	Terra-Gen Dixie Valley, LLC	Geothermal	other	2009
324	GAM	6361	TBD	Rising Tree Wind Farm III, LLC	Wind	wind	2012
325	GAM	6362	TBD	Rising Tree Wind Farm, LLC	Wind	wind	2013
326	GAM	11048	AZUSA_2_HYDRO	City of Pasadena - Grant Deed	Hydro	other	CTC Eligible
327	GAM	10045	SCEHOV_2_HOOVER	Hoover Electric Service Contract (CONTRACT NO. 16-DSR-12655)	Hydro	other	2016
328	GAM	11034	BIGCRK_2_EXESWD	Calpine Energy Services LP	Hydro	other	2017
329	GAM	11088	BIGCRK_2_EXESWD	Exelon Generation Company, LLC	Hydro	other	2017
330	GAM	11181	SCE1_MALIN500_I_F_CSFNO1	Shell Energy North America (US), L.P.	Wind	wind	2015
331	GAM	11181	SCE1_MALIN500_I_F_CSFSO1	Shell Energy North America (US), L.P.	Wind	wind	2015
332	GAM	11181	SCE1_MALIN500_I_F_CSFHB1	Shell Energy North America (US), L.P.	Wind	wind	2015
333	GAM	UOG	BIGCRK_2_EXESWD	Big Creek 1, 2, 3, 4, 8, Mampool	Hydro	other	Legacy UOG
334	GAM	UOG	BIGCRK_2_EXESWD	Portal Powerhouse	Small Hydro	other	Legacy UOG
335	GAM	UOG	BIGCRK_7_DAM7	Big Creek Dam 7	Small Hydro	other	Legacy UOG
336	GAM	UOG	BIGCRK_7_MAMRES	Mampool RS1, Fish Water Generator	Small Hydro	other	Legacy UOG
337	GAM	UOG	BISHOP_1_ALAMO	Bishop Creek 2, 5, 6	Small Hydro	other	Legacy UOG
338	GAM	UOG	BISHOP_1_UNITS	Bishop Creek 3, 4	Small Hydro	other	Legacy UOG
339	GAM	UOG	CHINO_2_SOLAR	SCE GBU Chino Solar, SPVP#002	Solar	fixed solar	2009
340	GAM	UOG	CONTRL_1_LUNDY	Lundy Powerhouse	Small Hydro	other	Legacy UOG
341	GAM	UOG	CONTRL_1_POOLE	Poole Powerhouse	Small Hydro	other	Legacy UOG
342	GAM	UOG	CONTRL_1_RUSHCK	Rush Creek	Small Hydro	other	Legacy UOG
343	GAM	UOG	EASTWD_7_UNIT	Eastwood	Hydro	other	Legacy UOG
344	GAM	UOG	ETIWND_2_FONTNA	Fontana Powerhouse, Lytle Creek	Small Hydro	other	Legacy UOG

Appendix F2
SCE Green Allocation Methodology Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
345	GAM	UOG	ETIWND_2_RTS010	SCE GBU Etiwanda, SPVP#010	Solar	fixed solar	2009
346	GAM	UOG	ETIWND_2_RTS015	SCE GBU Etiwanda, SPVP#015	Solar	fixed solar	2009
347	GAM	UOG	ETIWND_2_RTS017	SCE GBU Etiwanda, SPVP#017	Solar	fixed solar	2009
348	GAM	UOG	ETIWND_2_RTS018	SCE GBU Etiwanda, SPVP#018	Solar	fixed solar	2009
349	GAM	UOG	ETIWND_2_RTS023	SCE GBU Etiwanda, SPVP#023	Solar	fixed solar	2009
350	GAM	UOG	ETIWND_2_RTS026	SCE GBU Etiwanda, SPVP#026	Solar	fixed solar	2009
351	GAM	UOG	ETIWND_2_RTS027	SCE GBU Etiwanda, SPVP#027	Solar	fixed solar	2009
352	GAM	UOG	KERRGN_1_UNIT 1	Kern River 1, Units 1-4	Small Hydro	other	Legacy UOG
353	GAM	UOG	MIRLOM_2_ONTARO	SCE GBU Ontario Solar, SPVP#006, 008, 009, 012	Solar	fixed solar	2009
354	GAM	UOG	MIRLOM_2_RTS032	SCE GBU Ontario, SPVP#032	Solar	fixed solar	2009
355	GAM	UOG	MIRLOM_2_RTS033	SCE GBU Ontario, SPVP#033	Solar	fixed solar	2009
356	GAM	UOG	MONLTH_6_BOREL	Borel Powerhouse	Small Hydro	other	Legacy UOG
357	GAM	UOG	PADUA_2_ONTARO	Ontario 1, 2, Sierra Powerhouse	Small Hydro	other	Legacy UOG
358	GAM	UOG	RECTOR_2_KAWEAH	Kaweah Unit 2, 3	Small Hydro	other	Legacy UOG
359	GAM	UOG	RECTOR_2_KAWH 1	Kaweah Unit 1	Small Hydro	other	Legacy UOG
360	GAM	UOG	SBERDO_2_REDLND	SCE GBU Redlands Solar, SPVP#022	Solar	fixed solar	2009
361	GAM	UOG	SBERDO_2_RTS005	SCE GBU Redlands Solar, SPVP#005	Solar	fixed solar	2009
362	GAM	UOG	SBERDO_2_RTS007	SCE GBU Redlands Solar, SPVP#007	Solar	fixed solar	2009
363	GAM	UOG	SBERDO_2_RTS011	SCE GBU Redlands, SPVP#011	Solar	fixed solar	2009
364	GAM	UOG	SBERDO_2_RTS013	SCE GBU Redlands, SPVP#013	Solar	fixed solar	2009
365	GAM	UOG	SBERDO_2_RTS016	SCE GBU Redlands, SPVP#016	Solar	fixed solar	2009

Appendix F2
SCE Green Allocation Methodology Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
366	GAM	UOG	SBERDO_2_RTS048	SCE GBU Redlands, SPVP#048	Solar	fixed solar	2009
367	GAM	UOG	SBERDO_2_SNTANA	Santana 1, 3	Small Hydro	other	Legacy UOG
368	GAM	UOG	SBERDO_6_MILLCK	Mill Creek 1, 3	Small Hydro	other	Legacy UOG
369	GAM	UOG	SPRGVL_2_TULESC	Tule Powerhouse	Small Hydro	other	Legacy UOG
370	GAM	UOG	VALLEY_5_RTS044	SCE GBU Valley, SPVP#044	Solar	fixed solar	2009
371	GAM	UOG	VESTAL_2_KERN	Kern River 3, Unit 1, 2	Hydro	other	Legacy UOG
372	GAM	UOG	VESTAL_2_RTS042	SCE GBU Vestal Solar, SPVP#042 (Porterville)	Solar	fixed solar	2009
373	GAM	UOG	VISTA_2_RIALTO	SCE GBU Rialto Solar, SPVP#003	Solar	fixed solar	2009
374	GAM	UOG	VISTA_2_RTS028	SCE GBU Vista, SPVP#028	Solar	fixed solar	2009

Appendix F2
SCE Portfolio Monetization Mechanism Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
1	PMM	1028 ^(a)	HINSON_6_SERRGN	City of Long Beach	Biomass	other	CTC Eligible
2	PMM	2010	SBERDO_2_QF	Loma Linda University	Cogeneration	natural gas	CTC Eligible
3	PMM	2042	MOORPK_6_QF	CSU Channel Islands Site Authority	Cogeneration	natural gas	CTC Eligible
4	PMM	2043	CHINO_6_CIMGEN	O.L.S. Energy - Chino	Cogeneration	natural gas	CTC Eligible
5	PMM	2064	CENTER_2_QF	Wheelabrator Norwalk Energy Co, Inc	Cogeneration	natural gas	CTC Eligible
6	PMM	2072	SNCLRA_6_PROCGN	Procter & Gamble Paper Prod Oxnard II	Cogeneration	natural gas	CTC Eligible
7	PMM	2101	GOLETA_6_EXGEN	ExxonMobil Production Company	Cogeneration	natural gas	CTC Eligible
8	PMM	2180	SAUGUS_6_PTCHGN	Co of Los Angeles - Pitchess Honor Ranch	Cogeneration	natural gas	CTC Eligible
9	PMM	2205	SNCLRA_6_OXGEN	E. F. Oxnard Incorporated	Cogeneration	natural gas	CTC Eligible
10	PMM	2441	LAGBEL_6_QF	Metal Surfaces Inc.	Cogeneration	natural gas	CTC Eligible
11	PMM	2479	SAUGUS_6_QF	Termo Company	Cogeneration	other	CTC Eligible
12	PMM	2490	SNCLRA_6_QF	City of Oxnard	Cogeneration	other	CTC Eligible
13	PMM	4013 ^(a)	ANTLPE_2_QF	Tehachapi Cummings Co. Water District	Small Hydro	other	CTC Eligible
14	PMM	5010 ^(a)	VICTOR_1_QF	Curtis, Edwin	Solar	fixed solar	CTC Eligible
15	PMM	11104 ^(b)	MTWIND_1_UNIT 3	Avangrid Renewables, LLC	Wind	wind	2014
16	PMM	11016	ALAMIT_7_UNIT 1	BE CA LLC	Boiler - Conventional	natural gas	2013
17	PMM	11016	ALAMIT_7_UNIT 2	BE CA LLC	Boiler - Conventional	natural gas	2013
18	PMM	11016	ALAMIT_7_UNIT 3	BE CA LLC	Boiler - Conventional	natural gas	2013
19	PMM	11016	ALAMIT_7_UNIT 4	BE CA LLC	Boiler - Conventional	natural gas	2013
20	PMM	11016	ALAMIT_7_UNIT 5	BE CA LLC	Boiler - Super Critical	natural gas	2013
21	PMM	11016	ALAMIT_7_UNIT 6	BE CA LLC	Boiler - Super Critical	natural gas	2013
22	PMM	11016	HNTGBH_7_UNIT 1	BE CA LLC	Boiler - Conventional	natural gas	2013
23	PMM	11016	HNTGBH_7_UNIT 2	BE CA LLC	Boiler - Conventional	natural gas	2013
24	PMM	11016	REDOND_7_UNIT 5	BE CA LLC	Boiler - Conventional	natural gas	2013
25	PMM	11016	REDOND_7_UNIT 6	BE CA LLC	Boiler - Conventional	natural gas	2013
26	PMM	11016	REDOND_7_UNIT 7	BE CA LLC	Boiler - Super Critical	natural gas	2013
27	PMM	11016	REDOND_7_UNIT 8	BE CA LLC	Boiler - Super Critical	natural gas	2013

Appendix F2
SCE Portfolio Monetization Mechanism Resources List
(Leveraging R1706026 SCE Standard Data Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
28	PMM	11034	LEBECS_2_UNITS	Calpine Energy Services LP	Gas Turbine - Combined Cycle	natural gas	2014
29	PMM	11094	GOLETA_6_ELLWOD	GenOn Energy Management, LLC	Boiler - Conventional	natural gas	2015
30	PMM	11062	HIDSRT_2_UNITS	EDF Trading North America, LLC	Gas Turbine - Combined Cycle	natural gas	2017
31	PMM	11223	ALAMIT_7_UNIT 1	AES Alamitos, L.L.C.	Boiler - Conventional	natural gas	2016
32	PMM	11223	ALAMIT_7_UNIT 2	AES Alamitos, L.L.C.	Boiler - Conventional	natural gas	2016
33	PMM	11223	ALAMIT_7_UNIT 3	AES Alamitos, L.L.C.	Boiler - Conventional	natural gas	2016
34	PMM	11223	ALAMIT_7_UNIT 4	AES Alamitos, L.L.C.	Boiler - Conventional	natural gas	2016
35	PMM	11223	ALAMIT_7_UNIT 5	AES Alamitos, L.L.C.	Boiler - Super Critical	natural gas	2016
36	PMM	11223	ALAMIT_7_UNIT 6	AES Alamitos, L.L.C.	Boiler - Super Critical	natural gas	2016
37	PMM	11224	HNTGBH_7_UNIT 1	AES Huntington Beach, L.L.C.	Boiler - Conventional	natural gas	2016
38	PMM	11224	HNTGBH_7_UNIT 2	AES Huntington Beach, L.L.C.	Boiler - Conventional	natural gas	2016
39	PMM	UOG	SBERDO_2_PSP3	SCE Mountainview Unit 3	Gas Turbine - Combined Cycle	natural gas	NA
40	PMM	UOG	SBERDO_2_PSP4	SCE Mountainview Unit 4	Gas Turbine - Combined Cycle	natural gas	NA
41	PMM	UOG	VISTA_2_FCELL	CSU San Bernardino Fuel Cell	Fuell Cell	natural gas	2009
42	PMM	UOG	PVERDE_5_SCEDYN	Palo Verde	Nuclear	other	Legacy UOG
43	PMM	UOG	n/a	Pebbly Beach Generation Station	Diesel	other	Legacy UOG

(a) Contracts 1028, 4013 and 5010 are included in PMM because the facilities covered by the contracts are not currently certified as RPS eligible.

(b) Contract 11104 is included in PMM because it is an RA-only contract.

**Appendix F3
SDG&E Summary Table**

Line		Contract Type (refer to Column " <u>RPS Eligibility</u> ", Column " <u>Contract/Solicitation Type</u> ", and column " <u>Assigned Vintage</u> " of ALJ Matrix)	Allocation Proposal	Joint Utility Vintaging Proposal	Contract Capacity (MW) <i>(Maximum Contract Capacity or Nameplate Capacity for UOG)</i>	2019 Forecasted Total Costs (\$)¹	2019 Forecasted Total RECs²
1	CTC	QF Standard Contract, QF CHP	CTC	Non-Vintaged	217	61,022,112	1,405
2	RPS + Large Hydro	RAM, ReMAT, BioMAT, AB 1969	GAM	Non-Vintaged	203	19,974,573	237,462
3		RPS-eligible: PPA – Bilateral, PPA – Solicitation, Shape + Firm Only, UOG	GAM	Vintaged	2,533	670,862	6,855,279
4	Fossil + Energy Storage	Non-RPS: Tolling, UOG, PPA, Unspecified	PMM	Vintaged	2,199	540,245	N/A

¹ 2019 Forecasted Total Costs was based on the R1706026 SCE Standard Data Matrix, provided to parties on March 2, 2018

² REC estimates are based on the 2019 Forecasted Energy Volumes for RPS eligible resources from the R1706026 SCE Standard Data Matrix,

Appendix F3
SDG&E Green Allocation Methodology Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
1	GAM	Avangrid Renewables LLC (Mountain Wind)	MTWIND_1_UNIT3	Avangrid Renewables LLC (Mountain Wind)	Wind		Pre-2009
2	GAM	Avangrid Renewables LLC (Phoenix West)	PWEST_1_UNIT	Avangrid Renewables LLC (Phoenix West Wind)	Wind		Pre-2009
3	GAM	SDG00176	N/A	SDG&E - X-nth	Solar PV	Fixed Tilt	N/A
4	GAM	FPL Energy Green Power Wind LLC	GARNET_1_UNITS	FPL Energy Green Power Wind LLC	Wind		Pre-2009
5	GAM	Oasis Power Partners LLC	VINCNT_2_WESTWD	Oasis Power Partners LLC	Wind		Pre-2009
6	GAM	Kumeyaay Wind LLC	CRSTWD_6_KUMYAY	Kumeyaay Wind LLC	Wind		Pre-2009
7	GAM	SDG00170	N/A	SDG&E - Ladera Ranch I	Solar PV	Fixed Tilt	N/A
8	GAM	MM Prima Deshecha Energy LLC	CPSTNO_7_PRMADES	MM Prima Deshecha Energy LLC	BioGas		Pre-2009
9	GAM	SDG00168	N/A	SDG&E - Hunter Industries	Solar PV	Fixed Tilt	N/A
10	GAM	SDG00174	N/A	SDG&E - Towers at Bressi Ranch	Solar PV	Fixed Tilt	N/A
11	GAM	SDG00166	N/A	SDG&E - Del Sur Elementary School	Solar PV	Fixed Tilt	N/A
12	GAM	SDG00169	N/A	SDG&E - Innovative Cold Storage Enterprises	Solar PV	Fixed Tilt	N/A
13	GAM	NaturEner Glacier Wind Energy 1 LLC	N/A	Naturener Glacier Wind Energy 1 LLC	Wind		Pre-2009
14	GAM	Otay Landfill Gas LLC [Otay Landfill 1]	OTAY_6_UNITB1	Otay Landfill I	BioGas		2009
15	GAM	SDG00173	N/A	SDG&E - SDCCD - Skills Center	Solar PV	Fixed Tilt	N/A
16	GAM	NaturEner Glacier Wind Energy 2 LLC	N/A	Naturener Glacier Wind Energy 2 LLC	Wind		Pre-2009
17	GAM	SDG00167	N/A	SDG&E - Fairfield Grossmont Trolley	Solar PV	Fixed Tilt	N/A
18	GAM	SDG00175	N/A	SDG&E - Wilco Investments	Solar PV	Fixed Tilt	N/A
19	GAM	SDG00172	N/A	SDG&E - Sanford-Burnham Medical Research Institute I	Solar PV	Fixed Tilt	N/A
20	GAM	Coram Energy LLC	MIDWD_7_CORAMB	Coram Energy LLC	Wind		2010

Appendix F3
SDG&E Green Allocation Methodology Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
21	GAM	Sycamore Energy 1 LLC	CHILLS_1_SYCENG	Sycamore Energy 1 LLC	BioGas		2009
22	GAM	San Marcos Energy LLC	SMRCOS_6_LNDFIL	San Marcos Energy LLC	BioGas		2009
23	GAM	Otay Landfill Gas LLC [Otay Landfill 2]	OTAY_6_UNITB1	Otay Landfill II	BioGas		2011
24	GAM	SDG00171	N/A	SDG&E - Pacific Station	Solar PV	Fixed Tilt	N/A
25	GAM	Pacific Wind Lessee LLC	ROSMDW_2_WIND1	Pacific Wind Lessee LLC	Wind		Pre-2009
26	GAM	Ocotillo Express LLC	OCTILO_5_WIND	Ocotillo Express LLC	Wind		2011
27	GAM	Manzana Wind LLC	MANZNA_2_WIND	Manzana Wind LLC	Wind		2012
28	GAM	NRG Solar Borrego I LLC	BREGGO_6_SOLAR	NRG Solar Borrego I LLC	Solar PV	Tracking	2011
29	GAM	MM San Diego LLC [Miramar RAM]	MSHGTS_6_MMARLF	MM San Diego LLC (Miramar RAM)	BioGas		2012
30	GAM	Otay Landfill Gas LLC [Otay Landfill V]	OTAY_6_LNDFL5	Otay Landfill V	BioGas		2011
31	GAM	Otay Landfill Gas LLC [Otay Landfill VI]	OTAY_6_LNDFL6	Otay Landfill VI	BioGas		2011
32	GAM	Olivenhain Municipal Water District	N/A	Olivenhain Municipal Water District	Conduit Hydro		2013
33	GAM	Imperial Valley Solar 1 LLC [Mount Signal Solar Farm]	IVSLRP_2_SOLAR1	Imperial Valley Solar I LLC (Mount Signal)	Solar PV	Tracking	2012
34	GAM	Naturener Rim Rock Wind Energy LLC	N/A	Naturener Rim Rock Wind Energy LLC	Wind		2009
35	GAM	Campo Verde Solar LLC	CPVERD_2_SOLAR	Campo Verde Solar LLC	Solar PV	Fixed Tilt	Pre-2009
36	GAM	CSolar IV South LLC	CSLR4S_2_SOLAR	CSolar IV South LLC	Solar PV	Fixed Tilt	2010
37	GAM	Arlington Valley Solar II LLC	ARLVAL_5_SOLAR	Arlington Valley Solar II LLC	Solar PV	Tracking	2011
38	GAM	Catalina Solar LLC	CATLNA_2_SOLAR	Catalina Solar LLC	Solar PV	Fixed Tilt	2011
39	GAM	Cascade Solar LLC	DEVERS_1_SOLAR	Cascade Solar LLC	Solar PV	Tracking	2012
40	GAM	Sol Orchard 20 LLC [Ramona 1]	CRELMN_6_RAMON1	Sol Orchard 20 LLC (Ramona 1)	Solar PV	Tracking	2011
41	GAM	Sol Orchard 21 LLC [Ramona 2]	CRELMN_6_RAMON2	Sol Orchard 21 LLC (Ramona 2)	Solar PV	Tracking	2011
42	GAM	Sol Orchard 22 LLC [Valley Center 1]	VLCNTR_6_VCSLR1	Sol Orchard 22 LLC (Valley Center 1)	Solar PV	Tracking	2011
43	GAM	Sol Orchard 23 LLC [Valley Center 2]	VLCNTR_6_VCSLR2	Sol Orchard 23 LLC (Valley Center 2)	Solar PV	Tracking	2011
44	GAM	Oak Creek Wind Power LLC	OAKWD_6_ZEPHWD	Oak Creek Wind Power LLC	Wind		2013
45	GAM	Sycamore Energy 2 LLC	CHILLS_7_UNITA1	Sycamore Energy 2 LLC	BioGas		2014

Appendix F3
SDG&E Green Allocation Methodology Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
46	GAM	Centinela Solar Energy 1 LLC	CNTNLA_2_SOLAR1	Centinela Solar Energy LLC	Solar PV	Tracking	2010
47	GAM	Centinela Solar Energy 2 LLC	CNTNLA_2_SOLAR2	Centinela Solar Energy 2 LLC	Solar PV	Tracking	2010
48	GAM	SG2 Imperial Valley LLC	ZES1_IVLY2_I_UC_USE	SG2 Imperial Valley LLC	Solar PV	Tracking	2011
49	GAM	Desert Green Solar Farm LLC	BREGGO_6_DEGRSL	Desert Green Solar Farm LLC	Solar PV	Tracking	2011
50	GAM	San Geronio Westwinds II LLC	GARNET_2_WIND1	San Geronio Westwinds II LLC	Wind		2013
51	GAM	Energia Sierra Juarez US LLC	ENERSJ_2_WIND	Energia Sierra Juarez US LLC	Wind		2011
52	GAM	Maricopa West Solar PV LLC	MARCPW_6_SOLAR1	Maricopa West Solar PV LLC	Solar PV	Tracking	2013
53	GAM	Tallbear Seville LLC	ANZA_6_SOLAR1	Tallbear Seville LLC	Solar PV	Tracking	2012
54	GAM	Calpatria LLC	CALPSS_6_SOLAR1	Calpatria LLC	Solar PV	Tracking	2012
55	GAM	CSolar IV West LLC	IVWEST_2_SOLAR1	CSolar IV West LLC	Solar PV	Tracking	2011
56	GAM	NLP Granger A82 LLC	LILIAC_6_SOLAR	NLP Granger A82	Solar PV	Tracking	2014
57	GAM	NLP Valley Center Solar LLC	VLCNTR_6_VCSLR	NLP Valley Center Solar, LLC	Solar PV	Tracking	2015
58	GAM	N/A	CRELMN_6_RAMSR3	SDG&E Solar Energy Project-Ramona	Solar PV	Fixed Tilt	2010
59	GAM	Midway Solar Farm [97WI ME LLC]	N/A	Midway Solar Farm III	Solar PV	Fixed Tilt	2015
60	GAM	Lakeside BioGas	N/A	Lakeside Biogas LLC	BioGas		2017
61	GAM	Energia Sierra Juarez 2 U.S., LLC	N/A	Energia Sierra Juarez 2 US LLC	Wind		2017
62	GAM	Olivenhain-Lake Hodges - Contracts_Amendments	LAKHDG_6_UNIT 1	Lake Hodges Unit 1	Pumped Hydro		Pre-2009
63	GAM	Olivenhain-Lake Hodges - Contracts_Amendments	LAKHDG_6_UNIT 2	Lake Hodges Unit 2	Pumped Hydro		Pre-2009

Appendix F3
SDG&E Portfolio Monetization Mechanism Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
1	PMM	N/A	MRGT_6_MMAREF	SDG&E - Miramar	Natural Gas		Pre-2009
2	PMM	N/A	PALOMR_2_PL1X3	SDG&E - Palomar	Natural Gas		Pre-2009
3	PMM	N/A	MRGT_6_MEF2	SDG&E - Miramar 2	Natural Gas		Pre-2009
4	PMM	Otay Mesa Energy Center - Contracts and Amendments	OTMESA_2_PL1X3	Otay Mesa	Natural Gas		Pre-2009
5	PMM	El Cajon Energy Center - Contracts and Agreements	ELCAJN_6_LM6K	El Cajon Energy Center	Natural Gas		2010
6	PMM	Orange Grove Energy - Contracts and Amendments	OGROVE_6_PL1X2	Orange Grove	Natural Gas		2009
7	PMM	N/A	MRCHNT_2_PL1X3	SDG&E -Desert Star	Natural Gas		Pre-2009
8	PMM	N/A	ELCAJN_6_UNITA1	SDG&E - Cuyamaca	Natural Gas		2011
9	PMM	N/A	N/A	Morgan Stanley	Unspecified		2011
10	PMM	N/A	N/A	BP	Unspecified		2015

Appendix F3
SDG&E Competition Transition Charge Resources List
(Leveraging ALJ Matrix)

Line	Allocation Proposal	Contract ID or Internal ID	CAISO Resource ID	Contract Name or UOG Name	Technology Type	Technology Sub-Type	Assigned Vintage(s) as of April 2018
1	CTC	AEI ST - NTC-MCRD - Contracts and Amendments	PTLOMA_6_NTCCGN	AEI NTC Steam Turbine	Natural Gas		CTC
2	CTC	City of Oceanside (San Francisco Peak Hydro)	N/A	City of Oceanside (San Francisco Peak Hydro)	Conduit Hydro		CTC
3	CTC	AEI SO4 - Naval Station Contracts and Amendments	DIVSON_6_NSQF	AEI Naval Station (QF)	Natural Gas		CTC
4	CTC	AEI SO4 - North Island Contracts and Amendments	NIMTG_6_NIQF	AEI North Island (QF)	Natural Gas		CTC
5	CTC	AEI SO4 - NTC-MCRD Contracts and Amendments	PTLOMA_6_NTCQF	AEI NTC/MCRD	Natural Gas		CTC
6	CTC	City of Escondido (Bear Valley Hydro)	N/A	City of Escondido (Bear Valley Hydro)	Conduit Hydro		CTC
7	CTC	GL CHP - Amendments	ESCO_6_GLMQF	Goal Line (CHP)	Natural Gas		CTC
8	CTC	YCA CHP - Contracts and Amendments	NGILAA_5_SDGDYN	Yuma Cogeneration Associates CHP	Natural Gas		CTC

Note: SDG&E's CTC resources are collected in a separate rate and thus are labeled as such

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX G
PG&E 2017 RESOURCE ADEQUACY SALES

PUBLIC VERSION

Appendix G
Table 1-1: PG&E 2017 Resource Adequacy Sales

		A	B	C = A/B	D	E = (B*C)/(B+D)
Line	Month	Total \$	Sale Volume (MW) ¹	Weighted Average Price - Sold RA (\$/kw-mo)	Unsold Volume (MW) ²	Weighted Average Price - Sold and Unsold RA (\$/kw-mo) ³
1	Jan-17		634			
2	Feb-17		639			
3	Mar-17		549			
4	Apr-17		549			
5	May-17		549			
6	Jun-17		1,247			
7	Jul-17		1,412			
8	Aug-17		1,520			
9	Sep-17		1,550			
10	Oct-17		1,215			
11	Nov-17		1,109			
12	Dec-17		1,053			

¹ Sale volumes include all RA sold around the approximately T-45 RA compliance timeframe. This excludes sales after the T-45 RA compliance filing. Typically, sales after the T-45 RA compliance filing are shorter in term (e.g., daily sales) to fulfill outage replacement requirements. There were no transactions post T-45 in 2016 and one in 2017 for a total notional value of \$36,250.

² Prior to the decision on Resolution E-4907, PG&E may have retained some RA in its portfolio to meet annual requirements for load subsequently served by new or expanding CCAs that did not participate in the annual RA filing. These volumes may be reflected in the unsold volumes shown here.

³ The weighted average price of sold and unsold RA is calculated using a value of \$0/kw-mo for unsold volumes and does not represent prices from actual RA transactions.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX H
PG&E 2018 MULTI-YEAR RESOURCE ADEQUACY REQUEST
FOR BIDS RESULTS

THIS DOCUMENT IS CONFIDENTIAL IN ITS ENTIRETY