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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

366.3,[1] among others, which 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.[2] These statutes protect all customers by providing that costs must be appropriately allocated to those on whose behalf they were incurred.

This Commission has interpreted these statutes to require that customers on utility bundled service remain "indifferent" to the departure of other customers (*i.e.*, they are neither better off nor worse off as a result of another customer's choice).[3] Unfortunately, the current methodology intended to protect bundled service customers from increased costs due to departing load is deficient because it is based on hypothetical, projected market outcomes. A forecast-based methodology cannot ensure customer indifference to departing load. The

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[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.

shortcomings of the current approach will become more significant as greater levels of customers depart utility procurement service, which is happening now and accelerating.[4]

The Joint Utilities file this Application to propose a new methodology that results in an equitable and transparent allocation of energy and capacity benefits and costs, based on actual market results, to more effectively protect customers from cost shifts and increases as a result of departing load, as required by Sections 365.2, 366.2 and 366.3.

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[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."

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 allocation[5] 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.

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5 In this Testimony, "cost allocation" refers to the recovery of generation-related costs from departing load customers.

Currently, the Commission relies on a method to allocate costs to departing load customers based on an estimate of the above-market costs for resources procured prior to their departure from bundled utility procurement service. Basing cost allocation on the share of costs estimated to be above-market essentially assumes the utilities can sell excess resources resulting from customer departure "at market," thereby leaving only the above-market costs to be recovered. Since the Commission first adopted the Current Methodology, more accurate and transparent means of allocating procurement costs among customers of different procurement service providers (or LSEs) have been developed that result in far more accurate and transparent outcomes. Now is the time for the Commission to replace the existing estimated above-market cost allocation mechanism with a cost allocation approach that is based on actual market results, thus truly protecting all customers, bundled service and departing load alike, from cost shifting.

Accordingly, in this Application, the Joint Utilities propose a new approach to allocate bundled service generation portfolio costs and benefits to all customers – bundled service and departing load – that replaces the current method of approximating and recovering above-market costs from departing load customers. The Joint Utilities' proposal, the Portfolio Allocation Methodology ("PAM"), is accurate, equitable, transparent, scalable, and actually implements state law requirements that no cost shifting take place between bundled service and departing load customers as a result of customer choice.

The PAM will completely replace the Current Methodology. As described in more detail in the following chapters, the PAM will allocate a pro-rata share of recorded net costs of each utility's generation portfolio to departing load customers on whose behalf the portfolio was procured or built, on a "vintaged-portfolio" basis.[6] Departing load customers will only pay the "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.

revenues realized by the portfolio resources in the energy markets. In addition, under PAM, departing load customers' LSEs will receive a pro-rata allocation of attributes from those resources, including Resource Adequacy ("RA"), Renewable Energy Credits ("RECs"), and any future attributes if appropriate.[7] Symmetrically, bundled service customers will pay their pro-rata share of the recorded net costs as part of their bundled service generation rates, and the Joint Utilities will retain or use the remaining bundled service customers' pro-rata allocation of RA and REC attributes for their benefit.

Just as the Joint Utilities currently do for their bundled service customers, portfolio costs and market revenues will be forecasted under PAM, but then later "trued up" to reflect actual, realized resource costs and market revenues. This approach will eliminate the contentious and inaccurate process of forecasting above-market costs, and annually applying those ever-changing values to the Joint Utilities' respective portfolios, with no true-ups. PAM will also be more transparent, so that LSEs and their customers can thoroughly review the costs and benefits that are allocated as part of each vintaged portfolio. In these regards, PAM will ensure that the statutory indifference requirement is upheld, namely: That all customers pay their equitable share of costs, that costs are not shifted among customers (in either direction), and that customers who do not (or cannot) depart utility bundled service do not pay procurement costs that were incurred on behalf of departing load customers.[8]

PAM will be implemented through the Joint Utilities' respective Energy Resource Recovery Account ("ERRA") Forecast proceedings. Once approved, the Joint Utilities propose that PAM would take effect no sooner than one year from Commission approval through the next ERRA Forecast proceeding (*e.g.*, if approved in December 2017, PAM would be presented in the 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.

2019). Given the rapid expansion of customer choice programs in California, the time for the Commission to act is now to protect remaining bundled service customers from cost increases as required by law, ensure that future cost-shifting between remaining bundled service and departing load customers does not occur as required by law, and to provide planning certainty for communities considering CCA.

The remainder of this Testimony provides background information on the Legislature's and the Commission's regulatory framework governing utility electricity procurement and efforts regarding cost allocation and protecting customers, discusses the problems with the Current Methodology, and provides a detailed discussion of the PAM proposal.

III.

OVERALL PROCUREMENT POLICY GUIDING PRINCIPLES AND PROCUREMENT HISTORY

Following the 2000-2001 Energy Crisis, the Legislature and the Commission established the regulatory framework for the Joint Utilities to resume electricity procurement, beginning January 1, 2003. Section 454.5(d)(2) and (3) provided for a utility procurement framework that would:

> Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses. However, the commission may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved [and] [e]nsure timely recovery of … procurement costs incurred pursuant to an approved procurement plan.

Consistent with this statutory directive, the Joint Utilities have submitted their respective bundled procurement plans ("BPPs") as part of the long term procurement plan ("LTPP") proceedings for Commission review and approval.[9] The Joint Utilities' BPPs establish policies and cost recovery for electricity purchases, ensure that the utilities maintain a set amount of electric capacity for what they will need to serve their customers (plus a reserve margin), and implement the approved long-term energy planning process. The Joint Utilities implement their respective Commission-approved BPPs through various procurement methods and practices, including competitive solicitations, bilateral negotiations, and participation in various markets.

The Joint Utilities are also required to submit annual Renewables Portfolio Standard ("RPS") plans for Commission approval. These RPS plans cover the rigorous standards required for RPS procurement, including, but not limited to, a determination of whether or not additional renewable procurement is needed to meet the RPS targets by a specific date and a solicitation protocol. In addition to the utility-scale renewable resources procured pursuant to the utilities' approved RPS plans, the Commission also requires the utilities to procure RPS-eligible resources

[9] *See e.g.* Decision ("D.") 15-10-031 (approving 2014 BPPs).

through various siloed mandated programs such as the Renewable Auction Mechanism ("RAM"), Renewable Market Adjusting Tariff ("ReMAT"), and the Bioenergy Market Adjusting Tariff ("BioMAT").

As a measure of oversight for procurement of all resource types for each utility's bundled customer portfolio, the Commission created two entities: the Procurement Review Group ("PRG") and the Independent Evaluator ("IE"). The PRG is comprised of non-market participants, including the Commission's Energy Division, consumer advocacy groups, environmental groups and other parties. Its purpose is to review and consult on each utility's procurement process and most proposed contracts. The Commission also requires that an IE participate in a utility's competitive solicitation process for electric procurement, utility-built projects, utility turnkey projects, and bilaterally-negotiated contracts. The purpose of the IE is to increase fairness and transparency of the electric procurement contract selection process. Once a bid makes it through the rigorous solicitation, evaluation, and selection standards, it is then submitted to the Commission, which must determine if the contract is just and reasonable. Any interested party is free to intervene and comment on the merits of a contract.

While the Joint Utilities have procured resources pursuant to the procurement process described above, or through Commission-mandated programs, the RPS procurement done in the first several years of the RPS program was extremely costly (compared to today's market prices). This early procurement of renewable energy generation resources, which ultimately contributed to the rapid decrease in market prices that are accessible to CCAs and ESPs today, constitutes the majority of the above-market portfolio costs that have contributed to the recent increases in the departing load rates resulting from the Current Methodology. It is at least partially because of the Joint Utilities' early RPS procurement that current market prices are low (and therefore why those early-procured renewable resources are now so much above-market).

Every one of the Joint Utilities' contracts was approved by this Commission as just and reasonable, and various statutes mandate that the customers on whose behalf the contracts were signed pay the costs for those contracts in a manner that does not shift costs. Indeed, as the Commission noted less than six months ago in D.16-12-038:

> 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 customers should pay their share of the costs rather than shifting them to bundled customers.[10]

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[10] D.16-12-038, p. 11.

IV.

CURRENT METHODOLOGY [11]

A. Introduction

For more than a decade, the California Legislature has consistently enacted laws intended to ensure the equitable allocation of electricity procurement costs among the Joint Utilities' bundled electric service customers and customers who depart bundled electric service to receive service from another procurement service provider. Most recently, in Senate Bill ("SB") 350, codified in Section 366.3, the Legislature provided:

> Bundled retail customers of an electrical corporation [i.e., a utility] 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.

The Legislature enacted a comparable statute to address the situation where an electric service customer departs to receive DA service from an ESP.[12]

These statutes are based on principles of cost causation and their requirements are self-evident: When a customer chooses to receive service from another procurement service provider, that customer's choice should not increase the costs for, or otherwise detrimentally impact, the remaining bundled service customers, nor should that customer be required to pay for costs not incurred on its behalf. This prohibition against cost shifting as a result of customers departing bundled service is at the heart of all statutory provisions on departing load cost allocation. Because the Joint Utilities procure generation portfolios on behalf of all then-bundled service customers, including those that later decide to take service from another procurement

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[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.

service provider, it is axiomatic that all of those customers must pay their share of costs to avoid cost shifting as a result of departing load.

Since the 2000-2001 Energy Crisis, the Commission has implemented these statutory requirements 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. The Legislature has enacted, and the Commission has implemented, a number of "nonbypassable charges" to ensure that the indifference principle is maintained in the context of departing load. For example, when the California electric industry was originally restructured in 1997, the Legislature adopted Sections 367 - 369, which require that all customers share in any "uneconomic" procurement costs, including contracted and utility-owned resources, resulting from deregulation. The Commission implemented this statute through the ongoing Competition Transition Charge ("CTC"), which is set using the Current Methodology and collected from all utility distribution customers.[13] In addition, the Legislature required the Commission to adopt a nonbypassable charge to recover other procurement-related costs that are incurred on behalf of customers that depart utility bundled service for a DA or CCA program.[14] The Commission implemented this requirement through the nonbypassable Power Charge Indifference Adjustment ("PCIA") rate. Together, the PCIA and CTC rates (using the Current Methodology) attempt to recover the above-market costs of the Joint Utilities' respective generation portfolios from departing load customers.[15]

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[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.

More recently, the Legislature enacted statutes that require the costs for resources that provide system-wide or local reliability benefits, or facilitate the integration of renewable energy resources, be allocated to all customers that benefit from these resources, including end-use retail customers of the Joint Utilities, CCAs, and ESPs.[16] The Commission implemented system and local reliability cost allocation through the Cost Allocation Mechanism ("CAM"), which has proven largely effective in fairly allocating procurement costs and benefits to all benefitting customers; the CAM is the conceptual basis for the PAM, which is proposed to replace the Current Methodology.

Replacing the Current Methodology (and its resulting PCIA and CTC rates) with PAM is a critical step in ensuring indifference in the face of the current and anticipated significant load departures to alternative procurement service providers. The Current Methodology is out-of-date and unable to produce results based on actual market conditions. The Current Methodology was conceived during a time when levels of departing load were rather modest, and as detailed below, even if modified, the Current Methodology breaks down further with increasing levels of departing load.

Attempting to "fix" the inputs to the Current Methodology is not the answer. The Current Methodology is premised on market proxies which often do not reflect actual market outcomes. Nor does the Current Methodology employ a true-up mechanism to reflect actual market outcomes. It was put in place before more sophisticated mechanisms, such as CAM, were conceived and successfully implemented. It is not reasonable to try to "fix" a mechanism that is inherently inconsistent with State law; any cost-allocation mechanism that relies on administratively-set benchmarks ultimately will result in cost shifting to or from remaining bundled service customers depending on actual market outcomes.

The Current Methodology has also been the subject of endless litigation and disputes, and it is ill-designed to effectively manage currently-anticipated levels of departing load. Instead, the

[16] Cal. Pub. Util. Code §§ 365.1, 454.52.

Commission should replace it with the PAM, which is a transparent, accurate, equitable, and scalable mechanism that will appropriately allocate costs and benefits at all levels of departing load in a manner that always ensures customer indifference, as required by California law.

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

> If, due to future changing circumstances, the processes adopted by this decision for determining the [PCIA and CTC] become unworkable, unbalanced, or unfair, parties may propose and request, for our consideration, modifications to the form of the [PCIA and CTC] or the manner in which [it] should be determined or calculated.[17]

As will be described throughout this Testimony, circumstances have changed; the Current Methodology has become unworkable, unbalanced, and unfair; and a complete replacement to the Current Methodology is now necessary.

B. Need for Reform

The Current Methodology has undergone a number of modifications since it was first adopted by the Commission under the rubric of the Cost Responsibility Surcharge ("CRS") in 2002.[18] The central driver for these modifications has been a desire on the part of the Commission and the parties to more accurately determine and apportion the above-market costs of these resources.

The Joint Utilities' generation rates, set annually in their respective ERRA Forecast proceedings, recover the total resource costs (less the "Indifference Rate" payments by departing load customers) from bundled service customers. For departing load customers, an "Indifference Rate" is determined using the Current Methodology to approximate their pro-rata share of above-market costs, and recovered through the CTC and the PCIA. To approximate the above-market costs, the Indifference Rate starts with the forecast costs of

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[17] D.08-09-012 p. 58.

[18] *See* D.02-11-022 (adopting the initial CRS).

the utility generation portfolio and subtracts an estimate (proxy) of the revenue those resources could garner in the market using forecasts of energy prices and administratively-determined benchmarks, which collectively comprise the Market Price Benchmark ("MPB"). These values are not trued-up after the fact. Thus, the Indifference Rate is the result of a forecast of portfolio costs that is inevitably inaccurate and an imprecise proxy of theoretical market outcomes.

Proxies – by their nature – do not reflect actual market conditions and therefore shift costs in one direction or the other. Despite numerous Commission modifications, the Commission-adopted MPBs are much higher than actual realized market prices, particularly for renewable and RA values.[19] These discrepancies – which have resulted in cost shifts to remaining bundled service customers – were less consequential (although still prohibited by statute) when the level of departing load was stable and relatively modest. However, with the recently realized and expected increases in departing load in the immediate future from CCA expansion (not to mention the potential reopening of DA), these discrepancies will cause increasingly large cost shifts to remaining bundled service customers, which is prohibited by law and plainly inequitable.

C. History and Description of the Current Methodology

In D.02-11-022, the Commission first established the CRS to recover from departing load customers their share of the "(1) costs incurred by Department of Water Resources ("DWR") on behalf of customers in the service territories of the three IOUs ("DWR Power Charge"), and (2) costs incurred by each of the IOUs for their own resources and contracts (CTC)."[20] The method adopted for calculating these components of CRS was known as the "DA In – DA Out methodology" which used a production cost model to determine the increase in the average

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[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.

generation cost to the bundled service customers as the result of some customers switching to DA service, and the CRS applicable to those DA customers to keep the average bundled service generation rate at the same level.

Due to the complexity and lack of transparency in this methodology, especially as related to the market-clearing prices used in the modelling process, a working group established by the assigned Administrative Law Judge in Rulemaking ("R.") 02-01-011 proposed the Current Methodology for calculating the CTC and PCIA using a MPB that was comprised of a forward market energy price and a negotiated capacity adder on a $/MWh basis. The Commission adopted this proposed methodology in D.06-07-030.[21] The Commission ordered that the working group be reconvened in August 2006 to discuss and propose a capacity adder for 2007 and beyond.[22] However, due to the lack of a functioning and transparent capacity market or a suitable public index, the working group proposed to continue the use of a negotiated capacity adder until such a market was developed.[23]

The last and most recent decision to modify the MPB to arrive at its current structure was D.11-12-018. In that decision the Commission decided that because a larger portion of the Joint Utilities' respective portfolios will consist of relatively more expensive renewable resources procured to comply with RPS, it is reasonable to augment the MPB with an "RPS adder." Again, because of the lack of a robust and transparent renewable market or suitable public index at the time, the Commission adopted an administratively-set benchmark based on the average price of the Joint Utilities' newly delivering (but not newly executed) contracts (weighted at 68%) and

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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.

the average price of voluntary green pricing programs spread throughout the Western Electricity Coordinating Council ("WECC") geographical footprint (weighted at 32%).[24]

In the same decision, due to the lack of a transparent market price for RA capacity and having relied on negotiated numbers for many years, the Commission adopted a capacity adder equal to the going-forward costs of a simple combined-cycle combustion turbine as estimated by the California Energy Commission ("CEC") and updated biannually.[25]

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 and capacity provided by those resources is approximated using the MPB as described above;
3) This value is subtracted from the forecast costs to determine the above-market costs of the total portfolio, which are then allocated to various rate groups based on their contributions to the highest 100 hours of system load to establish an Indifference Rate;
4) Similar calculations are performed to approximate the above-market costs of resources identified in P.U. Code § 367[26] to calculate the CTC, which is then subtracted from the Indifference Rate to residually determine the PCIA;[27] and,
5) The Indifference Rate is set annually in each utility's ERRA Forecast proceeding on an estimated basis and is not subject to a true-up.[28]

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[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.

D. Reliance on Administratively-Set Benchmarks is Fundamentally Flawed and Does Not Result in Indifference

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.[29] To date, the Commission has relied on administratively-set price inputs as proxies for market value. Unfortunately, these efforts have not been successful and have resulted in convoluted and heavily-inflated MPBs. At best, benchmarks are "educated guesses" about future market outcomes, and when administratively set, they may become even more disconnected from actual market conditions. Consistent with State law and policy, PAM replaces the "guess work" with actual market outcomes and protects bundled service customers by ensuring customer indifference at any level of departing load.

1. Flaws in the Existing MPB Result in Cost Shifts

The values of the current administratively-set RPS and RA benchmarks are materially overstated. In other words, current market prices for these attributes are much lower than the benchmarks. The RA value is overstated because it is set equal to the going-forward cost of a 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. The RPS value is overstated because the costs of recently delivering resources are based on contracts negotiated and executed several years prior, when prices were much higher than they are today. Furthermore, the premiums associated with the voluntary green

(Continued from previous page)

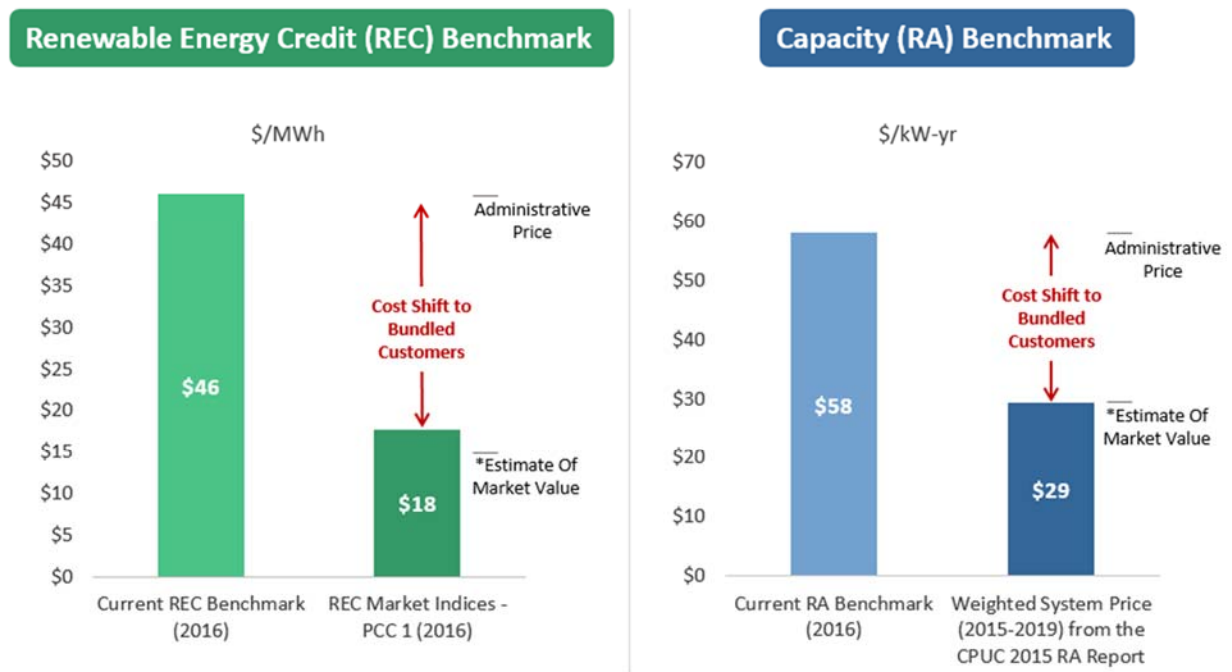
[28] Although these costs were subject to a true-up when the Commission first adopted this methodology, the true-up was later eliminated due to parties seeking more certainty and simplicity in the calculation of CTC and the PCIA. *See* D.08-09-012, p. 69.

[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-1*[30]**

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).

information, and reflect a conservative estimate of the current, substantial costs that are being shifted from departing load customers to bundled service customers.

During the Commission-ordered PCIA Working Group process[31] and over the past few years, the Joint Utilities have expressed concerns that the MPB is overstated and not reflective of the actual market value of the Joint Utilities' generation portfolios.[32] Other parties have disagreed. With PAM, the Commission does not need to adjudicate who is "right," or be satisfied with an inadequate approximation of indifference—deficiencies which become more problematic as departing load increases. Under PAM, estimation and forecasting are replaced with after-the-fact actual energy market results to determine the vintaged portfolios' net costs. PAM also uses actual customer demand to facilitate a pro-rata allocation of the value of those same portfolios (i.e., their "attributes") to all vintaged customers.[33] Compared to the Current Methodology, PAM is more transparent, based on actual portfolio costs and revenues, accurately allocates benefits and net costs of the Joint Utilities' portfolios to bundled service and departing load customers (and their LSEs), and will achieve a far superior implementation of the statutorily-mandated indifference requirement.

2. <u>Existing REC Benchmarks Are Volatile, Not Transparent, and Do Not Accurately Reflect Market Prices</u>

Some CCA and DA parties have expressed concerns that the Indifference Rate resulting from the Current Methodology is volatile, making it difficult to forecast and plan. As shown in the charts below, the volatility and uncertainty in current departing load CTC and PCIA

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[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).

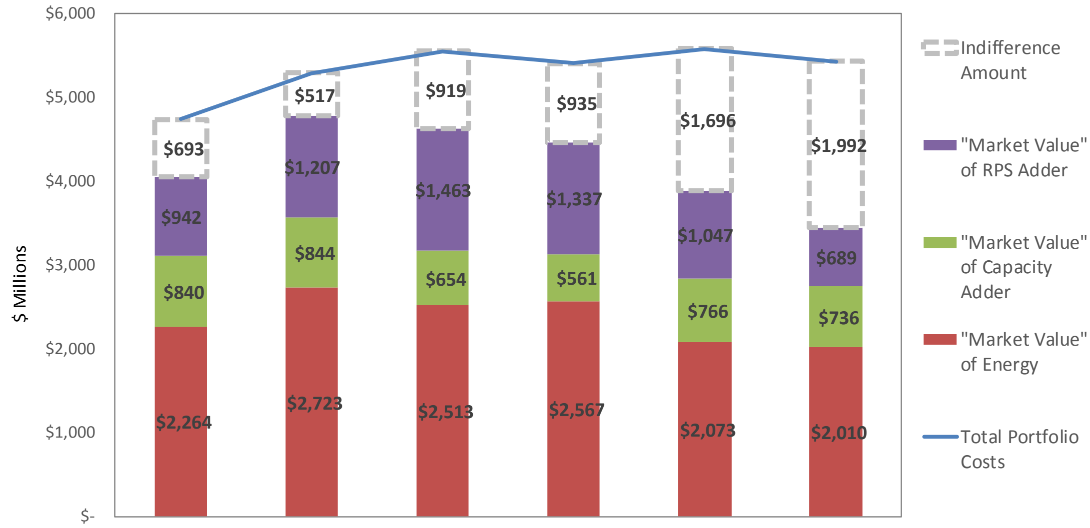
[33] For attributes such as Resource Adequacy which must be used prior to market results, PAM uses the latest forecasts reasonably available to make a pro-rata allocation to all load serving entities ("LSEs) based on each LSE's load share ratio.

rates is largely driven by the volatility[34] and lack of transparency in the RPS adder (or "REC Benchmark"). The REC Benchmark has fluctuated significantly since its introduction in 2012, and is based largely on confidential RPS contract-pricing data that is finalized and validated by 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 Vintage[36]



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.

increasing, its rate of increase has not sufficiently protected remaining bundled service customers from unlawful cost shifts. It should be noted that departing load customers (through their CCAs and ESPs) can now procure RPS-eligible resources on the open market at prices significantly less than they otherwise would have been paying absent this earlier utility procurement that helped transform the market, but remaining bundled service customers must still pay the fixed (high) costs of the early RPS contracts.[37] The Legislature and the Commission implemented the statutory indifference requirement precisely to prohibit the cost-shifting consequences that would result if departing load customers were permitted to avoid some of these unavoidable historical costs.

That cost-shift will only continue to increase if not addressed now. Looking ahead, under the Current Methodology, the RPS adder component of the MPB is likely to continue to diverge from market conditions. 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.[38] This would result in an RPS benchmark that will be set based on a limited set of resources – most, if not all, of which will be procured pursuant to state-mandated "carve-out" programs[39] and thus much more expensive than the current prices for market-based, large-scale renewable resource procurement. This will result in greater inflation of the RPS adder that does not reflect the actual market value of RPS resources. A significant portion of the Joint Utilities' CTC- and PCIA-eligible portfolios are comprised of renewable resources; thus, the Indifference Rate is and will continue to be largely driven by an unreliable and inflated RPS adder. Administratively-set benchmarks should not be used at all, when instead they can be replaced with a mechanism like the PAM which can allocate both the portfolio benefits (e.g., the RPS attribute) and actual net costs on a load share basis to each customer and its LSE.

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[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.

The Current Methodology also inhibits transparency of its calculations and results. The current RPS adder relies on confidential utility contract data, which limits the ability of the Joint Utilities to disclose forecast changes in their current Indifference Rates to CCA and DA entities, as they are market participants. The RPS adder data sources are not only highly variable, not representative of actual market conditions, and non-transparent, they are also the major underlying cause of the current and growing cost shifts between bundled service and departing load customers. There should be no question that the use of actual market outcomes and resource attributes is the most effective means to ensure customer indifference.

E. Need for a Methodology that Can Scale

The Current Methodology implicitly assumes that the Joint Utilities' excess remaining RA, RECs, and other potential portfolio attributes after load departs can either be sold at the MPB value or used to offset future procurement. While this assumption is flawed even when small amounts of load departs (as discussed above), the flaws are amplified with large amounts of load departure. In that situation – 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 their portfolios and their attributes at prices anywhere near the MPB because the market will be very long with excess bundled service portfolio attributes. Indeed, even a more accurate market-based index, if one existed, would be unable to capture the effects of such a scenario given the magnitude of the Joint Utilities' portfolios. Therefore, as the level of departing load increases, the current "above-market construct" will result in an ever-decreasing number of remaining bundled service customers absorbing an increasing level of above-market portfolio costs. This systematic cost shift to remaining bundled service customers is inherently inequitable, unsustainable, and incompatible with the indifference requirement clearly specified by law. Instead of contemplating further revisions to inputs of the MPB, PAM offers a structure that robustly ensures customer indifference at any level of departing load.

Second, allocating the attributes of the Joint Utilities' respective portfolios to all LSEs that serve departing load would enable those LSEs to scale their operations and plan to serve their load in a manner that optimizes the existing utility resources which were procured to also serve the departing load customers. This will ensure greater societal efficiencies in achieving the State's clean energy policy goals and mandates, including the requirement that 65 percent of each LSE's RPS compliance requirement be met with long-term RPS energy deliveries starting in 2021.[40] Absent such an allocation of attributes, as the level of departing load increases, there will be a glut of those attributes 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.

[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

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[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.

initial rates will be set in the Joint Utilities' respective annual ERRA Forecast proceedings based on a forecast of costs and offsetting market revenues (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.[44] This method mirrors the process used to set bundled service generation rates and New System Generation rates,[45] and most importantly, ensures that all customers pay their pro-rata share of the net resource costs for which they are responsible. Furthermore, net resource costs will be reviewed and validated annually in each utility's ERRA Compliance proceeding to ensure that the utility prudently managed its resources pursuant to the Commission's Standard of Conduct 4 ("SOC 4") Least-Cost Dispatch ("LCD") requirements. This is the same review the Commission currently conducts for the Joint Utilities' bundled service customers' portfolios in the annual ERRA Compliance proceedings, and under PAM the utilities will continue to be required by SOC 4 to efficiently dispatch the portfolio for all customers, both bundled service and departing load. In the ERRA Compliance proceedings, the Commission will also continue to scrutinize the Joint Utilities' prudent contract administration obligations (on behalf of all customers under PAM).

PAM also establishes a process for an equitable and efficient allocation of all of the attributes (value) of the resources in the utilities' portfolios, including the value of the energy and ancillary services (which will be realized through the market revenues that are used to offset the resource costs), and direct assignment of RECs, RA, and any future benefits that may come into existence with policy or market development, as appropriate.[46] As described in more detail below, 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. They will also realize the annual energy attributes of the portfolio (*i.e.*, the market revenues) as an offset to costs

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[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.

embedded in the PAM rate.[47] This is symmetrical to the way that bundled service customers' generation rates are set. The long-term planning information can also be used by LSEs to build out or rebalance their residual generation portfolios.[48] Actual REC and RA allocations will take place quarterly and monthly, respectively, and will reflect actual load (for REC allocation) and peak load shares (for RA allocation)[49] to ensure alignment between actual revenues received from customers and benefit allocations. Moreover, these ongoing allocations will reduce ESPs' and CCAs' future need for RA and RPS procurement, thereby serving as a long-term hedge against fluctuations in the prices for those products (again, symmetrical to the functions those resources serve for bundled service customers).

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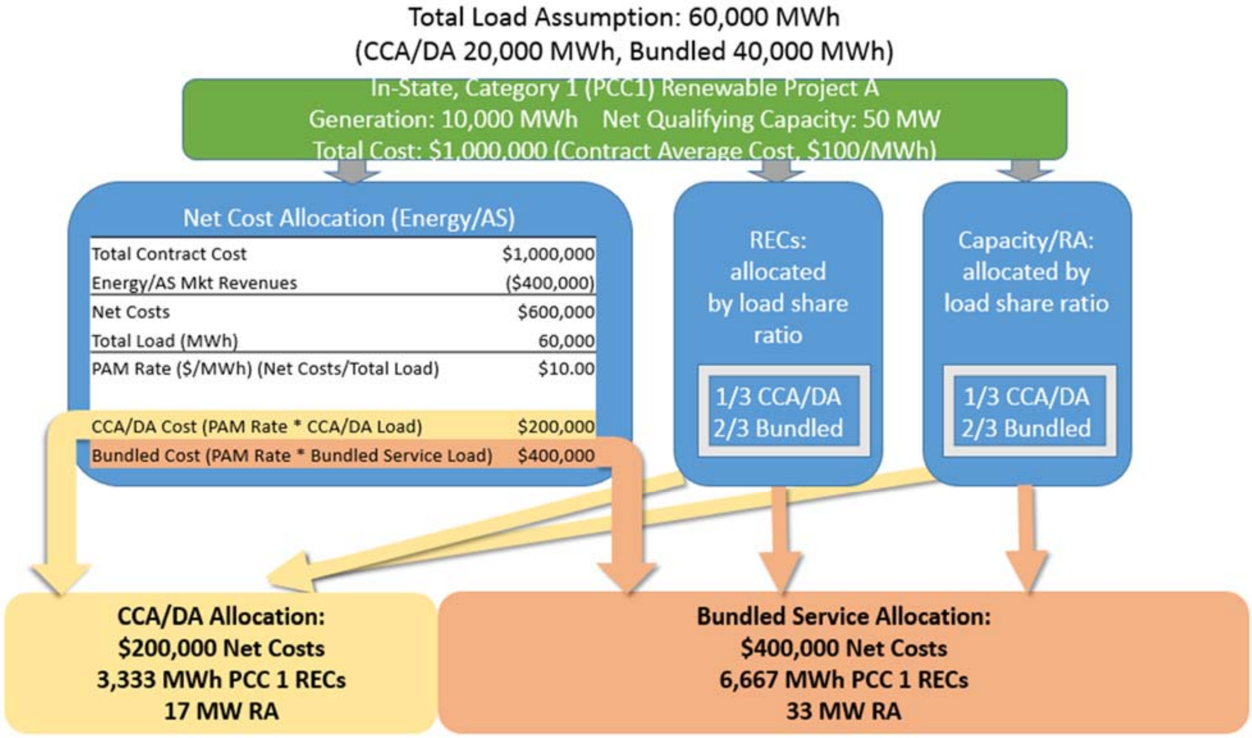
[47] The Joint Utilities' RPS contracts are largely fixed-price contracts. To the extent that market prices at any point exceed those contract-defined prices, the contracts will be "in the money" in the energy markets, and all customers will equitably benefit from the resulting market revenues. *See* 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.

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[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.

There are several advantages to PAM compared to the Current Methodology. First and foremost, PAM protects all customers through a transparent process that uses actual market results rather than hypothetical, administratively-set market proxies. PAM will replace an "estimation" construct that relies on inaccurate and contentious administratively-set MPBs with actual and verifiable net resource costs, including a true-up process, and a direct allocation of the full benefits of the resources. PAM results in both departing load customers and remaining bundled service customers paying the same net cost, on a per-kWh basis, for each resource for which they are collectively responsible.

In addition, given PAM's reliance on long-term contract information and actual market data, predictability and transparency of the rates are improved. Long-term contracts have predictable costs, and accordingly portfolio managers can forecast around the resulting, more-predictable, costs, revenues and benefits. Indeed, long-term renewable contracts, which comprise the majority of the PAM-eligible portfolio, have little to no variable operating costs and a "fixed price" per MWh of generated energy. CCAs and ESPs can use this predictable resource-specific data, along with their own forward energy price curve forecasts, to develop their own forecasts of future rates.

Finally, the resources that will be subject to PAM are all resources that were approved by the Commission and procured to meet then-bundled service load requirements consistent with State policy directives. By allocating to customers their pro-rata share of these resources' attributes, customers take with them the inherent value of actions taken to support the State's regulatory and public policy, and pay their equitable pro-rata share of the costs of those actions taken on their behalf.

B. <u>Resources Subject to PAM</u>

The resources that will be subject to PAM (PAM-eligible resources) include all resources eligible for recovery under the Current Methodology (*i.e.*, all CTC- and PCIA-eligible resources). In addition, as discussed in Chapter VII of this testimony, the Joint Utilities propose to eliminate the 10-year cost allocation period limit for UOG fossil fuel resources acquired through a procurement process after 2002, as adopted in D.04-12-048 and D.08-09-012, and make these UOG resources PAM-eligible. PAM-eligible resources, which have been approved by the Commission or procured through rules adopted by the Commission in the Joint Utilities' LTPPs, RPS Plans,[53] and Energy Storage Plans were procured or built on behalf of then-bundled service customers, and any forecast bundled service load growth, to meet bundled service load requirements or the State's policy directives, and their costs and benefits should be allocated to all customers for whom they were procured.

All costs associated with the PAM-eligible resources will be included in the calculation of the net costs of the PAM-eligible resources. These direct resource costs, and any associated indirect resource costs, are currently included in the "Total Portfolio Costs" used in the Current Methodology to calculate the PCIA and CTC rates and are described in further detail in Appendix D.

1. <u>PAM-Eligible Contracts</u>

The PAM-eligible portfolio will include all RPS-eligible, non-RPS-eligible, and energy storage contracts[54] included in the Current Methodology. As will be described in further detail in Chapter VI, the net costs of contracts that are currently recovered through the CTC rate will be recovered through a modified CTC rate component based on the PAM methodology,[55] and the net costs of resources that are currently recovered through the PCIA rate will be

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[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 terms[56] (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-

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[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**.**

eligible until the last of the long-term contracts associated with those customers' vintaged portfolios expires, with the caveat that the Joint Utilities specifically reserve the right to seek Commission approval of future UOG cost allocation should circumstances so warrant.[59] [60] As explained in more detail in Chapter 7 of the Joint Utilities' Testimony, the ten-year cost allocation limitation is discriminatory and unreasonable because it results in treating similarly situated resources differently. Instead of imposing an arbitrary cost allocation limitation, UOG and other resources currently subject to the ten-year cost allocation limit should receive similar cost allocation treatment and thus the costs for these resources should be recovered through PAM until the last of the long-term contracts associated with those customers' vintages expire so that all resources are treated similarly.

3. Resources Ineligible for PAM

PAM will exclude any current or new resources such as system reliability-, emergency-, and policy-based procurement that the Commission determines are eligible for broad cost allocation. Additionally, the Commission and the Legislature have previously

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[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 ERRA 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 ERRA 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 ERRA Forecast Phase 2 proceedings.

concluded that all customers, including departing load customers, bear responsibility for the cost of the Joint Utilities' procurement of biomass resources in response to the Governor's emergency proclamation on tree mortality.[61] As such, the Joint Utilities do not propose any changes to current cost allocation mechanisms associated with these existing programs.

The PAM will also exclude any short-term contracts or transactions less than one year in length. Exclusion of such resources is consistent with the Current Methodology.[62]

C. Market Revenues for Energy and Ancillary Services

The Joint Utilities propose that, instead of allocating to each LSE its customers' estimated share of the energy-related (*e.g.*, energy and ancillary services) benefits from the PAM-eligible resources, the PAM-eligible resources be bid or sold into energy and ancillary services markets and the actual revenues they generate be allocated to all customers for whom the resources were procured.[63] The actual revenues received from the energy and ancillary services markets (*i.e.*, the energy benefits) will be netted against the cost of the resources to reduce the costs of the resources ("net costs").[64] This approach is both consistent with CAM, in which the Joint Utilities use market revenues to reduce the costs of the CAM-eligible portfolio, and ensures that the energy benefits of the PAM portfolio, including any energy price hedge value, are shared equitably by all customers.

Under PAM, the Joint Utilities will continue to manage the PAM-eligible resources and bid or sell them into energy markets if the utility is the Scheduling Coordinator ("SC").[65] 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.

service customers' generation requirements as is currently done, the Joint Utilities will use the revenues received from participation in the energy markets[66] to directly offset the costs of the resource, resulting in a reduced net cost to bundled service and departing load customers. This proposal eliminates the enormous complexity that would be involved in attempting to allocate a pro-rata share of the energy to all LSEs—a process which would require LSEs to submit inter-SC trades for their small slices of power from numerous resources with the respective resources' SCs—and is reasonable given the Joint Utilities' obligation to realize market revenues by abiding by SOC 4's LCD principle,[67] which requires that "[t]he utilities … prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[68]

Additionally, the Joint Utilities' proposal ensures that the customers who are responsible for the costs of the resource receive the energy price benefit that the resource provides, regardless of their current LSE. This aspect of PAM will provide the same energy price protection to departing load customers as will be received by remaining bundled service customers. A simple example is shown in Figure V-4, below. Because the majority of the Joint Utilities' resources are fixed-price long-term contracts, each LSE is hedged against price fluctuations in the energy market by the amount of fixed price energy that represents their load share ratio of the utility's portfolio. In the example below, the utility contract provides a fixed cost of $60/MWh regardless of whether the spot price is higher ($80/MWh in Scenario 2) or lower ($40/MWh in Scenario 1) than the contract price of $60/MWh.

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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
Corresponding Load (1 MWh)		40.00	40.00
Total Cost			60.00
CAISO Price Scenario 2			
PAM RPS Delivery (1 MWh)	60.00	-80.00	-20.00
Corresponding Load (1 MWh)		80.00	80.00
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. **Proposed REC Attribute Language to Enable REC Allocation under PAM**

As will be described in further detail below, the Joint Utilities propose to allocate a portion of their total PAM-eligible REC portfolios[71] to a CCA or ESP under PAM. This proposal is designed to ensure that both bundled service and departing load customers do not experience cost shifts. In the past, parties have expressed some concern that allocating a PCC 1 REC[72] would result in the REC being classified as PCC 3,[73] decreasing the value of this benefit. Additionally, there may be questions regarding whether the full long-term compliance benefits of RECs transferred to other entities via PAM will count toward the transferee's long-term RPS compliance requirements.

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

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[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.

Additionally, this Application requests that the Commission implement the long-term procurement requirement in the RPS statute, as revised in 2015 by SB 350,[74] to the extent necessary to clarify that RECs associated with either contracts between the procuring utility and the generator for delivery terms of 10 years or more or the procuring utility's ownership or ownership agreements for eligible renewable energy resources and subsequently transferred to other LSEs under the PAM or another Commission-approved allocation methodology count for the transferee as RECs from "its contracts of 10 years or more in duration" or "its ownership or ownership agreements for eligible renewable energy resources."[75] These clarifications will allow other LSEs to realize the full benefits of renewable procurement done on behalf of their customers and for which they are paying their proportional share of the net costs.

2. <u>REC Allocation Basis and Mechanism for Transfer</u>

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 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.[76] There will likely be no need for a material true-up at the end of each year because RECs are created subsequently

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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. <u>REC Allocation Timing</u>

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. <u>REC Adjustments</u>

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.

(even as small as one REC), and may require a true-up REC transfer to ensure equitable treatment between the utility and a CCA or ESP.

In the event an adjustment occurs within WREGIS that requires a true-up, the utility will determine how all of the adjusted RECs from a given quarter must be allocated based on the CCA's or ESP's load share, and will then make this allocation during the next transfer window. This true-up allocation process may require the utility to transfer additional RECs to a CCA or ESP, or it may require a CCA or ESP to transfer RECs back to the utility.

E. Resource Adequacy Allocation Process

The RA attribute allocation methodology should ultimately align with the allocation of costs, distribute the attributes in proportion to compliance requirements, and provide portfolio predictability to the participating LSEs. Much of the Joint Utilities' PAM proposal relies on the existing RA allocation framework and process used for CAM, with a few modifications to accommodate the vintaged nature of PAM portfolios, equally distribute the risk exposure associated with managing unit outages, and match the timing of RA program requirements to allocations of RA.

The current CAM process requires the Joint Utilities to submit to the Commission a list of their CAM-eligible resources ("Eligible Resource List"). This list identifies each resource's CAISO ID, System, Local and Flex RA Net Qualifying Capacities ("NQCs"), and other relevant attributes, and is refreshed annually around August for the upcoming year's CAM allocation ("Year Ahead CAM list"), and again quarterly for CAM System RA allocation updates ("Quarterly CAM list"). The Joint Utilities propose to use the same CAM data template for allocation RA under PAM, whereby each utility will submit to the Commission a list of PAM-eligible resources with corresponding CAISO IDs, RA attribute designations and "portfolio 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 requirements[80] 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 forecasts[82] 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.

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[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.

The mechanics of attribute transfer should follow that of the existing CAM contracts accounting process whereby the IOU's RA requirement increases (*i.e.*, a PAM debit) by the quantity of RA transferred to PAM participants, and a receiving LSE's RA requirement decreases (*i.e.*, a PAM credit) by its peak load share of the PAM portfolio, resulting in a net zero total RA requirement change among all entities receiving PAM RA allocations. This process is conducted for System RA, Local RA, and Flex RA attributes. This process is well established in CAM, and will result in the least amount of administrative burden in the transition to a PAM RA attribute allocation.

2. <u>RA Allocation Timing</u>

Similar to the intent to utilize as much of the CAM process as possible for resource identification, peak load share determination, and transfer of attributes, the Joint Utilities propose to utilize the timing of the CAM allocation for PAM RA allocation, with the exception of the month-ahead allocation described in section b, below. The allocations would occur commensurate with all RA compliance requirement determinations, which are annually, monthly, and a mid-year update.

a) <u>Year-Ahead Allocation</u>

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

b) <u>Month-Ahead Allocation</u>

The forecasts submitted on the Month Ahead Load Forecast Template, which captures each LSE's forecast load migration amounts, sets each LSE's Month Ahead System RA requirements. These Month Ahead requirements should trigger a reallocation of 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-eligible energy, and net costs. At the same time, Joint Utilities are required to keep certain contract information confidential as required by the Commission's confidentiality rules and contract confidentiality provisions. The Joint Utilities will continuously seek to provide the most granular data while adhering to confidentiality obligations. In addition to providing ERRA year-ahead forecasts of costs, generation and RA, the Joint Utilities will provide contract level information where possible, and aggregate data where necessary, to support the LSEs' development of long term forecasts to meet their own planning needs.

The Joint Utilities recognize the need for a formal process to provide portfolio and contract data to LSEs as a part of PAM, and anticipate that a detailed process will need to be put in place that balances necessary transparency and planning certainty for LSEs; rules to protect customers and market integrity; and contractual counter-party confidentiality obligations. To that end, the Joint Utilities propose to open a second phase in this proceeding. In Phase 2, the Joint Utilities will work with LSEs to develop proposals on this issue, including on the frequency and format of the portfolio data that will be shared with LSEs to facilitate their portfolio planning. The Joint Utilities anticipate that ESP and CCA representatives, and other interested parties will actively engage in Phase 2, and the Joint Utilities are optimistic that the process will be collaborative and productive given the need for all LSEs to have access to necessary information to forecast their pro-rata share of the utility's energy portfolio.

G. Impact of PAM on Incremental Procurement Costs in the Event of a Mass Return

Because PAM allocates a proportionate share of the attributes to the LSE serving the CCA or DA customers and allocates the net costs to the customers based on a vintaged portfolio method, it ensures that costs and attributes of a vintaged portfolio are allocated equitably and that all customers are treated the same. In addition to ensuring equity between customers, in the event of a mass involuntary return[84] of CCA or DA customers to a utility's procurement service, 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.

the need for the utility to procure resources to serve the returned load, thereby mitigating some of the exposure to the incremental procurement cost risk resulting from such mass return of 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 portfolio[85] 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

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[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."

Amount, on a vintaged basis, and to set the departing load Indifference Rate.[88] Revenues collected from both bundled service customers' CTC and generation rates and departing load customers' CTC and PCIA rates ("billed revenues") are recorded in the ERRA.[89] [90] In other words, the ERRA has traditionally been the primary account used to record all generation-related costs—both the net costs associated with utility-owned and contracted resources and the costs of market purchases. Revenues from departing load customers' CTC and PCIA rates, intended to account for their "share" of the above-market costs of the utility-owned and contracted resources, are credited to the ERRA to theoretically ensure that bundled service customers' generation rates are not impacted by any customer's decision to depart bundled service.

But, as described in earlier chapters, the Current Methodology is not effective at quantifying and recovering the above-market costs of the Joint Utilities' generation resource portfolios. Additionally, although revenues collected from both bundled service and departing load customers are recorded in the ERRA, any differences between forecast costs, actual costs and billed revenues are solely assigned to the bundled service customers. As such, the Current Methodology cannot ensure the protection of bundled service customers from increased costs due to departing load. Although historically and currently that cost-shift results in bundled service customers subsidizing departing load customers, in theory, the Current Methodology could also result in cost shifts in the other direction. PAM eliminates cost shifting in either direction as required by statute.

The following sections describe the Joint Utilities' proposed changes to the existing cost recovery mechanisms that achieve indifference and provide transparency to that

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[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.

process. The Joint Utilities' proposal, which tracks the actual net costs by vintage—based on actual costs and market revenues, and actual billed revenues from customers — ensures that all customers pay only the actual net costs of the resources that were procured on their behalf and for which their LSEs receive benefits.

2. Ratemaking Proposal

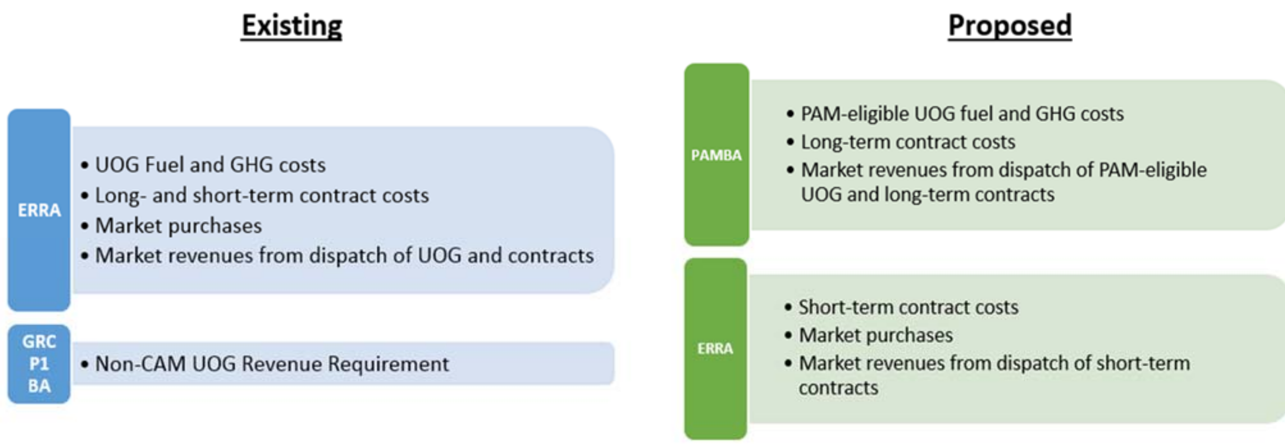
The Joint Utilities propose to modify the generation-related balancing accounts to more clearly delineate the costs and the associated market revenues of long-term[91] generation resources entered into on behalf of then-bundled service customers, the benefits of which will be shared with those customers, and the costs of meeting the residual requirements of the current bundled service customers.

To accomplish this objective, the Joint Utilities propose to establish the Portfolio Allocation Methodology Balancing Account ("PAMBA") and modify the ERRA and GRC Phase 1 generation-related balancing accounts, as is described in detail below. The changes to the ERRA and the GRC Phase 1 generation-related balancing accounts are necessary to ensure that costs and revenues are not double counted and that any UOG-related base revenue requirements eligible for recovery from both bundled service and departing load customers are also recorded in the PAMBA instead of the Joint Utilities' respective GRC Phase 1 generation-related balancing accounts.

Figure VI-5, 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.

[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) <u>PAMBA</u>

The PAMBA will have a subaccount for each vintaged portfolio[93] 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.

service customers that year—customers who are receiving the benefits of those resources (and on whose behalf those resources were procured or built), as described in Chapter V.

For example, there will be a 2010 vintaged subaccount that will record the costs and market revenues of all generation contracts executed in the calendar year 2010 and the UOG approved by the Commission for cost recovery in 2010. Departing load customers who leave after July 2010 (those with customer vintage 2010 or later) and current bundled service customers are thus responsible for these costs. As such, they will be responsible for the net costs recorded in that 2010 subaccount and all "prior" 2004-2009 subaccounts, including the non-vintaged CTC and Legacy UOG[94] subaccounts. Conversely, customers who departed before 2010 were not bundled service customers at the time those contracts were executed or UOG was approved by the Commission for cost recovery and would not be responsible for the net costs recorded in that 2010 subaccount.[95] This is illustrated in Figure VI-6, below.

The billed revenues collected from bundled service and departing load customers will also be recorded in the PAMBA (credit) on a vintaged basis, as is described in further detail below. Any differences between the actual recorded net costs and the billed revenues will be carried forward and included in bundled service and departing load customers' rates in the following year, similar to what is done for bundled service customers' generation rates today. Each vintaged subaccount of the PAMBA will thus include the following monthly debit and credit entries:

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[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.

Debits

1) Fuel and GHG costs associated with the PAM-eligible UOG resources in that vintaged portfolio;

2) Recorded utility payments to the long-term contracted generation resource counter-parties in that vintaged portfolio; and

3) GRC-derived base rate revenue requirement of the PAM-eligible UOG resources in that vintaged portfolio

Credits

1) Market energy and ancillary service revenues associated with the contracted and PAM-eligible UOG resources in that vintaged 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 portfolio multiplied by the actual kWh usage of departing load customers responsible for the costs of that vintaged portfolio.

Credits or Debits

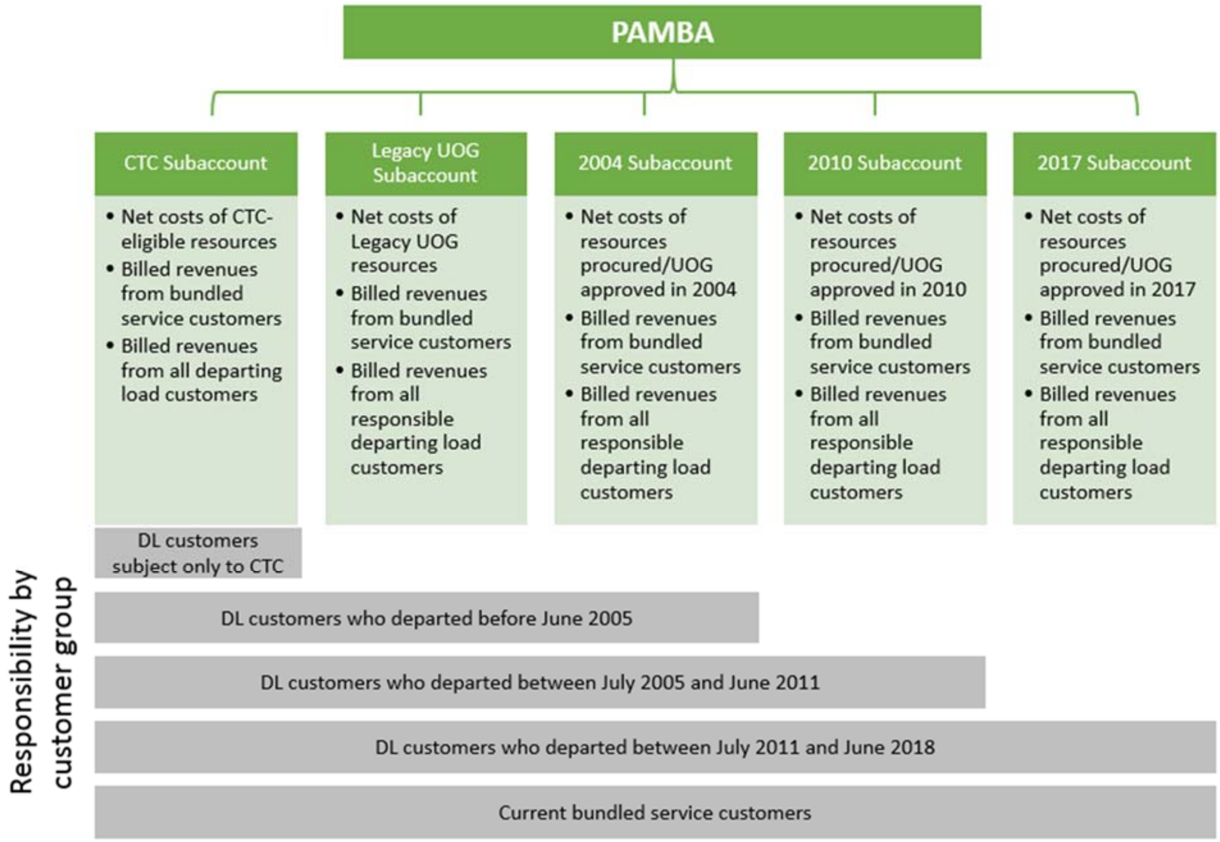
1) Interest on any monthly over-or under-collection at the three-month commercial paper rate

End-of-Year balances in each subaccount of PAMBA will be reflected in the vintaged rate in the 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.

In other words, the PAMBA will record all costs and revenues that are currently recorded in the ERRA except for the costs associated with payments to CAISO that are attributable only to meeting bundled service energy requirements and the costs of any other resources that are ineligible for PAM. Additionally, the PAMBA will also record the revenue requirements of all PAM-eligible UOG resources, which are currently recorded in the Joint Utilities' GRC Phase 1 balancing accounts. The following figure depicts the general structure of PAMBA subaccounts and customers' responsibility for the balances of those subaccounts with an illustrative assumption of 2005, 2011 and 2017 vintages of departing load.

Figure VI-6
Proposed PAMBA Structure[97]



b) <u>ERRA</u>

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.

generation revenues to cover these costs, as described below, will be recorded as a credit to the ERRA.

c) <u>GRC Phase 1 Generation-Related Balancing Account</u>

The base rate revenue requirement for PAM-eligible UOG, as determined in each utility's respective GRC proceeding, will now be recorded in the PAMBA, and will no longer be recorded as a cost in the GRC Phase 1 generation-related balancing account. Additionally, the portion of the monthly bundled service billed generation revenues that would have been credited to the GRC Phase 1 balancing account towards the recovery of the PAM-eligible UOG base revenue requirement will now be credited to the PAMBA.

3. <u>Determination of Billed Revenues to be Recorded in Each Balancing Account</u>

Billed revenues collected from bundled service customers' CTC and generation rates and departing load customers' CTC and PAC rates will be directed into the various accounts for which they are responsible. This process, which is done today to separate and direct bundled service customers' generation billed revenues into the ERRA and GRC Phase 1 balancing accounts, is described in the Preliminary Statements of the Joint Utilities' tariffs[99] and updated regularly to ensure that the correct amount of billed revenues, based on current revenue requirements, is directed to each balancing account. The Joint Utilities propose to utilize this same process to separate and direct billed revenues received from bundled service and departing load customers to the appropriate balancing accounts. A description of the process is included in Appendix D.

4. <u>ERRA Trigger</u>

Currently, the Joint Utilities are required to file an application with the Commission to propose to adjust their bundled service generation rates when the under- or over-collection in the ERRA balancing account exceeds 5% of the prior year's revenue that is

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[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

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[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.

RA to individual CGDL customers. Thus, the Joint Utilities propose that bundled service customers "buy back" the RECs and RA that would have otherwise been allocated to the CGDL customers. In other words, bundled service customers will purchase the RECs and RA from the CTC-eligible portfolio that would have otherwise been allocated to the CGDL customers, and those proceeds will be subtracted from the net costs to be collected from these customers. However, the Joint Utilities propose that the consideration of how to set the appropriate "purchase price" for the RECs and RA be deferred to a Tier 3 advice letter, to be filed upon receiving a final decision resolving this Application.

The Joint Utilities have also identified an additional category of customers that will need to be addressed. Pursuant to D.15-01-051, GTSR customers are subject to CTC and a vintaged PCIA based on the date they elect to begin service on GTSR. The Joint Utilities acknowledge that GTSR customers are responsible for the same generation-related above-market costs that are the subject of this Application; however, GTSR customers are also responsible for other generation-related costs that, together with the CTC and PCIA, are meant to ensure non-participant indifference. In light of the fact that indifference as it relates to GTSR customers consists of more than just the stranded costs associated with the new CTC and PAC rates, the Joint Utilities propose that GTSR non-participant indifference, including the consideration of how the new CTC and PAC rates should be applied, be considered once a final decision resolving this Application is issued.

C. <u>Rate Design</u>

The following section describes the Joint Utilities' proposal to allocate the forecast costs of each PAMBA subaccount to rate groups (*e.g.*, residential, small commercial, agricultural, etc.) and to set final rates. The Joint Utilities propose to recover the full net costs of all PAM-eligible resources from bundled service customers through their new CTC and generation charges and from departing load customers through their new CTC and PAC. As described in Chapter V, PAM results in both departing load customers and bundled service customers paying the same net costs, on a per-kWh basis, for each resource—a result that is wholly consistent with the Joint

Utilities' proposal to equitably allocate the benefits of the PAM-eligible resources to all customers.

Today, vintaged Indifference Amounts, as determined using the Current Methodology, are allocated to rate groups based on the contribution of each rate group[103] to the highest 100 hours of system load. This methodology is known as the "Top 100 hours" methodology. The resulting allocation factors are used to allocate revenues to each rate group which are then divided by the rate group's total forecast system sales to determine the indifference rate for that vintaged portfolio.

The Joint Utilities recommend deferring the issue of potential changes to the revenue allocation factors, which determine the allocation to individual rate groups to each utility's respective GRC Phase 2 proceedings or Rate Design Windows ("RDWs"), where the issue of cost allocation to rate groups is traditionally addressed on a holistic basis. Changes in allocation factors would have implications to other parties who otherwise would not participate in this proceeding but have interest in cost allocation issues. In addition, GRC Phase 2 proceedings also contain the marginal costs studies that provide the basis for changing allocation factors.

As such, the Joint Utilities propose to continue to use the current, Commission-approved, Top 100 hours revenue allocation factors to allocate the net costs, as calculated under PAM, to individual rate groups unless and until a new allocator can be agreed upon or is adopted by the Commission in each utility's GRC Phase 2 or RDW. Rate group-level net costs will be divided by the rate group-level sales of only those customers responsible for that vintaged portfolio (and not the rate group-level sales of all customers) to determine the applicable new CTC and PAC rates.[104]

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[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).

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

Commission needs to eliminate these arbitrary term limits on recovery periods and treat all resources equally under the PAM.

A. <u>Storage</u>

In D.14-10-045, the Commission ruled that energy storage projects would be subject to PCIA, but did not reach a conclusion regarding the method for estimating the above-market costs. The Commission also applied a 10-year limit due to its concerns about estimating the above-market costs for a "nascent" market, and concerns about the existing PCIA benchmark and lack of sufficient data as applied to energy storage. However, in doing so, the Commission also contemplated that utilities could seek cost allocation over the life of the contract.

The Commission considered this 10-year limit again in D.16-01-032, in which it found no new information to justify a change to its approach utilized in D.14-10-045, and again deferred the issue to a later date; specifically, when the Commission considered the Joint IOU Protocol for accounting for storage resources in the PCIA. However, when the Commission addressed the Joint IOU Protocol in D.16-09-004, the length of the cost allocation was excluded from the scope of the proceeding. With respect to the projects before it, the Commission continued the 10-year presumption with no explanation. Thus, the Commission has not yet squarely addressed the merits of a 10-year cost allocation for energy storage.

The PAM will eliminate the above-market cost construct entirely, and the need to determine when the above-market costs associated with a given resource no longer exist. In fact, the PAM by accounting for actual costs and benefits and by allocating all attributes, will eliminate the need for the Commission to continually relook at what "value" storage may be providing because the value is conveyed to all customers for whom the resource was originally procured. Including storage resources in PAM for the life of their contracts also makes sense because the Commission has resisted attempts to limit contract lengths to the current 10-year PCIA recovery period.

To ensure customer indifference, storage resources should be included in the PAM and the cost recovery period should span the length of the contract.[105] To do otherwise would be inconsistent with State law which requires bundled service customer indifference to departing load. There is no legal basis or equity consideration to require remaining bundled service customers alone to bear the costs of energy storage resources that were procured to serve all bundled service customers at the time of the resource commitment.

B. Post-2002 Utility Owned Fossil Generation

Another group of resources for which the Commission implemented a cost allocation limit is post-2002 utility owned fossil generation. The 10-year presumption was adopted and addressed in several decisions that are nearly a decade old. That presumption, however, was never intended to be an absolute limit. The Commission recognized that changed circumstances could necessitate the need to justify a longer nonbypassable recovery period. At that time, the Commission made it clear that it was making assumptions about the above-market value of those assets. Those assumptions are no longer reasonable. Described in greater detail below are the decisions and assumptions built into the Commission's analysis, and the changed circumstances that warrant a modification to the current approach. To ensure bundled service customer indifference, post-2002 UOG resources should be treated under PAM in the same manner as Legacy UOG. To do otherwise would be inconsistent with state law which requires bundled service customer indifference to departing load.

In D.04-12-048, the Commission adopted a 10-year cost allocation period for UOG fossil fuel resources acquired through a procurement process. The 10-year period commences upon commercial operation of the UOG facility. The Commission intended for utilities to recover above-market costs from departing load customers, yet the Commission assumed that emerging

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[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.

capacity and energy markets would result in credits against resource costs and, therefore, the costs of these UOG resources would not be above-market indefinitely.[106] The Commission recognized, however, that a 10-year limit might not be adequate,[107] and thus stated that the utilities could justify a longer-term recovery period in applications for these resources. Further, in D.08-09-012, the Commission again discussed issues associated with the 10-year cost allocation period from departing load customers. The Commission stated its assumption that utilities could adjust their load forecasts and portfolios to mitigate the impacts of DA and CCA. The Commission further assumed that the impact of departing load could be minimized. The Commission noted that it could be beneficial to extend the time that the resources remain in the total portfolio because they could put downward pressure on total portfolio costs. The Commission also reiterated its point in D.04-12-048 that the utilities are entitled to make a specific factual showing to justify a longer cost allocation period for non-RPS resources, beyond 10 years.

In short, the Commission has never held that the 10-year period is an absolute limit on allocating costs associated with UOG fossil resources to departing load customers. Instead, the Commission recognized that the 10-year limit was based solely on market value and other assumptions at the time, and has contemplated that the utilities may present specific facts and circumstances to justify a longer cost allocation period.

Today, facts are very different than those the Commission first considered when addressing this issue. The state has not developed a capacity market. Thus, a market does not exist that would provide additional revenues to compensate for the full capacity value. Likewise, the energy and ancillary service revenues are not sufficient to "minimize" any above-market costs. The Commission did not anticipate the current 50% RPS as outlined in SB350. The introduction of a significantly increased RPS has resulted in the introduction of thousands of

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[106] *See* D.04-12-048, p. 60.

[107] *Id*., pp. 61, 63.

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

Likewise, the level of potential load departure that the Joint Utilities face today is substantially higher than any load departure considered at that time. At that time, the assumption was that the Joint Utilities would be able to "adjust" their portfolios with no impact on costs to bundled service customers. This assumption was questionable at best. Adjusting the portfolio for small amounts of load loss spread over many years is very different than today's situation where more than half the load could depart in just a few years. Load reduction is also occurring by the growth in behind the meter generation and increased energy efficiency standards and programs. At the time the Commission made its decision around the 10-year limit, utilities' loads were increasing and expected to continue to increase. Today, utilities' loads may be decreasing, even without any new departing load.

Fundamentally, the purpose of this application is to replace the current PCIA and its outdated approach that relies on estimates of above-market costs with a mechanism that self-adjusts for actual market value and load departure. The Commission's decade-old determination that a 10-year cost allocation window is sufficient can no longer be used to ensure bundled service customer indifference. To ensure that costs are not shifted to remaining bundled service customers, as well as to ensure departing load customers are allocated the benefits of prior resource procurement, these post-2002 UOG resources must be treated like all other UOG commitments. These resources were approved by the Commission as being "just and reasonable," exactly like all other resources subject to PAM. There is no logic to treating these resources differently than other resource commitments under PAM. Indeed, to do otherwise would be inconsistent with statutory requirements to maintain customer indifference to departing 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. **<u>RA Allocation Overview</u>**

- 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

	Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre-Restructuring Portfolio	Total Peak Load
		Forecast of Q1 Peak Load and Peak Load Share of Each Portfolio					
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

	Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre-Restructuring Portfolio	Total RA Allocated
		Q1 Allocation of RA					
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 "trued-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

	Eq.	Description (Unit)	2017 Portfolio	2014 Portfolio	2009 Portfolio	Pre-Restructuring Portfolio
		True-Up - Costs				
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	$100
7.	AL1.	Actual Load Responsible for Each Portfolio (GWh)	4,200	5,800	9,000	10,200
8.	(7)*(5)	Actual Revenues Recevied from Customer ($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 allocators1/ and retail sales
  - Each vintaged portfolio will have its own rate group-specific rates
  - Incremental rates for each vintaged portfolio are set in the ERRA 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

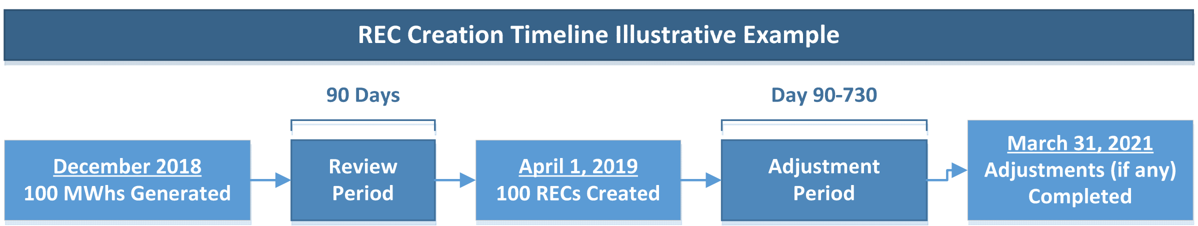
Appendix B

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 source[108] 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.

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[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.

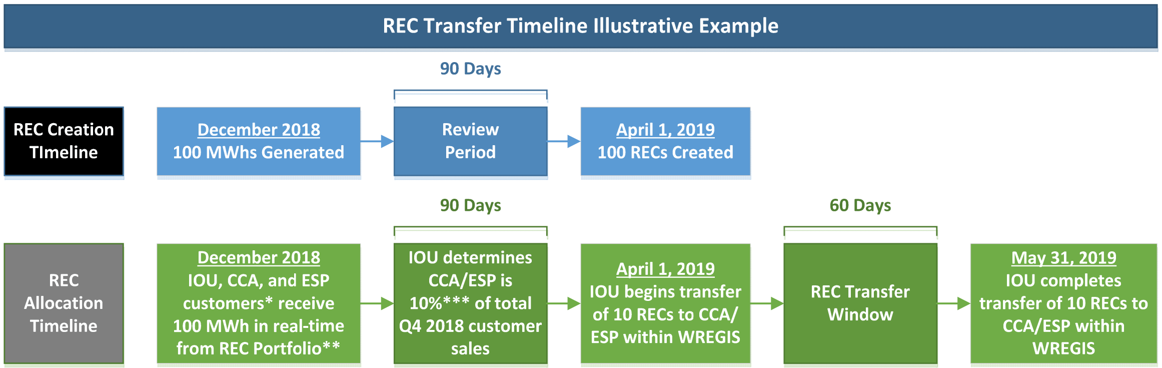
2. Retire them to show compliance with state/provincial programs by moving them from an "active" subaccount to a "retirement" subaccount.

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.

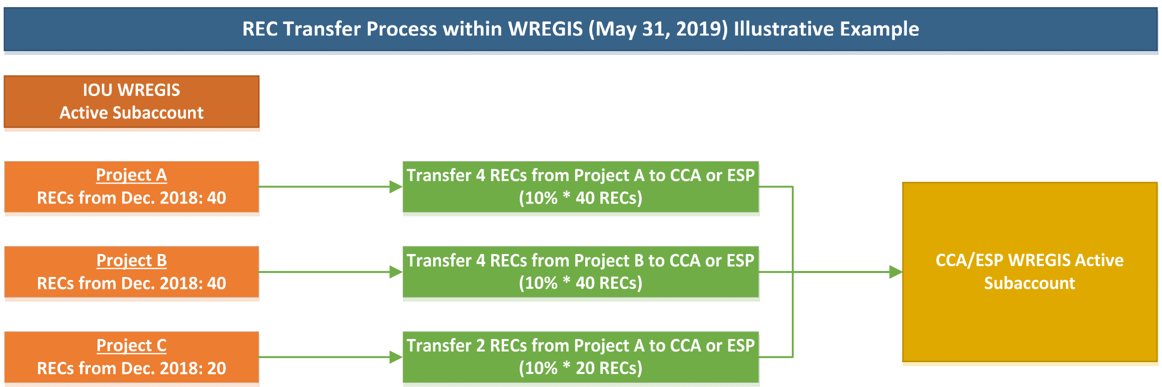
The following is an illustrative example of how the proposed transfer process of RECs would work under the PAM proposal:

[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 Statement[110] 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.

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[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

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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. <u>Excluded Costs and Revenues</u>

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.

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

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

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

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

In 2006, I was named VP of Energy Procurement.

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

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in Joint IOUs' Portfolio Allocation Methodology Case:

- Chapter 1, "Introduction."
- Chapter 2, "Executive Summary."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

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.

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.

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 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.

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.

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.

Q 9 What is the purpose of your testimony?

A 9 I am sponsoring the following testimony and workpapers in the Joint IOUs’ Portfolio Allocation Methodology Case:

- Chapter 6, “Cost Recovery and Rate Design.”
- Workpapers supporting Chapter 6, “Cost Recovery and Rate Design.”

Q 10 Does this conclude your statement of qualifications?

A 10 Yes, it does.

WITNESS QUALIFICATIONS

My name is Cynthia Fang and my business address is 8330 Century Park Court, San Diego, California 92123. I am the Rate Strategy and Analysis Manager in the Customer Pricing Department of San Diego Gas and Electric. My primary responsibilities include the development of cost-of-service studies, determination of revenue allocation and electric rate design methods, analysis of ratemaking theories, and preparation of various regulatory filings and overseeing the electric load analysis, electric demand forecasting and electric rate strategy for SDG&E. I began work at SDG&E in May 2006 as a Regulatory Economic Advisor and have held positions of increasing responsibility in the Electric Rate Design group. Prior to joining SDG&E, I was employed by the Minnesota Department of Commerce, Energy Division, as a Public Utilities Rates Analyst from 2003 through May 2006.

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

Policy and Affairs (RP&A) Department in March 2001. In that capacity, I oversaw all California Public Utilities Commission jurisdictional ratemaking, revenue requirements, revenue forecasting, load research, pricing and tariff functions. I also directed the activities of the Federal Energy Regulatory Commission (FERC) Rates and Regulation Section of the RP&A Department. I was promoted to the position of Vice President of Regulatory Operations in 2006 and served in that position until I retired in April 2013. In that capacity I maintained the responsibilities of Director of Revenue and Tariffs and assumed the responsibility of ensuring Company's compliance with State and Federal regulatory mandates including compliance with Federal Critical Infrastructure Protection (CIP) standards. I also led the Company's efforts on legislative bills with impact on its revenues and rate structures. After retiring from SCE I worked as a Senior Manager for Ernst & Young LLP between January 2015 and June 2016 providing ratemaking and other regulatory services to power and utilities clients. I have previously testified before this 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 6 of Exhibit No. Joint IOUs-01.

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 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.