

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise,
and Consider Alternatives to the Power Charge
Indifference Adjustment.

R.17-06-026
(Filed June 29, 2017)

TESTIMONY OF BILL POWERS

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POC Foundation Opening Testimony

Bill Powers

April 2, 2018

Please state your name, place of employment, and business address.

My name is Bill Powers. I am the owner and principal of Powers Engineering, located at 4452 Park Boulevard # 209, San Diego, CA 92116

What is the purpose of this testimony?

I submit this testimony on behalf of Protect Our Communities Foundation to support its position that the PCIA must be fundamentally altered to align with the Commission's goals and principles. Currently, the PCIA is calculated by taking the difference between actual IOU portfolio costs and the market value of the portfolio, determined largely by current least-cost market prices. The PCIA should instead use the actual generation charge paid by IOU bundled customers as the benchmark to assess the above-market costs of IOU portfolios. Using San Diego Gas & Electric as a case study, this testimony demonstrates that, as currently designed and implemented, the PCIA overcharges departing load and is inconsistent with the fundamental concept of price indifference.

Please describe your qualifications for providing this testimony.

I am a registered professional engineer, with extensive knowledge and experience in the fields of energy and environmental engineering, air emissions control, and regional energy planning. A copy of my resume is included as an exhibit to this testimony.

I. Introduction

The overall goal of this proceeding, as set forth in the Scoping Memo, is to ensure both that bundled customers do not experience any cost increases as a result of departing load and that departing load does not experience any cost increases as a result of allocation of costs that were

not procured on its behalf.¹ The Power Charge Indifference Adjustment (“PCIA”) as currently calculated does not satisfy this objective. Rather, in practice, it permits the investor-owned utilities (“IOUs”) to shed overpriced contracts for green power, brown power, and capacity resources made on behalf of all IOU customers, thereby reducing the generation charge for bundled load while passing the above-market prices for those contracts on to departing load. The consequence is that the PCIA penalizes departing load, deterring customers from joining Community Choice Aggregators (“CCAs”) and other non-IOU energy providers, while benefitting bundled load, whose generation is supplied through a less expensive portfolio that better matches current market prices.

The current PCIA methodology thus benefits bundled service customers at the expense of departing load. This is contrary to Final Guiding Principle 1(i), which requires that the PCIA “reflect the value of the benefits that departing customers impart to remaining bundled service customers.”² And it incentivizes imprudent IOU portfolio management by allowing IOUs to enter into over-priced contracts that they can later shed at the expense of departing load. This is contrary to Final Guiding Principle 1(h), which limits the PCIA to “legitimately unavoidable costs” and requires IOUs to “take all reasonable steps to minimize above-market costs.”³

The PCIA must be fundamentally altered to align with the Commission’s goals and principles. Currently, the PCIA is calculated by taking the difference between actual IOU portfolio costs and the market value of the portfolio, determined largely by current least-cost market prices. The PCIA should instead use the actual generation charge paid by IOU bundled customers as the benchmark to assess the above-market costs of IOU portfolios. Green power purchase agreement (“PPA”) prices and eligible cost recovery surcharge (“CRS”) brown power costs above the actual IOU generation charge benchmark would form the universe of above-market costs for which departing load customers are proportionately responsible. At the same time, the PCIA should contain a mechanism for assessing the avoidable component of above-market costs, which should be borne by IOU shareholders rather than departing load customers to satisfy the principle that the PCIA include only “legitimately unavoidable costs.”

The testimony that follows develops this proposal by using San Diego Gas & Electric Company’s (“SDG&E”) portfolio as a case study. Part II provides background on SDG&E’s post-energy crisis resource procurement and sets forth the basic parameters of the PCIA in its current guise. Part III discusses the disconnect between the actual costs of SDG&E’s portfolio and the market value of those resources as determined through the PCIA’s market price benchmark (“MPB”) in its current iteration. Parts IV and V elaborate on the major portfolio components driving the high PCIA: CRS-eligible brown power resources (including energy and capacity charges) and solar and wind green power PPAs.

¹ R. 17-06-026, Scoping Memo and Ruling of Assignment Commissioner at p. 13 (Sept. 25, 2017) (“Scoping Memo”).

² *Id.* at p. 14.

³ *Id.*

As discussed in Part IV, brown power contracts should play a diminishing role in the PCIA. Contract costs associated with Cost Allocation Mechanism (“CAM”) projects should not form part of the PCIA, as these are pass-through costs allocated to all load. CAM projects – including the 308 MW Pio Pico Energy Center and 500 MW Carlsbad Energy Center – are projects that the Commission has determined are necessary for grid reliability generally and therefore the cost must be shared by all customers, including CCA and Direct Access (“DA”) customers. Of the remaining CRS-eligible brown power contrast, several substantial contracts will terminate between 2019 and 2021, at which point they can no longer be priced into the PCIA. And, as discussed below, there is a 1,267 MW gap between 2017 NQC projects SDG&E identified in its response to POC’s data request and the brown power input in its 2017 PCIA calculation. This gap raises the possibility that SDG&E is putting contracts into the PCIA that are ineligible for that treatment, either because they are for CAM projects or because they are for utility-owned brown power resources that have exceeded ten years of operations.

Part V shows that SDG&E overpaid for much of its green power portfolio. Commission approval of certain high-priced solar PPAs around 2008 through an irregular process created an inflated benchmark for assessing the reasonableness of contracts. Because bids were confidential and procurement was not subject to rigorous scrutiny, there was no external check on this high priced procurement. As a consequence, the data shows that pricing of many of the green PPAs signed by SDG&E in the 2010-2012 timeframe was unjustifiably high in cost when compared with least-cost contracts SDG&E entered into during the same time period under the Renewable Auction Mechanism (“RAM”),⁴ or when compared to contracts being signed by other IOUs at the same time for the same technology. Part V takes a close look at SDG&E’s solar and wind contract to make this showing.

Part VI sets forth a proposal for modifying the PCIA to meet the objectives and principles set forth in the Scoping Memo. This proposal includes: (1) limiting the brown power resources in the PCIA to only those actually eligible for inclusion (2) using the actual average generation charge of IOU portfolios as the MPB to better satisfy the indifference principle at the heart of the PCIA concept, and (3) establishing a mechanism to assign the reasonably avoidable costs of green power contracts to shareholders rather than forcing departing load to absorb the costs of imprudent investments.

The potential for major customer departure to CCAs was ever-present during the early high-volume RPS contracting conducted by SDG&E in 2010-2012. The City of Chula Vista, the second largest city in SDG&E service territory, had pursued the formation of a CCA in 2006.⁵ One of four future scenarios examined in the PG&E Long-Term Procurement Plan application

⁴ D. 10-12-048, *Decision Adopting the Renewable Auction Mechanism*, Appendix A, at pdf pp. 101-02 (Dec. 16, 2010) (“Procurement Requirement: Each IOU must enter into a standard contract with each winning bidder up to the capacity limits in each solicitation and total program capacity limits. IOUs select on the basis of least costly projects first until the IOU fully subscribes its allocated capacity for that auction.”).

⁵ San Diego Union Tribune, *Chula Vista Moves Toward Energy Freedom* (Oct. 19, 2006), available at http://legacy.sandiegouniontribune.com/uniontrib/20061019/news_lz6e19castane.html.

submitted to the Commission in 2006 assumed 10 percent customer departure to CCAs by 2012.⁶ Marin Clean Energy launched in May 2010, before the Commission had approved any of SDG&E's in-state solar and wind contracts greater than 50 MW.⁷ High-priced solar and wind contracting has had a predictable effect – complicating the departure of SDG&E customers to CCAs.

II. Background

Until the AB 1890 deregulation statute was enacted in 1996, California IOUs were vertically integrated electricity and natural gas providers,⁸ owning all their own electric generating plants. SDG&E voluntarily sold off its electric generation fleet to third parties in the late 1990s, retaining only a 20 percent share in the San Onofre Nuclear Generating Station (SONGS).⁹ In effect, SDG&E voluntarily limited itself to a transmission and distribution role by the end of the 1990s, while its parent company, Sempra, formed a separate company (Sempra Energy Resources) to build power plants.¹⁰

With the failure of deregulation in 2000-2001, California's IOUs began to partially return to vertical integration. SDG&E has taken the lead among California IOUs in this regard, with more natural gas-fired capacity under its ownership or direct control through tolling agreements in 2018,¹¹ than at any time in its history.^{12,13} This gas-fired generation is identified as “brown power” in this proceeding. Since the enactment of the first renewable portfolio standard (“RPS”) requirements in 2003, SDG&E has also entered into contracts for renewable resources, including solar and wind generation, referred to as “green power” in this proceeding. The discussion that follows breaks down the major components of both classes of generation.

⁶ PG&E, R.06-02-013, *PG&E 2006 Long-Term Procurement Plan, Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans – Volume 1*, Table Vol. 1, IVB-3, p. IV-9 (Dec. 11, 2006).

⁷ Marin Clean Energy webpage, “About Us,” <https://www.mcecleanenergy.org/about-us/> (last accessed Mar. 30, 2018).

⁸ SCE is the exception, providing electricity only.

⁹ SDG&E, 1999 FERC Form 1 at pdf p. 162 (June 29, 2001).

¹⁰ Department of Water Resources, Energy Purchase Agreement Between Department of Water Resources and Sempra Energy Resources, Appendix B (Apr. 1, 2001).

¹¹ SDG&E, 2017 SEC Form 10-K at p. F-35, pdf p. 220 (Feb. 27 2018) (“Tolling Agreements: SDG&E has agreements under which it purchases power generated by facilities for which it supplies all of the natural gas to fuel the power plant (i.e., tolling agreements). SDG&E's obligation to absorb natural gas costs may be a significant variable interest. In addition, SDG&E has the power to direct the dispatch of electricity generated by these facilities.”).

¹² SDG&E, 1995 FERC Form 1 at pdf pp. 225-29 (Apr. 26, 1996). Total fossil generation owned = 2,024 MW. Total nuclear generation owned = 451 MW.

¹³ See Table 1, *supra*. Total fossil generation (excluding combined heat and power facilities), owned by SDG&E or controlled by SDG&E through tolling agreements = 2,803 MW.

A. Post Energy Crisis Power Procurement

Tale 1 below describes the major brown power purchases and contracts that SDG&E entered into following its return to vertical integration. The Commission authorized SDG&E to buy the 556 MW Palomar Energy Center from Sempra Generation in 2006.¹⁴ The Commission authorized SDG&E to buy the 526 MW Desert Star Energy Center (formerly El Dorado Energy Center), located in Boulder City, Nevada, from Sempra Generation in 2011.¹⁵ The Commission also authorized the sale of the 47 MW Cuyama peaker plant from a third party developer to SDG&E in 2011.¹⁶ SDG&E can only include SDG&E-owned capacity in the PCIA calculation for the first ten years from the commissioning date.¹⁷

The Commission also authorized SDG&E to enter into multiple power purchase tolling agreements (“PPTA”) with gas-fired generators. The largest is with Calpine for the 605 MW Otay Mesa Energy Center (“OMEC”). Under a tolling agreement, SDG&E pays for the fuel and has dispatch control over the plant.¹⁸ In addition to OMEC, SDG&E has PPTAs with the following peaker plants: 98 MW Orange Grove, 47 MW El Cajon, 308 MW Pio Pico, and 500 MW Carlsbad Energy.¹⁹ SDG&E also has long-term agreements with six combined heat and power qualifying facilities (“QF”) that date from the 1980s.²⁰ These PPTAs and QF agreements are included in Table 1.

¹⁴ SDG&E, 2006 SEC Form 10-K at p. 68 (Feb. 21, 2007). (“In March 2006, control and ownership of the 550-megawatt (MW) Palomar generating plant was transferred from Sempra Generation, which built the plant, to SDG&E. The CPUC has approved the revenue requirement for the plant as proposed by SDG&E.”).

¹⁵ CPUC Resolution E-4465, August 2, 2012.

¹⁶ D.11-12-002, December 1, 2011.

¹⁷ SDG&E Response to POC’s Third Data Request, Response 1, R. 17-06-026 (Mar. 23, 2018).

¹⁸ SDG&E, 2017 SEC Form 10-K at p. F-35, pdf. p. 220 (Feb. 27, 2018)..

¹⁹ SDG&E, D. Sullivan 2016 ERRR Compliance Testimony at pdf. pp. 1031-1032 A.17-06-006 (June 1, 2017) (“Sullivan Testimony”).

²⁰ *Id.*

Table 1. SDG&E natural gas-fired generation assets, owned or controlled through tolling agreements

Project	SDG&E-owned, tolling agreement, firm energy, or qualifying facility	Capacity, MW ^{21,22}	2016 Production, MWh ²³	Commercial online date (COD)	PCIA – eligible expiration date (IOU-owned) or contract end date
Palomar	SDG&E	566	2,299,052	2006	2016
Desert Star	SDG&E	536	1,223,034	2011	2021
Miramar	SDG&E	48	122,818	2005	2015
Miramar 2	SDG&E	48		2009	2019
Cuyamaca	SDG&E	47	8,173	2011	2021
OMECE	tolling	605	2,654,182	2009	2019 (contract end date)
Orange Grove	tolling	98	42,128	2010	2035 (transferred to SDG&E in 2035)
El Cajon	tolling	47	10,339	2010	2035 (transferred to SDG&E in 2035)
Pio Pico ²⁴	tolling	308	0	2017	2042
Carlsbad Energy ²⁵	tolling	500	0	2018 (estimated)	2038
Morgan Stanley ²⁶	firm energy	175	427,856	2013	2022
BP ²⁷	firm energy	68	150,114	2015	2019
Goal Line	CHP - QF ²⁸	50	23,018	2015	2025
Naval Station	CHP - QF	50	353,422	1989	2019
N. Island	CHP - QF	34	292,479	1989	2019
NTC	CHP - QF	23	150,314	1989	2019
NTC steam	CHP - QF	2.6	16,434	1989	2019
Yuma	CHP - QF	55	11,205	2015	2024
Gas-fired capacity, end of 2016:		2,453	7,784,568		
Gas-fired capacity, end of 2018:		3,261			

²¹ SDG&E 2016 FERC Form 1 at pp. 402-03 (Apr. 1, 2017). Palomar = 566 MW, Desert Star = 526 MW.

²² SDG&E 2016 Form 10-K at pdf p. 490 (OMECE = 605 MW).

²³ EIA, 2016 EIA-923, Page 4 Generator Data, Lines 2978-2980 (OMECE = 2,654,182 MW), Lines 3041-3043 (Desert Star = 1,223,034 MW), and Lines 3046, 3086, 3087 (Palomar = 2,299,052 MW).

²⁴ *Id.*

²⁵ *Id.*

²⁶ Sullivan Testimony at pdf p. 1032.

²⁷ *Id.*

²⁸ All CHP QF data from Sullivan Testimony, at pdf p. 1029.

SDG&E delivered 15,653,039 MWh to bundled customers in 2016.²⁹ Therefore, the average annual electricity demand in SDG&E service territory in 2016 was 1,787 MW. By the end of 2016, as shown in Table 1, SDG&E had over 2,400 MW of gas-fired capacity under ownership or some form of dedicated contract structure. The peak one-hour load in SDG&E service territory in 2016 was 4,343 MW on September 26, 2016.³⁰ About four-fifths of the load in SDG&E service territory is bundled customer load served by SDG&E, with the remainder Direct Access load served by others.³¹ Therefore, assuming the same fraction applies to the bundled customer portion of peak load, about 3,475 MW of the 2016 summer peak load was attributable to SDG&E bundled customer load.³²

By October of 2018, when the 500 MW Carlsbad Energy Center is scheduled to be fully online,³³ SDG&E will have about 3,300 MW of gas-fired generation under either its direct ownership, control through tolling agreements, or dedicated long-term contract. As a result, and assuming a peak load similar to 2016, SDG&E could meet its entire bundled customer load – nearly every hour of the year – with gas-fired generation already in its portfolio.

California IOUs have been subject to RPS requirements since 2003. The applicable current target is 50 percent RPS by 2030, with interim compliance goals.³⁴ At the time most of the RPS contracts at issue in this proceeding were approved by the Commission, the IOUs were subject to a requirement to achieve 33 percent renewables by 2020.³⁵ The metric the Commission used to assess the reasonableness of the pricing of these RPS contracts³⁶ was the market price referent (“MPR”), which represented the Commission’s determination of the cost of production from a new combined cycle gas turbine power plant.³⁷ Though last calculated in 2011, the Commission continues to view the MPR as the “best available methodology to determine the cost savings (benefits) of the RPS program.”³⁸

B. The PCIA and its Market Price Benchmark

The Commission determines the above-market PCIA cost that departing load customers are responsible for by comparing the current market pricing for wholesale brown energy, capacity, and green power, which collectively form the “Market Price Benchmark” or “MPB,” to

²⁹ SDG&E 2016 FERC Form 1 at p. 304, pdf. p. 180 (Apr. 1, 2017).

³⁰ *Id.* at p. 400, pdf p. 230.

³¹ According to the California Energy Commission, the 2016 SDG&E all sectors electricity consumptions was 19,168.70 GWh, Therefore, percentage of SDG&E bundled customer load to total load = 15,653,039 MWh ÷ 19,168,700 MWh = 0.817 (~82 percent). See CEC, Electricity Consumption by Entity (webpage). <http://www.ecdms.energy.ca.gov/elecbyutil.aspx> (last accessed March 30, 2018).

³² 0.80 x 4,343 MW = 3,474.4 MW.

³³ SDG&E, *SDG&E Procurement In Response to SONGS Retirement*, PowerPoint, at p. 3 (May 19, 2017).

³⁴ Senate Bill 350 (2015) (De León).

³⁵ See Executive Order S-14-08 (Nov. 17, 2008); Senate Bill X1-2 (2011).

³⁶ These RPS contracts fall under the umbrella term “green power” in this proceeding.

³⁷ CPUC, Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (Pursuant to Public Utilities Code Section 913.3 at p. 10 (May 1, 2017) (“Padilla Report”).

³⁸ *Id.* at p. 2, 10.

the actual generation charge paid by IOU ratepayers.³⁹ The PCIA is the difference between the actual generation charge paid by IOU ratepayers and the MPB. Although the MPB is intended to serve largely the same function as the MPR—assigning a market value to the IOUs’ generation portfolios—the two metrics are distinct.⁴⁰

The PCIA uses real-time “market value” for brown power, green power, and capacity payments to establish an idealized, lowest-cost bundled IOU customer generation charge, and then requires departing load customers to pay the difference between the idealized, lowest-cost charge and what the IOU customers actually pay.

This indifference criterion described in the R. 17-06-026 Order Instituting Rulemaking is applicable to the CRS-eligible brown power resources and green power resources. These brown power and green power resources also provide varying levels of reliable capacity to meet demand during times of peak load. Resource adequacy payments are made to these resources to assure their availability when needed for reliability purposes.⁴¹ These are the three resource types that comprise the PCIA. The sections that follow unpack these resources and show why the majority of contracts for them should not factor into a PCIA charge.

III. Actual SDG&E procurement costs are unrelated to market value costs used in the PCIA

The net result of the brown power and green power commitments SDG&E has made is that SDG&E bundled customers paid a generation charge of approximately \$0.096 per kilowatt-hour (kWh) in 2016.⁴² This is about one-half the total retail charge paid by SDG&E customers, which includes transmission and distribution, public purpose programs, and the DWR bond charge, of about \$0.20/kWh.⁴³ In other words, the retail cost paid by SDG&E ratepayers for SDG&E’s power procurement portfolio, at a time when there are no operational CCAs in SDG&E territory, is about \$100 per megawatt-hour.

The actual cost of generation passed on to bundled ratepayers by SDG&E for its two CRS-eligible combined cycle units, Desert Star and OMEC, is \$66/MWh, as shown in Table 2.⁴⁴ The actual average SDG&E brown power energy cost, when all forms of brown power are included, is about \$74/MWh.⁴⁵ The average brown power energy cost paid by SDG&E bundled customers is closer to the 2011 cost of energy production calculated in the MPR from a new

³⁹ See CPUC, Fact Sheet: Power Charge Indifference Adjustment at p. 2 (Jan. 2017). The actual generation charge paid by IOU ratepayers is equivalent to the utility’s “actual portfolio cost.”

⁴⁰ Commission Resolution E-4475; D.11-12-018.

⁴¹ CPUC, Resource Adequacy (webpage), <http://www.cpuc.ca.gov/RA/> (last accessed March 31, 2018).

⁴² CPUC, California Electric and Gas Utility Cost Report at Figure 1-4, p. 7 (Apr. 2017).

⁴³ *Id.*

⁴⁴ SDG&E Response to POC’s Third Data Request, Response 1 at p. 4, R. 17-06-026 (Mar. 23, 2018).

⁴⁵ 2016 cost of brown power energy ÷ brown power energy production = \$185,181,379 ÷ 2,516,476 MWh = \$73.59/MWh. See Table 2, *supra*.

combined cycle unit, at \$89/MWh,⁴⁶ than the market value of approximately \$33/MWh used by SDG&E in its 2017 and 2018 PCIA calculations. The use of a \$33/MWh market value for brown energy in the SDG&E PCIA calculation bears no relation to the actual cost incurred by SDG&E bundled customers for most of the brown power currently provided to them by SDG&E.

Table 2. Actual SDG&E CRS-eligible brown power resources and associated capacity and energy production costs in 2017 PCIA calculation⁴⁷

Class of "Brown" Power/Resource Type	2017 Net Qualifying Capacity (MW)	2017 Forecast Generation (GWh)	2017 ERRA Unit Cost forecast (\$/MWh)	2016 Capacity Costs (FERC Form 1)	2016 Energy Costs (FERC Form 1)	Unit capacity cost, \$/kW-yr	Production 2016, MWh
Natural Gas Combined Cycle	1,023		\$66	\$125,044,852	\$102,362,015		
Natural Gas Fired Peaker	237		\$473	\$41,118,852	\$5,021,264		
Pumped Hydro	40		\$67	\$2,732,375	\$268,016		
Unspecified Power Contract	190		\$84	\$ -	\$51,231,573		
Combined Heat and Power	181		\$77	\$39,756,703	\$26,566,527		
						122	1,550,940
						173	10,616
						68	4,000
						--	609,900
						147	345,020
	1,671			208,652,782	185,449,395		2,520,476

The same is true regarding capacity costs. The average actual SDG&E CRS-eligible brown power capacity cost is about \$143/kW-year,⁴⁸ which far exceeds SDG&E's assumed market value of capacity of \$58.27/kW-year in its 2017 and 2018 PCIA calculations.⁴⁹ The CRS-eligible capacity cost that SDG&E customers are now accustomed to paying is nearly three times the market value of capacity that SDG&E assumes in the 2017 and 2018 PCIA calculations. Again, the average actual SDG&E CRS-eligible brown power capacity cost of \$143/kW-year approximates the assumed capacity cost in the 2011 MPR of about \$170/kW-yr.⁵⁰

⁴⁶ Commission Resolution, E-4422, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/154753.PDF (Dec, 1, 2011). Resolution E-4422, Appendix A, xls spreadsheet:

⁴⁷ SDG&E Response to POC's Third Data Request, Response 1 at p. 4, R. 17-06-026 (Mar. 23, 2018).

⁴⁸ See POC Opening Testimony, Table 2, p. --. 2016 cost of brown power energy ÷ brown power energy production = \$185,181,379 ÷ 2,516,476 MWh = \$73.59/MWh.

⁴⁹ SDG&E Response to POC's First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet; SDG&E 2018 PCIA calculation spreadsheet, included as pp. 32-34 in the SDG&E PowerPoint presented at the PCIA workshop in San Diego, titled "SDG&E, PCIA Rulemaking Workshop #1C, December 6, 2017").

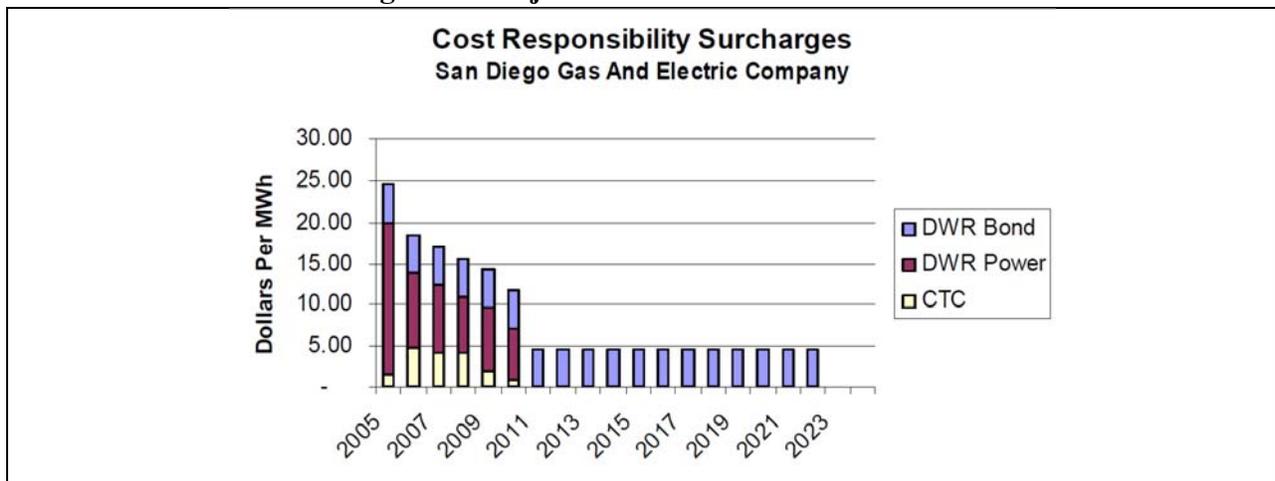
⁵⁰ CPUC, Resolution E-4422, *Adoption of 2011 Market Price Referent values for use in the 2011 Renewables Portfolio Standard solicitations* (Dec. 1, 2011) (attached xls worksheet, "Control Sheet" tab. 2011 MPR capacity value = \$170.77/kW-yr).

SDG&E identifies a total of 1,441 MW of brown power and 40 MW of pumped hydro net qualifying capacity (“NQC”) resources under contract in 2016, as shown in Table 2. SDG&E reports 2,520,476 MWh of energy production in 2016 from these resources and “unspecified power contracts” in its data response to POC, as shown in Table 2 above. The 2016 cost of this capacity and energy is \$394,102,177.⁵¹ However, in its 2017 PCIA calculation, SDG&E indicates that its CRS-eligible brown power resources provide 2,708 MW⁵² of NQC and produce 5,491,000 MWh at a cost of \$632,797,000.⁵³ There is a substantial discrepancy between the CRS-eligible brown power resources that SDG&E described in its data response to POC and the total CRS-eligible brown power resources assumed in the 2017 PCIA spreadsheet.

IV. Brown Power Contracts Should Comprise a Diminishing Part of the PCIA

Utilities are authorized to assess a surcharge – the CRS. The concept behind the CRS is that, for certain types of generation contract obligations, the utility is authorized to spread the cost across its entire bundled customer base at the time the obligation is entered into, and any customers departing subsequently – for example to join a CCA – must continue to pay their share of the obligation. The CRS was originally associated only with the 10-year Department of Water Resources (“DWR”) contracts signed by the state during the 2000-2001 energy crisis. One of the first CCA technical feasibility studies in SDG&E service territory, prepared by Navigant for San Diego County in 2005, showed the magnitude and rate of decline of the CRS. This graphic is shown in Figure 1.

Figure 1. Projected SDG&E CRS in 2005⁵⁴



CTC: Competitive Transition Charge

⁵¹ Table 2, \$208,652,782 (capacity) + \$185,449,395 (energy, including pumped storage) = \$394,102,177.

⁵² SDG&E 2017 PCIA spreadsheet: 3,400 MW (CRS-eligible NQC) – 692 MW (renewables NQC, SDG&E DR response to POC-03, at p. 5) = 2,708 MW.

⁵³ *Id.*, \$1,254,797,000 (CRS-eligible portfolio cost) – \$622,000,000 (2016 total green power payments, SDG&E A.17-06-006 D. Sullivan testimony, June 1, 2017, pdf pp. 1034-1036) = \$632,797,000 (brown power cost).

⁵⁴ Navigant, *County of San Diego CCA Technical Feasibility Study* at p. 51 (May 2005).

Navigant observed in the 2005 San Diego County study that the CRS could undermine the economic benefit of CCA stating:

The single greatest obstacle to achieving significant cost savings through CCA in the next several years is SDG&E’s imposition of cost responsibility surcharges on CCA customers, which are designed to shield SDG&E from any financial losses from cost increases that might result from customers switching to service by Aggregator.⁵⁵

In fact, the base case scenario in the study assumed a CRS of \$0.020/kWh, which made CCA energy more costly in the first few years of service than energy SDG&E delivered.⁵⁶ With the CRS at \$0.010/kWh, the CCA was more cost-effective than SDG&E in all years.⁵⁷

As shown in Figure 1, the CRS was projected in 2005 to end in 2011⁵⁸ as that was the year the 10-year DWR contracts were to end. However, nearly half of the MWhs included in the SDG&E 2017 and 2018 PCIA calculations is recent, post-DWR-contract brown power capacity.⁵⁹ The actual unit cost of brown and green power in the 2017 SDG&E PCIA calculation, which uses 2016 data, is shown in Table 3. The “cost” column in Table 3 includes both energy and capacity payments. The “total unit cost” column includes both energy and capacity payments levelized over the MWh quantity of energy produced in 2016.

Table 3. Unit cost of 2016 SDG&E CRS-eligible brown power expenses and green power contracts

Power type	Quantity, MWh	Cost, \$	Capacity, ⁶⁰ MW	Total unit cost, \$/MWh
Brown	5,491,000 ⁶¹	632,797,000	1,441	115
Green	6,899,000 ⁶²	622,000,000	692	90

The cost of long-term PPA contracts for brown power resources that the Commission has identified as necessary for grid reliability generally are to be spread equally over all customers,

⁵⁵ *Id.* at p. 50.

⁵⁶ *Id.* at pp. 50-52, 68 (Case 1: Base Case).

⁵⁷ *Id.* at p. 71 (Case 4: CRS Is Reduced By 50% From Base Case).

⁵⁸ With the exception of the \$0.005/kWh DWR bond charge which ends in 2023.

⁵⁹ SDG&E Response to POC’s First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet)

⁶⁰ SDG&E Response to POC’s Third Data Request, Response 1 at p. 4, R. 17-06-026 (Mar. 23, 2018), p. 5. Note that 40 MW of capacity associated with pumped hydro is included with green power capacity.

⁶¹ SDG&E Response to POC’s First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet). CRS eligible supply – CRS renewable supply = 12,460 GWh – 6,969 GWh = 5,491 GWh. Estimated CRS-eligible brown power cost = \$1,254,797,000 - \$622,000,000 = \$632,797,000.

⁶² Sullivan Testimony at pdf pp. 1029-1031. Total 2016 MWh and cost, 6,899,000 MWh and \$622,000,000 respectively, for all “Renewable Energy” contracts, including Badger Filtration Plant and San Francisco Peak Hydro conduit-hydro QF projects listed on pdf p. 1029.

including CCA and DA customers.⁶³ These projects are known as CAM projects.⁶⁴ The two CAM projects in SDG&E's brown power portfolio are 308 MW Pio Pico Energy Center⁶⁵ and the 500 MW Carlsbad Energy Center.⁶⁶ CAM costs are by definition direct pass-through costs that CCA and DA customers must pay and therefore should not be included in the PCIA calculation.

SDG&E buys relatively little wholesale "market value" brown power, which SDG&E values at about \$33/MWh in its 2017 and 2018 PCIA calculations. SDG&E projected in April 2017 that 35 percent of its customer power requirements in 2017 would come from green power, 45 percent from SDG&E-owned generation and tolling contracts, 15 percent from wholesale market purchases, and 5 percent from other long-term contracts.⁶⁷ In other words, only a quarter of the brown power consisted of wholesale market purchases.⁶⁸ The bulk of the brown power was supplied by SDG&E-owned generation (its 566 MW Palomar Energy Center and 526 MW Desert Star Energy Center) and the 605 MW OMEC combined cycle project, which SDG&E controls through a tolling agreement. Collectively, these three combined cycle plants produced 6,176,268 MWh of energy in 2016.⁶⁹

Two of the largest brown power generators in SDG&E's portfolio, the 605 MW OMEC project and the 526 MW Desert Star combined cycle project, will "term-out" in 2019 and 2021, respectively. Upon doing so, they can no longer form part of the PCIA, which has a 10-year limit on recovery of utility-owned generation costs through the PCIA.⁷⁰ Desert Star was purchased by SDG&E from Sempra Generation in 2011 and will be subject to the 10-year limit on recovery of utility-owned generation costs through the PCIA in 2021.⁷¹ The 10-year power purchase tolling agreement between SDG&E and OMEC ends in 2019.⁷² Unless SDG&E purchases OMEC from

⁶³ D.11-05-005, Decision Modifying New Generation and Long-Term Contract Cost Allocation Mechanism Pursuant to Senate Bill 695, at p. 3 (May 5, 2011).

⁶⁴ *Id.* at p. 7.

⁶⁵ D.14-02-016, Decision Granting SDG&E Authority to Enter Into a Purchase Power Tolling Agreement with Pio Pico Energy Center, LLC at p. 15, Conclusion of Law No. 8 (Feb. 5, 2014) ("As our approval of the amended PPTA is for purposes of meeting local reliability criteria, CAM treatment is appropriate and reasonable.").

⁶⁶ D.15-05-051, Decision Conditionally Approving SDG&E'S Application for Authority to Enter Into Purchase Power Tolling Agreement with Carlsbad Energy Center, LLC at p. 36, Conclusion of Law No. 12 (May 21, 2015).

⁶⁷ SDG&E, 2016 FERC Form 1 at pdf p. 103 (Apr. 1, 2017).

⁶⁸ *Id.*

⁶⁹ Table 1, *supra*. 2016 combined cycle plant production = 2,299,052 MWh (Palomar) + 1,223,034 MWh (Desert Star) + 2,654,182 MWh (OMEC) = 6,176,268 MWh.

⁷⁰ SDG&E Response to POC's Third Data Request, Response 1 at pp. 1-2, R. 17-06-026 (Mar. 23, 2018). This 10-year limit is the reason that 556 Palomar Energy Center and 98 MW Miramar are not included as CRS-eligible resources.

⁷¹ CPUC Resolution E-4465 (Aug. 2, 2012), available at http://docs.cpuc.ca.gov/word_pdf/COMMENT_RESOLUTION/169867.pdf.

⁷² 2016 SDG&E FERC Form 1, at pdf p. 41 (Page 123.2).

Calpine, which it has an option to do,⁷³ OMEC will no longer form part of the brown power ledger in the SDG&E PCIA calculation after 2019.

Table 2 lists the IOU-owned PCIA applicability termination dates and PPA or QF contract termination dates in the right-hand column. These termination dates indicate that brown power resources should comprise a diminishing part of the PCIA in future years. Within one to three years, a substantial component of SDG&E's CRS-eligible brown power procurement will no longer be eligible for PCIA treatment. New contracts, specifically the Pio Pico and Carlsbad Energy Center contracts, are CAM projects with pass-through costs to all ratepayers that should not be included in the PCIA calculation. With renewables taking up an increasingly large slice of the utilities' portfolio, and with load departures forecasted to increase, there is no basis for substituting expiring CRS-eligible brown power contracts with new brown power capacity.

Finally, it is possible the high PCIA is being driven by brown power contracts that are not eligible for PCIA costs. There is a large discrepancy between the CRS-eligible brown power resources that SDG&E affirmatively identifies in data responses to POC and the brown power energy production and the RA contribution of these resources, shown in the 2017 and 2018 PCIA calculations. SDG&E accounts for 2,516,476 MWh of CRS-eligible brown power 2016 energy production in its data response to POC.⁷⁴ However, SDG&E assumes 5,491,000 MWh of CRS-eligible brown power energy production in 2016 as an input to the 2017 PCIA.⁷⁵ This discrepancy calls into question whether SDG&E is including ineligible contracts in the PCIA calculation of brown power resources (possibly costs for CAM projects or utility-owned brown power resources that have passed ten years of operation).⁷⁶

V. SDG&E overpaid for most of its utility-scale solar and wind PPAs

A. Solar project case study

1. Early high priced contracts approved by the Commission set an artificially inflated benchmark for utility-scale solar

The Commission's least-cost best-fit ("LCBF") procurement framework is intended to govern IOU procurement of green power resources. Decisions D. 03-06-071 and D. 04-07-029 adopted criteria for the rank ordering and selection of LCBF renewable resources for use by the IOUs in

⁷³ SDG&E 2016 Form 10-K at pdf p. 118

⁷⁴ SDG&E Response to POC's Third Data Request, Response 1 at p. 4 (excluding pumped hydro MWh), R. 17-06-026 (Mar. 23, 2018).

⁷⁵ SDG&E Response to POC's First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet). CRS eligible supply – CRS renewable supply = 12,460 GWh – 6,969 GWh = 5,491 GWh.

⁷⁶ See SDG&E Response to POC's Third Data Request at p. 1 (Mar. 23, 2018) (stating that brown power resources are not included in the PCIA if they have "exceeded the ten-year limit on recovery of utility-owned generation costs through the PCIA").

RPS solicitations.⁷⁷ These decisions also established the role of the independent evaluator (“IE”) and procurement review group (“PRG”) in evaluating the reasonableness of RPS contracts.⁷⁸ In concept, based on these Commission decisions, the IOUs methodically rank-order bids received in RFO processes based on the criteria listed in Table 4, and enter into contracts with the highest ranked bidders.

Table 4. Least-cost, best fit RPS bid evaluation process⁷⁹

<ol style="list-style-type: none"> 1. Net Market Value <ol style="list-style-type: none"> a. Benefits (Energy, Capacity, Ancillary Services) b. Contract Payments c. Transmission Network Upgrade Costs (also called a “transmission adder”) d. Congestion Cost 2. Portfolio-Adjusted Value <ol style="list-style-type: none"> a. Location b. RPS Portfolio Need c. Energy Firmness d. Curtailment 3. Project Viability 4. RPS Goals 5. Supplier Diversity

The IOUs also have the discretion to evaluate bids received outside of the formal RFO solicitations and enter into contracts with those counterparts. Most of SDG&E’s solar and wind contracts greater than 50 MW capacity signed in 2010 or later are bilateral contracts that were not selected as part of an RFO solicitation. However, the LCBF standard applies to all RPS contracts, whether as a result of an RFO solicitation process or through a bilateral negotiation.^{80,81} The intent of the LCBF process is clear – that the lowest-cost, viable green projects receive contracts.

⁷⁷ See PG&E 2014 RPS RFO preamble at p. 1: https://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricssuppliersolicitation/RPS2014/Attachment_K_LCBF_01052015.pdf.

⁷⁸ D.03-06-071 and D.04-07-029.

⁷⁹ See PG&E 2014 RPS RFO preamble at p. 2.

⁸⁰ CPUC Resolution E-4358, *SDG&E requests approval of an amended and restated renewable power purchase agreement with Pacific Wind, LLC* at p. 5 (Sept. 23, 2010) (“Energy Division evaluated the bilateral amended and restated PPA.”); *Id.* at p. 8 (“The amended and restated PPA was evaluated consistent with the LCBF methodology identified in SDG&E’s 2009 RPS Procurement Plan.”).

⁸¹ D.09-06-050, *Decision Establishing Price Benchmarks and Contract Review Processes for Short-Term and Bilateral Procurement Contracts for Compliance with the California Renewables Portfolio Standard* at p. 34, Finding of Fact No. 15 (June 18, 2009) (“In order to promote consistency of evaluation of all RPS procurement contracts, it is reasonable to authorize Energy Division staff to review bilateral RPS contracts using the same methods and criteria, including those for reviewing price reasonableness, as are used to review contracts that result from the utilities’ annual RPS solicitation, using the MPR as a price reasonableness benchmark for long-term bilateral contracts.”)

Despite the clear intent of the LCBF procedure, many of SDG&E's post-2008 solar and wind PPAs for projects greater than 50 MW, which form the overwhelming majority of SDG&E's solar and wind capacity, were not competitively priced, followed ad hoc, qualitative selection criteria disconnected from the concept of "best price from qualified bidders," and disregarded the utility's obligation to maintain just and reasonable rates per section 454.5 of the PUC Code. As discussed below, the LCBF framework initially functioned as intended to guide IOU procurement of resources at competitive prices but soon gave way as unreasonably high-priced projects were approved and set the benchmark against which future projects were evaluated.

The first utility-scale solar project PPA between a California IOU and a third-party solar developer approved by the Commission was the SCE-NRG January 2009 PPA for the 21.5 MW Blythe Solar LLC project.⁸² The contract price for this project between SCE and the solar panel manufacturer First Solar was \$89.625/MWh with an additional time-of-day (TOD) price adjustment.⁸³

SCE followed a methodical bid evaluation process in this case. The Blythe solar project was among projects bidding in response to SCE's 2007 RPS RFP. According to the IE, Sedway Consulting, the response to SCE's 2007 (RPS RFP) was quite robust.⁸⁴ SCE established a five-tier merit-order ranking system to categorize the bids received.⁸⁵

1. Projects within SCE's service territory with well-defined proposals that complied with SCE's RFP,
2. Projects within SCE's service territory with less-well-defined proposals that did not comply with SCE's RFP or seemed problematic,
3. Projects outside of SCE's service territory but within the CAISO grid,
4. Projects outside of CAISO with baseload energy deliveries that could potentially be scheduled as firm imports, and
5. Projects outside of CAISO with intermittent energy deliveries.

"Sedway Consulting reviewed SCE's grouping decisions and ranked each group's proposals based on their economic value (benefit/cost ratio), confirming SCE's selection of the top-ranked proposals in each of the groups."⁸⁶ The Blythe project pricing was below the 2007

⁸² CPUC Resolution E-4157, Approval of RPS PPA FSE Blythe 1, LLC at p. 9 (July 10, 2008)

⁸³ SCE, Renewable Power Purchase and Sale Agreement between Southern California Edison Company and FSE Blythe 1, LLC (RAP ID #5207), December 21, 2007, p. 4 and pp. 37-38.

⁸⁴ SCE, Advice Letters 2198-E/E-A/E-B, December 10, 2008, Attachment 2 (Dec. 1, 2008): Sedway Consulting, Independent Evaluation Report for Southern California Edison's 2007 Renewable Resource Solicitation at p. 7 (Dec. 31, 2007).

⁸⁵ *Id.* at p. 8.

⁸⁶ CPUC Resolution E-4157, Approval of RPS PPA FSE Blythe 1, LLC at p. 9 (July 10, 2008) ("This contract is below the 2007 MPR and will not be applied to SCE's cost limitation.").

MPR.⁸⁷ In the case of this PPA, selection based on best price appears to have been the primary driver for bid selection.

The energy price in the FSE Blythe 1 PPA is consistent with the publicly-stated pricing described by the developer, First Solar, at the time. First Solar was an active participant in the Renewable Energy Transmission Initiative (“RETI”), led by the California Energy Commission (“CEC”). The Commission was also an active party in RETI. First Solar identified a levelized cost-of-energy of \$90/MWh as achievable in its April 4, 2008 comment letter in the RETI process.⁸⁸ This comment letter was written approximately three months after SCE and First Solar had signed a PPA for FSE Blythe 1 with an energy price of \$89.625/MWh, and a TOD adjustment.^{89,90}

The April 2008 First Solar PPA shows that solar PV was cost competitive as early as 2008 and outperforming solar thermal technology in pricing. First Solar challenged RETI contractor Black & Veatch’s position that all solar PV technologies should have a similar cost of energy.⁹¹ First Solar points out that approval of the cost-effective FSE Blythe 1 PPA was pending before the Commission.⁹² Finally, First Solar summarizes recent studies of the cost of solar thermal projects with an average levelized cost-of-production of approximately \$170/MWh.⁹³

The intended effect of the LCBF framework—to guide reasonable and competitive procurement—was lost with the next solar PPA approved by the Commission, the 10 MW El Dorado solar project developed by Sempra Generation, which represented PG&E’s first large-scale solar PPA. The El Dorado solar project uses the same PV technology (First Solar) as the FSE Blythe 1 project. The PPA was approved by Commission in June 2009, with an energy price of \$139/MWh and a TOD adjustment. The El Dorado solar project was approved by the Commission six months after the Blythe solar project was approved, used the same solar PV technology as Blythe, but was priced \$50/MWh higher than the Blythe PPA.

It was known at the time of contracting that the El Dorado project failed to perform well in the LCBF framework and that far more prudent investment opportunities existed. The project’s location in Boulder City, NV put it outside the CAISO control area, and as such the project would have been classified in the lowest of the five merit order tiers established by SCE. The IE report noted numerous weaknesses in the El Dorado PPA (including that there was the appearance of favoritism toward Sempra Generation by PG&E and that the project ranked low

⁸⁷ *Id.*

⁸⁸ First Solar, Comments on the Renewable Energy Transmission Initiative (RETI) Phase 1A DRAFT Report at p. 1 (Apr. 4, 2008) [

⁸⁹ SCE-FSE Blythe 1 PPA at pp. 4, 84 (Dec. 21, 2007).

⁹⁰ The energy price also included a time-of-day (“TOD”) price adjustment described on pp. 37-38..

⁹¹ First Solar, Comments on the Renewable Energy Transmission Initiative (RETI) Phase 1A DRAFT Report at p. 1 (Apr. 4, 2008).

⁹² *Id.* at p. 2.

⁹³ *Id.* at p. 3.

among the bids received), but concluded that since no other bidders were harmed by the PPA, the contract should be approved by the Commission.⁹⁴

The IE report's executive summary states:⁹⁵

Arroyo (Seco Consulting) identified specific concerns regarding the process by which the El Dorado project was added to PG&E's short list after the list was finalized and provided to the CPUC on July 15, 2008. These concerns were communicated to PG&E's RPS RFO steering committee on August 8, 2008, as it considered, then made a decision to include El Dorado on the short list for negotiation. These specific concerns about how the El Dorado offer was treated, involving apparently preferential treatment of Sempra Generation by PG&E, create an appearance that the process that led to its inclusion in the short list, weeks after a short list was submitted to the CPUC, was less than fully fair.”

The IE report notes that the RPS procurement process established by state legislation required that the PG&E procurement process use criteria for the selection of LCBF renewable resources.⁹⁶ However, it goes on to note that the process that PG&E used to select a short list of projects “makes greater use of subjective judgment to consider the import of non-valuation criteria, as opposed to relying on an objective analysis or on a quantitative weighing formula.”⁹⁷

The IE goes into some detail on the weaknesses of relying on subjective judgment to bid selection purposes:⁹⁸

- Relying on subjective judgment to create the short list opens the risk that other considerations than those publicly identified within the Solicitation Protocol's stated list of non-valuation criteria may play a role in selecting or rejecting Offers for the short list. This risk is lower when a mechanical weighting approach or other objective process is used to incorporate the non-valuation criteria in creating the short list.
- The valuation methodology has some properties that, when combined with the specific elements of some Offers, may appear counterintuitive to some observers.

⁹⁴ PG&E, Advice Letters 3386-E and 3386-E-A, December 22, 2008, IE report, pdf. pp 20-72.

⁹⁵ CPUC Resolution E-4240, p. 7: PG&E did not receive Commission approval of its PPA with El Dorado Solar prior to taking deliveries under the PPA. In general, CPUC approval is required for generation under a PPA to be used for RPS compliance. p. 13: As a general rule, this Commission requires that a utility seek approval of long-term contracts prospectively. PG&E accordingly placed itself at some risk by incurring costs under the PPA, as the Commission could potentially deny or condition approval of the PPA. Under the specific circumstances of this case, the Commission concludes that advice letter should be approved, despite PG&E's “jumping the gun.”

⁹⁶ *Id.* at pdf p. 31.

⁹⁷ *Id.* at pdf p. 35.

⁹⁸ *Id.* at pdf. p, 37.

Ultimately the IE report claimed that the contract was acceptable despite many flaws in the process, including the project scoring poorly relative to other bids and required wheeling through an out-of-state utility,^{99,100} because no other bidder was injured by the PPA. This is an illogical conclusion. Other bidders were denied 10 MW of PG&E solar procurement awarded to Sempra Generation, and ratepayers were left with far higher costs than were reasonable for solar power at the time.

Approval of the El Dorado PPA based on purely qualitative criteria at a far higher price than the SCE Blythe solar project points to the problems inherent in a confidential PPA procurement process that relies too heavily on the independent evaluator and the Procurement Review Group to assure price reasonableness. The subjective process utilized by PG&E to select the Sempra Generation bid produced a poor result for ratepayers. The agreed upon energy price of \$139/MWh was more than 50 percent higher than the \$89.625/MWh energy price agreed upon in the FSE Blythe 1 contract approved by the Commission six months earlier, for the same solar technology and at a time when solar prices were declining rapidly.

The approval of this PPA pushed the cost of thin-film solar from demonstrably least cost into the same range as other forms of solar PV and solar thermal, and shifted the bid selection criteria from LCBF to “subjective and counterintuitive.”

The approval of the El Dorado Solar PPA opened the door to an “anything goes” attitude toward solar and wind PPA pricing after 2008, with subsequent utility-scale RFO and bilateral solar and wind PPAs consistently 50 to 100 percent above verifiable competitive market pricing for the date the contracts were approved by the Commission. Table 5 includes only California IOU solar projects using First Solar panels to demonstrate how misaligned with LCBF principles the contract price of solar became following the approval of the PG&E-Sempra Generation El Dorado Solar PPA.¹⁰¹

Table 5. IOU PPA contract prices for solar projects using First Solar thin-film PV

Project ¹⁰²	IOU	Capacity, MW	PPA approval date by CPUC	Energy cost, \$/MWh	TOD adjustment
FSE Blythe 1	SCE	21.5	January 2009	89.625	Y

⁹⁹ *Id.* at pp. 51-53 “Based on the valuation of the El Dorado PPA compared to other Offers as initially priced, and on the PPA’s pricing compared to the proposed Market Price Referent, Arroyo’s judgment is that the El Dorado contract ranks low in market valuation. . . The proposed project would impose the burden of a contract price that today appears to be both relatively high when compared to competing Offers, and absolutely high when compared to the proposed MPR, on ratepayers for twenty years. . . The handling of the El Dorado involved preferential concessions to Sempra Generation that tend to create the appearance of unfair treatment.”

¹⁰⁰ *Id.* at p. 35. “PG&E had originally applied a TRCR (transmission) adder to the economics of the El Dorado offer . . . The physical location of the El Dorado substation (Southern Nevada) is far from PG&E’s service territory.”

¹⁰¹ This is a partial list of California IOU solar PPAs where First Solar technology is utilized. The relevant pages from each PPA listed in Table 5 are included in **Attachment A**.

¹⁰² SCE Advice Letter (AL) 4107-E at pp. 21-22, September 10, 2012.

				(no annual increase)	
Topaz Solar	PG&E	550	Feb 2009	104.00	Y
El Dorado	PG&E	10	July 2009	139.00	Y
Agua Caliente	PG&E	290	June 2010	147.50	Y
AV Solar Ranch	PG&E	230	March 2010	129.25	Y
Desert Sunlight	SCE	250	Sept 2010	119.50 (+1% per year)	Y
Campo Verde	SDG&E	139	May 2012	113.00	Y

Failure to prioritize the LCBF standard following the Commission’s approval of the El Dorado PPA resulted in many high-cost, above-MPR PPAs, such as the 250 MW Mojave solar thermal project. Former Commissioner Mike Florio characterized the Mojave solar thermal project as burdening ratepayers with \$1.25 billion in excessive life-of-contract costs.¹⁰³ It was a bid selection process failure that led to these inflated solar bids being awarded PPAs, and not a lack of competitively-priced bids that would have eliminated ratepayer exposure to above market contract costs.

2. TOD adders drove up contract prices even further

The inclusion of a TOD adjustment to California IOU solar PPAs, in addition to the already inflated contract price, inflated payments even further. The value of electricity varies throughout a 24-hour day relative to the electricity demand in those hours. The highest demand for electricity occurs on weekday afternoons in the summer months. Solar output is greatest at mid-day and early afternoon. As a result, the application of a TOD value adjustment increases the “all-in” price paid to the solar operator by about 20 percent on average. This is shown in Table 5 for a number of the large solar projects in SDG&E’s portfolio.

¹⁰³ Forbes, *California Approves High-Priced Mojave Solar Project Over Objections*, November 10, 2011. “The PPA unnecessarily saddles ratepayers with extraordinary above-market costs - \$1.25 billion,” said Commissioner Mike Florio, who voted against the contract at Thursday’s meeting. “We could probably get almost 500 megawatts of renewable energy for the price we’re paying for this 250 megawatts.” See: <https://www.forbes.com/forbes/welcome/?toURL=https://www.forbes.com/sites/toddwoody/2011/11/10/california-approves-high-priced-mojave-solar-project-over-objections/&refURL=https://www.google.com/&referrer=https://www.google.com/>.

Table 5. Impact of TOD adjustment on the unit price paid by SDG&E for utility-scale solar power¹⁰⁴

Project	Capacity, MW	2016 MWh Production	Base contract price w/o TOD, \$/MWh	Payment by SDG&E, \$	Effective price w/ TOD, ¹⁰⁵ \$/MWh	Unit price increase w/TOD, %
Arlington Valley	127	364,397	108	44,445,979	122	13
Catalina Solar	110	269,372	113	34,954,456	130	15
CSolar IV South	130	292,750	126	43,930,768	150	19
Imperial Valley Solar	200	535,403	99	67,077,350	125	27

California IOUs pay a TOD adjustment to solar developers in addition to the contracted energy price. Other Southwestern IOUs, such as Public Service of New Mexico (“PNM”) and NV Power, do not pay a TOD adjustment.^{106,107}

The TOD adjustment is not inherently flawed. For example, it could be used to put a portion of a LCBF contract at performance risk, where full payment of a competitive contract price must be earned by maintaining the facility in top condition. That is how it appears to have been used by bids in the RAM procurement process, which achieves least-cost pricing with a TOD adjustment.¹⁰⁸ However, when added to the cost of contracts that already exceeded market value at the time, the TOD adder made these contracts even more expensive.

3. Low-cost RAM contracts derived from a competitive auction provide a benchmark to evaluate the imprudent component of solar PPAs

The Renewable Auction Mechanism (“RAM”) procurement process for projects 20 MW and less, based on price-based competitive bidding and standard offer contracts, resulted in far lower PPA prices – one-half the price of utility-scale contracts in some cases—for smaller solar projects in SDG&E territory. This discrepancy is counter-intuitive, as economy-of-scale principles would anticipate lower prices for utility-scale projects. The discrepancy is due to the

¹⁰⁴ SDG&E, A.17-06-006 D. Sullivan 2016 ERRRA Compliance Testimony, June 1, 2017, at pdf p. 1030 and pp. 1035-1036.

¹⁰⁵ Arlington Valley example: $[(\text{total SDG\&E 2016 payment}) \div ((\text{energy price})(\text{energy production}))] = \$44,445,979 \div \$39,354,876 = 1.129$ (12.9 percent increase).

¹⁰⁶ New Mexico PRC Recommended Decision Case No. 12-00131-UT, In the Matter of PNM’s Renewable Energy Portfolio Procurement Plan for 2013, November 7, 2012, p. 31.

¹⁰⁷ Nevada Power Company, Nevada Public Utilities Commission Application A.15-07---, Seeking Approval of a 100 MW PPA with SunPower and a 100 MW PPA with First Solar, July 1, 2015.

¹⁰⁸ SDG&E, RAM Power Purchase Agreement Between SDG&E and Cascade Solar, LLC, October 19, 2012.

fact that RAM auctions prioritize objective cost competitiveness while utility-scale solar PPAs were selected through the subjective and skewed process described above. RAM contracts, which represent the market value of solar PV projects at the time, provide a benchmark against which to assess the avoidable component of utility-scale PPA pricing.

In 2010, the Commission in D. 10-12-048 adopted the 1,000 MW RAM program to create “a simplified market-based procurement process for smaller RPS projects.”¹⁰⁹ The first RAM auction closed on November 15, 2011.¹¹⁰ The RAM program was “designed to reduce transaction costs by providing a streamlined contracting mechanism utilizing a standard contract while at the same time relying on market-based pricing.”¹¹¹ It was “intended to complement the RPS Program by providing a procurement opportunity for smaller RPS-eligible projects which have not been able to effectively participate in the RPS solicitations.”¹¹²

In its December 2012 advice letter to the Commission requesting approval of the 18.5 MW Cascade Solar project, SDG&E confirms that it “established an open, transparent and competitive process for the procurement effort.”¹¹³ The price to be paid by SDG&E was “[b]ased on Seller offer and adjusted by Time of Delivery (“TOD”) factors as proposed in the RAM PPA.”¹¹⁴ In the case of Cascade Solar, the 2016 actual contract price, adjusted for TOD factors, was \$75.13/MWh.¹¹⁵

These RAM projects were approved and built in the same time period that SDG&E was constructing its in-state utility-scale solar PPA projects.¹¹⁶ Table 6 compares the unit cost of 2016 payments made by SDG&E to three RAM projects approved by the Commission in the second half of 2012 and first half of 2013 to the unit cost of SDG&E’s 2016 payments to the 139 MW Campo Verde solar project, which uses First Solar panels and was approved by the Commission in mid-2012.

¹⁰⁹ RAM program: http://www.cpuc.ca.gov/Renewable_Auction_Mechanism/.

¹¹⁰ *Id.*

¹¹¹ SDG&E, Advice Letters 2418-E and 2418-E-A, *Request for Approval of Standard Renewable Auction Mechanism Renewable Power Purchase Agreements with Cascade Solar LLC, ClearVista Energy LLC, MM San Diego LLC, Rugraw LLC and Supplemental Filing*, December 13, 2012, at p. 2.

¹¹² *Id.*

¹¹³ *Id.* at p. 3.

¹¹⁴ *Id.* at p. 7.

¹¹⁵ SDG&E, A.17-06-006 D. Sullivan 2016 ERRAs Compliance Testimony, June 1, 2017, at pdf p. 1030 and p. 1035. PPA terms: \$64.81/MWh in 2013 escalating to \$103.61/MWh in 2033 adjusted by TOD Factors. 2016 all-in energy price paid by SDG&E: \$4,106,601 ÷ 54,660 MWh = \$75.13/MWh.

¹¹⁶ RAM program: http://www.cpuc.ca.gov/Renewable_Auction_Mechanism/.

Table 6. Comparison of actual unit cost of Campo Verde and RAM project(s) solar power¹¹⁷

Project	Capacity, MW	Date PPA signed	2016 production, MWh	2016 SDG&E payments, \$	Unit cost of production, \$/MWh
Campo Verde	139	May 2012	362,328	42,148,755	116.30
Cascade	18.5	Oct 2012	54,660	4,106,601	75.10
Calipatria	19.9	Dec 2012	47,438	3,541,070	74.60
Maricopa West	20	April 2013	52,566	3,403,504	64.70

All of the RAM PPAs were well under the MPR at the time. By contrast, many of the utility-scale solar and wind contracts entered into by SDG&E are above the applicable MPR.

B. Wind Projects Case Study

SDG&E signed four in-state utility-scale wind power PPAs in the 2010-2012 time period that account for about 80 percent of SDG&E's contracted wind capacity. Three of these contracts were dramatically higher in price relative to those executed a few years before. The one exception is the 100 MW Manzana wind project. These four wind projects are discussed in turn below.

There was some increase in the cost of building wind projects between 2006 and 2013, on the order of 10 percent, as shown in Figure 2.¹¹⁸ The COD of the 50 MW Kumeyaay wind project was 2006. The PPA price is \$51.75/MWh.¹¹⁹ If the same project had been built later with a COD of 2013, it is reasonable to assume that, holding other variables constant, the PPA price would increase by about 10 percent to approximately \$57/MWh.¹²⁰

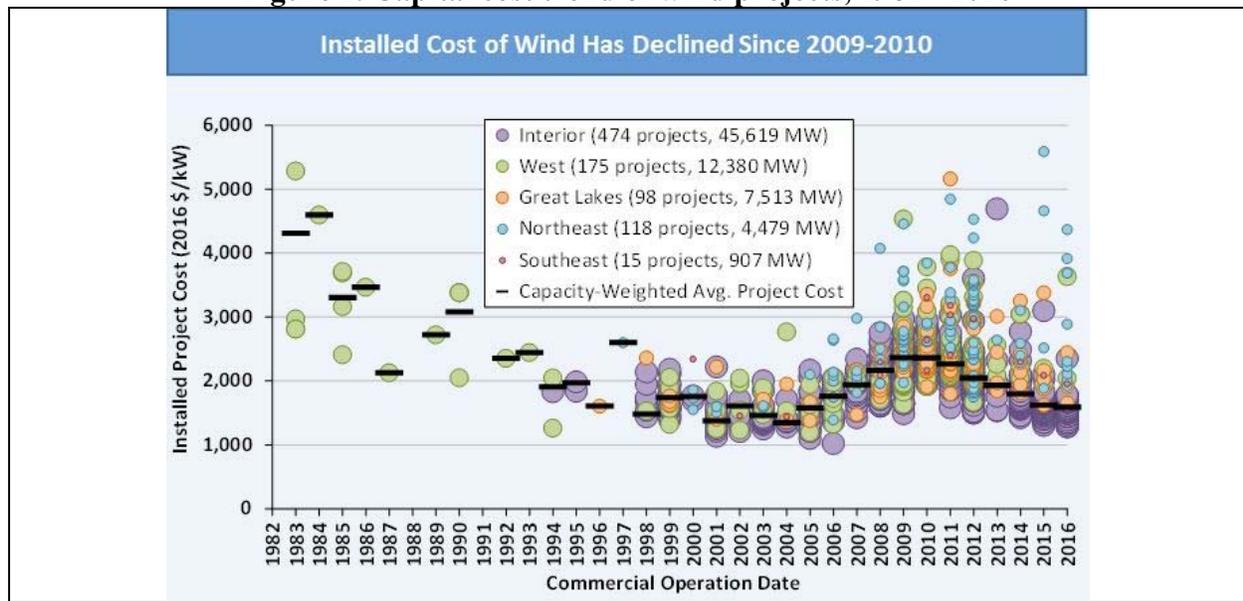
¹¹⁷ SDG&E, A.17-06-006 D. Sullivan 2016 ERRAs Compliance Testimony, June 1, 2017, pdf pp. 1029-1031 and pp. 1034-1036.

¹¹⁸ Average installed cost ~\$1,800/kW in 2006, average installed cost ~\$2,000/kW in 2013. Increase in installed cost = $\$2,000 \text{ kW} \div \$1,800/\text{kW} = \sim 10$ percent. Data from Lawrence Berkeley National Laboratory webpage, accessed March 30, 2018: http://newscenter.lbl.gov/wp-content/uploads/sites/2/2017/08/wind_2016_image_2.jpg.

¹¹⁹ SDG&E, A.17-06-006 D. Sullivan 2016 ERRAs Compliance Testimony, June 1, 2017, pdf p. 1036. PPA terms: \$49/MWh in Year 1 and escalating to \$51.75/MWh in Years 5-20.

¹²⁰ $\$51.75/\text{MWh} \times 1.10 = \$56.93/\text{MWh}$.

Figure 2. Capital cost trend of wind projects, 1982 - 2016¹²¹



The analysis that follows evaluates the four utility-scale wind project PPAs SDG&E entered into between 2010 and 2012. Comparison between them reveals that that prices of three of the four projects were known, or should have been known, to be well above market at the time they were approved by the Commission.

1. 265 MW Ocotillo Express

The 265 MW Ocotillo Express wind project is the largest project in SDG&E's portfolio at 265 MW and one of only four wind projects under contract over 100 MW. The installed capital cost of Ocotillo Express project of \$2,088/kW,¹²² as reported by SDG&E and with a COD of 2013, is approximately equal to the average installed cost of approximately \$2,000/kW for wind projects reported by LBNL for wind projects with CODs in 2013.

Yet the average PPA contract price reported by NREL for wind projects with CODs between 2012 and 2014 was \$60/MWh, compared to the \$105/MWh price SDG&E pays for wind power from Ocotillo Express pursuant to its 2012 PPA and 2013 COD.¹²³

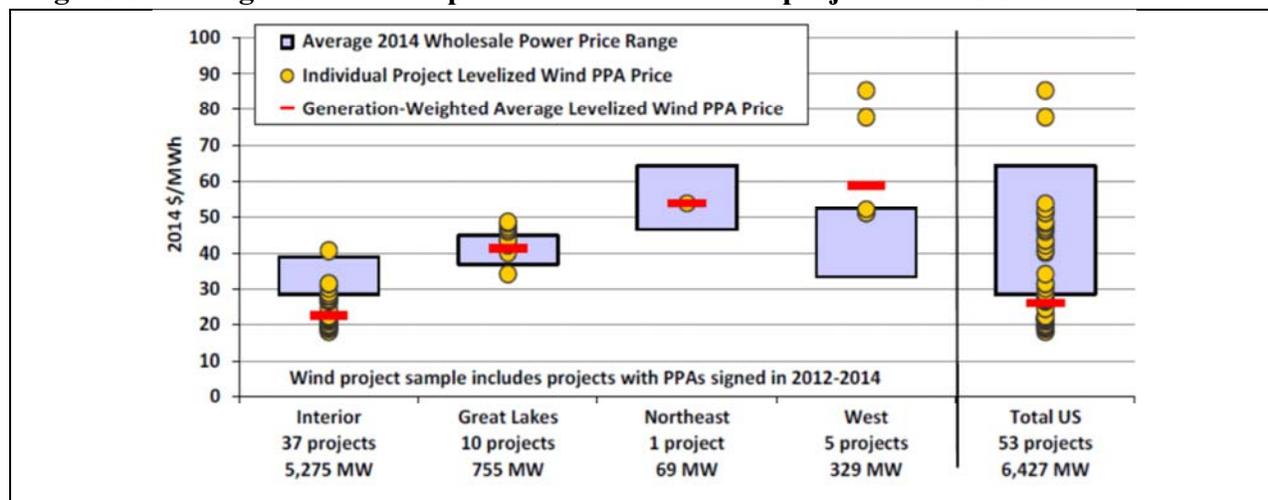
¹²¹ Lawrence Berkeley National Laboratory webpage, accessed March 30, 2018:

http://newscenter.lbl.gov/wp-content/uploads/sites/2/2017/08/wind_2016_image_2.jpg.

¹²² SDG&E, *California's Energy Future*, PowerPoint, 7th Annual Imperial Valley Renewable Energy Summit, March 12-14, 2014, p. 3 (public presentation).

¹²³ SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at pdf. p. 1036.

Figure 3. Average cost of wind power PPAs in West for projects with CODs in 2012-2014¹²⁴



Despite these discrepancies, the Commission determined that the Ocotillo Express PPA would result in no above market cost burden on SDG&E ratepayers:¹²⁵

Based on the 2012 commercial online date for the Ocotillo PPA, the 20-year PPA, as amended, is below the 2009 MPR. Thus, the Ocotillo PPA does not have any above-market costs.

The Commission’s determination that the \$105/MWh price tag for Ocotillo Express was not above market is contradicted by its evaluation of the 155 MW Sempra ESJ Wind project, discussed below. The Commission’s 2012 resolution authorizing the ESJ contract determined that its price - \$106.50/MWh, nearly identical to the Ocotillo price - was above market.¹²⁶

2. 140 MW Pacific Wind

The 140 MW SDG&E Pacific Wind contract is a case study in unjustified PPA cost inflation. The initial PPA contract between SDG&E and Pacific Wind was approved by the Commission in 2006 for 205.5 MW at a contract price of \$57/MWh,¹²⁷ identified by the Commission as below the 2004 MPR.¹²⁸ This 2006 contract price is consistent with SDG&E’s

¹²⁴ Lawrence Berkeley National Laboratory, *2014 Wind Technologies Market Report: Summary*, August 2015, at p. 52.

¹²⁵ CPUC Resolution E-4458, January 12, 2012, at p. 9:

http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/157540.pdf

¹²⁶ CPUC Resolution E-4467, March 22, 2012, at p. 29. “The ESJ PPA price of \$106.50/MWh is above the applicable 2009 MPR.” See:

http://docs.cpuc.ca.gov/word_pdf/AGENDA_RESOLUTION/161368.pdf.

¹²⁷ SDG&E-Pacific Wind, LLC Power Purchase Agreement, October 12, 2005, at p. 6.

¹²⁸ Resolution E-3979, *SDG&E requests approval of the Pacific Wind renewable resource procurement contract. This contract is approved without modifications*, May 25, 2006, at p. 3. “On October 27, 2005, SDG&E filed Advice Letter (AL) 1734-E requesting Commission approval of one renewable procurement contract: Pacific Wind.”

first in-state utility-scale wind PPA, the 50 MW Kumeyaay wind project. Kumeyaay came online in 2005 with a PPA price of \$51.75/MWh.¹²⁹

However, the Pacific Wind project was delayed, the PPA contract capacity adjusted downward to 140 MW to resolve local radar interference issues,¹³⁰ and the contract price increased from \$57/MWh to \$115.47/MWh.¹³¹ The Commission noted in its September 2010 authorizing resolution for the Pacific Wind PPA that an independent engineer, R.W. Beck, had reviewed the project's original and revised financial proformas, and that the IE found Beck's analysis "credible and that the pricing of the amended and restated Pacific Wind PPA [was] reasonable in comparison to the market."¹³² It concluded that the "amended and restated PPA is a bilateral contract for renewable generation that fits SDG&E's identified renewable resource needs."¹³³

The case for Commission approval of the substantial increase in contract price rested largely on the R.W. Beck report. In its authorizing resolution, the Commission continues:¹³⁴

The Pacific Wind amended and restated contract price is above the market price referent (MPR) and is a new bilateral contract; thus, certain criteria outlined in E-4199 apply. . . As required, SDG&E explained why the contract change is needed and provided a showing which included relevant data and information to justify the change. . . Specifically, the amended and restated contract's price was compared to the projects that SDG&E is negotiating and to its most recent shortlist. Additionally, an independent engineer, R.W. Beck, reviewed the project's original and revised financial proformas. Specifically, R.W. Beck reviewed documentation from enXco showing the components of the price increase and reviewed data from other sources to confirm changes are reasonable from a market perspective."

POC requested the R.W. Beck report in a data request to SDG&E in an intent to understand the reasonableness of the Pacific Wind contract price increasing from \$57/MWh to \$115.47/MWh in less than five years. The R.W. Beck report was confidential Appendix H to SDG&E Advice Letter 2159-E, submitted to the Commission on April 30, 2010.¹³⁵ SDG&E responded to the POC data request stating that it did not have the R.W. Beck report.¹³⁶ This

¹²⁹ SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at p. DLS-22.

¹³⁰ CPUC Resolution E-4358, September 23, 2010, at p. 4:

http://docs.cpuc.ca.gov/word_pdf/COMMENT_RESOLUTION/122269.pdf.

¹³¹ SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at p. DLS-22.

¹³² CPUC Resolution E-4358, September 23, 2010, p. 7.

¹³³ *Id.* at p. 8.

¹³⁴ *Id.* at pp. 6-7.

¹³⁵ SDG&E Advice Letter 2159-E, *Request for Approval of Third Amendment of Renewable Power Purchase with Pacific Wind, LLC*, April 30, 2010, at p. 5. Appendix H: RW Beck (IE) Price Increase Due Diligence. See: <http://regarchive.sdge.com/tm2/pdf/2159-E.pdf>.

¹³⁶ SDG&E Response to POC's Second Data Request in R.17-06-26, Response 9 at p. 10 (Mar. 16, 2018) ("SDG&E does not have the referenced report.").

response by SDG&E cannot be accurate, given the requested document is an attachment to an April 2010 SDG&E advice letter.

The dramatic price escalation of the Pacific Wind PPA in less than a five-year period is particularly striking when considered in light of the fact that the final amended PPA was executed only two years after the U.S. entered a major economic recession, which drove down equipment costs that had reached a post-2000 high point in 2008.¹³⁷

3. 155 MW Energía Sierra Juarez

The 2012 SDG&E PPA with Sempra Generation for 155 MW of Energía Sierra Juarez (“ESJ”) wind power in Mexico just over the border about 70 miles east of San Diego is an affiliate transaction. Affiliate transactions are subject to special reporting requirements by the Commission due to the potential hazard to ratepayers of IOUs contracting directly with their unregulated affiliates.¹³⁸ The sale by Sempra Generation of 556 MW Palomar Energy Center combined cycle project to SDG&E in 2006 was an affiliate transaction. The sale of 526 MW Desert Star Energy Center combined cycle project by Sempra Generation to SDG&E, in 2011, was also an affiliate transaction.¹³⁹

Sempra Generation had made public statements prior to the 2012 signing of the ESJ PPA that it was developing projects in Mexico to take advantage of low labor costs, fast permitting, and less restrictive environmental laws.¹⁴⁰ Though Sempra Generation may have capitalized on a comparative lack of regulation and low labor costs in Mexico, the contract price for ESJ wind power, at \$106.50/MWh, was more expensive than the \$105/MWh contract for the Ocotillo Express project, sited in California about 100 miles east of San Diego.

4. 100 MW Manzana Wind PPA

SDG&E’s 100 MW Manzana Wind PPA, with a contract price of \$95/MWh,¹⁴¹ is the sole utility-scale PPA it signed in the 2010-2012 timeframe that resulted in an actual contract payment in the range of the average PPA contract price for wind PPAs in the West for the 2012-2014 time period. SDG&E used a contract pricing formula unique among the utility-scale wind and solar contracts signed in the 2010-2012 timeframe. The average locational market price (“LMP”) is subtracted from the contract energy price to arrive at a net payment price.¹⁴² The net payment price in 2016 was \$71/MWh. Although incrementally higher than the \$60/MWh average wind PPA price for projects in the West

¹³⁷ Chemical Engineering (magazine), Chemical Engineering Construction Price Index (CEPCI), at p. 84, April 2012 edition. 2008 CEPCI = 575.4, 2010 CEPCI = 550.8.

¹³⁸ See SDG&E “Affiliate Transactions” webpage, accessed April 1, 2018: <https://www.sdge.com/rates-and-regulations/other-regulatory-filings/affiliate-transactions>.

¹³⁹ Resolution E-4465, August 2, 2012.

¹⁴⁰ Gas Turbine World, *Sempra Energy: Mexicali plant spurs surge of capacity*, at p. 36, April-May 2004.

¹⁴¹ SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at p. DLS-21.

¹⁴² *Id.*

in 2012-2014, the Manzana wind net price is much lower than the price paid by SDG&E for wind production from Pacific Wind, Ocotillo Express, and ESJ.

The Commission resolution approving the Manzana Wind PPA, was issued in August 2012. The Commission resolutions approving the Ocotillo Express and ESJ PPAs were issued in January 2012. These two PPAs are nearly 50 percent more expensive than the Manzana Wind PPA, as shown in Table 7.

Table 7. Actual price paid by SDG&E for wind power from Manzana Wind, Ocotillo Wind, and ESJ in 2016¹⁴³

Project	Capacity, MW	2016 production, MWh	2016 SDG&E payment, \$	Unit cost, \$/MWh
Manzana Wind	100	283,511	20,180,686	71.2
Ocotillo Express	265	529,476	54,972,377	103.8
ESJ	155	423,308	44,282,091	104.6

SDG&E provides no explanation in its July 2017 ERRAs testimony, which discussed the Manzana Wind contract structure, as to why it chose to use a pricing structure in the case of the Manzana Wind PPA that reasonably protects the interests of ratepayers but did not include this contract structure in two other large wind PPA contracts authorized the same year.

C. The IE and PRG are inadequate safeguards to assure PPA contracts are reasonably priced

The IE and PRG are an inadequate safety net to assure that SDG&E green power PPA contract pricing accords with LCBF principles. The excessively high cost of most of SDG&E’s post-2008 utility-scale solar and wind contracts is testament to the inadequacy of the current contract review procedure. More rigorous scrutiny is particularly necessary in light of the self-dealing nature of much IOU procurement.

SDG&E’s parent company is Sempra Energy. Sempra Renewables, an affiliate of Sempra Energy, has as its two largest solar clients PG&E and SCE.¹⁴⁴ These two IOUs have over 1,000 MW of solar capacity under contract with Sempra Renewables. As discussed above, SDG&E also heavily contracts with Sempra projects. Inflated solar PPA contract pricing directly benefits SDG&E’s affiliate.

Neither the IE nor the PRG possess the independence or duty to safeguard load against self-dealing transactions. SDG&E used the same IE for all of its post-2008 in-state solar and wind PPAs, Jonathan Jacobs of PA Consulting. Mr. Jacobs was a PG&E executive, and PG&E

¹⁴³ SDG&E, A.17-06-006 D. Sullivan 2016 ERRAs Compliance Testimony, June 1, 2017, at pp. 1030-1031 and pp. 1035-1036.

¹⁴⁴ See Sempra Renewables solar projects webpage: <http://www.semprarenewables.com/energy-solutions/solar/solar-projects/>.

affiliate company executive, for ten years prior to becoming a consultant. On his resume, he lists SDG&E and PG&E as primary clients.¹⁴⁵

In addition, the IOUs have no obligation to address comments by PRG members, even if comments are received. This was underscored by SCE in the A. 14-11-012 evidentiary hearing,¹⁴⁶ during cross-examination of SCE witness Cushnie:¹⁴⁷

Q: Very good. And so how does it work? Is it evidentiary? Is it majority vote? If someone in the PRG says "I have an issue with how you structure your demand response contracts" for example, is there some formal process so that SCE incorporates that or does SCE just hear from someone on the PRG and you decide one way or the other whether you're going to incorporate or not that suggestion?

A: So the Procurement Review Group process is a consultive process. There is no membership, per se. The entities that participate that are not Commission staff sign nondisclosure agreements. The Commission personnel participate under the Commission's confidentiality Public Utility Code requirements. And it is a process in which Edison as the utility puts forward its procurement recommendations and it seeks feedback from these participants. And it's an iterative process at times. It is certainly a dialogue. But at the end of the day, there's no vote taken. Edison takes the feedback that it gets under advisement, and then it moves forward.¹⁴⁸

The PRG comes nowhere near the level of scrutiny achieved in an evidentiary process where independent parties can probe the validity of the facts at issue. The PRG process creates only the illusion of independent review.

VI. PCIA reliance on market value of resources is flawed and should be reformed.

The PCIA fundamentally conflicts with the objective that “bundled IOU customers should be neither worse off nor better off as a result of customers departing the IOU for other energy providers.” The indifference concept imbedded in the current PCIA calculation is “indifference to the real-time market value of SDG&E’s generation portfolio” using various PCIA assumptions regarding the market value of brown power, capacity, and green power, and not price indifference to the generation charge that SDG&E customers actually pay.

As a consequence, the PCIA currently enables IOUs to shed over-priced contracts, allowing them to reduce generation charges for bundled customers while placing the above-market component of those projects on the backs of departing load. That is, it effectively requires

¹⁴⁵ J. Jacobs resume.

¹⁴⁶ A.14-11-012, Evidentiary Hearing, May 6, 2015, Volume 2 at pp. 323-324.

¹⁴⁷ B. Powers, A.14-11-012 Opening Brief of Powers Engineering, June 10, 2015, pp. 8-9.

¹⁴⁸ Testimony of Colin Cushnie, A.14-11-012, Application of Southern California Edison Company (U 338-E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Western Los Angeles Basin.

departing load customers to subsidize non-departing load customers in a “treadmill” effort to have non-departing load generation charges track current real-time market value rates of brown power, capacity, and green power. The PCIA thus enables a substantial reduction in the generation charge paid by non-departing load relative to what non-departing load actual pays now. This is not cost indifference. This is a cost subsidy by departing load to non-departing load customers.

The PCIA must be fundamentally reformed to meet the Commission’s objectives and guiding principles. The average SDG&E retail generation charge in 2015 and 2016 was approximately \$0.10/kWh, or \$100/MWh. The indifference concept, applied to SDG&E customers in 2018, means non-departing load customers should not be subject to a generation charge greater than ~\$100/MWh. Brown power CAM project costs should be passed through directly and not added to the PCIA. Any SDG&E green contract obligation under \$100/MWh should not contribute to the PCIA, as it is at or below the generation charge that SDG&E customers currently pay.

At the same time, the Commission should adjudicate what portion of the price of high cost solar and wind contracts was reasonably avoidable, and it should instruct the utilities to absorb this cost. The Commission can use the market price referent and/or RAM contract pricing as a benchmark for evaluating this avoidable component. No SDG&E solar or wind contract that was significantly above the applicable market price referent (or the benchmark set by RAM contract pricing) was reasonable at the time it was signed. The contract terms were confidential and subject to little arms-length scrutiny. The Commission accepted, with its 2009 approval of the 10 MW El Dorado Solar PPA between PG&E and Sempra Generation, that PPA terms were subject only to qualitative weighing based on the IOU’s expertise, effectively nullifying the primacy of LCBF as a deciding factor in bid selection and opening the door to the IOUs contracting for solar and wind at virtually any price for any reason.

The upshot of this analysis is that the PCIA, rather than escalating in price, should be approaching zero. The removal of brown power CAM projects will eliminate one of the most significant slices of the PCIA, and the upcoming ineligibility of wholesale brown power contracts will eliminate another slice. Adoption of the average generation charge as the MPB eliminates the vast majority of green power contracts. Solar contracts being signed by SDG&E under demonstrably more transparent contracting regimes, like the RAM standard offer auction mechanism, were signed at substantially lower cost than \$100/MWh. As a consequence, most costs above \$100/MWh on any SDG&E solar or wind contract should be borne by shareholders.

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