UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Public Utilities Commission of the	)	
	)	
State of California	)	
Complainant,	)	
v.	)	
	)	
Sellers of Long-Term Contracts	)	
to the California Department	)	
of Water Resources	)	Docket Nos. EL02-60-018
Respondents	)	
	)	
	)	and
	)	
California Electricity Oversight Board	)	EL02-62-017
	)	
	)	
Complainant,	)	(Consolidated)
v.	)	
	)	
Sellers of Energy and Capacity Under	)	
Long-Term Contracts with the	)	
California Department of Water Resources	)	
Respondents.	)	

PREPARED ANSWERING TESTIMONY OF
STEVEN L. PULLER
ON BEHALF OF SHELL ENERGY NORTH AMERICA (US), L.P.

February 4, 2025

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SUMMARY

Dr. Puller is an economist with expertise in energy economics, regulation, empirical industrial organization, and public economics, testifying on behalf of Shell Energy North America (US), L.P. Dr. Puller's testimony evaluates the factual and economic reasoning for the benchmarks provided in the testimonies of the California Parties' witnesses Mr. Read, Dr. Celebi and Dr. Fox-Penner. Dr. Puller's testimony primarily responds to Mr. Read's testimony and Dr. Celebi's use of the price series created by Mr. Read to develop his benchmarks and responds to Dr. Fox-Penner's testimony to the extent it provides support for the approaches used by Mr. Read and Dr. Celebi.

Dr. Puller's testimony evaluates the five Dr. Celebi benchmarks that are based on forward contract prices. Dr. Puller finds that the first of these benchmarks, which is based on forward contracts signed by Shell between June 20, 2001 and December 31, 2002, is unreliable because the sample used by Dr. Celebi is comprised of small, short-term contracts. Further, some of these contracts were signed well after market fundamentals had changed, lowering the competitive price. Dr. Puller also evaluates the four benchmarks based on purported "forward prices" developed by Mr. Read. Dr. Puller finds that, like Dr. Celebi's first benchmark, these four benchmarks are unreliable because they rely on price quotes for contracts that are small and short-term relative to the Shell Contract and fail to control for changes in market fundamentals.

Dr. Puller's testimony explains the economics of long-term contracting and concludes that the appropriate benchmark for the Shell Contract price is an appropriately-calculated long-run marginal cost. Dr. Puller's testimony explains why the California Parties witnesses' selective endorsement of long-run marginal cost for the second half of their preferred benchmark is inconsistent with economic theory.

LIST OF SUPPORTING EXHIBITS

Table of New Exhibits

Exh. No.	Exhibit Title	Protected Exhibit (Y/N)
SHE-0052	Answering Testimony of Steven L. Puller	N
SHE-0053	Resume of Steven L. Puller	N
SHE-0054	Workpapers of Steven L. Puller	Y
SHE-0055	“Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities,” FERC, November 1, 2000	N
SHE-0056	PWX-2, Report of James L. Sweeney, Ph.D. In Support of Powerex Corp., Docket No. EL09-56-000, September 3, 2009	N
SHE-0057	“White Paper on Stabilization of NOx RTC Prices,” *South Coast Air Quality Management District*, January 11, 2001	N
SHE-0058	Joskow, P. L., “California’s Electricity Crisis,” *Oxford Review of Economic Policy*, Vol. 17, No. 3, September 1, 2001	N
SHE-0059	SCAQMD, *Historical Trade Registrations*	N
SHE-0060	Puller, S., “Pricing and Firm Conduct in California’s Deregulated Electricity Market,” *The Review of Economics and Statistics*, Volume 89, Issue 1	N
SHE-0061	Mehta, S., “Fire-Damaged San Onofre Reactor May Not Be Back Online Till June,” *Los Angeles Times*, March 22, 2001	N
SHE-0062	“CAISO 2001 Summer Assessment,” *CAISO*, March 22, 2001	N
SHE-0063	“Power Reactor Status Reports for 2001,” *U.S.NRC*	N
SHE-0064	“Revenue Requirement & Consultant’s Report Briefing to the Staff of CEC and CPUC on DWR Energy Procurement Program,” Navigant, May 18, 2001	N
SHE-0065	Wolak, F. A., “Wholesale electricity market design,” *Handbook on Electricity Markets*, 2021	N

SHE-0066	Anderson, E. J. *et al*., "Forward Contracts in Electricity Markets: The Australian Experience," *Energy Policy,* Volume 35, Issue 5, May 2007	N
SHE-0067	"Study of Western Power Market Prices Summer 2000," *Northwest Power Planning Council*, October 11, 2000	N
SHE-0068	Weare, C. "The California Electricity Crisis: Causes and Policy Options," *Public Policy Institute of California*, 2003	N
SHE-0069	Alonso-Zaldivar, R., and N. Vogel "Natural Gas, Power Prices Drop Sharply," *Los Angeles Times,* June 6, 2001	N
SHE-0070	"News Release: CPUC Sets New Electric Rates For PG&E And Edison Customers," *California Public Utilities Commission*, May 15, 2001	N
SHE-0071	Bushnell, J. B. and E. T. Mansur, "Consumption Under Noisy Price Signals: A Study of Electricity Retail Rate Deregulation in San Diego," *Journal of Industrial Economics*, Volume LIII, No. 4, December 2005	N
SHE-0072	"Forecaster Says End of Crisis in Sight, Gas Likely to Tumble," *Platts Electric Power Daily*, April 13, 2001	N
SHE-0073	"Calif. Controller Argues State Will Need $4B More for Power; Davis Aides Claim She's Wrong," *Platts Electric Power Daily*, May 22, 2001	N
SHE-0074	Decker, T., "Californians Cut Energy Use 12.3% From Last Year," *Los Angeles Times*, July 2, 2001	N
SHE-0075	Batteiger, J., "Energy Crisis / Governments setting their sites on helping with energy savings," *SFGate*, June 3, 2001	N
SHE-0076	Lutzenhiser, L., et al. "Lasting Impressions: Conservation and the 2001 California Energy Crisis." *American Council for an Energy Efficient Economy*, 2004	N
SHE-0077	Lutzenhiser, L., et al. "Crisis in Paradise: Understanding Household Conservation Response to California's 2001 Energy Crisis" *American Council for an Energy Efficient Economy*, 2002	N
SHE-0078	"Calif. Releases Long-Term Power Deals; Davis Aide Calls Them 'Insurance' Against High Prices," *Platts Electric Power Daily*, June 18, 2001	N
SHE-0079	"Causes and Lessons of the California Electricity Crisis," *Congressional Budget Office*, September 2001	N

SHE-0080	Lazarus, D., "Cooler weather leaving state with surplus of power / SUDDEN GLUT: Turnaround leaves regulators skeptical," *SFGate*, June 9, 2001	N
SHE-0081	"In Latest Forecast, California ISO Predicts State Is Likely To Be In For A Tough Summer," *Platts Electric Power Daily*, May 18, 2001	N
SHE-0082	Bessembinder, H. and M. Lemmon, "Equilibrium Pricing and Optimal Hedging in Electricity Forward Markets," *The Journal of Finance,* Vol. 57, No. 3, June 2002	N
SHE-0083	Index of Tables, Docket No. EL02-71-057, (formerly Ex. TC-0018), Table 23	N
SHE-0084	"History of California's General Obligation (GO) Credit Ratings", *California State Treasurer*	N
SHE-0085	Bustillo, M. and J. Tamaki, "Effort to Repay State for Power Is Delayed," May 8, 2001	N
SHE-0086	State of California Executive Department, Executive Order D-42-01, June 18, 2001	N
SHE-0087	"State Closes on $4.3-Billion Interim Loan to Buy Power," *Los Angeles Times*, June 27, 2001	N
SHE-0088	Bustillo, M., "GOP Tries to Force Its Dramatically Different Energy Plan on Governor," *Los Angeles Times,* May 4, 2001	N
SHE-0089	State of California Executive Department, Executive Order D-24-01, February 8, 2001	N
SHE-0090	"SCAQMD Suspends RECLAIM Rules on NOx Credit Requirements," *Platts Utility Environment Report*, February 23, 2001	N
SHE-0091	"Annual RECLAIM Audit Report for 2001 Compliance Year," *SCAQMD*, March 7, 2003	N
SHE-0092	"Power Plants Dropped from Southern California NOx Emissions Trading Program," *Platts Utility Environment Report*, May 18, 2001	N
SHE-0093	State of California Executive Department, Executive Order D-40-01, June 11, 2001	N
SHE-0094	"Davis Issues Order Waiving Emission-Related Operating Limits on Calif.'s Gas-Fired Capacity," *Platts Electric Power Daily*, June 12, 2001	N
SHE-0095	Allaz, B., and JL. Vila, "Cournot Competition, Forward Markets and Efficiency," *Journal of Economic Theory*, Volume 59, February 1993	N

SHE-0096	Bushnell, J. B., et al., "Vertical Arrangements, Market Structure, and Competition: An Analysis of U.S. Electricity Markets," *American Economic Review,* Vol. 98, No. 1, March 2008	N
SHE-0097	Borenstein, S., "The Trouble With Electricity Markets: Understanding California's Restructuring Disaster," *Journal of Economic Perspectives*, Volume 16, Number 1, 2002	N
SHE-0098	Answering Testimony of Tara Nolan On Behalf of Shell Energy North America (US), L.P., Docket Nos. EL02-60-013 et al., November 4, 2021, (formerly "Ex. SHL-0005, Nolan Testimony")	N
SHE-0099	"California PUC Approves Provisions SoCal Ed Needs To Implement Its Agreement With State," *Platts Electric Power Daily*, June 15, 2001	N
SHE-0100	"Calif. Releases Long-Term Power Deals; Davis Aide Calls Them 'Insurance' Against High Prices," *Platts Electric Power Daily*, June 18, 2001	N
SHE-0101	Calif. Controller Argues State Will Need $4B More for Power; Davis Aides Claim She's Wrong," *Platts Electric Power Daily*, May 22, 2001	N
SHE-0102	Deng, S.J. and S.S. Oren, "Electricity derivatives and risk management," *Energy*, 2006	N
SHE-0103	Omitted	N
SHE-0104	Pacific Gas and Electric Company's 2006 Long-Term Procurement Plan, March 19, 2008	N
SHE-0105	"Dynegy Continues to Withhold Power from ISO in Dispute over 'Reasonableness' of Calif. Prices," Platts Electric Power Daily, April 17, 2001	N
SHE-0106	"Allocation of Emission Cost Allowances," *CAISO*, September 21, 2006	N
SHE-0107	*Thirty-Eighth Status Report of the California Independent System Operator Corporation on Settlement Re-Run Activity*, FERC, Docket No. ER03-746-000 *et al.*, September 6, 2007	N
SHE-0108	Taylor, G. et al., *Market Power and Market Manipulation in Energy Markets*, 2015	N

***Table of Exhibits from Pre-existing Record*[1]**

Exh. No.	Exhibit Title	Protected Exhibit (Y/N)	Docket No. & Date Admitted into the Record
CAL-31	Master Power Purchase and Sale Agreement between CDWR and Coral Power L.L.C. ("Shell Contract")	N	Docket Nos. EL02-60-003; EL02-62-003 Dec. 6, 2002
CAL-50	Summary of Executed CDWR Power Contracts	N	Docket Nos. EL02-60-003; EL02-62-003 Dec. 6, 2002
CAL-51	Prepared Direct Testimony of Ronald Nichols on Behalf of the California Electricity Oversight Board and the California Public Utilities Commission	N	Docket Nos. EL02-60-003; EL02-62-003 Dec. 5, 2002
CAL-200	Prepared Supplemental Direct Testimony of Ronald O. Nichols on Behalf of the California Parties, Docket Nos. EL02-60-007, *et. al.*, May 19, 2015	N	Docket Nos. EL02-60-007; EL02-62-006 Nov. 10, 2015
CAL-216	Month-by-month summary of all payments and volumes delivered under the Shell Contract for its entire term	N	Docket Nos. EL02-60-007; EL02-62-006 Nov. 16, 2015
CAL-634R	Prepared Direct Testimony of Metin Celebi, Ph.D. on Behalf of the California Parties, including 11/15/15 errata, Docket Nos. EL02-60-007 *et al.*, May 19, 2015 (formerly "Exh. No. CAL-634R")	N	Docket Nos. EL02-60-007; EL02-62-006 Nov. 16, 2015

[1] In accordance with the joint stipulation concerning the use of previously admitted exhibits, the referenced exhibits from the pre-existing record in the above-referenced dockets are being resubmitted.

CAL-647i	E-mail from B. Bowman to L. Raymond et al. dated May 11, 2001, Subject: "FW: CDWR_050901_Base_Hedge.xls"	N	Docket Nos. EL02-60-007; EL02-62-006 Nov. 16, 2015
CAL-647ii	Attachment to B. Bowman e-mail to L. Raymond et al. dated May 11, 2001, Subject: "FW: CDWR_050901_Base_Hedge.xls" [Excel file]	N	Docket Nos. EL02-60-007; EL02-62-006 Nov. 16, 2015
CAL-865	California State Auditor Bureau of State Audits, "California Energy Markets: Pressures Have Eased, but Cost Risks Remain," dated December 2001	N	Docket Nos. EL02-60-007; EL02-62-006 Nov. 23, 2015
EPME-1	Prepared Direct Testimony of Joseph P. Kalt, Ph.D.	N	Docket Nos. EL02-60-003; EL02-62-003 Dec. 10, 2002
EPME-13	Western US Power Plant Capacity Additions Currently Operating Or Under Construction 2001-2003 (Megawatts of Capacity By In- Service Date)	N	Docket Nos. EL02-60-003; EL02-62-003 Dec. 10, 2002
EPME-22	Companies Responding to CDWR's Requests for Bids (Including Unsolicited Responses)	N	Docket Nos. EL02-60-003; EL02-62-003 Dec. 10, 2002
EPME-23	Contract Offers Rejected By CDWR	N	Docket Nos. EL02-60-003; EL02-62-003 Dec. 10, 2002
SHL-0005	Answering Testimony of Tara Nolan	N	Docket Nos. EL02-60-013; EL02-62-012 Nov. 4, 2021
SNA-219	Supplemental Answering Testimony of Edward Brown	N	Docket Nos. EL02-60-007;

			EL02-62-006 Nov. 20, 2015

I. INTRODUCTION

A. Qualifications

Q. Please state your name, business address, and occupation?

A. My name is Steven L. Puller. My business address is 2935 Research Pkwy Suite 200, College Station, Texas 77843. I am a Professor of Economics and the Rex B. Grey Professor in the Department of Economics at Texas A&M University.

Q. Please describe your background and experience.

A. I hold a Ph.D. in Economics from University of California, Berkeley and an A.B. in Economics from University of Chicago. I am an academic economist who has published on competition in the electricity sector with expertise in energy economics, regulation, empirical industrial organization, and public economics. My research on wholesale and retail electricity markets, including in California, has been published in economics journals such as the *American Economic Review*, the *RAND Journal of Economics*, and the *Review of Economics and Statistics*. I co-edited a book published by University of Chicago Press in 2004, *Electricity Deregulation: Choices and Challenges*. I have presented my research at the Federal Energy Regulatory Commission ("FERC") and at state public utility commissions, in addition to academic and industry conferences. I teach Ph.D. and undergraduate courses in topics including econometrics, energy policy, industrial organization, and regulation and antitrust. My professional experience and qualifications are summarized in my curriculum vitae, which is included as Exh. No. SHE-0053.

Q. Are you sponsoring any exhibits?

A. Yes. The list of the exhibits I am sponsoring is provided in the section immediately preceding my testimony.

B. Purpose of and Context for Testimony

Q. What is the purpose of your testimony?

A. The purpose of this phase of the proceeding is to evaluate if the realized rate in Shell's eleven-year bilateral power sale contract with the California Department of Water Resources ("CDWR") delivered May 25, 2001 through June 30, 2012 ("Shell Contract")[2] is just and reasonable. My testimony evaluates the testimonies of Mr. Read and Drs. Fox-Penner and Celebi ("California Parties' witnesses") in which the California Parties' witnesses claim that the Shell Contract rate is not just and reasonable based on a comparison of the Shell Contract rate against a variety of benchmarks. My testimony evaluates the factual basis and economic reasoning for the benchmarks provided by the California Parties' witnesses. I primarily focus on responding to Mr. Read's testimony and Dr. Celebi's use of the price series created by Mr. Read to develop his benchmarks. My testimony also responds to Dr. Fox-Penner's testimony to the extent it provides support for the approaches used by Mr. Read and Dr. Celebi.

Q. As an academic economist, how do you understand what "just and reasonable" means in the context of ratemaking?

A. As I understand from Mr. Hibbard, rate regulation is intended to achieve outcomes mimicking those of a competitive market. From Dr. Morris' testimony, I understand that in conferring market-based rate authority to sellers, the Commission considers prices to be just and reasonable if the transactions are made by a seller that the Commission finds to be without market power. Additionally, I understand from Mr. Cavicchi and Mr. Hibbard that the Commission also uses cost-based rates to set contracts rates that are just and reasonable. For a long-term

[2] Exh. No. CAL-31, Master Power Purchase and Sale Agreement between Coral Power L.L.C. and CDWR, May 24, 2001.

contract, Mr. Cavicchi explains that a cost-based rate is formed from the same inputs as long-run marginal cost, which forms the basis of competitive prices for long-term contracts as I discuss below. Thus, as an economist, my analysis throughout this testimony considers a just and reasonable rate as synonymous with the competitive price.

Q. Please summarize the elements of Dr. Fox-Penner's testimony to which your testimony responds.

A. I evaluate Dr. Fox-Penner's recommendation that the Commission set the just and reasonable price for the Shell Contract as Dr. Celebi's benchmark that uses the "corrected May 2001 forward prices from 2001-2005" developed by Mr. Read and the long-run marginal costs ("LRMC") from 2006-2012 developed by Dr. Celebi.[3] I also evaluate Dr. Fox-Penner's claims that "we have ample evidence that [] fraud and manipulation successfully raised the price of the Shell contract."[4]

Q. Please summarize the elements of Dr. Celebi's testimony to which your testimony responds.

A. I evaluate five of the seven benchmarks Dr. Celebi uses in reaching his conclusion that the price of the Shell Contract was unjust and unreasonable.[5] Specifically, I evaluate the five benchmarks offered by Dr. Celebi that are based on forward

[3] Exh. No. CAL-00988, Prepared Testimony of Peter S. Fox-Penner on Behalf of the California Parties, Docket No. EL02-60-015 *et al*., November 15, 2024, ("Exh. No. CAL-00988, Fox-Penner Testimony") at 40:14-41:4.

[4] Exh. No. CAL-00988, Fox-Penner Testimony, at 7:10-12.

[5] Exh. No. CAL-00973, Prepared Direct Testimony of Metin Celebi, Ph.D. on Behalf of the California Parties, Docket No. EL02-60-015 *et al*., November 15, 2024, ("Exh. No. CAL-00973, Celebi Testimony") at 3:4-14, 15:4-16:22.

contract prices, which I refer to as the California Parties' "forward price-based benchmarks":[6]

- **Benchmark 1:** The prices specified in Shell's other long-term contracts with deliveries in California with execution dates from the period June 20, 2001–December 31, 2002;

- **Benchmark 2:** Post-crisis forward market power prices for the products and delivery locations set forth in the Shell/CDWR contract;

- **Benchmark 3:** Pre-crisis forward market power prices for the products and delivery locations set forth in the Shell/CDWR contract;

- **Benchmark 4:** Forward market power prices near the Shell/CDWR contract execution date (May 22, 2001) for the products and delivery locations set forth in Shell/CDWR contract, adjusted to remove the effects of market dysfunction due to manipulation and fraud ("corrected May 2001 forward prices"); and

- **Benchmark 6:** Prices based on corrected May 2001 forward prices for 2001–2005 energy deliveries, and LRMC-based prices for 2006–2012 energy deliveries.

Shell's expert Mr. Cavicchi has analyzed the other two benchmarks offered by Dr. Celebi (LRMC-based prices and prices based on the FERC benchmark of $74).

[6] Here, I list Dr. Celebi's benchmarks verbatim and I use his terminology of "forward market *prices*" and "*corrected* forward prices" throughout my testimony. However, I agree with the critiques of Shell witness Dr. John Morris as they relate to these terms. Dr. Morris critiques the California Parties' witnesses' use of these terms in his testimony, preferring the term "postings" over "prices" and "manipulated" over "corrected."

My lack of comment on these two benchmarks in my testimony does not imply I agree with them.

Q. Please summarize the elements of Mr. Read's testimony to which your testimony responds.

A. With respect to Mr. Read's testimony, I evaluate his two methods of estimating "forward market prices, absent the effects of fraud and manipulation by Shell and others in the western energy markets, as of late May 2001, for delivery of electric power to the NP-15 and SP-15 zones of the California ISO from June of 2001 through December of 2005."[7] Specifically, Mr. Read attempts to estimate forward price curves for NP-15 and SP-15 as of May 22, 2001 excluding the impact of fraud and manipulation.[8] I also evaluate his assertion that his adjusted forward price curves can be used to create appropriate benchmarks for assessing the justness and reasonableness of the Shell Contract rate.

C. Summary of Conclusions

Q. Please summarize your conclusions as they relate to Dr. Fox-Penner's testimony.

A. As I explain below, Dr. Fox-Penner's claimed just and reasonable rate understates the competitive price level. My testimony identifies numerous flaws in the price benchmarks that Dr. Fox-Penner uses to establish a "zone of reasonableness" and

[7] Exh. No. CAL-00978, Prepared Testimony of James Read on Behalf of the California Parties, Docket No. EL02-60-015 *et al.*, November 15, 2024, ("Exh. No. CAL-00978, Read Testimony") at 2:5-10.

[8] The Shell Contract was executed on May 25, 2001, which is acknowledged by Drs. Fox-Penner and Dr. Celebi and is used by Dr. Celebi as the reference date in many of his benchmarks. Mr. Read does not explain why he selected May 22, 2001. However, for consistency, when discussing the relevant date of price expectations as of contract execution, I use Mr. Read's date of May 22, 2001. My conclusions are not affected by this choice.

argue that the Shell Contract rate is unjust and unreasonable. Additionally, Dr. Fox-Penner mischaracterizes the record when claiming that there is ample evidence that fraud and manipulation impacted the bilateral contract price negotiated by Shell and CDWR. Instead, economic theory and evidence in the record supports that the structure of the CDWR procurement process facilitated competitive pricing of long-term contracts via a contract negotiation setting with many competing sellers, even accounting for the Commission's findings that Shell made misrepresentations in its negotiations with CDWR.

Q. Please summarize your conclusions as they relate to Dr. Celebi's testimony.

A. The California Parties' witnesses' five forward price-based benchmarks are closely related by their reliance on forward prices and should not be understood as independently supporting a "zone of reasonableness." Rather, these five benchmarks share the same fundamental flaws because they are all based on the same faulty comparisons and flawed and unsupported assumptions. I summarize the fundamental flaws for these five benchmarks below:

- Dr. Celebi's first benchmark is based on the prices of small forward contracts executed by Shell between June 20, 2001 and December 31, 2002. These small forward contracts are not comparable to the Shell Contract. 95 percent of these contracts were for two years or less and for 30 MW per hour or less, while the Shell Contract extended 11 years and delivered between 100 MW and 850 MW each hour.[9] Additionally, these contracts were executed after the Shell Contract and thus rely on and contain new information on market fundamentals that was not available to market participants at the time of the Shell Contract's execution. As I describe in

[9] The Shell Contract also allowed Shell to increase the contract quantities over 850 MW. *See* Exh. No. CAL-31, at p. 15.

Section VI below, between May 22, 2001 and June 21, 2001,[10] a series of pivotal events reshaped expectations of market fundamentals. These events altered market expectations about demand and supply conditions, CDWR's creditworthiness, expected emissions costs, natural gas prices, and the impact of long-term contracts. Each of these changes in market fundamentals occurring after contract execution and prior to Dr. Celebi's benchmark date, cause Dr. Celebi to understate competitive forward power prices. Furthermore, fundamentals continued to change thereafter. Dr. Celebi essentially assumes that none of these fundamentals lowered the competitive price. Rather, he attributes all changes in forward curves between May 22, 2001 and June 20, 2001 to the June 19, 2001 FERC Order regarding west-wide market mitigation.

- Dr. Celebi's second benchmark is based on "post-crisis" forward prices from trade dates between June 20, 2001 and November 30, 2001. As with the forward contracts used in his first benchmark, which were small and short-term relative to the Shell Contract, the "post-crisis" forward prices used by Dr. Celebi are for short-term, small volume forward contracts, rather than for large volume, long-term contracts to provide 850 MW of energy and capacity. Thus, these forward contracts are not equivalent to the Shell Contract, rendering Dr. Celebi's forward prices inappropriate for benchmarking the Shell Contract price. Further, like Dr. Celebi's first benchmark, this second benchmark fails to properly account for changes in fundamentals that caused prices to fall after the Shell Contract was signed, again causing him to understate competitive forward prices.

[10] I use the date of June 21, 2001 because this is the date used by Mr. Read in choosing "post-crisis" forward prices.

- Dr. Celebi's third benchmark is "pre-crisis" forward prices from trade dates in March and April 2000. Like the "post-crisis" forwards, these "pre-crisis" forward prices are based on price quotes for short-term, small volume forward contracts. Furthermore, this benchmark assumes that there were no changes in expectations regarding market fundamentals from March/April 2000 through late May 2001. For this to be a valid assumption, one would have to believe that the market participants in March/April 2000 anticipated the market fundamental changes that occurred in demand, generation supply, fuel costs, credit risks, and emissions credit costs between March/April 2000 and late May 2001. Such an extraordinary level of foresight seems implausible. Assuming such foresight contradicts ample evidence to the contrary, as I discuss below in **Section VI.A**, and the California Parties' witnesses present no evidence that these changes in market fundamentals were foreseen and incorporated into forward prices as of March/April 2000.

- Dr. Celebi's fourth benchmark is based on May 22, 2001 forward prices "corrected to remove price distortion due to market manipulation and fraud," which he has received from Mr. Read and becomes the first segment of Dr. Fox-Penner's preferred benchmark. This benchmark suffers from the same flaws as Dr. Celebi's other forward price benchmarks, in addition to a variety of other flaws that I discuss in response to the next question regarding the flaws in Mr. Read's analyses.

- Dr Celebi's sixth benchmark is the combination of the "corrected" May 22, 2001 forward price benchmark for 2001-2005 and his LRMC benchmark for 2006-2012. This benchmark, which is Dr. Fox-Penner's preferred benchmark, is a combination of Dr. Celebi's fourth and fifth benchmarks. The segment of this benchmark given by the "corrected" May 22, 2001 forward prices suffers from the same deficiencies I describe above. As I describe in **Section III** below, I agree that LRMC, an estimate of which forms the second segment of Dr. Celebi's sixth benchmark, is theoretically an appropriate benchmark. However, as Mr. Cavicchi describes, Dr. Celebi's approach to estimating LRMC fails to correctly reflect the capacity value of the Shell Contract, among other unrealistic assumptions, and thus underestimates the LRMC of serving the Shell Contract. Moreover, bifurcating his benchmark for the Shell Contract into two segments based on when long-run equilibrium would be achieved (allegedly in four to five years per Dr. Celebi), has no basis in economics—there is no moment when long-run equilibrium is achieved as fundamentals are always changing. Instead, a correctly-calculated LRMC used for the entire period is an appropriate benchmark for the Shell Contract.

Q. Please summarize your conclusions as they relate to Mr. Read's testimony.

A. As I discuss in greater detail below, like Dr. Celebi's post-crisis and pre-crisis forward price benchmarks, Mr. Read's estimated forward prices absent the effect of fraud and manipulation are based on purported price quotes for short-term, small volume forward contracts that render them inappropriate for benchmarking the Shell Contract price.

Mr. Read presents two methods of estimating forward market prices absent the effect of fraud and manipulation, which he calls Method 1 and Method 2. In Method 1, Mr. Read asserts that if there had been no manipulation or fraud, the average forward curves for NP-15 and SP-15 between June 21, 2001 to June 27, 2001, adjusted for changes in forward natural gas prices would have been "a good estimate" for the forward curves for these zones on May 22, 2001. In Method 2, Mr. Read estimates the impact of fraud and manipulation on spot market prices based on Mitigated Market Clearing Prices ("MMCPs") developed by FERC for determining spot market refunds, relative to actual spot prices, and then assumes that fraud and manipulation had a similar impact on near-term forward prices that decayed until January 2003 according to an exponential decay function (i.e., he assumes market participants expected the impact of fraud and manipulation to decline over time). Mr. Read further claims that these short-term forward contracts can be strung together to replicate a long-term forward contract, and thus they can be used as a benchmark for the long-term Shell Contract. Ultimately, Drs. Celebi and Fox-Penner choose to rely on Method 2 in calculating the allegedly just and reasonable rate for the 2001-2005 segment of the Shell Contract.

As I discuss below, both of Mr. Read's methods are based on flawed economic reasoning. In particular, Methods 1 and 2 fail to account for changes in market fundamentals that occurred during their relevant periods, as I highlight above when discussing Dr. Celebi's benchmarks.

Mr. Read's Method 2 has additional deficiencies. First, Method 2 is fundamentally flawed because it relies on prices originally developed for a different purpose – to calculate spot market refunds by generators. These prices were designed in a manner to exclude factors critical for analyzing competitive long-term contracts, such as emissions costs, counterparty-specific credit risk, capital costs, and other components of long-run marginal cost. Second, Method 2 assumes spot market fraud and manipulation carried over directly into forward prices according to an assumed and unsubstantiated decay function. Third, this method is further flawed in that his estimate of the impact of fraud and manipulation on forward prices, and consequently, the Shell Contract, is based on spot market MMCPs, which the Commission has previously stated cannot form the basis of a just and reasonable rate for the long-term bilateral Shell Contract.

Q. Have you reached any other conclusions based on your review of the California Parties' witnesses' testimony?

A. Based on my review of California Parties' witnesses' testimonies, I conclude that their testimonies have a number of deficiencies that lead to erroneous conclusions about the competitiveness of the Shell Contract price:

- The California Parties' witnesses fail to acknowledge the *a priori* reasons that the CDWR procurement process was competitive and would yield competitive or below-competitive prices. CDWR was a large and primary purchaser of long-term contracts for electricity in California, which gave it monopsony power. In contrast, Shell was one of many sellers competing to sell long-term contracts to CDWR. Economic theory states that this market structure would yield contract prices that are lower than the prices that would arise in a competitive marketplace.

- The California Parties' witnesses' testimonies fail to recognize the role of CDWR's long-term bilateral contract procurement process in alleviating the expected electric generation capacity shortage. Instead, California Parties' witnesses describe what could have happened in an assumed reality that was not the world that existed and, importantly, not the world in which Shell operated when determining how much it would cost to deliver the power it was agreeing to deliver to CDWR under the contracts. In addition, they assume that their benchmark prices are consistent with the thousands of MWs of new electric generation capacity brought into service following 2001 despite the fact that their benchmark prices would have been too low to compensate the new generation for its capital costs, as demonstrated by Mr. Cavicchi.

- A suitable benchmark for competitive prices of long-term contracts to supply power in the quantities and delivery horizons specified in the Shell contract is the long-run marginal cost which includes fixed and variable costs of operations and maintenance, fuel costs, incremental capital costs of building production capacity, and counterparty credit risk. The long-run marginal cost is a benchmark used by buyers, sellers, and regulators when evaluating a long-term contract because it represents the competitive price of the contract. As I describe in **Section IV**, the CDWR contracting process was competitive. Additionally, comparable contracts entered into by CDWR at the same time as the Shell Contract provide a reference to evaluate if the Shell Contract reflects a competitive price. As demonstrated by Mr. Cavicchi, the Shell Contract price is consistent with the prices of other comparable bilateral contracts entered into by CDWR and thus is consistent with the competitive price level.

II. BACKGROUND ON CRISIS

Q. Please describe the background of the California electricity crisis that is relevant for understanding why CDWR entered into the Shell Contract.

A. California and Western U.S. electricity spot market prices increased in the late Spring/early Summer of 2000, and were volatile and elevated relative to historical levels through the Spring of 2001. As shown in **Figure 1** below,[11] on-peak spot market prices in California had averaged roughly $36/MWh from April 1999 to May 2000, before increasing to an average of roughly $160/MWh in June through September 2000. In Winter 2000 and Spring 2001, prices increased further, averaging over $250/MWh from December 2000 to May 2001.

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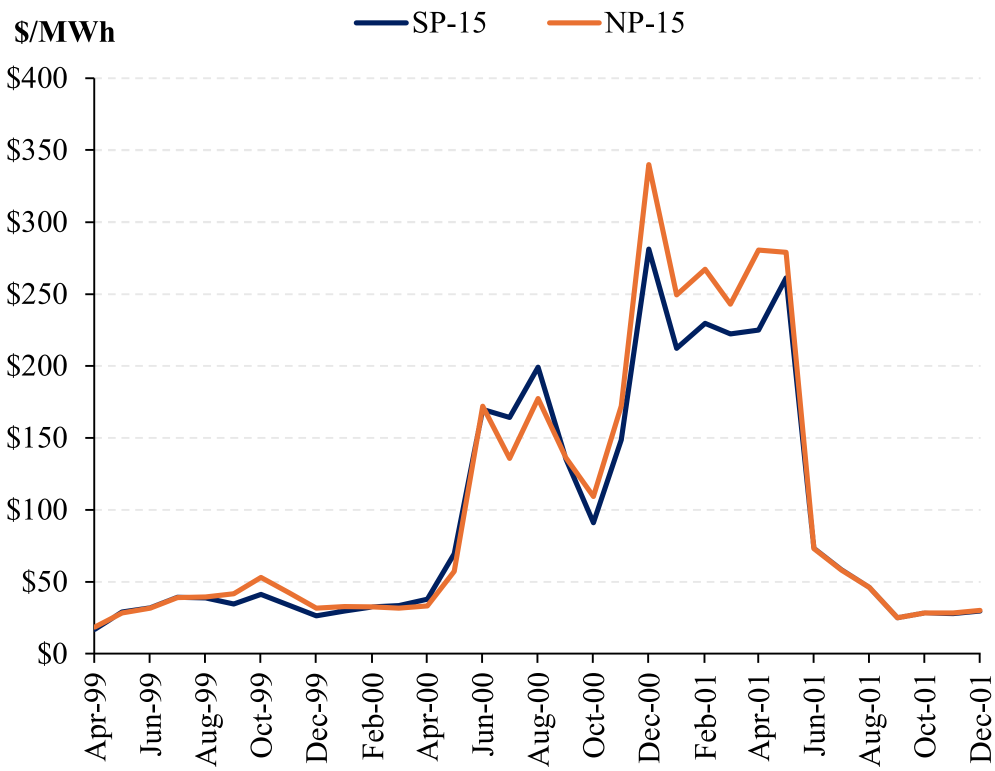
[11] Appendix A collects each of the Figures that I present in my testimony in one document for ease of reference.

Figure 1[12]
Average Monthly SP-15 and NP-15 On-Peak Spot Prices
April 1999 - December 2001



Western U.S. electricity price increases arose from increased demand, supply constraints such as decreased hydroelectric production, aging and unreliable generation resources, lack of new generation capacity, increases in the prices of inputs for natural gas electricity production and a complex confluence of market design and policy choices by California and FERC in restructuring California's electricity market in the late 1990s.

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[12] Index of Tables, Docket No. EL02-71-057, (formerly Ex. TC-0018), Table 23, at pp. 26-27, Exh. No. SHE-0083.

A. Electricity Market Conditions in Summer 2000

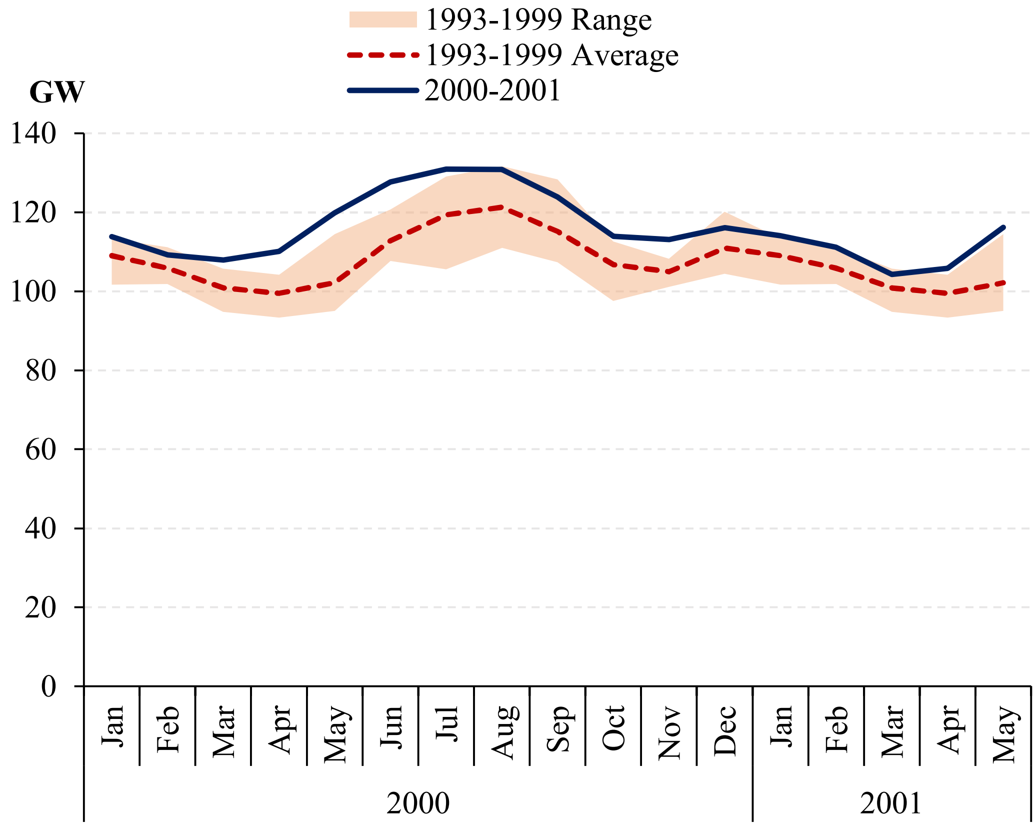
Q. How did increased electricity demand contribute to tight supply-demand conditions in the Western market leading into the Summer of 2000?

A. Dr. Morris provides significant detail regarding the nature of the power and gas systems in the West during the relevant period. While I will not repeat his full analysis here, I have reviewed it and agree. To provide context for the analysis and opinions presented below, I provide an abbreviated discussion of the crisis in what follows.

The West experienced significant increases in electricity demand in 2000. In the 1990s, demand was steadily growing in the West due to economic growth, and high temperatures in Summer 2000 led to historically high peak and average demand.[13] As shown in **Figure 2,** monthly peak demand (i.e., demand in the hour with the highest demand) in the West was higher in most months in 2000 than in any of the same months from 1993 to 1999. This increase was most pronounced in Spring of 2000, when monthly peak demand considerably exceeded monthly peak demand from the same months in prior years. **Figure 3** shows that, for all months other than October, average hourly demand in 2000 was higher than demand in any year from 1993 to 1999.

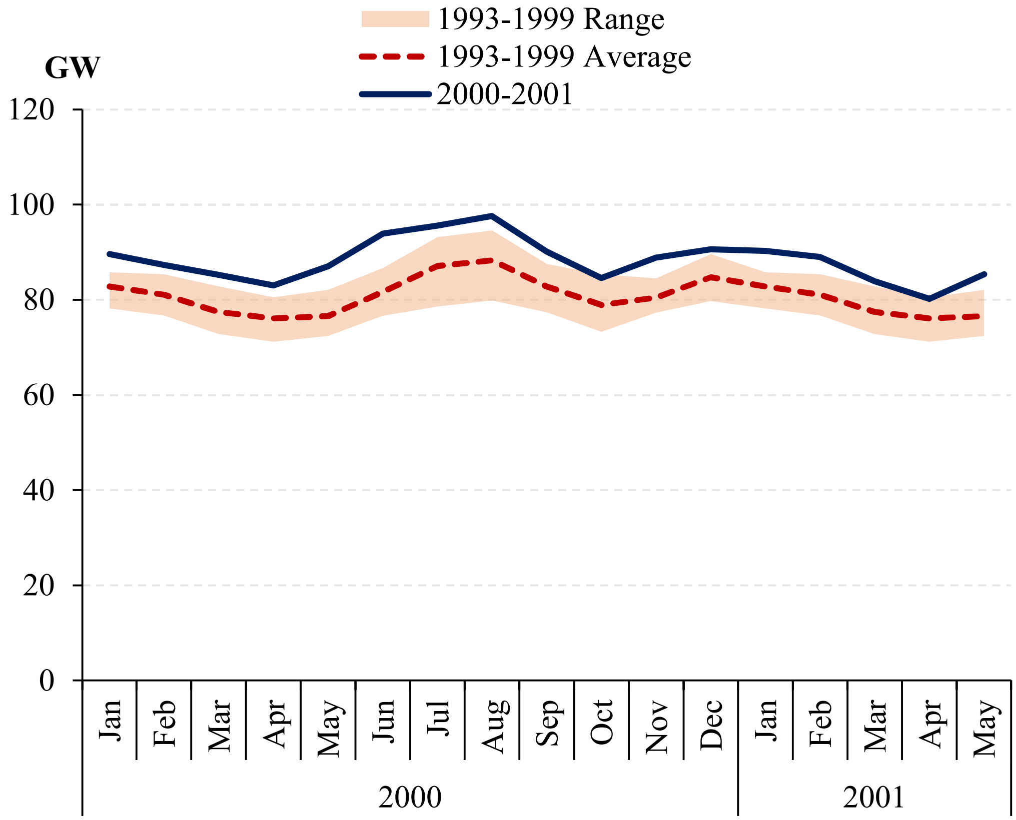
[13] "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," FERC, November 1, 2000, ("FERC Report, November 2000"), at pp. 2-9 to 2-15, Exh. No. SHE-0055.

Figure 2[14]
WSCC Monthly Peak Demand
1993-1999 vs. 2000-May 2001



[14] WSCC 10-Year Coordinated Plan Summaries 1994-2001; WECC 10-Year Coordinated Plan Summary 2002. Peak Load is the sum of Firm Load and Interruptible Demand, and WSCC Region includes Western Canada and Western Mexico load.

Figure 3[15]
WSCC Monthly Average Hourly Demand
1993-1999 vs. 2000-May 2001



Q. How did supply factors contribute to tight supply-demand conditions for power in the Western U.S. leading into the Summer of 2000?

A. In order to meet the increasing demand for power I describe above, new generation capacity and firm import power supply was needed. However, California's utilities had not matched the growth in demand with a corresponding investment in new generation capacity. Specifically, from 1996 to 1999, peak load in California increased by 5,522 MW, while only 672 MW of net generation capacity was added.[16] The slow pace of generation additions in California was in large part a

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[15] WSCC 10-Year Coordinated Plan Summaries 1994-2001; WECC 10-Year Coordinated Plan Summary 2002. WSCC Region includes Western Canada and Western Mexico load.

[16] FERC Report, November 2000, at p. 5-7.

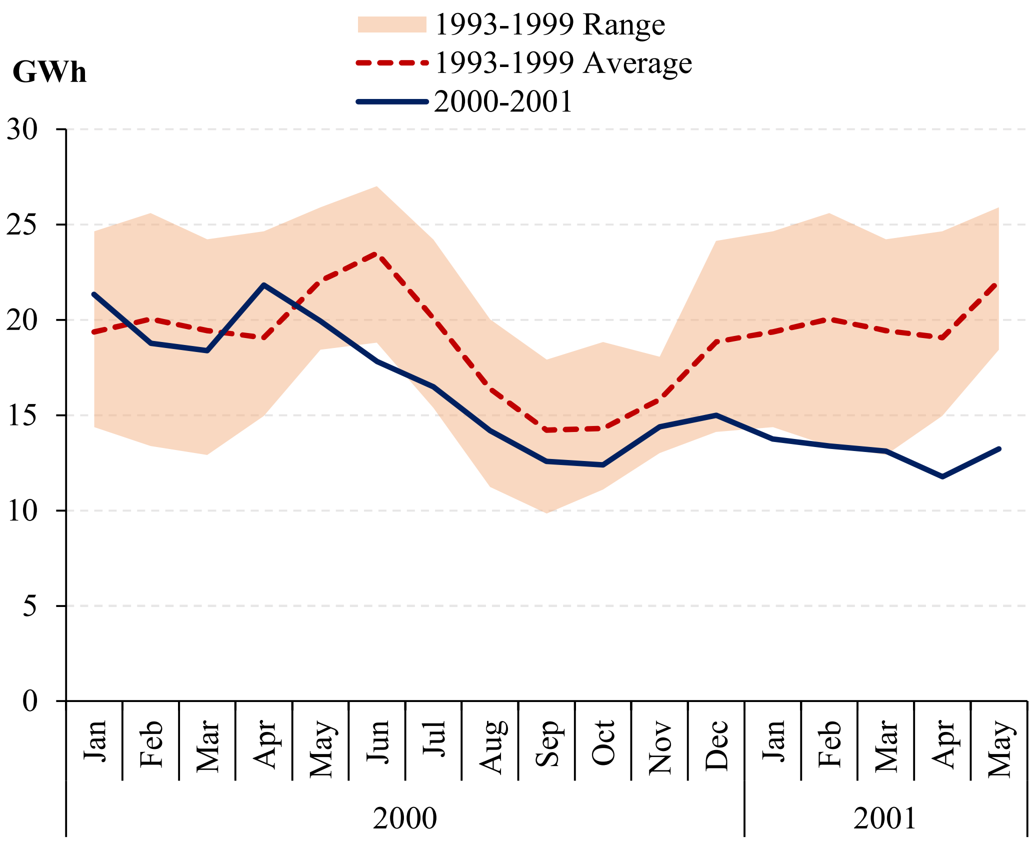
result of the difficulty of permitting in the California regulatory environment.[17] Although new generation resources were in development in 2000, few were ready to be put into service at the time of growing demand in 2000, leading to tight supply-demand conditions, i.e., shortage conditions, going into the Summer of 2000.[18] Little excess supply relative to expected demand led to thin reserve margins and left California at risk to supply or demand shocks.

In addition to tight supply-demand conditions in terms of installed capacity, there were changes in the availability and costs of the inputs to generating electricity, raising the cost and thus the price of power. As shown in **Figure 4,** hydroelectric output in the West outside of California was lower than average relative to earlier years beginning in May 2000.

[17] FERC Report, November 2000, at p. 5-8.

[18] Report of James L. Sweeney, Ph.D. in Support of Powerex Corp., Docket No. EL09-56-000, (formerly "Ex. PWX-2"), September 3, 2009, at PP 99-101, Exh. No. SHE-0056.

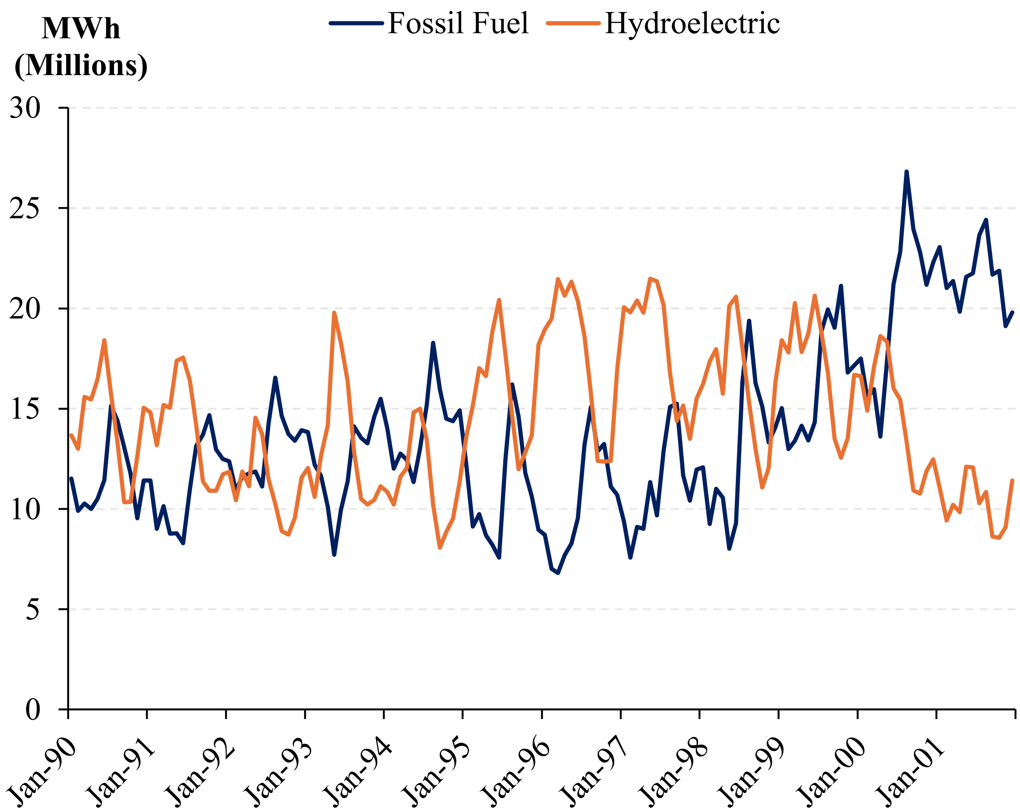
Figure 4[19]
Western U.S. Monthly Average Hourly Hydroelectric Output (Outside CA)
1993-1999 vs. 2000-May 2001



As shown in **Figure 5**, the decreased hydroelectric generation led to the West relying, to an unprecedented extent, on older, less efficient and more expensive fossil fuel generation.

[19] Ventyx Velocity Suite data (January 1993-January 1995); EIA Electric Power Monthly, May 1996-March 2003 (February 1995-December 2001), Table 11. Western U.S. (Outside CA) generation is calculated as the sum of the Mountain and Pacific Contiguous census divisions (excluding California) as provided in Electric Power Monthly. When the regional totals in Electric Power Monthly did not equal the sum of the state totals, the table reflects the sum of individual state figures.

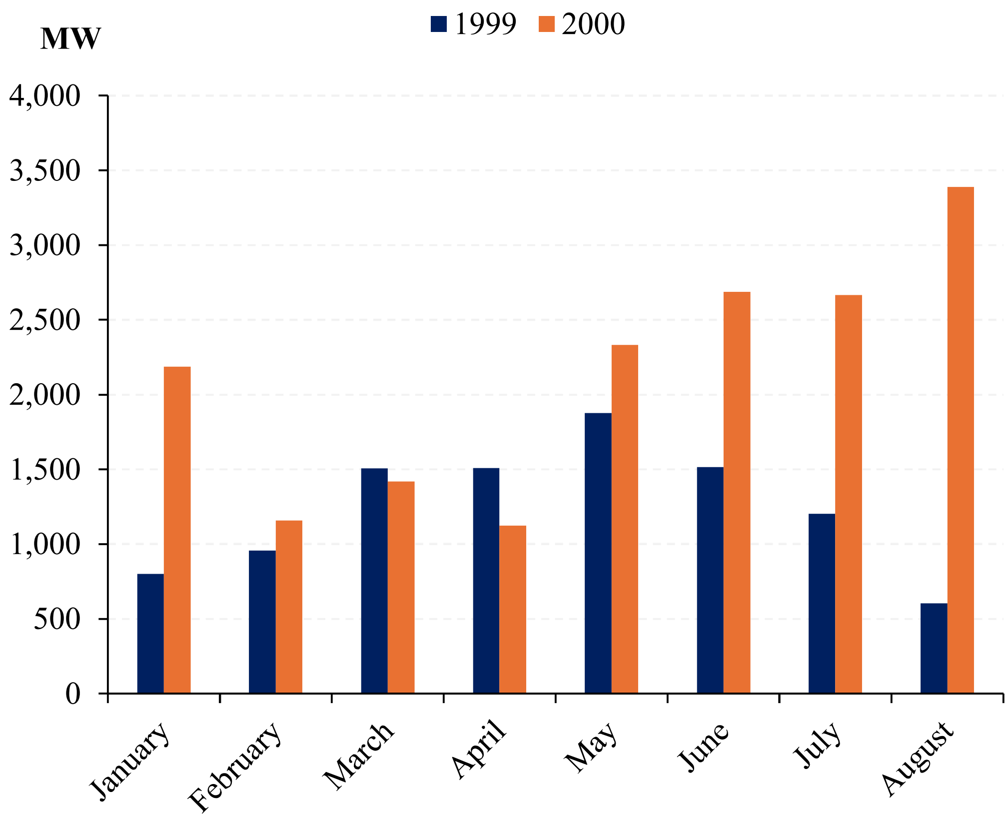
Figure 5[20]
Western U.S. Fossil Fuel vs. Hydroelectric Generation Output
January 1990 - December 2001



As I describe below, many of these units were required to purchase NOx emissions credits, driving up emissions credit demand and contributing to the price increases for such credits. Moreover, these units were prone to outages given their age and condition. In **Figure 6**, I show that the increased use of older gas-fired generation units resulted in a sharp increase in forced outages in Summer 2000. The increased reliance on natural gas generation also made spot prices for power more sensitive to increases in the price of natural gas.

[20] Ventyx Velocity Suite data. Generation is categorized based on the 'Fuel Code Description' column in the Raw Data. Fossil generation includes generators fired by coal, natural gas, oil, jet fuel, coke, and biomass gases. Output is for Western States including Arizona, California, Nevada, Idaho, New Mexico, Oregon, and Washington.

Figure 6[21]
CAISO Average Unplanned Outages (MW)
January - August 1999 and January - August 2000



Q. Did the increased reliance on natural gas contribute to high prices?

A. Yes. There were large increases in the prices for the inputs for natural gas-fired electricity production, which contributed to high electricity prices.

Dr. Morris provides significant detail regarding natural gas prices during the relevant period. I have reviewed his testimony and agree with it. I will not repeat the specifics here but focus on the market effects of higher natural gas prices on power prices. First, the spot price of natural gas at the gas hubs relevant for California power plants increased beginning in May 2000 and rapidly accelerated

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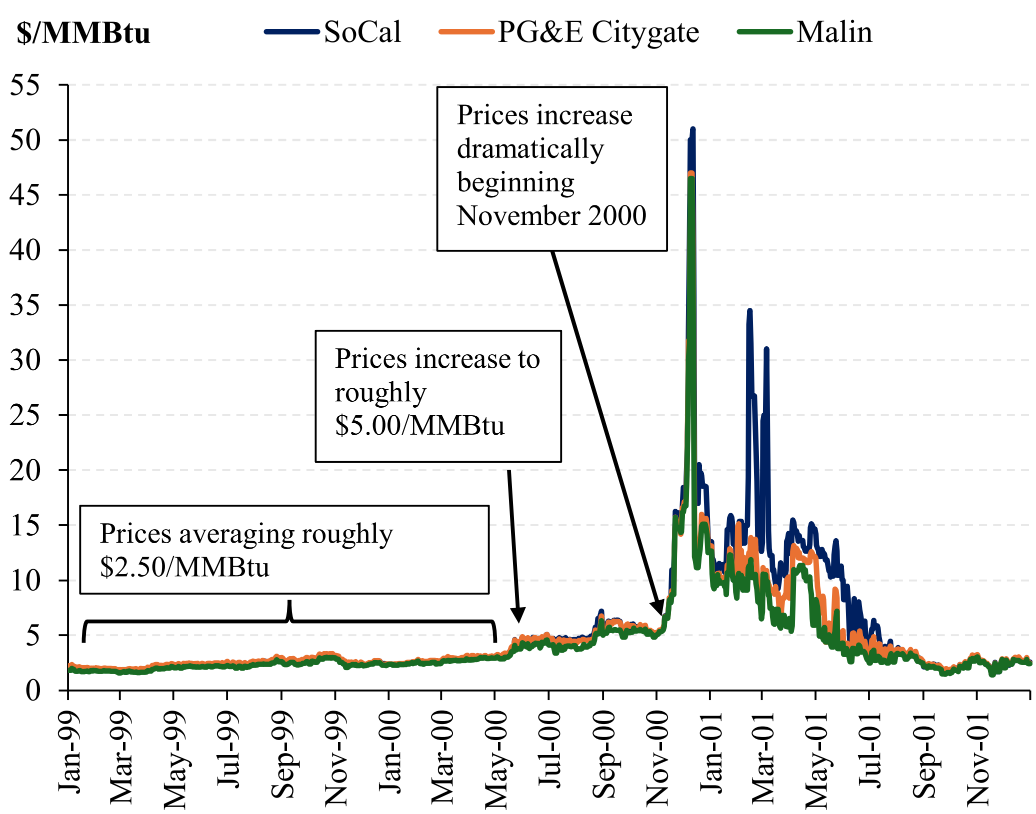
[21] FERC Report, November 2000, Figure 2-12. Comparison of Average Megawatts Out of Service in the CAISO Planned and Unplanned, 1999 and 2000, at p. 2-20.

in November 2000.[22] As shown in **Figure 7**, spot prices at the SoCal Border, PG&E Citygate, and Malin natural gas hubs that had averaged around \$2.50/MMBtu from January 1999 to April 2000 rose to an average of roughly \$5.00/MMBtu during the Summer of 2000.

Figure 7[23]
Daily Natural Gas Spot Prices
1999-2001



These natural gas price increases are significant because the variable cost of generators using natural gas is determined by the price of natural gas. For example, doubling the price of natural gas would roughly double the variable cost of

[22] As discussed by Shell witness Dr. Morris, the increase in natural gas prices was caused by capacity constraints as well as outages on pipelines into California and other changes in market fundamentals.

[23] Platts Daily Average Gas Data.

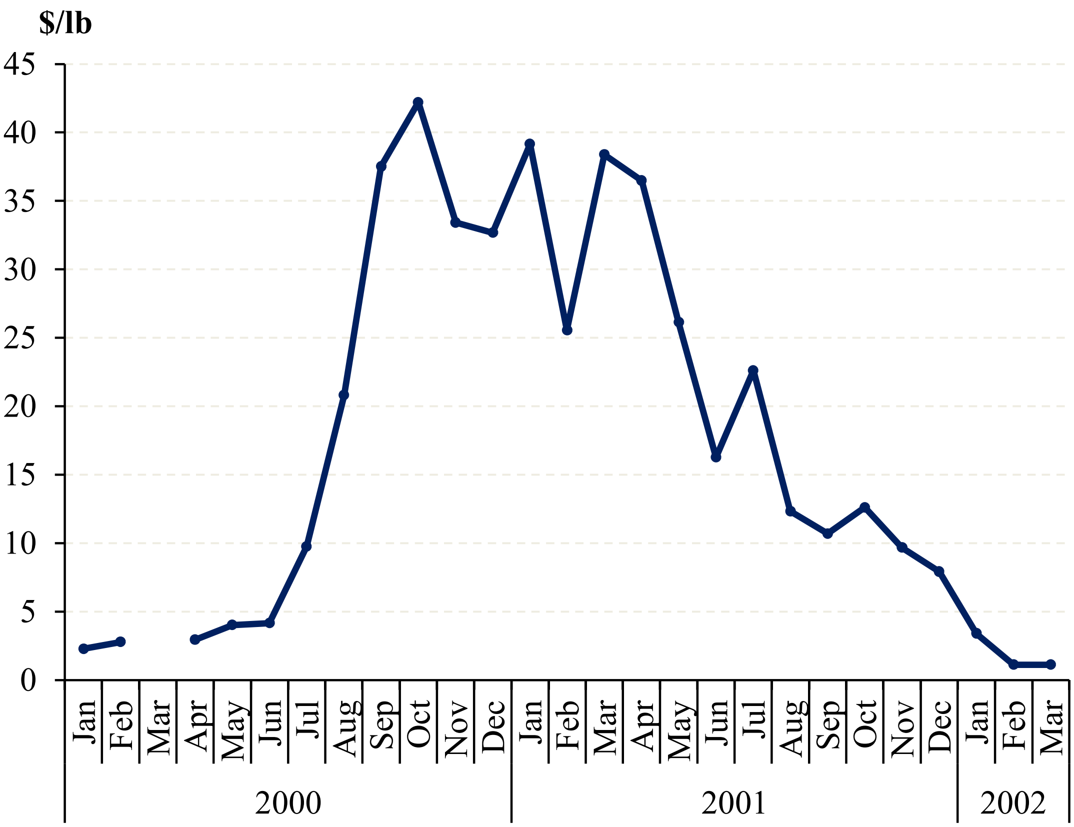
producing electricity for a given gas-fired generation unit. When this shock is combined with increased demand that required less efficient (i.e. higher heat rate) generators to be called into production, the spot price of electricity could increase even further.

Second, as shown in **Figure 8**, beginning in July 2000, the price of NOx emissions credits in the RECLAIM emissions reduction program in Southern California increased from less than $5/lb to nearly $40/lb, driven in part by the increased use of natural gas generators in Southern California. This led the average price of NOx emissions credits traded in 2000 to be nearly ten times the price of credits traded in 1999.[24] Because natural gas-fired plants in parts of Southern California were required to have sufficient credits to cover their NOx emissions, these unprecedented increases in NOx credit prices further increased the price of electricity by $30 to $90/MWh, depending on the emission rate of the marginal unit.[25]

[24] "White Paper on Stabilization of NOx RTC Prices," *South Coast Air Quality Management District*, January 11, 2001, at p. 5, Exh. No. SHE-0057.

[25] Joskow, P. L., "California's Electricity Crisis," *Oxford Review of Economic Policy*, Vol. 17, No. 3, September 1, 2001, pp. 365–388, ("Joskow 2001"), at pp. 379-380, Exh. No. SHE-0058; PWX-2, Report of James L. Sweeney, Ph.D. In Support of Powerex Corp., Docket No. EL09-56-000, September 3, 2009 at ¶ 106, Exh. No. SHE-0056.

Figure 8[26]
Monthly Weighted Average Price of RECLAIM Program NOx Emissions Credits
2001 Vintage



Q. How did market design and regulatory choices contribute to the large increase in spot market prices in 2000?

A. Market design and regulatory choices exacerbated the impact of the changes in market fundamentals described above. For example, due to regulatory choices associated with the restructuring of the California electricity market, California's investor-owned utilities (IOUs) were highly exposed to wholesale electricity spot

[26] SCAQMD, *Historical Trade Registrations*, Exh. No. SHE-0059. Prices are weighted by the quantity allowed by the credit. SCAQMD has two vintages per year, one expiring in June and the other in December (e.g., June 2001 and December 2001). The averages above are calculated across the June and December vintages for 2001. Prices are unavailable for 2001 vintage credits traded in March 2000.

market volatility. As part of the restructuring, the three IOUs, PG&E, SCE, and SDG&E, divested most of their fossil-fueled capacity to five merchant generators: AES, Reliant, Duke, Southern and Dynegy. Although California had introduced retail choice, the vast majority of retail customers remained with the IOUs. Additionally, regulations limited the IOUs' ability to purchase power through forward contracts, and required the IOUs to purchase the energy to serve load on the volatile day-ahead California Power Exchange ("PX") auction and hour-ahead CAISO (spot) market. Although market designers set a price cap to limit the exercise of market power—set at $250 per megawatt-hour until September 1999, raised to $750 in October 1999, and then lowered to $500 in July 2000 and $250 in August 2000—this failed to fully restrain market prices, particularly in the Summer of 2000.

Q. Were there actions taken by sellers that affected clearing prices in the CAISO/PX spot markets in the Summer and Fall of 2000?

A. Yes. I understand that the Commission has found that certain sellers committed tariff violations in the CAISO/PX spot markets during the period May 1, 2000 to October 1, 2000 that had a price effect in those spot markets.[27] Also, Puller (2007), as well as other academic research, finds evidence that is consistent with the theory that the five large California generators withheld some of their generation in that period to increase CAISO/PX spot price.[28]

[27] *Pub. Utils. Comm'n v. Sellers of Long-Term Contracts*, Opinion No. 587, 185 FERC ¶ 61,197, at P 91 (2023) ("Opinion No. 587").

[28] Puller, S., "Pricing and Firm Conduct in California's Deregulated Electricity Market," *The Review of Economics and Statistics*, Volume 89, Issue 1, pp. 75–87, February 2007, Exh. No. SHE-0060.

Q. Did the tariff violations identified by the Commission occur in the period in which the Shell Contract was negotiated?

A. No. The tariff violations found by the Commission occurred prior to the closure of the PX spot market in January 2001. They also occurred during the period in which the California IOUs were required to purchase all of their requirements in the PX market. That requirement terminated in December 2000.[29] By contrast, the Shell Contract was negotiated between March and May 2001, well after the PX was shut down and the spot market became predominantly bilateral and long-term contracting was permitted to serve load.

Q. Would generation withholding in the CAISO/PX spot market by the generators in the Summer and Fall of 2000 have benefited Shell in signing long-term contracts with CDWR in May 2001?

A. No, there are three critical distinctions between withholding by generation owners in the spot market in 2000 and Shell's role in long-term contracting in 2001, as I discuss in greater detail in the remainder of my testimony.

First, unlike the five generation owners, Shell owned or controlled little generation capacity and so did not control enough production capacity to influence spot market prices or have an incentive to do so.[30] Second, while withholding by generation owners may have *contributed* to the California electricity crisis in 2000, long-term contracting with entities such as Shell played an important role in *resolving* the crisis, and as I discuss in **Section IV**, the contracting process was competitive. Third, while withholding in the spot market may have resulted in elevated prices within California's *spot* markets (the PX and CAISO) in 2000, such actions would not affect the competitiveness of CDWR's *long-term* contracting

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[29] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 93 FERC ¶ 61,294, at 61,982 (2000) ("December 15, 2000 Order").

[30] As. Dr Morris shows, Shell had only 25 MW of capacity under its control in California.

process in 2001. Moreover, even if generators withheld generation from the *spot* market in spring 2001, this would not be expected to affect the competitiveness of CDWR's *long-term* contracting process, and the California Parties' witnesses provide no evidence that it did.

B. Changes in Market Conditions from Summer 2000 to Spring 2001

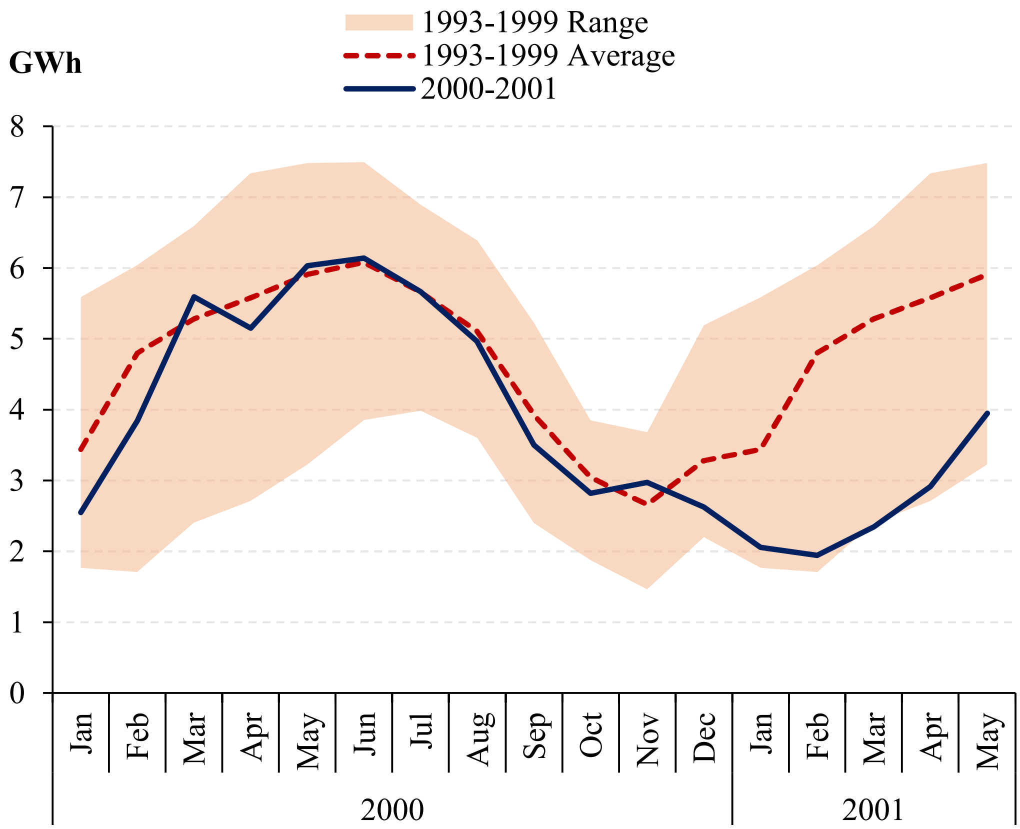
Q. How did the crisis evolve over Fall 2000 and Winter 2000/01?

A. As shown in **Figure 1**, spot electricity prices continued to increase after Summer 2000, reaching over $200/MWh in Winter 2000/01, as a result of the continuation of the supply and demand factors that preceded the Summer 2000 price spikes, as well as new supply and demand issues. Further, regulatory choices exacerbated the crisis, as is also discussed by Dr. Morris.

Many of the supply and demand factors that preceded the Summer 2000 price spikes continued through Winter 2000/01:

- Peak and average electricity demand in the West remained at historically high levels in Fall 2000 and Winter 2000/01 (see **Figure 2** and **Figure 3**).
- Natural gas prices increased dramatically beginning in November 2000 (see **Figure 7**).
- The price of NOx emissions credits reached more than $40/lb by October 2000 and remained high throughout the Winter (see **Figure 8**).
- Hydroelectric output outside of California sunk to some of its lowest levels since 1993 beginning in Winter 2000/01 (see **Figure 4**). Hydroelectric output within California also sunk to historically low levels in Winter 2000/01 (see **Figure 9** below).

Figure 9[31]
California Monthly Average Hourly Hydroelectric Output
1993-1999 vs. 2000-May 2001



At the same time, nuclear generation decreased unexpectedly due to outages, such as an electrical problem at San Onofre Nuclear Generating Station's Unit 3 on February 3, 2001 when returning to service after refueling, reducing nuclear capacity by 1,100 MW.[32]

Furthermore, as wholesale spot market prices increased from Spring 2000 to Winter 2000/01, two of the IOUs were unable to raise retail rates due to a retail

[31] Ventyx Velocity Suite (January 1993-January 1995); EIA Electric Power Monthly, May 1996-March 2003 (February 1995-December 2001), Table 11. Data include energy usage and production associated with Pumped Storage Units.

[32] Mehta, S., "Fire-Damaged San Onofre Reactor May Not Be Back Online Till June," *Los Angeles Times*, March 22, 2001, Exh. No. SHE-0061.

rate cap imposed by state regulators that prevented them from passing their costs of purchasing electricity supply onto ratepayers. This led to financial challenges for California's IOUs by early 2001, including bankruptcy for PG&E, and an inability to pay power suppliers, particularly the owners of Qualifying Facilities ("QFs").[33] As a result, many QFs were unwilling to generate electricity in early 2001, exacerbating the supply shortages.

Q. What was the regulatory response to the crisis in Winter 2000/01?

A. There were major regulatory changes in the Winter of 2001 intended to resolve the crisis.

First, FERC issued a key Order on December 15, 2000 that eliminated the requirement that the IOUs purchase all of their electricity from the PX, a spot market, and allowed them to enter into bilateral and forward contracts. The Commission recognized "that the central cause of the exposure of California to high prices can be traced directly to a mandated over reliance on these spot markets."[34]

Second, in January 2001, Governor Gray Davis ordered CDWR to purchase long-term contracts on behalf of residents of California.[35] CDWR held two requests for

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[33] Qualifying Facilities (QFs) included small power production facilities and cogeneration facilities not owned by utilities. Utilities were required to purchase the power produced by QFs, which represented approximately 22 percent of California's capacity in March 2001. *See* "CAISO 2001 Summer Assessment," *CAISO*, March 22, 2001, Figure II-G at p. 17, Exh. No. SHE-0062.

[34] December 15, 2000 Order at 61,992.

[35] Opinion No. 587 at P 6.

bids in January and February 2001.[36] Negotiations for these long-term contracts continued through July 6, 2001.[37]

Q. How did market conditions change across Spring 2001 when the Shell Contract was negotiated and executed?

A. Many of the same market issues were still present in Spring 2001, including on March 16, 2001 when the Shell Contract terms were initially agreed upon and on May 22, 2001, at the time of the Contract's execution.[38]

- Spot prices for power remained elevated: SP-15 on-peak average prices were above $220/MWh in March, April and May 2001, while NP-15 on-peak average prices were above $240/MWh (see **Figure 1**).

- Peak and average load remained at historically high levels in Spring 2001 (see **Figure 2** and **Figure 3**). In March 2001, CAISO forecasted that peak demand during the Summer of 2001 would surpass that of the Summer of 2000.[39]

- In addition, there continued to be supply availability issues related to hydroelectric, nuclear, and QF generation in Spring 2001. As shown in **Figure 4**, hydroelectric generation in the West outside of California dipped to historically low levels between March and May 2001. Similarly, **Figure**

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[36] Exh. No. CAL-200, Prepared Supplemental Direct Testimony of Ronald O. Nichols on Behalf of the California Parties, Docket Nos. EL02-60-007 *et al.*, May 19, 2015, ("Nichols Supplemental Testimony") at 8:12-15.

[37] Opinion No. 587 at P 6.

[38] As noted above, I reference May 22, 2001 based on the date used by Mr. Read in his analysis, though the contract was not executed until May 25, 2001.

[39] "CAISO 2001 Summer Assessment," *CAISO*, March 22, 2001, at p. 28.

9 shows that hydroelectric generation in California in Spring 2001 was at a level consistent with the lowest levels from 1993-1999.

- In addition, the outage at San Onofre Nuclear Generating Station Unit 3 continued until early June 2001 and there was a refueling outage at nuclear Palo Verde Unit 1 from March 31, 2001 to May 16, 2001 that reduced available nuclear capacity in the West by 1,243 MW.[40]

- Moreover, approximately one-third of QFs were offline from January to April 2001, with some QFs not having been paid since November 2020.[41] However, QFs appeared to be coming back online faster than expected as of May 2001.[42]

- As a result, California continued to be much more reliant on fossil fuel generation than it had been historically (see **Figure 5**). The combination of historically high expected demand and limitations on existing supplies contributed to concerns about shortages and summer blackouts.[43]

- Additionally, fuel and emissions credit prices remained high relative to historic levels. As shown in **Figure 7**, while daily SoCal Border, PG&E Citygate, and Malin natural gas spot prices decreased from their winter

[40] *See* "Power Reactor Status Reports for 2001," *U.S.NRC*, Exh. No. SHE-0063.

[41] Exh. No. CAL-51, Prepared Direct Testimony of Ronald Nichols on Behalf of the California Electricity Oversight Board and the California Public Utilities Commission, Docket Nos. EL02-62-003 *et al*., ("Exh. No. CAL-51, Nichols Testimony"), at 24:1-7.

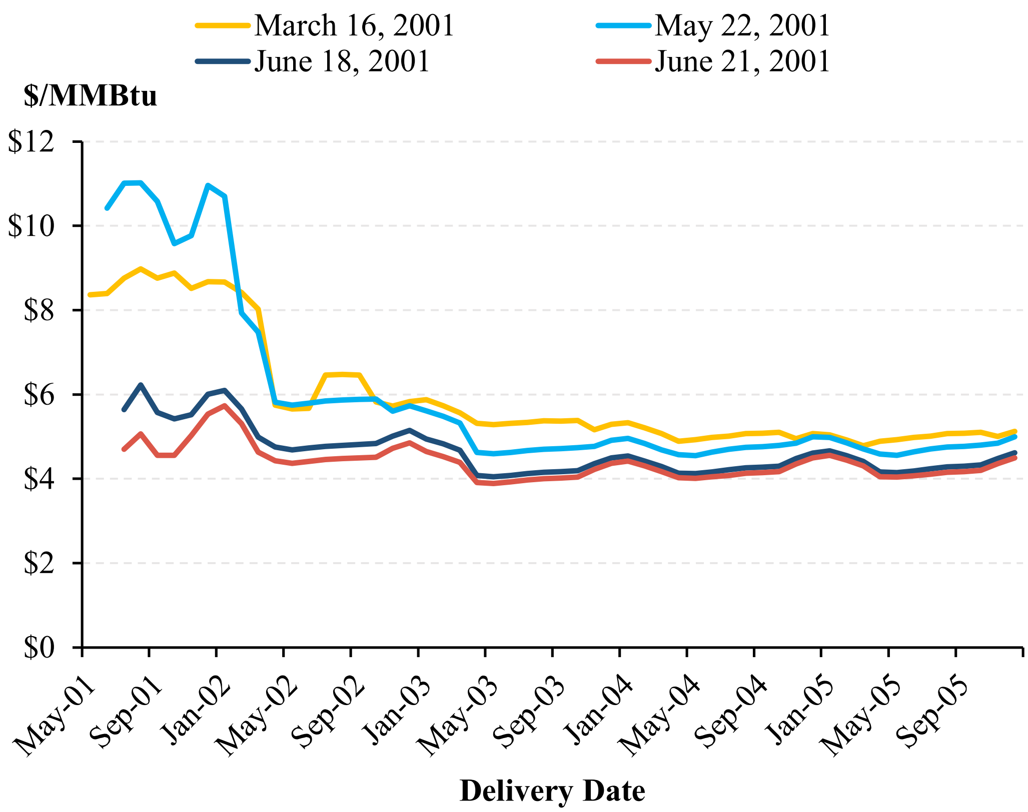
[42] "Revenue Requirement & Consultant's Report Briefing to the Staff of CEC and CPUC on DWR Energy Procurement Program," Navigant, May 18, 2001, at pp. 27-28, Exh. No. SHE-0064.

[43] "CAISO 2001 Summer Assessment," *CAISO*, March 22, 2001, at pp. 4, 6, 28; *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Services*, 95 FERC ¶ 61,418, at 62,546 (2001).

levels, they remained between $4/MMBtu and $16/MMBtu between March and May 2001, far higher than the roughly $2.50/MMBtu that had persisted from 1999 to mid-2000. Moreover, as shown in **Figure 10** and **Figure 11**, natural gas forward prices for PG&E Citygate and SoCal Border were above $8/MMBtu for near-term delivery on March 16 and above $10/MMBtu for near-term delivery on May 22, with prices on both dates persisting at above $4/MMBtu for delivery dates through the end of 2005.

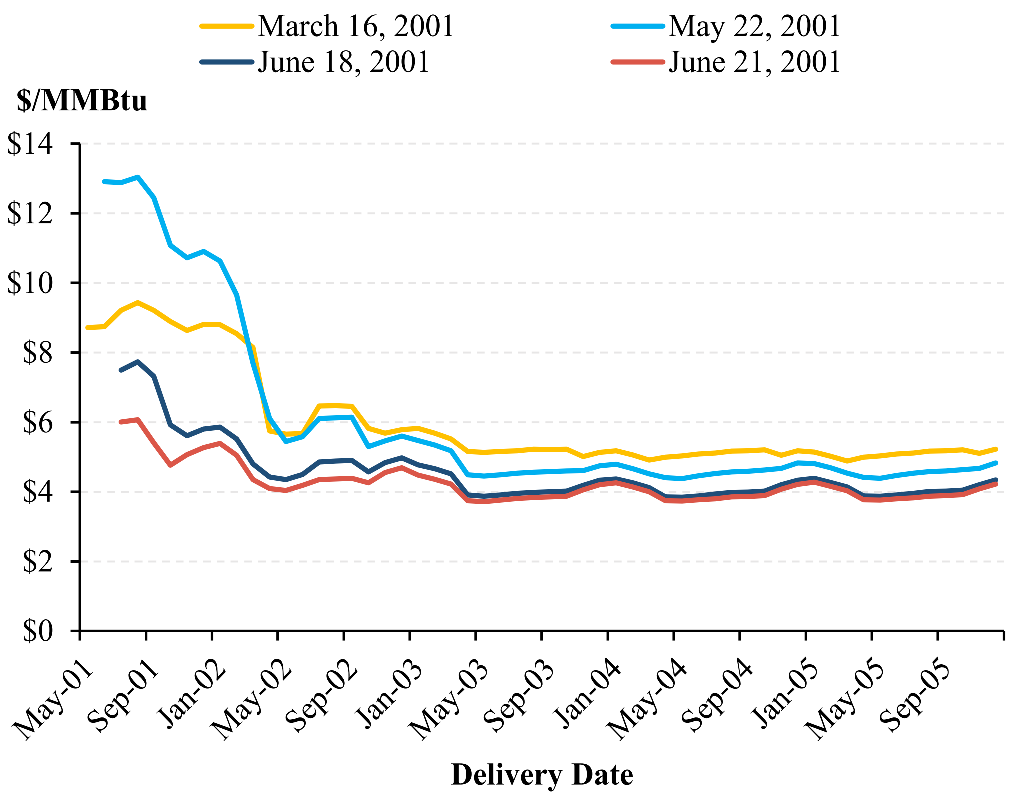
- As shown in **Figure 8**, NOx emissions credit prices also remained high, with prices above $35/lb in March and April 2001 and above $25/lb in May 2001.

Figure 10[44]
PG&E Citygate Natural Gas Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



[44] Exh. No. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read uses PG&E Citygate Natural Gas Prices in his adjustments to NP-15 Power Prices. Mr. Read obtains natural gas prices from Enron.

Figure 11[45]
SoCal Border Natural Gas Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



Q. Were there any dynamics that attenuated the impact of the factors discussed above that were keeping forward power prices high in Spring 2001?

A. Yes. First, CDWR began signing long-term bilateral contracts in February 2001 and by the end of April 2001 had signed 26 contracts.[46] Second, as shown in **Figure 12**, construction began on over 9,000 MW of new generation capacity in the West between March and May 2001.

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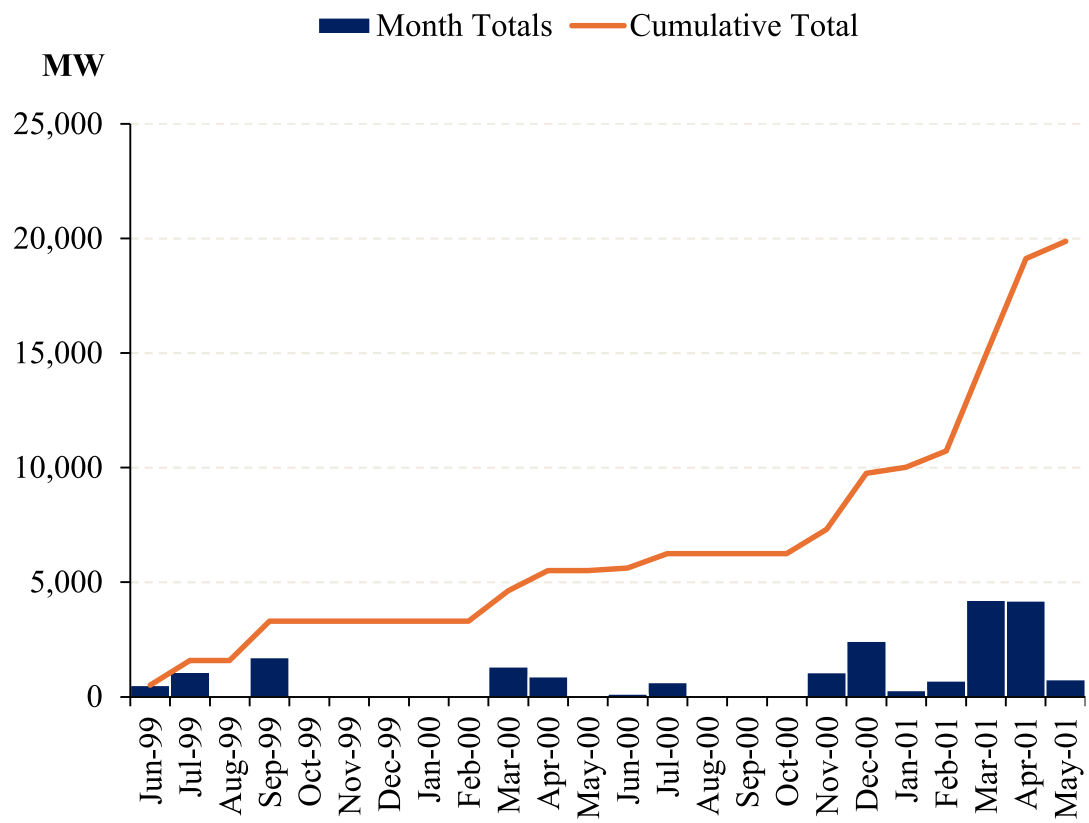
[45] Exh. No. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read uses SoCal Border natural gas forward prices in his adjustment to SP-15 Power Prices. Mr. Read obtains the natural gas prices from Enron.

[46] Exh. No. CAL-50, Summary of Executed CDWR Power Contracts, showing 26 "Modeled Agreements" executed before the end of April 2001.

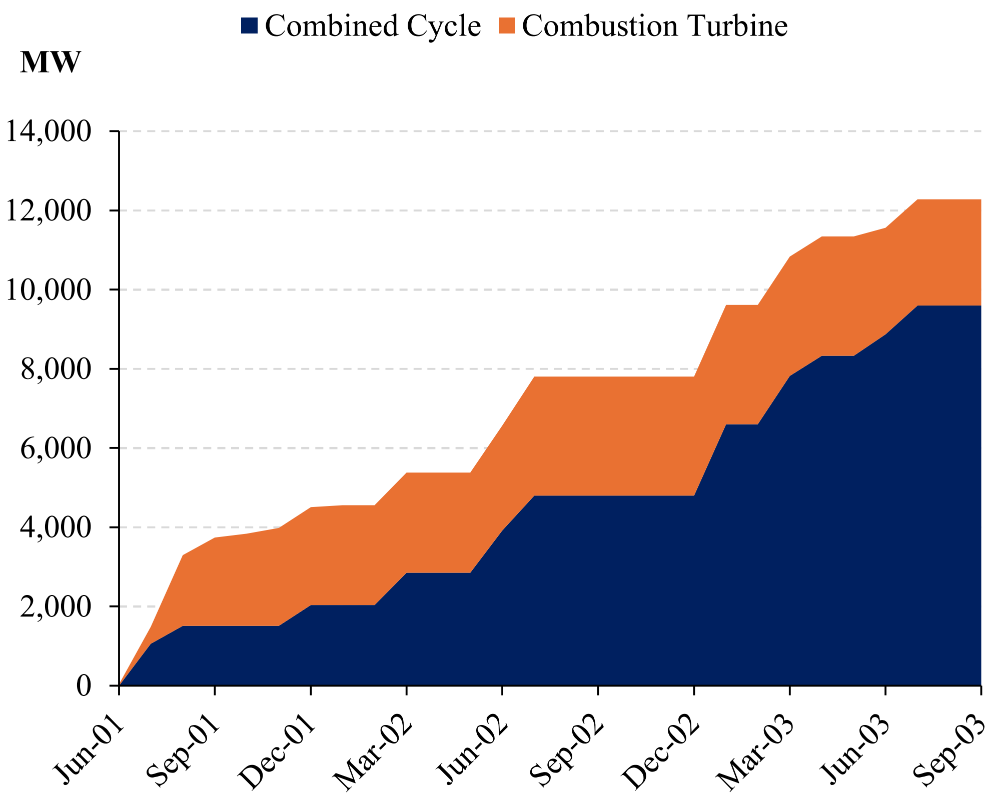
Third, the capacity under construction as of May 2001 was expected to start coming online in July 2001. As shown in **Figure 13** below, as of May 18, 2001, CDWR's consultants were forecasting that 4,500 MW of new capacity additions would come online between July 2001 and December 2001, and approximately 8,000 MW more was expected to come online in 2002 and 2003.

Figure 12[47]
Cumulative Quantity of New Power Generation Plants by Construction Start Date
June 1999 – May 2001



[47] Various trade press. The power plants included are located in Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, and Washington, and include only a subset of power plants constructed in these states in these years.

Figure 13[48]
CDWR Expected New Capacity Additions by Commercial Online Date as of May 18, 2001



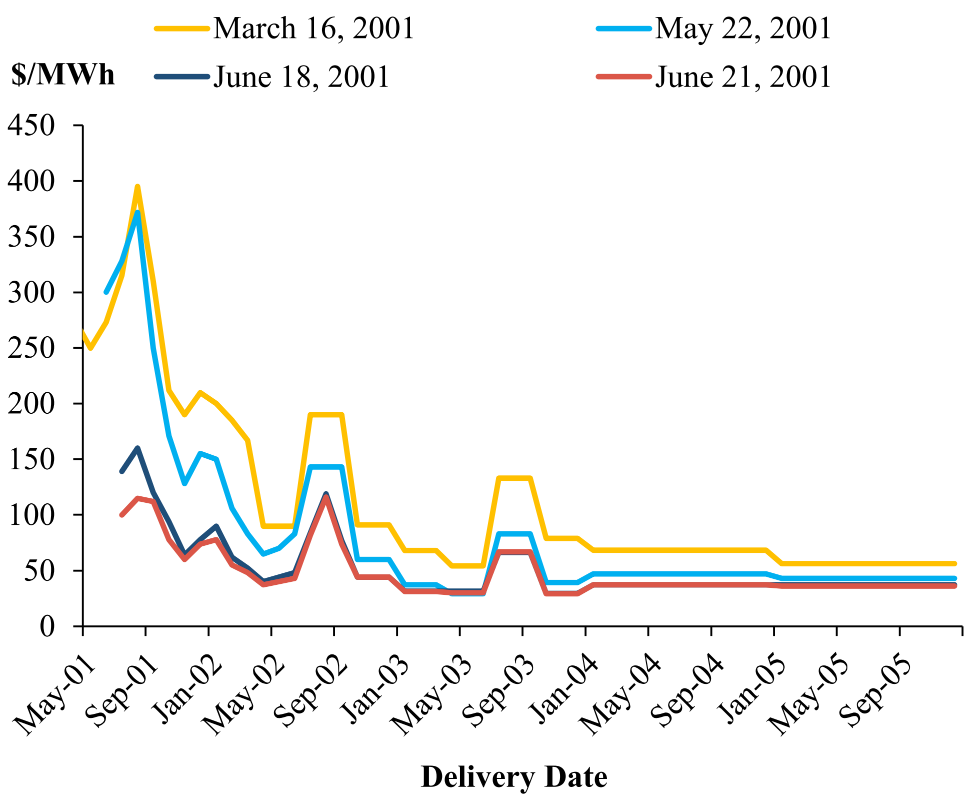
Q. What was the impact of these fundamentals on forward power prices in Spring 2001?

A. The continued concerns for the near term, including potential supply shortages and high natural gas and emissions credit prices, led to high forward power prices in Spring 2001 for near-term delivery months. This can be seen in **Figure 14** and **Figure 15**, which show forward power prices as of March 16, 2001 and May 22, 2001 for NP-15 and SP-15. Consistent with the expectations that natural gas prices would fall starting in mid-2002 (see **Figure 10** and **Figure 11**) and that CDWR's

[48] "Revenue Requirement & Consultant's Report Briefing to the Staff of CEC and CPUC on DWR Energy Procurement Program," Navigant, May 18, 2001, at pp. 10-12. Data are not available for October through December 2002.

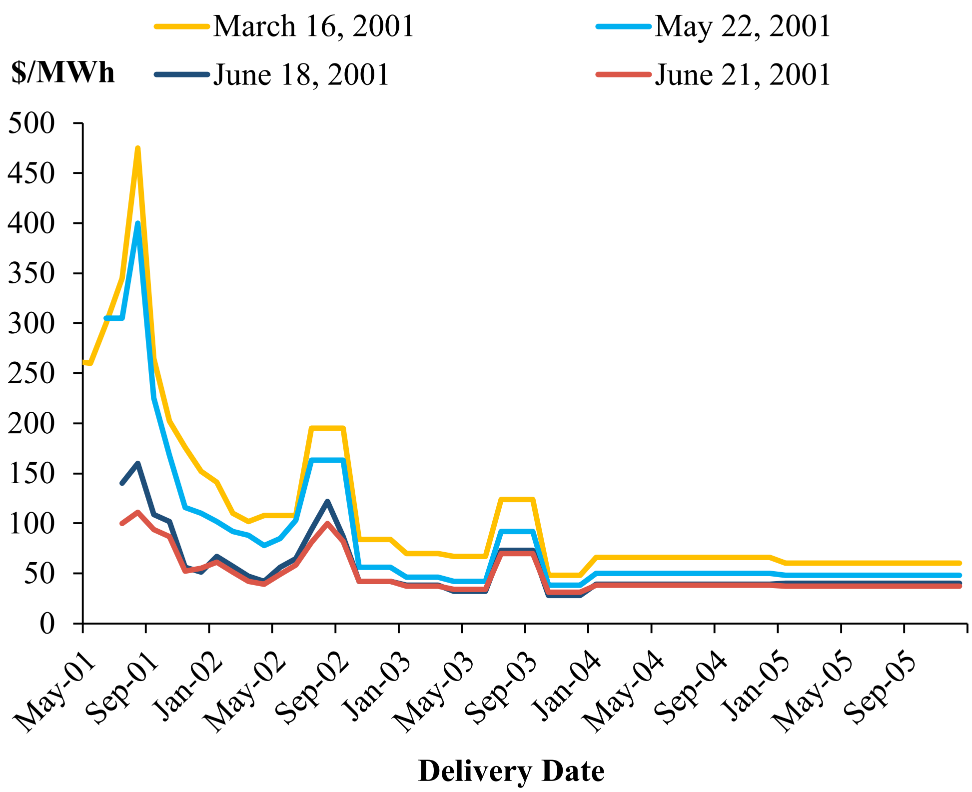
signing of long-term contracts and the construction of new capacity would ease supply shortages, **Figure 14** and **Figure 15** also show that forward power prices on March 16 and May 22 were expected to fall for delivery months in 2003 and beyond. However, as I discuss below and as Dr. Morris discusses, although these price patterns are consistent with expected fundamentals at the time, these forward power prices do not represent an appropriate benchmark for the Shell Contract.

Figure 14[49]
NP-15 Power Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



[49] Exh. No. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read obtains these power forward curves from Natsource fax sheets.

Figure 15[50]
SP-15 Power Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



III. THE COMPETITIVE PRICE OF A LONG-TERM CONTRACT SHOULD REFLECT LONG-RUN MARGINAL COST

Q. Please describe the economic theory behind long-term contract pricing, and industry practice in assessing long-term contract pricing.

A. In this section, I explain the conceptual framework that economists use to analyze long-term contract pricing theoretically and how economic theory informs contract pricing for electric power. As I discuss below, economic theory states that LRMC

[50] Exh. No. CAL-00987, Read Workpapers. Mr. Read obtains these power forward curves from Natsource fax sheets.

set the competitive price for long-term contracts under perfect competition. Moreover, LRMC are also the costs that are considered by buyers and sellers in negotiating long-term contracts for electric power, and by regulators in assessing whether such contracts are just and reasonable.

A. Long-Run and Short-Run Costs Drive Contract Prices

Q. What are Short-Run Marginal Costs?

A. Short-run marginal costs ("SRMC") include variable costs such as fuel costs and certain maintenance and operation costs. In the short run, only these inputs can vary whereas other inputs primarily related to production capacity (such as machinery, equipment, and buildings as well as certain maintenance costs) are considered fixed. In the short run, under perfect competition, firms choose to produce until their SRMC equal the market price.[51]

Q. What are LRMC?

A. LRMC include fixed and variable costs of operations and maintenance, fuel costs, incremental capital costs of building production capacity, and risk. Economic theory states that under perfect competition, firms choose long-run production capacity such that their LRMC are equal to the long-run expected price. The firm has the option to choose from multiple bundles of production capacity, each with its own SRMC.

Firms assess decisions to expand production capacity based on future expected long-term average market prices. If expected market prices rise such that they are

[51] When markets are not perfectly competitive, such firms will take into account the impact of the quantity sold on the market price such that their production decisions will be based on equating the marginal revenue to the marginal cost of the last unit sold. For simplicity, I focus on price formation under the assumption of perfect competition in providing this background.

greater than LRMC at the firm's current level of capacity, this implies that expanding capacity may be profitable and firms will be incentivized to enter the market or expand production capacity. If the firm expands its capacity, it faces a new SRMC curve which in turn determines its new level of production in the short run.

Q. Please explain how long-term contract prices are determined.

A. Under perfect competition, long-term contract prices are determined by sellers' LRMC and buyers' willingness to pay. Thus, the competitive price of a long-term contract will be set based on LRMC.[52] That is, because production capacity can be adjusted to serve a long-term contract, in determining whether to agree to a long-term contract, sellers will consider the full cost of building and maintaining the resources needed to serve the contract.

Q. Why are spot market prices and SRMC not accurate benchmarks for long-term contract prices?

A. Spot market prices, based on sellers' SRMC, do not provide proper benchmarks for long-term contract prices if they fail to account for the full costs of building and maintaining capacity to serve long-term contracts and reflect momentary idiosyncratic market conditions that may or may not continue into the future.

[52] Dr. Fox-Penner concurs, stating "competitive markets are expected to compete such that prices approximate the costs of sellers, which in this case is precisely per-unit LRMC." *See* Exh. No. CAL-00988, Fox-Penner Testimony, at 33:13-15.

B. Long-term Bilateral Contracting for Electric Power

Q. According to economic theory, what are the advantages of bi-lateral contracting?

A. Both buyers and sellers of electricity may find long-term bilateral contracts attractive because pre-determined prices help reduce volatility and risk by guaranteeing a fixed expenditure for buyers and fixed income for sellers. This results in reduced financing costs and can enable long-term investments which would otherwise be unlikely to occur. Relatedly, there are regulatory and policy reasons for long-term contracting for electricity such as reducing customer exposure to volatility, reducing seller market power in the spot market, and incentivizing construction of new generation capacity to ensure resource adequacy and/or encourage the development of renewables.

Q. How is price typically set in negotiating long-term bilateral contracts for electric power?

A. As explained by Mr. Cavicchi, in competitive solicitations, sellers typically price their bids by calculating: (1) the fixed capital and financing costs, including site control and permitting costs, engineering, procurement, and construction costs, (2) variable fuel costs, (3) variable operations and maintenance costs, (4) regulatory compliance costs, and (5) a risk adder to reflect uncertainty around the range of potential costs faced by the seller in committing to provide supply under the terms of the contract, including fuel price risk and counterparty credit risk. This approximates the seller's theoretical LRMC.

On the buyer side, Mr. Cavicchi explains that CDWR (like other entities seeking to procure power to serve load) considered the range of price and non-price factors (such as contract length, dispatch rights, and other factors) associated with each offer in selecting which of the offers to accept. In addition, CDWR evaluated the offer prices against internal estimates of the cost of power.

Similarly, Mr. Hibbard discusses that buyers and regulators may benchmark the offers received against the cost of a self-build option (again approximating the theoretical LRMC), wherein the buyer constructs its own generation rather than entering into a contract. In particular, regulatory approval of contracts is often required, wherein regulators may assess the selected offer(s) relative to the range of offers and the cost of the self-build option to determine whether the contract is just and reasonable. Moreover, per both Mr. Hibbard and Mr. Cavicchi, when long-term contracts are priced at cost-based rates approved by the Commission, such rates rely on the same inputs as the theoretical LRMC. In other words, regulators regularly use cost-based measures that approximate LRMC to assess whether long-term contract prices are just and reasonable.

Thus, as stated by Dr. Fox-Penner, "long-run marginal cost[] is an obvious benchmark for a market-based rate"[53] because "competitive markets are expected to compete such that prices approximate the costs of sellers, which in this case is precisely per-unit LRMC."[54] Thus, both theoretically and practically, LRMC, when correctly calculated, is an appropriate benchmark for the Shell Contract price.

Q. Dr. Celebi's and Dr. Fox-Penner's preferred benchmark relies upon the LRMC only for January 2006 and beyond, based on their claims that LRMC is only applicable for deliveries well into the future. Do you agree with this?

A. No. Specifically, Dr. Fox-Penner claims that LRMC is only applicable "[f]or periods well into the future" and claims that it is a "very common convention is to assume that, as of 2006 and beyond, annual average power prices would equal…

[53] Exh. No. CAL-00988, Fox-Penner Testimony, at 17:1-2.

[54] Exh. No. CAL-00988, Fox-Penner Testimony, at 33:13-15.

the levelized long-run marginal cost (LRMC) of power."[55] Dr. Celebi similarly claims that "for later year deliveries, the prices formed in a workably competitive market should reflect LRMC-based prices."[56] I know of no literature that states that LRMC is only applicable to long-term contract prices "well into the future," or that it is a "very common convention" to use LRMC only for 2006 and beyond (or, more generally, only for 4.5 years or more in the future). Although it may be true that market participants could look at forward curves for up to five years out to inform their bids, the price that a generator would demand for a long-term contract would be based primarily on its LRMC in order to cover its full capital and operating costs for the entire duration of the contract. Similarly, a marketer that has to serve a long-term contract will consider the LRMC of the generators with which it might contract to obtain supply in assessing its offer,[57] particularly in a time of expected shortage (like California was experiencing in May 2001).

Dr. Celebi also claims that "that long-run equilibrium conditions would have been expected to prevail shortly after the time when a new combined-cycle generation plant could have been installed because many of the remaining types of adjustments (such as retirement of existing resources, demand reductions and new load) in response to market price signals could have been implemented within that same four-year time frame. Therefore, I expect the long-run equilibrium conditions can be expected to be in place in four to five years."[58] However, the long run doesn't start on some particular future date when everything stops changing and

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[55] Exh. No. CAL-00988, Fox-Penner Testimony, at 33:1-5, 10-13.

[56] Exh. No. CAL-00973, Celebi Testimony, at 45:3-4.

[57] Notably, this is evident in Shell's analysis of the contract where it considered the capital and operating costs of potential generators that could be used to serve the contract. *See* Exh. No. CAL-647ii, tabs "SP15-LRPP Costs" and "SP15-Peaker Costs." *See also* Wolak, F. A., "Wholesale electricity market design," *Handbook on Electricity Markets*, 2021, pp. 73-97, at p. 97, Exh. No. SHE-0065.

[58] Exh. No. CAL-00973, Celebi Testimony, at 46:1-8.

equilibrium is reached and LRMC is not a metric that only applies in some future long-run equilibrium. In particular, LRMC will determine the price at which a generator is willing to sell its output over a long time horizon and will determine the costs a marketer will incur to serve a contract because the marketer must ultimately contract for the output of a generator.[59]

IV. THE STRUCTURE OF THE CDWR PROCUREMENT PROCESS ENABLED A COMPETITIVE MARKET ENVIRONMENT

Q. Please describe the overall level of competition in the CDWR long-term contract procurement process.

A. The market structure of the CDWR procurement process was designed in a manner to facilitate competitive pricing so that Shell (and other sellers) would not have market power to raise the price above the competitive level. In fact, economic theory suggests that CDWR's position as the sole buyer in the process would lead to competitive or below-competitive prices.

Shell was one of many firms offering to sell long-term contracts and it did not own or control a significant share of generation in the California market. As such, Shell would need to procure power or build new generation to fulfill its contract obligations. Many other sellers and potential sellers were in similar positions, and this feature of the procurement process incentivized sellers to undercut one another until prices approximated the expected LRMC at the time of contracting. This

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[59] Anderson, E. J. *et al.*, "Forward Contracts in Electricity Markets: The Australian Experience," *Energy Policy,* Volume 35, Issue 5, May 2007, pp. 3089–3103, at p. 3099, Exh. No. SHE-0066 ("Hence contract prices are based on calculations of capital and operational expenses. Whatever the time span for the contracts, in price discussions generators will be acutely aware of how much they need in order to cover their financing requirements, and generators likewise will try to lock in a margin against the retail price they charge.").

would preclude Shell from exercising market power in the negotiation of long-run bilateral contracts.

Moreover, CDWR was the sole buyer of long-term contracts during the period. A sole buyer may have the ability to exercise what is known as monopsony power (akin to monopoly power where there is a single seller, rather than a single buyer), to push prices below competitive levels. Further, CDWR was a sophisticated buyer that had detailed information about the prevailing forward contracting environment of the market as of March-May 2001, when the contract was being negotiated. As the Commission agreed in Opinion No. 587: "CDWR had experienced personnel in charge of negotiations and hired sophisticated consultants, benefited from being the principal purchaser of electricity in California, and was able to dictate key terms, including rates."[60]

Thus, there are strong *a priori* reasons for the prices of contracts procured by CDWR to be at or below the benchmark competitive contract price.

A. CDWR's Procurement Process

Q. Why did CDWR procure long-term electricity contracts on behalf of IOU retail customers?

A. In January 2001, CDWR took responsibility for procuring long-term contracts on behalf of IOU retail customers in order to procure capacity to address the expected generation capacity shortage in California, decrease the California IOUs' reliance on high and volatile spot market prices, mitigate the ability of large generation owners to exercise market power, and address concerns that the IOUs would not be able to pay for their power needs due to the retail rate caps and financial

[60] Opinion No. 587 at P 93.

insolvency.[61] These purchases were to be funded by state-backed bonds that would be repaid by retail customers from the California IOUs.

Q. Please explain CDWR's procurement process for these long-term electricity contracts.

A. CDWR conducted a comprehensive competitive procurement process. The primary objective of the process was to "find and contract for resources to meet the supply gap ('net-short') that was contributing to the soaring prices and black-outs that California was experiencing."[62]

CDWR issued two requests for bids, on January 23, 2001 and February 2, 2001. Ultimately, CDWR received offers from over 130 respondents[63] and signed dozens of long-term contracts with more than 20 counterparties.[64] CDWR received offers for and ultimately signed contracts that varied across several dimensions, such as time of day (6x16, also known as "peak," or 7x24, also known as "base"), location (SP-15 or NP-15), contract length (ranging from less than one year to over ten years). Additionally, contracts varied on more complex characteristics, including unit contingency, start limits, capacity charges, and fuel provisions, resulting in a final portfolio of complex contracts.

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[61] Exh. No. CAL-200, Nichols Supplemental Testimony, at 25:8-12; Joskow 2001, at p. 384.

[62] Answering Testimony of Tara Nolan On Behalf of Shell Energy North America (US), L.P., Docket Nos. EL02-60-013 et al., November 4, 2021, (formerly "Ex. SHL-0005, Nolan Testimony") at 4:5-6, Exh. No. SHE-0098.

[63] Exh. No. EPME-1, Prepared Direct Testimony of Joseph P. Kalt, PH.D. On Behalf of El Paso Merchant Energy, L.P., Docket Nos. EL02-60-003 *et al.*, October 17, 2002, ("Exh. No. EPME-1, Kalt Testimony"), Exh. No. EPME-22 showing that 68 firms responded to at least one of CDWR's two requests for bids, and that 63 firms submitted unsolicited offers.

[64] Exh. No. CAL-50, Summary of Executed CDWR Power Contracts.

Q. What did CDWR's assessment of each potential contract entail?

A. CDWR's assessments of potential contracts were extensive. To assist the agency in performing comprehensive evaluations of each option and negotiating competitive long-term agreements, CDWR engaged experienced consultants. The evaluation process included complex modeling of contracts and spot market pricing.[65] Along with its consultants, CDWR evaluated potential contracts on several criteria including, but not limited to:

- "matching an energy supply portfolio to the expected quantity of net short energy requirements;
- seeking a weighted average cost of long-term contract energy expected to be within the combined average cost of energy supply reflected in the IOUs' retail rates, as of January 2001;
- selecting the lesser of comparative cost of proposed energy supplies for similar energy products;
- providing special consideration to renewable energy supplies; and
- setting priority for contracts which support timely completion of new generation capacity to improve California's electric capacity reserves."[66]

These criteria indicate that CDWR was evaluating contracts based on each contract's individual characteristics, while also assessing the price relative to comparable contracts and the contract's contribution to its complete portfolio and other policy goals.

[65] Exh. No. CAL-51, Nichols Testimony, at 11:10-14:2.

[66] Exh. No. CAL-51, Nichols Testimony, at 10:26-11:9.

B. Economic Theory Supports that CDWR's Process would Result in a Competitive Price

Q. From a broad economic perspective, can you describe a framework for a contracting process that would promote competitive prices for long-term contracts to deliver power?

A. A general structure that would facilitate long-term contracts with competitive prices is one with many potential buyers and sellers of long-term contracts to supply power. The buyers and sellers in such a setting would need to have information about the range of possible demand and cost conditions over the time period of delivery as well as information about potential uncertainty over future variable costs, capital and financing costs, counterparty credit risk, and regulatory risk. In that setting, any specific seller, among many other potential sellers, would not possess the ability to exercise market power if it owned a small share of the electric generators in the relevant market because that seller would need to procure power and/or build new electric generation capacity in order to fulfill its contract obligations over the term of the contract.

Q. Does the CDWR procurement process exhibit the characteristics necessary to enable a competitive outcome?

A. On the seller side, Shell was one of over 130 firms that submitted bids for the contracts with CDWR. As Dr. Morris shows, Shell controlled only a small amount of available generation capacity in California, so it knew that it would need to procure power and/or construct new generation capacity to fulfill any awarded contract obligations, exposing it to price risk associated with either fulfillment approach. Given substantial competition on the supply side, on *a priori* grounds, Shell was not in a position to exercise market power in the negotiation of prices for long-run contracts.

On the buyer side of this procurement process, there were not multiple buyers but rather a single buyer – CDWR. Basic economic fundamentals suggest that the structure of the contract negotiation process (with many sellers and only one buyer) could yield contract prices that are *lower* than the prices that would arise in a competitive marketplace. If there is a sole buyer, that entity may have the ability to exercise monopsony power, reducing the amount of power purchased in order to lower the price paid for all power that is purchased. This logic is similar to that of monopoly power, except it is the sole buyer who is exercising market power to *lower* prices rather than the sole seller exercising market power to *raise* prices. Note that Dr. Fox-Penner also recognizes the ability of a single buyer to move market prices in the buyer's favor when stating that a workably competitive market requires "a sufficient diversity of buyers so as to avoid monopsony power" in his testimony.[67] CDWR had sole ability to sign long-term contracts to buy power in this procurement process, and it was equipped with detailed information about the prevailing forward contracting environment of the market as of March-May 2001, when the contract was negotiated. As the Commission agreed in its December 2023 Order: "CDWR had experienced personnel in charge of negotiations and hired sophisticated consultants, benefited from being the principal purchaser of electricity in California, and was able to dictate key terms, including rates."[68] In Opinion No. 587, the Commission finds that CDWR had strong bargaining power: "both CDWR and Shell were sophisticated parties that spent months negotiating a complex contract for the sale and purchase of energy. The record contains numerous examples of CDWR extracting favorable concessions from Shell including, for example, last-minute changes to pricing terms, a change to the delivery point, and a tolling structure in the later years of the contract."[69] Evidence

[67] Exh. No. CAL-00988, Fox-Penner Testimony, at 21:16-22:7.

[68] Opinion No. 587 at P 93; *see also id.* at PP 97, 131.

[69] *Id.* at P 248.

also shows that CDWR walked away from offers where it found the price too high.[70] Therefore, the broad structure of the CDWR contracting process in March through May of 2001 is consistent with a procurement process that leads to prices that are at *or below* what one would expect from a competitive market for power.

C. Economic Theory and Evidence in the Record Indicates that the CDWR Procurement Process Resulted in Competitive Prices

Q. Is there evidence of competitive prices consistent with LRMC that resulted from CDWR's competitive process?

A. Yes. Mr. Cavicchi has identified long-term contracts comparable to the Shell Contract that resulted from that process. He finds that the Shell Contract is in the price range of the comparable contracts and that the Shell Contract and comparable contract prices are consistent with the cost-based rate of a new combined cycle unit at the time (akin to the theoretical LRMC). Dr. Morris has also evaluated those contracts in the context of Shell's market-based rate status. Both have determined that the prices of other long-term contracts resulting from CDWR's competitive process validate that the rates in the Shell Contract are just and reasonable.

Q. What concerns have been raised with respect to the competitiveness of the prices negotiated in the CDWR's procurement process?

A. Dr. Fox-Penner claims that "the power markets during the negotiation period were not workably competitive" and that in many hours, Shell had market power as a pivotal supplier, i.e., its supplies were required to keep the lights on.[71] Dr. Fox-Penner also claims that "the Shell contract rates were excessive because they reflected (or 'locked in') prices that were artificially inflated due to fraud and market manipulation by Shell and other sellers" based on findings from Opinion

[70] *Id.* at P 93; Exh. No. EPME-1, Kalt Testimony, Exh. No. EPME-23.

[71] Exh. No. CAL-00988, Fox-Penner Testimony, at 11:16-12:6.

No. 587 that "Shell's spot market strategies artificially inflated prices and Shell then knowingly negotiated to include those inflated prices into the Shell contract… In other words, Shell's fraudulent market activities were the cause of CDWR agreeing to the specific rates of the Shell Contract, based on Shell's deceptive statements about its losses on the April/May 2001 sales that were motivated by the goal of locking in Crisis Period profits."[72]

Q. Are Dr. Fox-Penner's claims that Shell had market power relevant to the negotiations of the Shell Contract?

A. No. Dr. Fox-Penner's claim that Shell was a pivotal supplier is related to "some hours" of the spot markets. Thus, his claim is unrelated to the bilateral contract negotiations with CDWR for long-term contracts. As Dr. Morris explains, the California Parties' witnesses have presented no evidence that Shell was physically pivotal, and even a temporary pivotal spot market position would not affect long-term contract prices.

Q. Economically, is it reasonable to claim that Shell could have caused the price of the Shell Contract to be artificially inflated?

A. No. According to economic theory, Shell would have needed to possess market power in the long-term contracting market in order to raise the price above competitive levels. As I explain above, Shell did not have market power in negotiating with CDWR, but rather CDWR was in the stronger negotiating position, and Shell was competing with a large number of other firms that would have undercut Shell had it offered an inflated price.

[72] Exh. No. CAL-00988, Fox-Penner Testimony, at 10:7-13 (citing Opinion No. 587 at P 224).

Q. In your testimony above, you explain that the firms that owned the power plants withheld generation in the CAISO/PX spot market. Does that imply that Shell had market power in negotiating long-term contracts with CDWR?

A. No. I am not aware of any economic theory suggesting previous efforts to withhold generation by generation owners in the spot market would influence the competitiveness of prices in a later long-term forward contract negotiation. Furthermore, no such theory is presented in the California Parties' witnesses' testimony. Long-term contracts are inherently forward-looking with respect to future market fundamentals about demand and costs. Moreover, these contracts were procured through a process involving numerous potential sellers, including potential entrants and others who may not have owned generation assets.

Economic theory states that for a company to possess market power with respect to near-term sales, the relevant feature is the amount of generation capacity that it controls that is not financially committed (e.g. via a contract) to some other market participant. Sometimes, this is called the owner's "net generation position" in economics parlance. For example, if a firm owns and controls 100 MW of generation, but has previously committed 90 MW via a prior contract, then the firm only has 10 MW for which it is a net seller. Likewise, if that firm has 90 MW of its own power needs, then the firm only has 10 MW for which it is a net seller. Importantly, from a competition perspective, the amount of net seller capacity that a firm possesses determines a firm's ability to exercise market power. In the examples above, the number that should be used in considering the potential to exercise market power is 10 MW rather than 100 MW.

As Dr. Morris describes in his testimony, Shell had only a very small amount of net seller capacity as of May 2001. In particular, Dr. Morris finds that Shell had only 25 MW of capacity under its operational control or less than 1 percent of total capacity in CAISO at the time, well below the Commission's thresholds for presuming a seller has market power.

Moreover, economic theory states that in the long-term, as long as there are no barriers to entry, markets are competitive because new entrants can build new supplies.[73] Thus, economic evidence, both empirical and theoretical, indicate that Shell had no market power in the CDWR procurement process. Furthermore, unlike generation firms, power marketers like Shell provided a moderating influence on market prices by taking on price risk arising from the highly volatile electricity prices on behalf of buyers with limited creditworthiness.

Q. Would you expect the misrepresentations by Shell identified in Opinion No. 587 to have a meaningful impact the Shell Contract price?

A. No. Although the Commission found that Shell made misstatements during the negotiations, it emphasized that "this finding does not constitute a determination that the rates in the Shell Contract are unjust and unreasonable."[74] In other words, the Commission recognized that Shell's misrepresentations may not have necessarily led to a price above the competitive level.

Economic principles clearly illustrate why misrepresentations by Shell in the spot market do not impact negotiated prices in CDWR's procurement process. CDWR was a sophisticated buyer with ample bargaining power and ability to dictate key terms as discussed above. Moreover, there were multiple other firms competing with Shell to sign contracts with CDWR and those firms had the ability to undercut Shell if Shell had offered an above-competitive price for the energy and capacity provided in the Shell Contract. As noted above, over 130 companies responded to

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[73] This is also supported by Commission precedent. *See Market-Based Rates*, Order No. 697, 119 FERC ¶ 61,295, at P 122 (2007).

[74] Opinion No. 587 at P 441.

CDWR's requests for bids. Such companies included other power marketers like Shell, such as Morgan Stanley, Merrill Lynch, and Williams, as well as nearby utilities including Tucson Electric Power, Xcel Energy, Idacorp Energy, and Pacificorp, among many others.[75] Nearly 10,000 MW of potential supply from dozens of suppliers was rejected by CDWR either because the capacity was not needed, the price was too high, or the terms were not satisfactory. For example, Tucson Electric and Constellation, offered substantial quantities of firm power not tied to a particular resource, like Shell, but CDWR rejected the bids, finding the prices too high.[76]

Because other sellers would have assessed the cost of the generation resources needed to supply power to CDWR (i.e., their LRMC), other sellers had an objective (unmanipulated) benchmark on which they could price their bids. If other sellers' LRMC, including the costs associated with the risks of contracting with CDWR, had been below the price offered by Shell, other parties would have undercut Shell and CDWR would not have contracted with Shell. For example, Pegasus and the City of Colton both offered combined cycle natural gas generation units but were rejected by CDWR based on their offered prices and/or contract terms.[77] The only economic force that could get in the way of such undercutting would be for all of the over 130 potential competitors to have colluded—California Parties' witnesses provide no such evidence, nor do I know of any case in any industry when such a large number of firms ever colluded.

[75] Exh. No. EPME-1, Kalt Testimony, Exh. No. EPME-22.

[76] Exh. No. EPME-1, Kalt Testimony, Exh. No. EPME-23.

[77] Exh. No. EPME-1, Kalt Testimony, Exh. No. EPME-23.

V. THE CALIFORNIA PARTIES' WITNESSES FAIL TO ESTABLISH THAT FRAUD AND/OR MANIPULATION AFFECTED THE SHELL CONTRACT RATE OVER THE LIFE OF THE CONTRACT

Q. Based on Opinion No. 587, Dr. Fox-Penner claims that "Shell's fraudulent and manipulative trading activities artificially inflated the market prices Shell induced CDWR to build into the Shell contract."[78] Is this plausible economically?

A. No. The implicit mechanism underlying this claim is that past violations in the CAISO/PX market prior to January 2001, and possibly isolated spot market fraud and manipulation thereafter, led forward prices as of Spring 2001 to be inflated, and that market participants assumed that the artificially high prices would continue indefinitely, which then led to artificial inflation in the long-term contract prices to which CDWR agreed as CDWR was unaware of the artificiality of spot and forward prices. This claim is inconsistent with the Commission's finding that CDWR did not rely upon forward prices in negotiating long-term contracts.[79] Moreover, as discussed above, given CDWR's strong bargaining power, for CDWR's procurement process to result in an artificially high price, other sellers would have had to collude to avoid undercutting each other down to their LRMC. However, California Parties' witnesses present no evidence of such collusion and it is wholly implausible given the large number of sellers. And, as discussed above, the structure of the CDWR procurement process, which involves numerous sellers competing for contracts, promotes pricing that reflects expectations of market fundamentals during the delivery years rather than relying on prior spot market pricing.

California Parties' witnesses may claim that but-for fraud and manipulation throughout the crisis period, the IOUs may not have been insolvent and CDWR

[78] Exh. No. CAL-00988, Fox-Penner Testimony, at 9:17-19.

[79] Opinion No. 587 at PP 90, 94.

would not have entered into bilateral forward power contracts with any sellers.[80] However, California Parties present no evidence of this and it is entirely plausible that the market fundamentals in 2000-2001 described in **Section II**, particularly the IOUs' lack of forward contracting with the five generation owners, the retail rate cap, fuel cost increases, and supply shortages could have led to the need for CDWR long-term contracting even if no market participant had committed fraud or engaged in manipulative actions.

Q. Do Dr. Celebi and Mr. Read provide any evidence or causal link as to how fraud and manipulation impacted CDWR's bilateral contract negotiations with Shell?

A. No. Mr. Read's testimony is limited to providing forward market prices that allegedly exclude the impact of fraud and manipulation to Dr. Celebi. Dr. Celebi then asserts that his benchmarks, calculated from Mr. Read's forward market prices and other Shell forward contracts that also allegedly exclude the impact of fraud and manipulation, form an appropriate benchmark for the Shell Contract. Upon finding that his forward market price series fall below Shell Contract prices, Dr. Celebi claims that this proves that fraud and manipulation inflated the Shell Contract price. However, as I discuss in the next sections, Dr. Celebi's and Mr. Read's calculations assume (rather than prove) that alleged spot market fraud and manipulation carried over directly to forward prices, erroneously ignore the impacts of market fundamentals on forward prices, and rely on prices that are not appropriate benchmarks for the product CDWR procured through the Shell Contract. These flaws invalidate their comparison.

Moreover, such a comparison does nothing to prove that fraud and manipulation was the cause of the differential. None of California Parties' witnesses provide any

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[80] *See, e.g.,* Exh. No. CAL-00988, Fox-Penner Testimony, at 9:9-12.

evidence of how the fraud and manipulation that allegedly increased forward prices seeped into the Shell Contract rate.

Further, beyond claiming that MMCPs represent a measure of unmanipulated spot market prices, Mr. Read and Dr. Celebi do not establish that, but-for the alleged fraud and manipulation, spot or forward market prices in California would have been significantly different than they were. Even this claim is unreliable as MMCPs were a simplistic measure of short-run marginal cost that underestimates short-run marginal cost, as discussed further below and by Dr. Morris. Moreover, the myriad market fundamentals I discuss above resulted in supply scarcity that would drive spot market prices above variable costs, even in a well-functioning competitive market, and would similarly increase expected forward prices for as long as such scarcity was expected to continue.

Q. How does Commission precedent invalidate the argument that fraud and manipulation in the spot market negatively impacted CDWR's bilateral contract pricing negotiations?

A. In Opinion No. 587, the Commission noted that it has "previously rejected similar claims of unequal bargaining power, and [sees] no reason to depart from those conclusions here."[81] Further, the Commission noted that it "reject[s] the California Parties' arguments that they did not have equal negotiating power due to prevailing high spot market prices that 'set a floor' for contract negotiations,"[82] and further that "CDWR had experienced personnel in charge and hired a multi-million dollar stable of consultants and advisers, it benefitted from being the sole purchaser of electricity in California, and CDWR often dictated terms later in the Crisis Period

[81] Opinion No. 587 at P 93.

[82] *Id.* at P 97.

as sellers of electricity competed to finalize a deal."[83] As discussed above, when a buyer has equal or stronger bargaining power than the seller, the price resulting from a bilateral contract negotiation should be at or below the competitive level. Moreover, given the number of other potential sellers, there were strong incentives to underbid Shell if in fact Shell prices were above competitive levels.

VI. DR. CELEBI'S BENCHMARKS IGNORE CHANGES IN MARKET FUNDAMENTALS

Q. Dr. Celebi presents five benchmarks based on forward market prices. What concerns do you have regarding the timing of the information he uses?

A. Dr. Celebi claims that forward market prices as of May 25, 2001, when the contract was executed, would be an appropriate benchmark for the Shell Contract prices. He claims however, that he cannot use forward market prices as of that date because they were distorted by fraud and manipulation. As a result, he uses a variety of alternative measures to construct forward-price benchmarks, including pre-crisis forward prices, post-crisis forward prices, and forward prices developed by Mr. Read as of May 22, 2001 "absent the effect of fraud and manipulation."[84] However, each of these alternative forward price series ignores changes in market fundamentals, which the California Parties' witnesses simply assume away, causing their forward prices to understate the competitive price level in late May 2001.

Additionally, Dr. Fox-Penner stated that "it is appropriate to base our analysis on information available to the parties at the time of contract formation."[85] Yet, the California Parties' witnesses' benchmarks are all based on information that was

[83] *Id.* at P 131.

[84] Mr. Read and Dr. Celebi do not explain why Mr. Read uses May 22, 2001 as his reference date when Dr. Celebi states that May 25, 2001 would be the appropriate date.

[85] Exh. No. CAL-00988, Fox-Penner Testimony, at 30:1-3.

not available at the time the Shell Contract was executed and thus, could not have been used in negotiations.

A. Dr. Celebi's Pre-Crisis Benchmark

Q. Dr. Celebi's third benchmark uses pre-crisis forward prices. Is that an appropriate benchmark?

A. No, Dr. Celebi's third benchmark is not based upon sound economic principles. This benchmark uses data from March/April 2000, more than a year before the execution of the Shell Contract, as an estimate of what forward prices would have been on May 25, 2001, when the Shell Contract was executed, had there been no "fraud and manipulation." However, forward prices as of March and April 2000 reflect the beliefs about market fundamentals as of Spring 2000, and Dr. Celebi makes no effort to adjust the pre-crisis prices for changes in expectations regarding market fundamentals between March/April 2000 and May 25, 2001. Instead, he assumes that any difference between forward prices on May 25, 2001 versus March/April 2000 was due only to fraud and manipulation. Dr. Celebi provides no analysis in support of this assumption. For this to be a valid assumption, one would have to believe that the market participants in March/April 2000 correctly anticipated the impact of each of the following changes in market fundamentals on forward market prices for May 2001 (when delivery on the Shell Contract started) to December 2005: (1) supply shortages, (2) natural gas price increases, (3) emissions credit price increases, and (4) the interaction of these changes with the retail rate caps in place at the time and the IOUs' lack of long-term contracts. Assuming that market participants possessed such foresight conflicts with common sense and available evidence. The California Parties' witnesses present no evidence that these changes in market fundamentals were foreseen and incorporated into forward prices as of March and April 2000.

Q. Please elaborate on the evidence indicating that expectations regarding market fundamentals changed between Dr. Celebi's pre-crisis, March/April 2000, period and the Shell Contract's execution on May 25, 2001 that contradicts the assumption made by Dr. Celebi in constructing his third benchmark.

A. Dr. Celebi assumes that forward prices for delivery from May 2001 (when delivery on the Shell Contract started) to December 2005 (when Dr. Celebi shifts to alternative methods of computing a benchmark) would have been the same on the contract's execution date of May 25, 2001 as they were in March and April 2000 before the crisis began. However, as explained above in **Section II**, market fundamentals shifted dramatically along numerous dimensions between March/April 2000 and May 25, 2001.

In particular, demand increased at the same time hydroelectric supply decreased, leading to increased reliance on antiquated and expensive natural gas generators, while natural gas prices and emissions credit prices increased dramatically. Additionally, regulatory changes being implemented at the time led IOUs to have retail price caps coupled with few long-term contracts, exposing them to high spot prices without an ability to recover the costs. This caused financial challenges for the IOUs, including PG&E declaring bankruptcy, and led to CDWR procuring long-term contracts on the IOUs' behalf, despite sellers also having concerns about CDWR's creditworthiness as discussed in more detail in **Section VI.B**. While some of these changes may have been partially anticipated, the full breadth of the crisis took market participants by surprise and led to changes in expectations regarding market fundamentals for May 2001 to December 2005.

For example, while some concerns had been raised about potential supply shortages in certain scenarios as of Spring 2000, the full implications of this finding were not anticipated or understood.[86] Additionally, shortages appear to have materialized sooner than anticipated,[87] the amount of new generation in the West that came online in 2001 was not as large as anticipated as of January 2000,[88] and hydroelectric generation in 2000 turned out to be lower than expected.[89] Each of these factors would have contributed to an upward shift in the forward price curve between March/April 2000 and May 25, 2001.

Moreover, changes in natural gas prices and emissions costs were also not anticipated nor was the combined impact of all of the changes in fundamentals. To illustrate the scale of the change in natural gas price expectations from March/April 2000 to May 25, 2001, **Figure 16** and **Figure 17**, respectively, show PG&E Citygate and SoCal Border natural gas forward prices as of March 1, 2000, April 28, 2000, and May 25, 2001. It is clear from these figures that expected forward natural gas prices increased dramatically from March/April 2000 to May

[86] For example, a March 6, 2000 report from the Northwest Power Planning Council identified the potential for capacity shortages in winter months in the Northwest, but per an October 2000 report "it has been difficult for people to get too concerned about probabilities generated by arcane computer models." Similarly, a May 2000 forecast from "the WSCC concluded that if normal temperatures were to prevail during the summer period, projected regional capacity margins and reliability should be adequate. It also stated that if higher than normal unplanned generator outages occur, an area experiences significantly higher than normal temperatures, or the loads in multiple areas peak simultaneously, portions of the region may need to issue public appeals for customers to reduce their electrical consumption or other measures may be necessary." *See* "Study of Western Power Market Prices Summer 2000," *Northwest Power Planning Council*, October 11, 2000, pp. 1-2, Exh. No. SHE-0067.

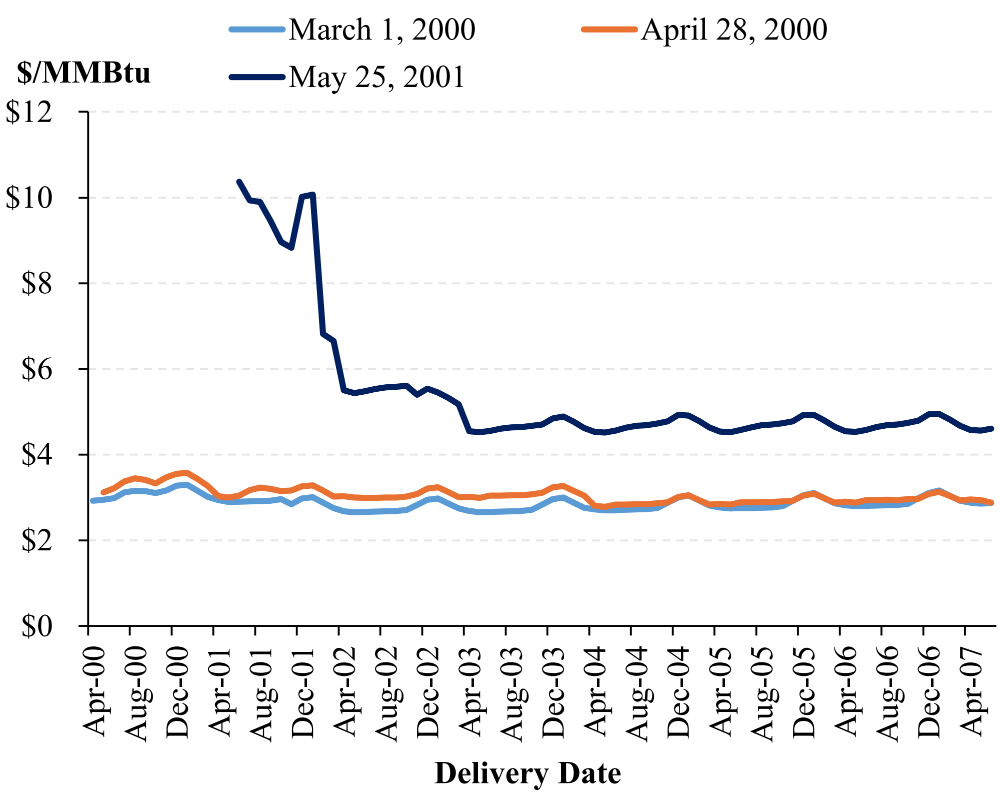
[87] Weare, C. "The California Electricity Crisis: Causes and Policy Options," *Public Policy Institute of California*, 2003, at p. 20, Exh. No. SHE-0068.

[88] During 2001, 4,597 MW of generation came online in the west while a January 2000 forecast of planned generation showed 5,790 MW of generation, *net of retirements,* was expected to come online in 2001. *See* Exh. No. EPME-1, Kalt Testimony, Exh. No. EPME-13; FERC Report, November 2000, at p. 2-5.

[89] *See, e.g.,* "Study of Western Power Market Prices Summer 2000," *Northwest Power Planning Council*, October 11, 2000, pp. 3-4.

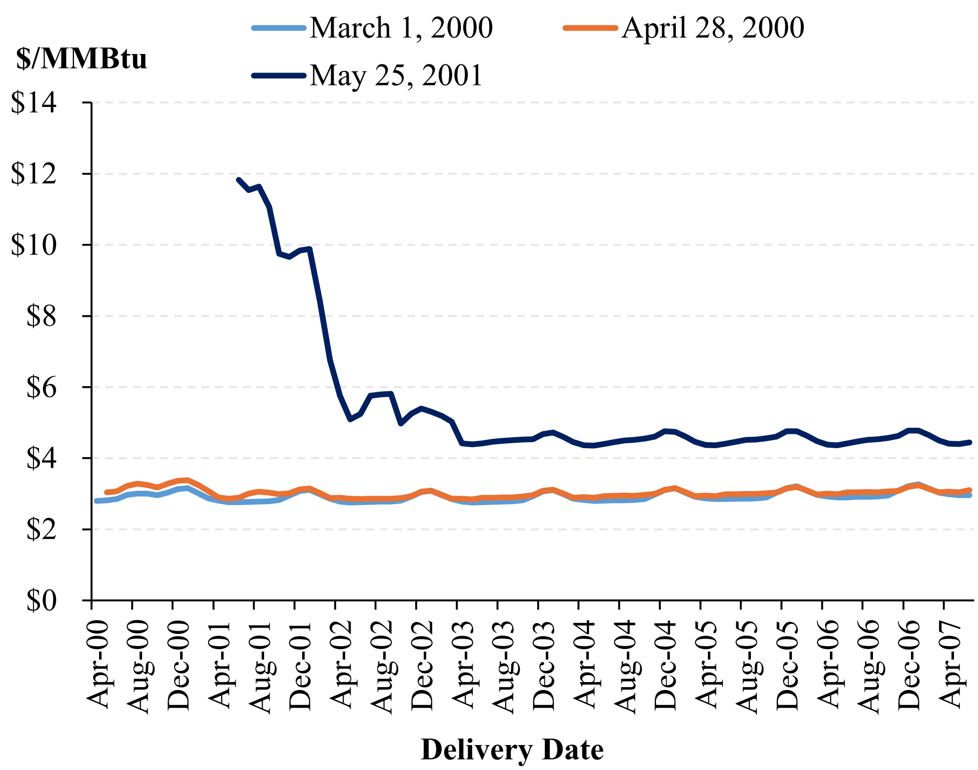
25, 2001, even for delivery months as far out as 2007, which would lead directly to increases in forward power prices.

Figure 16[90]
PG&E Citygate Forward Natural Gas Prices
March 1, 2000, April 28, 2000, and May 25, 2001



[90] Exh. No. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read uses PG&E Citygate Natural Gas Prices in his adjustments to NP-15 power prices. Mr. Read obtains natural gas prices from Enron.

Figure 17[91]
SoCal Border Natural Gas Forward Prices
March 1, 2000, April 28, 2000, and May 25, 2001



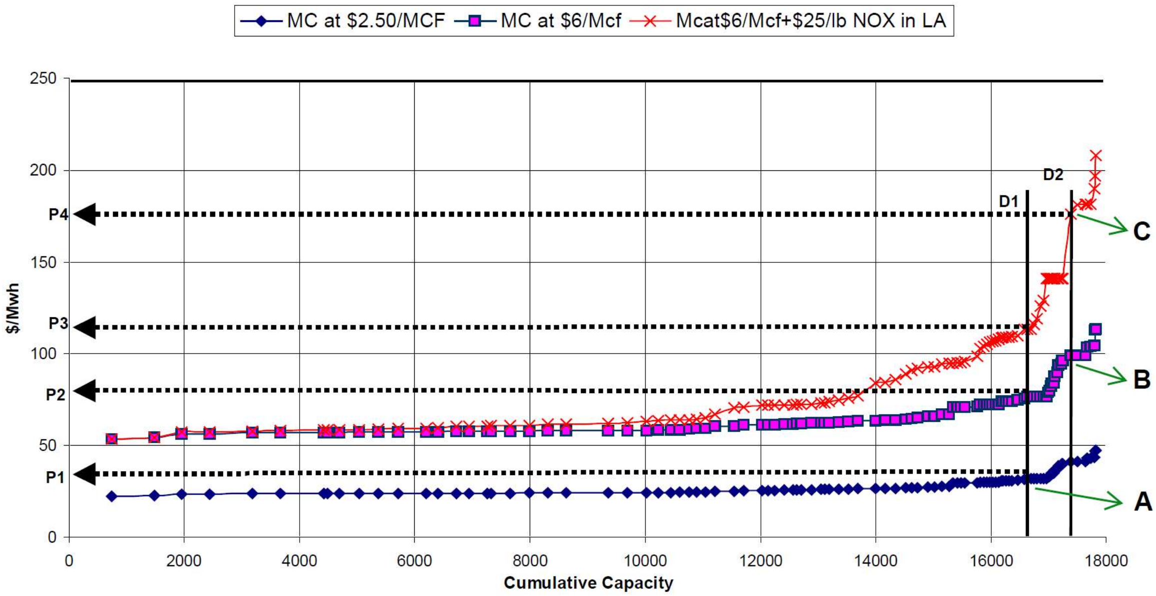
Similarly, **Figure 8** shows that as of April 2000, NOx emissions credit prices for 2001 vintage year were trading at less than $5/lb, while in May 2001 they were trading at more than $25/lb, a more than five-fold increase. This would further increase forward power prices.

It is important to recognize that each of these changes have compounding effects, and Dr. Celebi makes no effort to account for the individual or combined impact of all the factors that changed from March/April 2000 to May 2001. For example,

91 Exh. No. CAL-00987, Read Workpapers. Mr. Read uses SoCal natural gas forward prices in his adjustment to SP-15 power prices. Mr. Read obtains natural gas prices from Enron.

an expected increase in power demand leads to expectations that higher cost generators will set power prices, amplifying the increase in expected power prices due to higher expected fuel and emissions costs. This can be seen in **Figure 18**, reproduced from Joskow (2001). The figure shows three possible market supply curves with varying assumptions regarding fuel and emissions costs as well as two possible demand levels. The blue curve is the supply curve at low natural gas prices and low emissions credit prices. The pink curve shows how the supply curve shifts when gas costs increase, and the red curve shows the additional impact of high emissions credit costs. The increase in demand for thermal generation is represented by the shifting out of demand from D1 to D2. The increase in demand means that less efficient (i.e. higher heat rate) generators will set the market price. When the increase in demand is coupled with an increase in fuel prices from \$2.50/MMBtu to \$6.00/MMBtu, power prices increase from roughly \$30/MWh to roughly \$100/MWh (point A to point B). And when emissions costs rise to \$25/lb, power prices rise to roughly \$175/MWh (point C). This figure illustrates how the changes in market fundamentals significantly raise power prices.

Figure 18[92]
Marginal Cost for Gas Units



Q. Are there any other problems with Dr. Celebi's pre-crisis benchmark?

A. Yes. The pre-crisis forward price series Dr. Celebi relies for this benchmark was constructed by Mr. Read from limited data and, as such, was not an available data series at the time. Rather it represents an imputation and extrapolation process undertaken by Mr. Read that starts with limited data for forward delivery months through the first quarter of 2001 to estimate a forward price series through the year 2005. Thus, Mr. Read's data do not even cover the delivery months of interest (May 2001 to December 2005), and his constructed prices series was not available as of May 25, 2001. Thus, neither the original data nor Mr. Read's constructed price series could or would have been used in negotiations, again contrary to Dr. Fox-Penner's claims that California Parties' analyses are based on information available at the time of contract formation. In other words, Dr. Celebi and Mr. Read do not know what forward prices for delivery in May 2001 and beyond were as of March/April 2000. Rather, they are guessing what prices would have been

[92] Joskow 2001, Figure 3, at p. 380. I have added the indicators for points A, B, and C.

based on average relationships between power prices at various hubs and natural gas prices—assumptions that may or may not be accurate.

B. Dr. Celebi's Post-Crisis Benchmarks

Q. How does Dr. Celebi use data from after the crisis to create his benchmarks?

A. Dr. Celebi's first and second benchmarks directly use forward prices from after the crisis, which he defines as after June 19, 2001, to approximate "competitive" prices as of May 25, 2001. Similarly, Mr. Read's Method 1 uses forward prices from after the crisis to estimate prices as of May 22, 2001 "absent the effect of fraud and manipulation." Method 1 is an alternative version of the inputs to Dr. Celebi's fourth and sixth benchmarks and is used by the California Parties' witnesses to corroborate their results. Dr. Celebi and Mr. Read fail to adjust any of these potential benchmarks for changes in expectations regarding fundamentals between late May 2001 and the various "post-crisis" periods used. Consequently, they attribute all observed price changes to fraud and manipulation, disregarding substantial evidence indicating that expectations of market fundamentals changed significantly during that timeframe.[93]

Mr. Read's Method 2, which is California Parties' witnesses preferred version of the inputs to Dr. Celebi's fourth and sixth benchmarks, relies on MMCPs, which were not developed until after the Shell Contract was executed. The MMCPs used by Mr. Read were set by the Commission on March 26, 2003 to estimate "price[s] that would be paid in a competitive market, in which sellers have the incentive to

[93] Mr. Read's Method 1 adjusts his forward power prices for some changes in gas market forward prices, but he attributes much of the change in gas prices to "gas market dysfunction" and therefore does not allow his forward power prices to be influenced by the gas prices changes he attributes to dysfunction.

bid their marginal costs"[94] Mr. Read thus assumes that the difference between MMCPs and spot market prices provides an estimate of the "premium" in spot market prices associated with spot market fraud and manipulation. Mr. Read then assumes that the spot market "premium" carried over to the forward market according to an exponential decay function such that later delivery months have smaller "premiums" associated with fraud and manipulation However, as I discuss in greater detail in **Section VIII.B**, Mr. Read's "premium" decay rate is based on the unsupported assumption that the only reason forward prices declined for delivery months in 2003 and beyond was the result of "fraud and manipulation" ending, ignoring that changes in market fundamentals can also explain the shape of the forward curve, i.e., expectations that 12,000 MW of new generation capacity would be coming online by 2003 (see **Figure 13**).

Q. Please explain in detail why it is inappropriate to use information from the post-June 20, 2001 period to develop a benchmark for prices on May 22, 2001.

A. Any assessment of the competitiveness of a contract should be based on the market fundamentals as of the time a contract is negotiated and signed. However, California Parties' witnesses use several different pieces of information from post-June 20, 2001, including forward curves and other contracts executed by Shell, in developing their benchmarks.

While the June 19, 2001 FERC Order was a notable step towards ending the Western Energy Crisis, numerous market and policy factors continued to evolve over Spring and Summer 2001, as I describe in **Section II** and below. As I understand the economic arguments made by California Parties' witnesses, they claim that the difference in forward curves between May 22, 2001 and June 21, 2001 reflects the dissipation of fraud and manipulation. While Mr. Read

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[94] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 97 FERC ¶ 61,275, at 62,212 (2001).

acknowledges that other events occurred in that interval that could have affected expectations of future electricity prices, he claims he is left to conjecture on the magnitude of the effects of other market fundamentals: "[s]ince we cannot observe expectations of fundamentals directly, we are left to conjecture."[95] The implication of these conjectures in his subsequent conclusions is that he assumes that the effects of those new market fundamentals would cancel each other out and have a net zero effect on pricing.

However, my analysis identifies five factors, classified as market fundamentals that affect competitive pricing, that changed between the contract negotiation/signing dates and June 21, 2001.[96] Evidence shows that the following expectations about market fundamentals changed between May 22, 2001 and June 21, 2001: changes in demand expectations, supply expectations, emissions costs, CDWR's expected creditworthiness, and the signing of long-term contracts. Economics principles indicate that each change unambiguously reduced the expectations of near-term futures prices of wholesale power. The California Parties' witnesses' benchmark rates do not reflect market fundamentals as of contract negotiation and signing, and instead are significantly lower than what competitive rates were at the time. Thus, attributing all changes in forward prices during this period to the dissipation of fraud and manipulation, as Mr. Read and Dr. Celebi do, is economically flawed.

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[95] Exh. No. CAL-00978, Read Testimony, at 28:9-29:9.

[96] These changes in fundamentals and that these changes were unanticipated at the time are corroborated by multiple other authors. *See e.g.,* Joskow 2001; Exh. No. EPME-1, Kalt Testimony, at 38:6-54:2; Weare, C. "The California Electricity Crisis: Causes and Policy Options," *Public Policy Institute of California*, 2003, at pp. 52-54; Alonso-Zaldivar, R., and N. Vogel "Natural Gas, Power Prices Drop Sharply," *Los Angeles Times,* June 6, 2001, Exh. No. SHE-0069.

Q. Please take us through each of those five factors. What is the first factor that changed between May 22, 2001 and June 21, 2001?

A. The first factor that changed is that the market received new information in late May and early June 2001 that demand in Summer 2001 was likely to be lower than expected, implying that supply conditions were unlikely to be as tight as previously projected. Several elements contributed to an unanticipated softening of market conditions. First, upon approval from the CPUC, PG&E and SCE increased retail rates on average by 19 percent beginning June 1, 2001.[97] These higher rates that PG&E and SCE customers would first see on their bills in June 2001 would have been expected to induce a notable reduction in consumption. For example, research has shown that the rate increases implemented for SDG&E customers in Summer 1999 led to a 6 percent reduction in demand.[98] However, the exact magnitude of the reduction in demand due to the rate hikes would have been uncertain in May 2001. For example, commentary in industry news in April 2001 predicted that "the rate hikes proposed in California [would] reduce demand by another 1,200 MW to 1,300 MW, although some of that reduction may have already occurred in anticipation of the hikes, and there should be more reductions from the huge energy conservation program the state is enacting."[99] Thus, although the retail rate change was previously announced, as market participants saw how consumers reacted to the rate increases after June 1, they would update their expectations on its impact.

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[97] *See* "News Release: CPUC Sets New Electric Rates For PG&E And Edison Customers," *California Public Utilities Commission*, May 15, 2001, pp. 1-2, 5, Exh. No. SHE-0070.

[98] Bushnell, J. B. and E. T. Mansur, "Consumption Under Noisy Price Signals: A Study of Electricity Retail Rate Deregulation in San Diego," *Journal of Industrial Economics*, Volume LIII, No. 4, December 2005, pp. 493-513, at p. 504, Exh. No. SHE-0071.

[99] "Forecaster Says End of Crisis in Sight, Gas Likely to Tumble," *Platts Electric Power Daily*, April 13, 2001, at pp. 1, 4, Exh. No. SHE-0072.

Second, public calls for voluntary reductions in electricity consumption were leading to additional demand reductions above what would be expected from the rate hikes alone. State officials launched an intensive "Flex Your Power" campaign, leveraging media messaging, news coverage, collaborations with major customers, and other public outreach to encourage widespread, voluntary energy conservation.[100] Research suggests that the size of the voluntary reduction was sizeable.[101] Third, unlike Summer 2000 which registered record high temperatures, the weather in Summer 2001 was cooler than expected.[102] This further drove the electricity demand below the expected levels.[103] In June 2001, CAISO load was 8.7 percent lower than in 2000 (8.4 percent lower when adjusting for weather

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[100] "Calif. Controller Argues State Will Need $4B More for Power; Davis Aides Claim She's Wrong," *Platts Electric Power Daily*, May 22, 2001, at pp. 1, 4, Exh. No. SHE-0073; Decker, T., "Californians Cut Energy Use 12.3% From Last Year," *Los Angeles Times*, July 2, 2001, Exh. No. SHE-0074; Batteiger, J., "Energy Crisis / Governments setting their sites on helping with energy savings," *SFGate*, June 3, 2001, Exh. No. SHE-0075; Alonso-Zaldivar, R. and N. Vogel "Natural Gas, Power Prices Drop Sharply," *Los Angeles Times,* June 6, 2001.

[101] Lutzenhiser, L., et al. "Lasting Impressions: Conservation and the 2001 California Energy Crisis." *American Council for an Energy Efficient Economy*, 2004, Exh. No. SHE-0076; Lutzenhiser, L., et al. "Crisis in Paradise: Understanding Household Conservation Response to California's 2001 Energy Crisis" *American Council for an Energy Efficient Economy*, 2002, Exh. No. SHE-0077.

[102] "Calif. Releases Long-Term Power Deals; Davis Aide Calls Them 'Insurance' Against High Prices," *Platts Electric Power Daily*, June 18, 2001, p. 4, Exh. No. SHE-0078 ("Electricity prices wouldn't have fallen without the contracts, Freeman said, adding that recent cool weather and better-than-expected conservation efforts have helped."); "Causes and Lessons of the California Electricity Crisis," *Congressional Budget Office*, September 2001, pp. viii-ix, Exh. No. SHE-0079 ("July 2001: Moderate temperatures help keep the demand for electricity lower than during the previous summer."). That weather turned out to be cooler than expected is also borne out by industry news stating that traders were expecting a hotter than normal summer as of April 2001. *See* "Forecaster Says End of Crisis in Sight, Gas Likely to Tumble," *Platts Electric Power Daily*, April 13, 2001, at pp. 1.

[103] Lazarus, D., "Cooler weather leaving state with surplus of power / SUDDEN GLUT: Turnaround leaves regulators skeptical," *SFGate*, June 9, 2001, Exh. No. SHE-0080.

conditions).[104] However, the impact of conservation efforts and summer temperatures were uncertain as of May 22, 2001. For example, a *Platts* report from May 18, 2001 stated: "[o]fficials with the California Independent System Operator Thursday presented their latest forecast of the June-through-September power supply picture, confirming what many observers expected—the state is likely to be in for a tough summer… The ISO also appears to be worried that utility load curtailment programs will offer little relief over the summer."[105]

The scale of the unexpected demand reductions would have been sufficient to meaningfully reduce prices. Such magnitudes of demand reduction in a time of tight supply will lower prices by shifting the marginal generator, which sets the price, to lower-priced generators. Moreover, academic research shows that forward electricity prices include a premium above the spot market price that varies with the expected spikiness of prices.[106] That is, if spot prices are expected to have high price spikes, the value to load-serving entities of insuring against such spikes by contracting forward at a fixed price is greater and so there will be a larger gap between forward prices and realized spot prices in periods when spot prices are expected to have high price spikes versus periods with relatively constant spot prices. As a result, if the expected likelihood of potential scarcity conditions declines, due to a decline in expected demand, forward prices can go down by

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[104] Additionally, the reduction in demand in June 2001 relative to the same month in 2000 was larger than in previous months. For example, in May 2001, CAISO load was 1.7 percent lower than May 2000 and 4.6 percent lower after adjusting for weather conditions. Joskow 2001, Table 5 at p. 385. *See also* Lutzenhiser, L., et al. "Lasting Impressions: Conservation and the 2001 California Energy Crisis," *American Council for an Energy Efficient Economy,* 2004, at p. 7-232.

[105] "In Latest Forecast, California ISO Predicts State Is Likely To Be In For A Tough Summer," *Platts Electric Power Daily*, May 18, 2001, at pp. 1-2, Exh. No. SHE-0081.

[106] Bessembinder, H. and M. Lemmon, "Equilibrium Pricing and Optimal Hedging in Electricity Forward Markets," *The Journal of Finance,* Vol. 57, No. 3, June 2002, pp. 1347-1382, at p. 1378, Exh. No. SHE-0082.

more than the decline in the expected spot price. These information shocks about demand reductions occurred after the Shell contract was signed, but were likely incorporated into the post-June 21, 2001 information that the California Parties' witnesses rely on. However, California Parties' witnesses make no effort to control for these information shocks in estimating forward prices absent the effect of fraud and manipulation.

Q. What is the second factor that changed between May 22, 2001 and June 21, 2001?

A. The second factor is that CDWR credit risk was substantially higher as of May 2001 than on June 21, 2001. In January 2001, credit rating agencies placed the state on credit watch, with Standard & Poor's placing California's General Obligation and general appropriation-backed debt ratings on "CreditWatch with negative implications."[107]

By April 2001, Standard & Poor's lowered California bond ratings from AA to A+, citing the cost of the crisis and its effect on the economy. Also in April 2001, Fitch placed California's bonds on "Rating Watch Negative," citing potential delays in the issuance of the bonds, and Moody's changed its outlook on California's Aa2 bonds from stable to negative, again citing the crisis. In May 2001, Moody's downgraded California's bonds from Aa2 to Aa3. These downgrades and credit watch notices underscored the credit risks associated with contracting with CDWR during the contract negotiation period. These events were particularly important because CDWR's power purchases were to be financed by the issuance of state-backed bonds. Thus, the lower California's credit rating, the

[107] "History of California's General Obligation (GO) Credit Ratings", *California State Treasurer*, Exh. No. SHE-0084.

higher the cost of borrowing and the greater the chance that buyers would not purchase them and CDWR would run out of funding.

Both Shell and CDWR clearly recognized the credit risks. Shell and CDWR negotiated intensely over whether to include a provision that would cancel the contract if CDWR was unable to issue bonds to finance its purchases and if such a provision was not included, the impact on the contract pricing.[108] In particular, if CDWR did not obtain financing, there was a chance it would not be able to make the payments under the contract as it would otherwise have to rely on State funds, and thus Shell would be exposed to the risk that it would deliver power for which it would not be paid.[109]

However, these credit concerns had begun to ease by June 21, 2001. Specifically, on June 18, 2001, Governor Gray Davis issued Executive Order D-42-01, which authorized CDWR to "accept loans and utilize the proceeds to purchase electric power and natural gas to generate electric power to mitigate the effects of the emergency, and to pay costs related thereto."[110] D-42-01 allowed CDWR to enter into a bridge loan, which was closed on June 26, 2001, to provide financing until a long-term bond offering could be issued.[111] Prior to Executive Order D-42-01, the state's ability to obtain a bridge loan was not certain as it had been threatened

[108] Exh. No. SNA-219, Supplemental Answering Testimony of Edward Brown on Behalf of Shell Energy North America (US), L.P., Docket Nos. EL02-60-007, EL02-62-006, at 21:23-23:13.

[109] *See, e.g.,* Bustillo, M. and J. Tamaki, "Effort to Repay State for Power Is Delayed," May 8, 2001, Exh. No. SHE-0085.

[110] State of California Executive Department, Executive Order D-42-01, June 18, 2001, at p. 1, Exh. No. SHE-0086.

[111] "State Closes on $4.3-Billion Interim Loan to Buy Power," *Los Angeles Times*, June 27, 2001, Exh. No. SHE-0087.

by California Republicans.[112] This was particularly significant because many contracts allowed sellers to cancel their contracts if the CDWR did not obtain financing by July.[113] The increased certainty of the bridge loan had two interrelated effects that contributed to a decline in expected long-term power prices following the June 18, 2001 Executive Order. First, the improved likelihood of the bridge loan being issued reduced the risk premium embedded in any competitive contract price. Second, this benefit was amplified by the market's expectation that the enhanced creditworthiness would ensure existing long-term contracts were not canceled, facilitate additional long-term contracting, and ensure the state reduced its reliance on the spot market.[114] As I discuss below, transitioning from a procurement process dominated by spot market transactions to one that incorporates substantial long-term contracting will reduce electricity prices.

Q. What is the third factor that changed between May 22, 2001 and June 21, 2001?

A. The third factor is that Dr. Celebi's benchmarks systematically underestimate the costs of NOx emissions credits and fail to account for the corresponding impact of changes in those costs on competitive power prices, as informed by market fundamentals at the time that the contract was negotiated and signed. As shown in **Figure 8**, the average transaction prices for 2001 vintage of NOx emissions credits were \$38.4/lb in March 2001, \$36.5/lb in April 2001, and \$26.1/lb in May 2001. These prices represent the market consensus on the price of NOx emissions for calendar year 2001, and as such represent the price market participants would

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[112] *See, e.g.,* Bustillo, M., "GOP Tries to Force Its Dramatically Different Energy Plan on Governor," *Los Angeles Times,* May 4, 2001, Exh. No. SHE-0088; Bustillo, M. and J. Tamaki, "Effort to Repay State for Power Is Delayed," May 8, 2001.

[113] "Revenue Requirement & Consultant's Report Briefing to the Staff of CEC and CPUC on DWR Energy Procurement Program," Navigant, May 18, 2001, at pp. 23, 25.

[114] Bustillo, M. and J. Tamaki, "Effort to Repay State for Power Is Delayed," May 8, 2001.

expect to pay both now and through March 2002[115] for NOx emissions credits (if prices for 2001 vintage credits were expected to be lower in the future, participants would simply wait to buy them). High emissions credit prices persisted throughout the Spring of 2001, despite legislative attempts to reduce costs by allowing generators to pay a reduced price ($7.50/lb) but still deducting such emissions from future credit allocations to maintain environmental neutrality.[116] This approach proved ineffective because, under this framework, emitting one pound of NOx in Spring 2001 still incurred the opportunity cost of the future expected credit price, as the generator would forfeit a future credit. Thus, generators continued to trade credits at prices higher than $7.50/lb instead of using future allocations as they were concerned that they "will end up paying mitigation fees year after year, never being able to catch up."[117]

However, this economic design flaw was addressed by a June 11, 2001 Executive Order that allowed generators to pay the $7.50/lb mitigation fees *without* losing valuable future emissions allowances or facing any other penalties.[118] This June action reduced the marginal cost of electricity generation for impacted generators which Mr. Read acknowledges stating it "could have had a material effect on the market prices" of credits and "that may in turn have reduced the costs of running

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[115] NOx emissions credits for vintage 2001 were traded until March 2002.

[116] State of California Executive Department, Executive Order D-24-01, February 8, 2001, Exh. No. SHE-0089; "SCAQMD Suspends RECLAIM Rules on NOx Credit Requirements," *Platts Utility Environment Report*, February 23, 2001 Exh. No. SHE-0090; "Annual RECLAIM Audit Report for 2001 Compliance Year," *SCAQMD*, March 7, 2003, at p. 3-7, 3-8, Exh. No. SHE-0091.

[117] *See* "Power Plants Dropped from Southern California NOx Emissions Trading Program," *Platts Utility Environment Report*, May 18, 2001, Exh. No. SHE-0092.

[118] State of California Executive Department, Executive Order D-40-01, June 11, 2001, Exh. No. SHE-0093; *See also* "Davis Issues Order Waiving Emission-Related Operating Limits on Calif.'s Gas-Fired Capacity," *Platts Electric Power Daily*, June 12, 2001, at p. 1, Exh. No. SHE-0094.

some generating units."[119] Dr. Celebi's benchmarks based on post-June 20, 2001 information ignore this change in market fundamentals.

Q. What is the fourth factor that changed between May 22, 2001 and June 21, 2001?

A. The fourth factor is changes in expectations of future natural gas prices. In particular, as of May 22, 2001, near-term forward gas prices were higher than the prices used in the benchmarks presented by Dr. Celebi. As shown in **Figure 10** and Figure **11**, the May 22, 2001 natural gas forward market price curves for PG&E Citygate and SoCal Border were considerably higher, especially for near-term delivery months, than the same curves on June 21, 2001.[120] Moreover, it is evident from June 18, 2001 natural gas forward market price curves in the same exhibits that much of the change in natural gas forward market price curves over this period occurred prior to the June 19, 2001 FERC Order. The California Parties' witnesses argue that one should not use the information available at the time—i.e., gas forwards prices as of May 2001—but rather should use market expectations of gas prices as of a later date or alternative gas prices due to later findings of manipulation of gas markets. However, this is misguided because competitive prices can only reflect the information available to the buyers and sellers at the time of contract negotiation.

Q. What is the fifth factor that changed between May 22, 2001 and June 21, 2001?

A. According to economic theory, the signing of long-term contracts reduces spot market prices and thus forward prices as well. The Shell Contract was signed as

[119] Exh. No. CAL-00978, Read Testimony, at 28:14-29:1.

[120] Mr. Read uses PG&E gas forward prices for NP-15, and SoCal gas forward prices for SP-15.

CDWR was entering into multiple long-term contracts, which the economics literature suggests will cause both spot and forward prices to fall, including the June 2001 forward curves. Relative to a setting with no or little forward contracts, the signing of forward contracts causes both spot and forward prices to fall in markets. This phenomenon is supported both by economic theory and empirical studies of wholesale electricity markets.[121] In fact, this phenomenon is cited as a reason that California spot prices were so high in 2000, when forward contracting was very limited[122] and CDWR's signing of numerous long-term contracts in Spring 2001 has been cited as a reason that prices fell in June 2001.For example, on June 15, 2001, a spokesman for the CA governor stated: "These contracts are in large part responsible for the recent sharp drop in electricity prices."[123]

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[121] *See, e.g.*, Allaz, B., and JL. Vila, "Cournot Competition, Forward Markets and Efficiency," *Journal of Economic Theory*, Volume 59, February 1993, pp. 1-16, Exh. No. SHE-0095; Bushnell, J. B., et al., "Vertical Arrangements, Market Structure, and Competition: An Analysis of U.S. Electricity Markets," *American Economic Review,* Vol. 98, No. 1, March 2008, pp. 237-266, Exh. No. SHE-0096; Borenstein, S., "The Trouble With Electricity Markets: Understanding California's Restructuring Disaster," *Journal of Economic Perspectives*, Volume 16, Number 1, 2002, pp. 191-211, Exh. No. SHE-0097; Anderson, E. J. *et al*., "Forward Contracts in Electricity Markets: The Australian Experience," *Energy Policy*, Volume 35, Issue 5, May 2007, pp. 3089–3103 ("The retailers were asked whether they agreed with the statement: contract prices are higher than the average spot price, but if contracts were not signed then spot prices would rise. All but one of the retailers answered ''yes''. One retailer stated: ''Sometimes you will get a new board member [argue that] our average contract rate last year was $40 and the average spot was only $27 why didn't we just take the spot? And we say yes, but it wouldn't be $27 if we weren't contracted.").

[122] *See, e.g.,* December 15, 2000 Order at 61,993; Weare, C. "The California Electricity Crisis: Causes and Policy Options," *Public Policy Institute of California*, 2003, at p. 38-39.

[123] "California PUC Approves Provisions SoCal Ed Needs To Implement Its Agreement With State," *Platts Electric Power Daily*, June 15, 2001, at pp. 1, 5, Exh. No. SHE-0099. *See also* "Calif. Releases Long-Term Power Deals; Davis Aide Calls Them 'Insurance' Against High Prices," *Platts Electric Power Daily*, June 18, 2001, at pp. 1, 4, Exh. No. SHE-0100.

Similarly, FERC stated in its June 19, 2001 order that "the actions of the State of California in moving to longer-term contracts and conservation efforts have had a significant dampening effect on prices."[124] Thus, using prices formed after the Shell Contract and other long-term contracts were signed[125] understates the competitive price prior to the signing of the Shell Contract when it was uncertain whether the Shell Contract and other contracts would be signed.[126] In fact, the Commission has previously dismissed the California Parties' attempt to use price data from September 2001 as a benchmark, in part because it reflects the price-reducing benefits of having signed the Shell Contract.[127]

Q. You have identified five changes in market fundamentals that would have lowered expectations for near-term spot power prices between May 22, 2001 and June 21, 2001. What is the implication of these factors on the conclusions from the California Parties' witnesses?

A. As I mention above, the conclusions formed by Mr. Read and Drs. Celebi and Fox-Penner effectively assume these changes in fundamentals have zero net impact, because their benchmarks attribute all changes to eliminating fraud and manipulation rather than separating how much was driven by changes in fundamentals. It is important to emphasize that the changes in each of these five factors independently reduces prices *and* their combined impact further contributes to a significant reduction in prices based on the fundamental economics of

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[124] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 95 FERC ¶ 61,418, at 62,546 (2001).

[125] *See* Exh. No. CAL-50, showing that the Calpine San Jose and PG&E Energy Trading contracts were signed after the Shell Contract and before June 20, 2001.

[126] "Calif. Controller Argues State Will Need $4B More for Power; Davis Aides Claim She's Wrong," *Platts Electric Power Daily*, May 22, 2001, at pp. 1, 4, Exh. No. SHE-0101 ("If various tentative agreements are reached, 47% of May is under long-term contract, 73% of June, 67% of July and 60% of August, he said.").

[127] Opinion No. 587 at PP 300-02.

electricity markets. As illustrated above in **Figure 18**, a decrease in power demand amplifies the reduction in power prices caused by lower fuel prices and reduced emissions costs. As a result, the California Parties benchmarks that are based on post-crisis forward prices underestimate the competitive price in late May 2001. Absent a quantification of the combined impacts of changes in these market fundamentals, reliance on their findings to establish credible benchmarks is deeply flawed and unreliable.

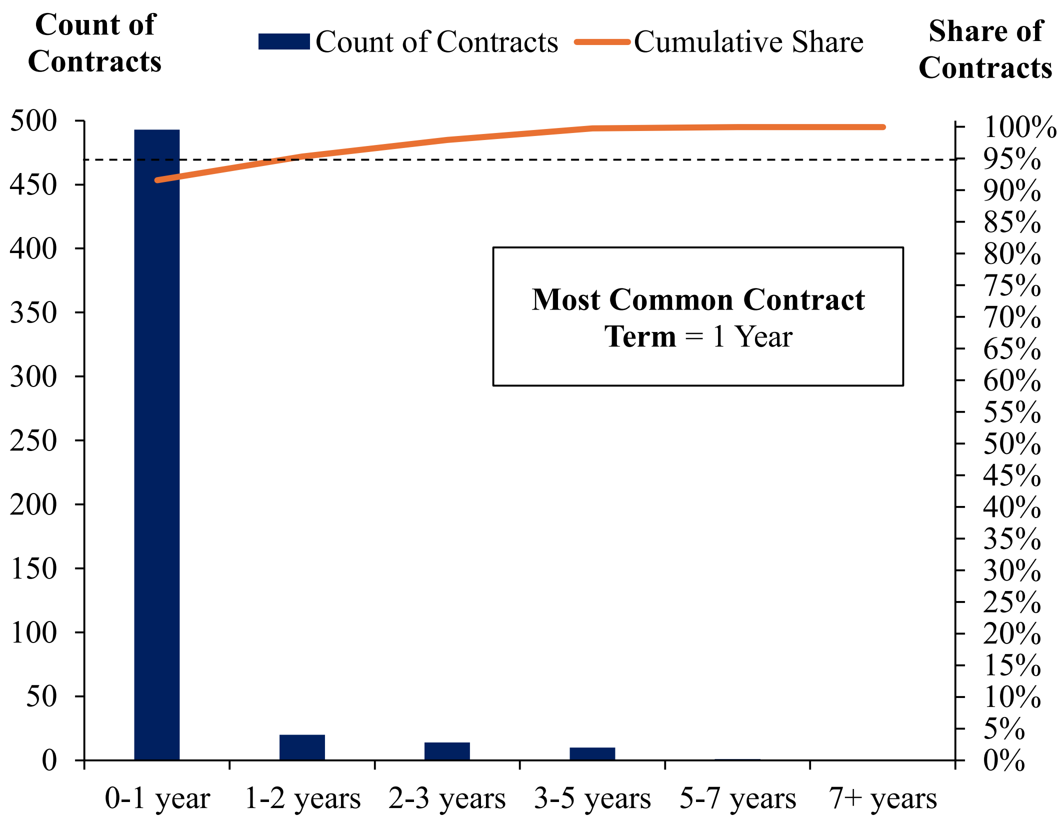
VII. THE FORWARD PRICES USED BY MR. READ AND DR. CELEBI ARE NOT APPROPRIATE BENCHMARKS FOR CDWR'S LONG-TERM BILATERAL CONTRACT PRICES

A. The Data Dr. Celebi and Mr. Read Rely Upon for Forward Prices Are Not a Reliable Source for Benchmarking the Price of the Shell Contract

Q. Please describe the data that Dr. Celebi and Mr. Read use to develop Dr. Celebi's forward price-based benchmarks.

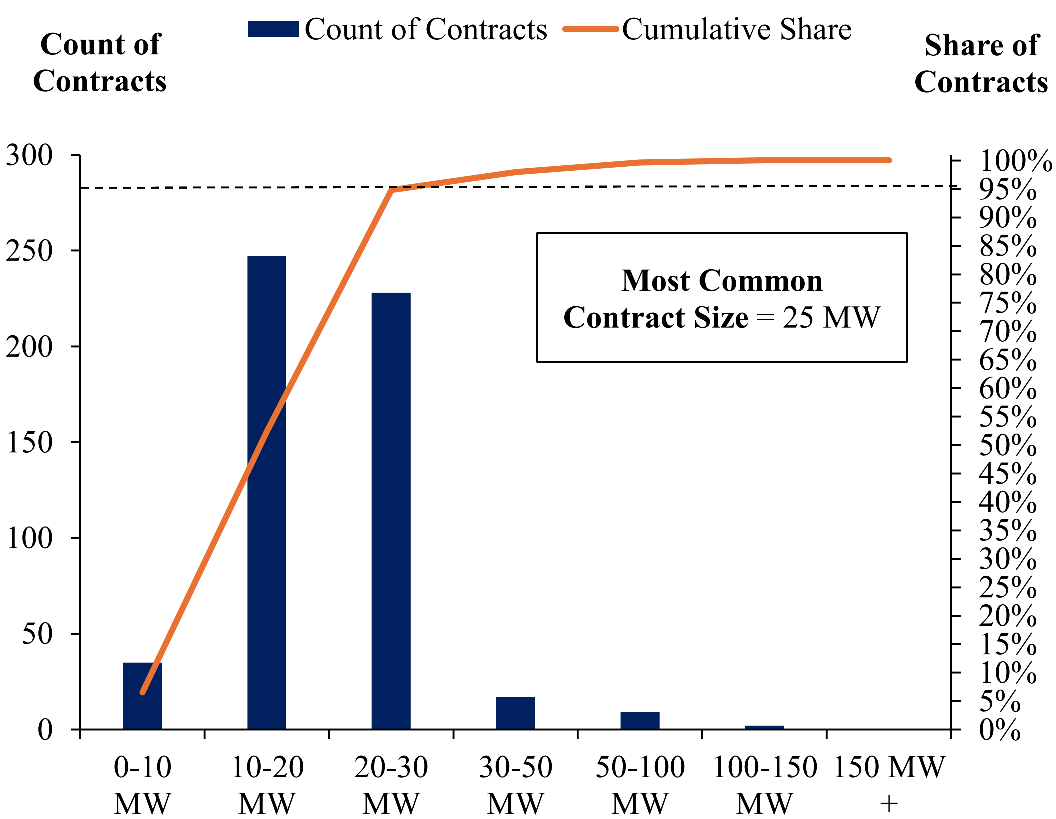
A. Dr. Celebi's first benchmark is based on the prices of 538 forward contracts with a term of one year or longer executed by Shell between June 20, 2001 and December 31, 2002 for on-peak power delivered to NP-15 and SP-15. As I show in **Figure 19** and **Figure 20**, 95 percent of these contracts were for two years or less and for 30 MW per hour or less, where the Shell Contract extended eleven years and delivered between 100 MW and 850 MW each hour.

Figure 19[128]
Contract Length
Dr. Celebi's Sample of Post-Crisis Long Term Shell Contracts



[128] Exh. No. CAL-00973, Celebi Testimony at pp. 17:14-18:3; CAL-00977_Other LTKs.txt.

Figure 20[129]
Delivery Volume
Dr. Celebi's Sample of Post-Crisis Long Term Shell Contracts



Mr. Read also prepares pre- and post-crisis forward prices as well as forward prices "absent the impact of fraud and manipulation" for Dr. Celebi to use in developing his other forward price-based benchmarks based on "daily fax sheets" from two voice brokers (Natsource and TFS) that provide purported price quotes (or "indicative prices" as Mr. Read calls them) for forward power deliveries at NP-15 and SP-15. As explained by Dr. Celebi: "[t]he forward prices reported by these brokers represent the brokers' assessment of where the market was at the end of

[129] Exh. No. CAL-00973, Celebi Testimony, at pp. 17:14-18:3; CAL-00977_Other LTKs.txt. I estimate the hourly contract volume by dividing the total delivered volume by the estimated number of on-peak hours during the term of the contract.

each trading day based on their discussions with market participants about potential or actual transactions and other information they deemed relevant."[130] The fax sheets relied upon by Mr. Read and Dr. Celebi provide daily price quotes for monthly, quarterly, and/or annual contracts. They do not provide price quotes for 11-year contracts (like the Shell Contract).

Q. Please summarize why the data that Mr. Read and Dr. Celebi are using are not a reliable source for benchmarking the price of the Shell Contract.

A. Mr. Read explains his use of the Natsource/TFS forward price data by claiming that "long-term contracts like the Shell/CDWR Contract can be represented as combinations of simpler contracts that are actively traded in the market."[131] In other words, his analysis begins with the premise that CDWR could have replaced the Shell Contract with a series of small, short-term forward contracts. However, the forward prices Mr. Read and Dr. Celebi rely upon have a number of shortcomings, resulting in an apples-to-oranges comparison that does not withstand careful scrutiny. First, the short-term forward price quotes used by Mr. Read differ from the Shell Contract across various dimensions, particularly with respect to credit risks, the duration of the contract, and the quantity associated with the quotes. Second, the quotes are simply indicative prices and do not reflect actual transaction prices from the period. Given Dr. Celebi's description of the process by which the prices were developed, as quoted above, there may not have even been a trader willing to transact at the quoted price. Third, Dr. Morris explains in his testimony that these small, relatively short-term forward contract transactions should be considered a different product than long-term contracts. In particular, he notes that large long-term contract prices reflect the seller's total long-term costs—

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[130] Exh. No. CAL-00973, Celebi Testimony, at 20:8-21:2. *See also* Exh. No. CAL-00978, Read Testimony at 12:5-7 ("Indicative prices were the broker's assessment of market prices, based on their conversations with market participants and on other information.").

[131] Exh. No. CAL-00978, Read Testimony, at 4:16-5:1-2.

for instance, the total cost of new generation capacity adjusted for the scarcity or surplus in the market at the time the contract was signed.

Q. What is the difference between Mr. Read's forward price quotes and the Shell Contract with respect to credit risk?

A. The forward prices that Mr. Read relies upon differ from those one might expect in energy markets today. In particular, the price quotes Mr. Read relies upon were not for standardized financial futures products, traded in a transparent liquid market, settled at the spot price of power, and cleared by a centralized clearing house with credit and collateral requirements. Rather, as I understand from Mr. Hunter, those quotes were for physically-delivered products traded bilaterally in a non-transparent marketplace between market participants with varying credit and provide no indication of available liquidity at the quoted prices. Actual offer prices for long-term bilateral contracts are specific to counterparty credit risk, which is not captured in Mr. Read's use of these quoted forward prices. Because Mr. Read's prices are based on price quotes from voice brokers and do not reflect actual trades or even transactable prices for the product offered in the Shell Contract, Mr. Read does not know how the quoted prices would vary with respect to the counterparty's credit (i.e. whether would they be higher given concerns about CDWR's creditworthiness) or if the traders willing to transact at the specified price had sufficient credit or expertise to transact with CDWR in the volumes specified by the Shell Contract.

Q. Would CDWR have been able to obtain the volume specified in the Shell Contract at the price quotes Mr. Read relies upon?

A. The fax sheets Mr. Read relies upon do not specify the volumes available at the quoted prices, and Mr. Read simply does not know if it would have been possible to purchase the volumes specified in the Shell Contract in May 2001 through a voice broker.[132] In particular, as I understand from Mr. Hunter, there was no guarantee of executing transactions at the prices specified in the fax sheets, particularly for the large volumes specified in the Shell Contract, due to credit constraints and the potential variations in price induced by larger volumes and the relative bargaining power of the parties.[133] Indeed, the typical volume for forward contracts at the time was 25 MW per hour.[134] By comparison the Shell Contract specified 100 MW to 850 MW be delivered each hour between 2001 and 2012.[135] The parties indicating they would trade at the prices quoted by Natsource/TFS may have had limited electricity to sell. Thus, a price quote to sell a small number of MWs may be far lower than the price the seller would quote if that same seller

[132] This may have been particularly true for contracts with maturities beyond 15 months where liquidity is often even lower than for near-dated contracts, as evidenced by the price quotes in the Natsource fax sheets only being available for quarterly or annual strips for maturities beyond approximately 15 months. *See* Exh. No. CAL-00978, Read Testimony, at Figure 1. *See also* Deng, S.J. and S.S. Oren, "Electricity derivatives and risk management," *Energy*, 2006, at p. 943, Exh. No. SHE-0102.

[133] Similar issues were noted by traders in Australia in 2006 with respect to published forward curves based on market participants' opinions: "The Australian Financial Markets Association (AFMA) publishes electricity forward curves based on a poll of NEM participants' opinions and brokers may provide additional price analyses as well. In addition, the SFE's bid/ask spread provides price guidance. However, some participants indicated that the AFMA forward curve can be misleading, and price discovery either through the SFE or through offers appearing on brokers screens, is problematic, partly because the market is illiquid in the longer term." *See* Anderson, E. J. *et al*., "Forward Contracts in Electricity Markets: The Australian Experience," *Energy Policy*, Volume 35, Issue 5, May 2007, pp. 3089–3103, at p. 3098.

[134] *See* **Figure 20** above, showing that the most common contract size for the forward contracts Dr. Celebi uses in his first benchmark was 25 MW. *See also* Deng, S.J. and S.S. Oren, "Electricity derivatives and risk management," *Energy*, 2006, at p. 944.

[135] Exh. No. CAL-31, at pp. 13-15.

were asked to sell hundreds of MWs (as in the Shell Contract),[136] and the seller may not have even had the capacity or ability to deliver such a quantity.

Q. Dr. Celebi's first benchmark, based on actual transaction prices for forward contracts gives similar results to his benchmarks based on Mr. Read's forward price quotes. Doesn't this show that the broker fax sheets do in fact provide reliable data?

A. No. Dr. Celebi's first benchmark, based on forward contracts executed by Shell confirms that the volumes for such transactions were small (95 percent were 30 MW per hour or less) and the durations rarely exceeded two years, as shown in **Figure 19** and **Figure 20**. Moreover, Dr. Celebi's only contract longer than five years is actually an intercompany transaction. Thus, these data confirm that the product on offer through the fax sheets was not equivalent to what CDWR procured through the Shell Contract. Moreover, examining the distribution of the number of years between the trade date and delivery start date for the contracts in Dr. Celebi's sample in **Figure 21** shows how dramatically trading volume diminishes for delivery dates far in advance of the trade date. In other words, these data are consistent with there being limited trading opportunities for contracts with delivery dates far into the future, implying that Mr. Read's fax sheet prices are especially likely to underestimate the cost of purchasing 850 MW for delivery dates more than two or three years in advance.

Additionally, the sample used in Dr. Celebi's first benchmark averages across transactions executed as late as December 2002, more than 18 months after the

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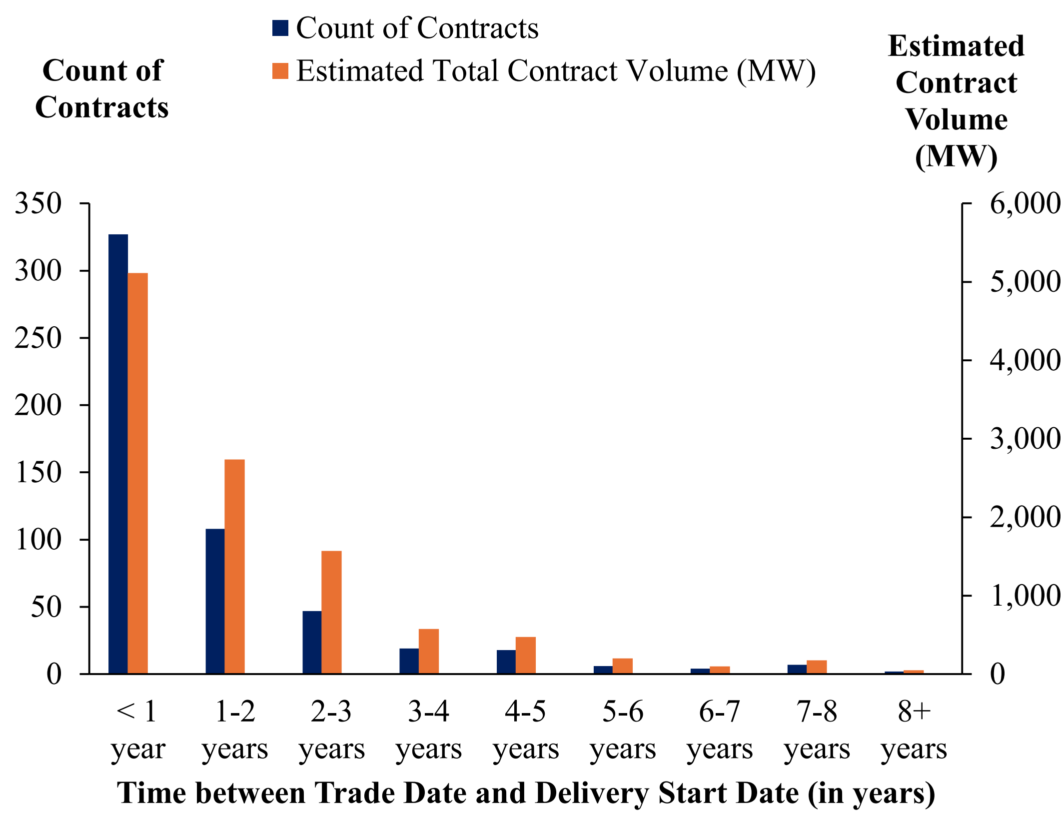
[136] *See, e.g.,* Anderson, E. J. *et al*., "Forward Contracts in Electricity Markets: The Australian Experience," *Energy Policy*, Volume 35, Issue 5, May 2007, pp. 3089–3103, at p. 3098 ("Even if a lower price is available for, say a 10MW contract through a broker, if the retailer keeps going back to the brokers' screens for trades, then the price will rise after the first few deals as generators respond to the increased demand for this particular product.").

Shell Contract was signed, with no effort to control for changes in fundamentals during this period.

Figure 21[137]
Time between Trade Date and Delivery Start Date
Dr. Celebi's Sample of Post-Crisis Long Term Shell Contracts



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137 Exh. No. CAL-00973, Celebi Testimony, at pp. 17:14-18:3; CAL-00977_Other LTKs.txt. I plot the distribution of Dr. Celebi's 538 benchmark contracts based on the time between the contract's trade date and delivery start date. I estimate the hourly contract volume for these benchmark contracts by dividing the total delivered volume by the estimated number of on-peak hours during the term of the contract.

Q. Did CDWR use voice brokers to procure forward contracts as part of its procurement process?

A. No. CDWR used a structured competitive process to solicit offers and enter into such contracts. Executing a large number of small transactions for an 11-year period through voice brokers, if it was even possible, was not an efficient method to enter into long-term supply arrangements, as demonstrated by the fact that it did not enter into such arrangements.[138]

Additionally comparing the Shell Contract price for 2001-2005 against Mr. Read's forward prices as of May 22, 2001 shows that supply procured through forward contracts was not a feasible substitute for the energy and capacity supplied by the Shell Contract. Specifically, I use Dr. Celebi's procedure to weight Mr. Read's forward price series as of May 22, 2001[139] according to the quantities delivered under the Shell Contract to compute the weighted average forward price, as of May 22, 2001, of procuring the quantities specified in the Shell Contract relative to the weighted average Shell Contract price for May 2001 through December 2005. This analysis shows that if Mr. Read and Dr. Celebi were correct that CDWR could easily have replaced the Shell Contract with a series of forward contracts at the prices in the fax sheet on May 22, 2001, then the price of doing so would have been \$61.72/MWh, which is \$54.55/MWh lower (or nearly 50 percent lower) than

[138] Exh. No. CAL-865, Table 10.

[139] The price series used is based on the raw Natsource fax sheet prices for delivery dates from June 2001 to December 2005 and does not reflect Mr. Read's shaping procedure to create variations in monthly prices from quarterly and annual prices or any of his adjustments to "remove" the impact of fraud and manipulation. As forward market prices for delivery dates between May 25, 2001 and May 31, 2001 were not available for the trade date of May 22, 2001 in Mr. Read's data, I use an average of actual spot prices for delivery dates in May 2001.

the weighted average Shell Contract price in that period ($116.27/MWh).[140] That CDWR did not do this, despite being aware of forward prices at the time (per the California Parties[141]) and this substantial difference in price, shows that these types of forward contracts were not feasible replacements for the energy and capacity procured through the Shell Contract and/or that the prices in the fax sheets are not reliable estimates of the price for such a large transaction. This comparison also shows that, of the $64.52/MWh difference between the California Parties' witnesses' preferred benchmark and the Shell Contract price for 2001 to 2005, only $9.97/MW is due to "removing" the impact of fraud and manipulation.[142] The remaining $54.55/MWh is due to using a different, non-comparable product.

Moreover, CDWR expressly did not rely on forward prices available at the time in determining the prices at which it was willing to contract nor contemplate entering into a series of short-term forward contracts.[143] Instead, CDWR set a benchmark for its power purchases at the all-in price of power reflected in retail rates at the time, $70/MWh,[144] which included remuneration for variable costs as well as fixed and capital costs and would thus have been expected to be sufficient to compensate generators for the cost of constructing new capacity.

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[140] CAL-00977_Post-Crisis.txt, Celebi Workpapers. CAL-216, Invoice Data. Exh. No. CAL-00973, Celebi Testimony, 25:9-18. To calculate the weighted average forward price as of May 22, 2001, first, I multiplied monthly delivery volumes for each product and location by the corresponding forward prices. Next, I divided the total monthly revenue calculated in the previous step by the month's total delivered MWhs to derive a volume-weighted average $/MWh for each month from May 2001 to December 2005.

[141] Opinion No. 587 at PP 68, 94.

[142] Exh. No. CAL-00973, Celebi Testimony, at 48, Figure 11.

[143] Opinion No. 587 at PP 90, 94.

[144] *Pub. Utils. Comm'n v. Sellers of Long-Term Contracts*, 155 FERC ¶ 63,004, at P 176 (2016).

B. The Price for the Shell Contract Would be Expected to Exceed Mr. Read's and Dr. Celebi's Forward Prices

Q. Why would the price for the Shell Contract be expected to exceed Mr. Read's and Dr. Celebi's forward prices?

A. First, as discussed above, Mr. Read's and Dr. Celebi's forward prices do not reflect the fact that for large quantities of power, as in the Shell Contract, prices necessarily will be higher than the prices for the small quantity forward contracts used by Mr. Read and Dr. Celebi. Higher quantities of power require the production of less efficient, more expensive generators. The forward price quotes cited by Mr. Read and Dr. Celebi contain no information about how much higher the cost would be for larger quantities.

Moreover, Mr. Read's and Dr. Celebi's forward prices do not incorporate the value of the generation capacity included in the Shell Contract during a period with an expected shortage of capacity or the risks involved in contracting over a longtime horizon with a counterparty posing substantial credit risk.

Q. Why are there differences in the capacity value incorporated into the Shell Contract price relative to Mr. Read's and Dr. Celebi's forward prices?

A. The Shell Contract price reflects beliefs about market fundamentals at the time of contract negotiation and execution in March-May 2001. Importantly, as I discuss in **Section II.B**, as of May 22, 2001, capacity shortages were expected and thus the value of capacity would have been reflected to some degree in Mr. Read's original May 22, 2001 forward prices.[145] By contrast, his *pre-crisis* price series (used for Dr. Celebi's third benchmark) is from a period where the magnitude and potential implications of capacity shortages were not anticipated while his *post-*

[145] Price caps were in place at the time in the spot markets that may have limited the ability of spot and short-term forward contracts to reflect capacity value. *See San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.,* 95 FERC ¶ 61,115, at 61,353 (2001).

crisis price series (used for Dr. Celebi's second benchmark) is from a period where the expectations of shortages had diminished.[146] Thus, each of these price series is designed to exclude the value of capacity as of May 22, 2001. Moreover, Mr. Read's estimates of forward prices absent the impact of fraud and manipulation (used for Dr. Celebi's fourth and sixth benchmarks) are "corrected" by either basing forward prices on the post-crisis period, which again excludes the value of capacity, or by removing from May 22, 2001 forward prices a "premium" he estimates using a conservative measure of short-run marginal cost (i.e., MMCPs), which excludes capacity value by construction. In other words, much of Mr. Read's "premium" is the value of capacity at the time, and thus Dr. Celebi's fourth and sixth benchmarks also exclude the value of capacity; contradicting Dr. Fox-Penner's claim that these benchmarks "build[] in the pricing issues such as fuel availability and generation scarcity."[147]

Notably, the Shell Contract provided a large quantity (up to 850 MW in peak periods) of firm capacity that came to be counted as a capacity resource, equivalent to a generator of the same size, by the state of California when it developed its resource adequacy framework.[148] Even if it was not specifically backed by a new 850 MW generation plant, the price of the Shell Contract would have to be high enough for Shell to be able to cover the cost of building generation or contracting with generators (who may evaluate whether to contract with Shell based on their LRMC) to supply the contract, as well as the risks associated with (1) compiling

[146] Price caps were also tightened in this period by the June 19, 2001 FERC Order reducing the ability of spot and short-term forward prices to reflect any lingering shortage concerns. *See San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 95 FERC ¶ 61,418, at 62,546-47 (2001).

[147] Exh. No. CAL-00988, Fox-Penner Testimony, at 18:5-19:1.

[148] *See* Interim Opinion on Procurement Issues: DWR Contract Allocation, CPUC, September 19, 2002, at Table 1, SHE-0012; Pacific Gas and Electric Company's 2006 Long-Term Procurement Plan, March 19, 2008, at p. 71, Exh. No. SHE-0104.

the needed power to serve the contract in a time of expected capacity shortage and (2) contracting with CDWR.[149]

Q. Please explain why there are differences with respect to counterparty credit risk for the Shell Contract versus Dr. Celebi and Mr. Read's forward prices.

A. In determining its long-term forward contract bid in the CDWR procurement process, Shell faced risks related to the creditworthiness of CDWR. That is, there was broad concern among sellers in Spring 2001 that CDWR would have insufficient revenue to honor payments under its contracts.[150] As described above in **Section VI.B**, in April 2001, Standard & Poor's, Fitch, and Moody's all downgraded California bond ratings. The difficulties that CDWR faced related to the delays in intended state bond issuance and securing interim financing made sellers wary of contracting with the agency, which increased sellers' bids in CDWR's procurement process. This also led forward market prices more generally to be elevated at the time as many contracts allowed sellers to cancel their contracts if the CDWR did not obtain financing by July. However, Mr. Read

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[149] As explained in Wolak (2021), the seller of a fixed price forward contract "bears all the risk associated with higher spot prices at that location. To prudently hedge this risk, the seller has a very strong incentive to ensure that sufficient generation capacity is available to set the lowest possible price in the short-term market at that location in the network for the quantity of energy sold in the fixed-price forward contract. This logic implies that if a generation unit owner signs a forward contract guaranteeing the price for 500 MWh of energy for 24 hours a day and seven days per week at a specific location in the network, it will construct or contract for more than 500 MW of generation capacity to hedge short-term price risk. Building only a 500 MW facility to hedge this risk would be extremely imprudent and expose the producer to significant risk, because if this 500 MW facility is unavailable to provide electricity, the producer must purchase the energy from the short-term market at the price that prevails at the time. Moreover, if this generation unit is unavailable, then the short-term price is likely to be extremely high." *See* Wolak, F. A., "Wholesale electricity market design," *Handbook on Electricity Markets*, 2021, pp. 73-97, at pp. 96-97.

[150] "Dynegy Continues to Withhold Power from ISO in Dispute over 'Reasonableness' of Calif. Prices," Platts Electric Power Daily, April 17, 2001, p. 1, 5, Exh. No. SHE-0105.

and Dr. Celebi's benchmarks remove this effect by using prices from other periods and products. Moreover, such risk would have been more attenuated for small, shorter-term contracts that did not involve transacting with CDWR, and thus I would expect such prices to be somewhat lower than the price of a long-term bilateral contract with CDWR.

Q. Is there other evidence that Dr. Celebi's forward-market price benchmarks exclude the value CDWR ascribed to firm capacity procurement and the risks faced by sellers?

A. Yes. Looking instead at actual forward contract prices for comparable bilateral contracts to which CDWR agreed at the time, as renegotiated—a benchmark the California Parties' witnesses ignored—shows that such prices are higher than Dr. Celebi's corrected forward price benchmarks. Specifically, Mr. Cavicchi shows that Dr. Celebi's fourth benchmark, which forms the first segment of his sixth benchmark, was considerably lower than the realized prices of comparable one- to five-year contracts that CDWR signed. Further, Mr. Cavicchi shows that Dr. Celebi's sixth benchmark was considerably lower than the realized prices of comparable eight- to eleven-year contracts that CDWR signed. In other words, Dr. Celebi has calculated benchmarks based on prices that are not applicable to the long-term contracts which CDWR procured. If Dr. Celebi's forward prices represented prices for the type of long-term contracts CDWR was procuring based on market fundamentals at the time of contract negotiation, there is every reason to believe that CDWR would have received offers at prices close to his calculated prices. The fact that his prices are so different from the contracted prices, despite a contracting environment that favors the single buyer negotiating with multiple sellers, suggests that his calculations are inconsistent with fundamental economic principles.

VIII. MR. READ'S ESTIMATES OF FORWARD MARKET PRICES "ABSENT THE EFFECT OF FRAUD AND MANIPULATION" ARE BASED ON FLAWED ECONOMIC REASONING

Q. Mr. Read proposes two methodologies ("Method 1" and "Method 2") to estimate forward market prices as of May 22, 2001 "absent the effect of fraud and manipulation." Please summarize the flaws you have found in Mr. Read's analyses.

A. Mr. Read's Methods 1 and 2 are based upon unsupported assumptions and flawed economic reasoning and suffer from all of the flaws discussed in previous sections. In addition, in Method 2, Mr. Read uses MMCPs to infer the impact of fraud and manipulation on forward prices and thus on the Shell Contract, contrary to the Commission's instructions that it should not be used as a proxy for just and reasonable rates in the context of bilateral contracts. In addition to this fatal flaw, MMCPs underestimate SRMC and thus, even assuming that the differential between SRMC and the actual spot price represents the impact of fraud and manipulation on spot prices, Mr. Read has overestimated his "premium."

A. Mr. Read's Method 1 is based on unsubstantiated assumptions and flawed economic reasoning

Q. What is Mr. Read's Method 1?

A. In Method 1, Mr. Read begins with forward price data as of June 21 to June 27, 2001,[151] after FERC issued its Order on west-wide market mitigation on June 19, 2001. He first adjusts this forward price data, which is incomplete, to impute a complete monthly forward curve covering the delivery months July 2001 to December 2005 for both NP-15 and SP-15. He then asserts that if there had been

[151] Specifically, Mr. Read uses June 21, June 22, June 25 and June 27, 2001 to estimate forward market prices but-for fraud and manipulation on May 22, 2001. Mr. Read does not explain why he chose to estimate prices as of May 22, 2001 rather than the contract execution date of May 25, 2001.

no manipulation or fraud, the average forward curves for NP-15 and SP-15 between June 21 to June 27, 2001, adjusted for changes in forward natural gas prices, which were a key driver of power prices, would have been "a good estimate" for the forward curves for these zones on May 22, 2001. The basis for his assertion is his claim, supported with no analysis, and few citations, that any changes in expectations of market fundamentals between May 22, 2001 and June 21, 2001 to June 27, 2001, aside from natural gas prices, canceled each other out. To obtain forward prices for the May and June 2001 delivery months, he "back-casts" the July 2001 forward prices for each zone using a similar method to the one used to impute missing delivery months. Additionally, he claims to remove the impact of fraud and manipulation in natural gas prices by adjusting his forward prices downward based on the difference between actual forward gas prices and gas prices specified by FERC as appropriate proxies for unmanipulated prices. This final step assumes that most of the change in natural gas prices from May 22, 2001 to June 21, 2001 was due to manipulation, not market fundamentals, and so ultimately, Mr. Read effectively reverses his adjustment to reflect changes in forward gas prices.

Q. A number of general flaws with the California Parties' analyses were discussed above in your testimony. Which of these applies to Mr. Read's Method 1?

A. Mr. Read's Method 1 suffers from all of the flaws mentioned above. In particular, (1) he assumes without evidence that fraud and manipulation affected CDWR's negotiation with Shell, (2) bases his analyses on prices that are not appropriate benchmarks for the Shell Contract, (3) uses information not available at the time the contract was negotiated, and (4) assumes that (nearly) all price changes from May 22, 2001 to June 21, 2001 were due to fraud and manipulation, despite ample evidence that expectations regarding market fundamentals changed. Mr. Read admits that the challenge for him with this method "is to distinguish the extent to which changes in market prices were attributable to changes in expectations of continuing market dysfunction versus changes in market fundamentals."[152] He further admits that he is "left to conjecture" since he cannot observe changes in expected fundamentals[153] and concludes that his assumption that expected market fundamentals did not change leaves this method less reliable than Method 2. Additionally, in describing this method, Dr. Fox-Penner claims, with no analysis that "very few of the true underlying market fundamentals that were in place on May 22nd could have changed much in less than a month."[154] This claim is obviously refuted by the evidence presented in **Section VI.B.**

B. Mr. Read's Method 2 is based on unsubstantiated assumptions and unfounded economic reasoning and contradicts the Commission's Order to not rely on the MMCP

Q. What is Mr. Read's Method 2?

A. In Method 2, Mr. Read estimates the impact of fraud and manipulation on spot market prices based on MMCPs developed by FERC for determining spot market refunds, relative to actual spot prices, and then assumes that fraud and manipulation had a similar impact on near-term forward prices that decayed until January 2003 according to an exponential decay function (i.e., he assumes market participants expected the impact of fraud and manipulation to decline over time).

Specifically, Mr. Read begins with forward price data as of May 22, 2001 for NP-15 and SP-15. He first adjusts this forward price data, which is incomplete, to impute a complete monthly forward curve covering the delivery months June 2001 to December 2005 for both NP-15 and SP-15. Next, he calculates the average MMCP for May 1 to May 22, 2001 and estimates the MMCP's "market implied

[152] Exh. No. CAL-00978, Read Testimony, at 20:19-21:1.

[153] Exh. No. CAL-00978, Read Testimony, at 28:9-10.

[154] Exh. No. CAL-00988, Fox-Penner Testimony, at 37-19-21.

heat rate" by dividing the MMCPs by the gas prices embedded in the calculation. He then asserts that the ratio of the average actual market implied heat rate for May 1 to May 22, 2001 (i.e. actual spot prices divided by actual gas prices) relative to the average MMCP heat rate for those dates represents the "premium" attributable to fraud and manipulation. Next, he applies an exponential decay function to the "premium" that declines each delivery month, going to 1.0 by January 2003 (implying zero premium in January 2003). Then, he applies his declining premium function to the actual May 22, 2001 forward market prices for each delivery month to "remove" the impact of fraud and manipulation. Additionally, he claims to remove the impact of fraud and manipulation on natural gas prices by adjusting his forward prices downward based on the difference between actual forward gas prices and gas prices specified by FERC as appropriate proxies for unmanipulated prices.

Q. A number of general flaws with the California Parties' analyses were discussed above in your testimony. Which of these applies to Mr. Read's Method 2?

A. Mr. Read's Method 2 suffers from all of the flaws mentioned above. In particular, he (1) assumes without evidence that fraud and dysfunction affected CDWR's negotiation with Shell, (2) bases his analyses on price that are not appropriate benchmarks for the Shell Contract, and (3) uses information not available at the time the contract was negotiated.

Q. Are there other flaws with Mr. Read's Method 2?

A. Yes, beyond those flaws that apply to both of Mr. Read's methods, there are several additional flaws with Method 2. MMCPs were developed for the purpose of calculating refunds from sellers for spot market sales. By construction, this metric excludes several factors that are relevant for analyzing long-term contracting.

First, the MMCP prices developed by the Commission explicitly did not incorporate emissions credit prices and other variable costs that some generators may incur.[155] At the time emissions costs alone were on the order of $25/MWh for a gas turbine[156] (relative to the average MMCP for May 1, 2001 to May 22, 2001 of $59.8/MWh).[157] The Commission recognized that plant-specific emissions costs, as well as fuel and other variable costs, could exceed the MMCP for plants that operated during the crisis.[158] Accordingly, it allowed sellers to apply to reduce their refund liabilities based on their demonstrated costs.[159] This plant-specific re-evaluation of costs relative to MMCPs occurred for at least 14 sellers, which demonstrates that the MMCP, while useful for other Commission purposes, is not a meaningful metric for the purpose of evaluating long-run contract prices.[160] Second, the MMCP was developed to issue refunds, and thus although counterparty credit risk was included in the calculation, the amount was tailored

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[155] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 96 FERC ¶ 61,120, at 61,519 (July 25, 2001).

[156]According to Joskow 2001, a "conventional gas-fired steam unit without special NOx controls, emits roughly 1 lb of NOx per megawatt-hour." (Joskow 2001, at p. 380) As I show in **Figure 8**, the price of NOx credits was $26.1/lb in May 2001.

[157] Exh. No. CAL-00987_Corr May01 Fwds.txt, Read Workpapers (Mr. Read calculates the average MMCP for On-Peak hours for the period of May 1, 2001 to May 22, 2001 as $59.8/MWh and the average MMCP for All-Hours for the period of May 1, 2001 to May 22, 2001 as $58.1/MWh).

[158] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.,* 127 FERC ¶ 61,250, at P 14 (2009).

[159] *Id.* at P 18.

[160] "Allocation of Emission Cost Allowances," *CAISO*, September 21, 2006, Exh. No. SHE-0106; *Thirty-Eighth Status Report of the California Independent System Operator Corporation on Settlement Re-Run Activity*, FERC, Docket No. ER03-746-000 *et al.*, September 6, 2007, at p. 6, Exh. No. SHE-0107. Most likely, the total number of sellers receiving refund offsets of various kinds would be greater as additional cost offsets were approved by FERC but were subject to further modification. *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 127 FERC ¶ 61,269, at PP 10, 14 (2009).

to that setting.[161] As discussed above in this testimony, there was substantial risk that CDWR would not be able to pay for the power for which it contracted, exposing sellers to CDWR to substantial credit risks. This CDWR-specific cost should be incorporated into a competitive price for a long-term contract with CDWR.

Third, the purported goal of the MMCP method is to estimate the short-run marginal cost (SRMC) of the highest-cost generator dispatched to serve load.[162] However, the appropriate metric for long-term contracts is long-run marginal cost (LRMC), as discussed above.

Fourth, Mr. Read provides no causal evidence that fraud and manipulation impacted forward prices as of May 22, 2001 nor does he make any effort to quantify the impact of fraud and manipulation on forward prices as of that date or analyze whether market fundamentals could explain the elevated forward prices he observes—rather he simply assumes that prices were high because of fraud and manipulation.

Fifth, as explained by Dr. Morris, Mr. Read's claim that he needs to adjust his forward power price series down to compensate for natural gas prices that were artificially high is without basis. In particular, Dr. Morris explains that although the Commission concluded that certain natural gas price indices were not sufficiently reliable to be used for calculating refunds, it did not conclude that the prices were artificially high and further allowed refunds to those sellers whose actual costs, including natural gas costs, exceeded the MMCPs.

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[161] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 96 FERC ¶ 61,120 at 61,159.

[162] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Services*, 95 FERC ¶ 61,418 at 62,568.

Q. You stated above that the Commission has instructed the California Parties not to use MMCPs as a proxy for just and reasonable rates for a bilateral contract. Have the California Parties' witnesses disobeyed this instruction?

A. Yes. The Commission has instructed the parties not to use the MMCP to determine whether the Shell Contract prices were just and reasonable as "the Commission has consistently rejected the notion of using the MMCP as a proxy for just and reasonable rates in the context of bilateral contracts."[163] In particular, MMCPs were simplistic and conservative estimates of SRMC created by regulators for purposes of issuing refunds to California consumers for high *spot market* prices during the energy crisis, not long-term contract prices.[164]

In defending Mr. Read's analysis, Dr. Fox-Penner claims that "[i]n no way does Mr. Read use the level of MMCP as an indicator of the proper price for the Shell contract. He uses the difference between MMCP (a proxy for spot prices) and actual spot prices as datum that informs his adjustment of the prices of forward generation contracts."[165] However, for May 2001, Mr. Read's estimate of the forward market price "absent the effect of fraud and manipulation" is essentially just a weighted average of MMCPs for May 1 to May 22, 2001.[166] Similarly, his estimates for June 2001 onward assume that the "premium" in forward market prices attributable to fraud and manipulation is equal to the spot market premium

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[163] Opinion No. 587 at P 442.

[164] *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Services*, 95 FERC ¶ 61,418 at 62,568.

[165] Exh. No. CAL-00988, Fox-Penner Testimony, at 35:11-14.

[166] Specifically, Mr. Read replaces missing adjusted heat rates for May 2001 with the average MMCP heat rates for May 2001 (SP15, NP15, All-Hours, and On-Peak). Mr. Read then multiplies these heat rates by the respective gas prices for May 2001 in order to get his corrected forward prices for May 2001. Additionally, Mr. Read's use of May 1 to May 22, 2001 MMCPs is inappropriate because it is for delivery dates prior to those specified for May 2001 in the Shell Contract, for which he could have used spot or balance of month forward prices.

with an adjustment factor (his exponential decay assumption) to diminish the premium to zero by January 2003,[167] with no support provided for the assumed shape of his decay function or for his assumption that spot market fraud and manipulation carried into forward market prices.

Q. Please explain the flaws related to the assumed shape of the "premium" decay function in Method 2?

A. Mr. Read assumes that the "premium" in forward market prices attributable to fraud and manipulation "declined exponentially as the time to delivery increased" and becomes "zero [] by the January 2003 delivery month."[168] He does not provide any tangible support for assuming, first, the "premium" in forward market prices "declined exponentially," and, second, that it became "zero [] by the January 2003 delivery month." Instead, Mr. Read refers to a figure presenting forward curves for trade dates of May 22, June 20, July 9, and August 1, 2001, noting that "forward prices for later delivery periods [are] well below forward prices for nearby delivery periods" and the "decline in forward prices pretty much leveled off by the Q1 2003 delivery period."[169] However, forward market prices declining with time to delivery, and levelling off by early 2003, can be easily explained by reasons completely unrelated to the expectation that fraud and manipulation in forward market will take until early 2003 to dissipate. For instance, nearly 25,000 MW of new generation facilities were expected to start delivering electricity in the West by the end of 2003, which would be expected to reduce spot prices and thus forward prices for later maturities would fall as new generation was expected to come online.[170]

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[167] Exh. No. CAL-00978, Read Testimony, at 33:8-34:1.

[168] Exh. No. CAL-00978, Read Testimony, at 33:8-34:1.

[169] Exh. No. CAL-00978, Read Testimony, at 34:1-6.

[170] EPME-1, Kalt Testimony, Exh. No. EPME-13.

Moreover, in the context of Method 1, Mr. Read assumed that expectations of fraud and manipulation in forward markets dissipated "likely over a period of many weeks"[171] after the Mitigation Order in June, if not within few days, as his choice of trade dates in June 2001 for Method 1 would suggest. Similarly, Dr. Celebi in a prior phase of this proceeding notes that based on his review "dysfunction persisted in the forward markets through July and into the first part of August, but that by September 2001, the forward markets had returned to competitive levels."[172] Even if Mr. Read is correct that forward prices in May 2001 were elevated to some degree by fraud and manipulation and that the June 19, 2001 FERC Order was the cause of its dissipation, Mr. Read provides no tangible evidence that market participants expected that fraud and manipulation would persist through January 2003 as opposed to some earlier date. Indeed, even Dr. Fox-Penner and his co-authors on a 2015 book stated that as of April 26, 2001, "the writing was on the wall… forward prices for the coming summer of 2001 (Q32001) began a steady decline about the time of the April 26, 2001 Order."[173]

Q. Are there any other problems with Mr. Read's assumption that spot market fraud and manipulation carried into forward market prices?

A. Yes. Even if the method correctly estimated the "premium" associated with fraud and manipulation in the *spot* market (a position I do not agree with), it does not necessarily represent the "premium" associated with fraud and manipulation in *forward* market prices. In particular, idiosyncratic market conditions on the days Mr. Read uses to estimate his "premium" could influence the difference between

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[171] Exh. No. CAL-00978, Read Testimony, at 26:1-9.

[172] Exh. No. CAL-634R, Prepared Direct Testimony of Metin Celebi, Ph.D. on Behalf of the California Parties, including 11/15/15 errata, Docket Nos. EL02-60-007 *et al.*, May 19, 2015, at 28:1-29:16.

[173] Taylor, G. et al., *Market Power and Market Manipulation in Energy Markets*, 2015, p. 80, Exh. No. SHE-0108.

the spot price and MMCP but be irrelevant to the impact of fraud and manipulation on forward market prices due to differing conditions in future months, e.g. if the fraud and manipulation had a greater impact on low demand days than on high demand days.

Moreover, a historical spot market “premium” does not necessarily provide information about the size of the “premium” associated with fraud and manipulation in CDWR’s long-term forward contract prices. Yet, Dr. Celebi assumes that the fraud and manipulation Mr. Read claims with respect to forward prices carried into the bilateral contract negotiations for the Shell Contract when he claims that the differential between his fourth and sixth benchmarks, based on Mr. Read’s Method 2 forward price series, and the Shell Contract rate is attributable to fraud and manipulation. Claiming that the impact of fraud and manipulation in the spot market is proportional to the impact of fraud and manipulation in the CDWR bilateral contract negotiations makes the same errors the California Parties’ witnesses previously made in claiming that MMCP alone should be used to proxy the just and reasonable bilateral contract price—it fails to account for differences between long-term bilateral contracts and spot markets and assumes that the alleged fraud and manipulation in the spot market carried over directly to the bilateral contract negotiations, despite evidence to the contrary.[174]

Q. Does this conclude your testimony?

Yes.

[174] *Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy*, 137 FERC ¶ 61,001, at P 24 (2011); *Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy*, Opinion No. 537, 151 FERC ¶ 61,173, at PP 74-75 (2015).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

VERIFICATION OF STEVEN L. PULLER

I, Steven L. Puller, do hereby declare under penalty of perjury that I prepared or caused to be prepared the foregoing Answering Testimony, and that the facts set forth herein are true and correct to the best of my knowledge, information and belief.

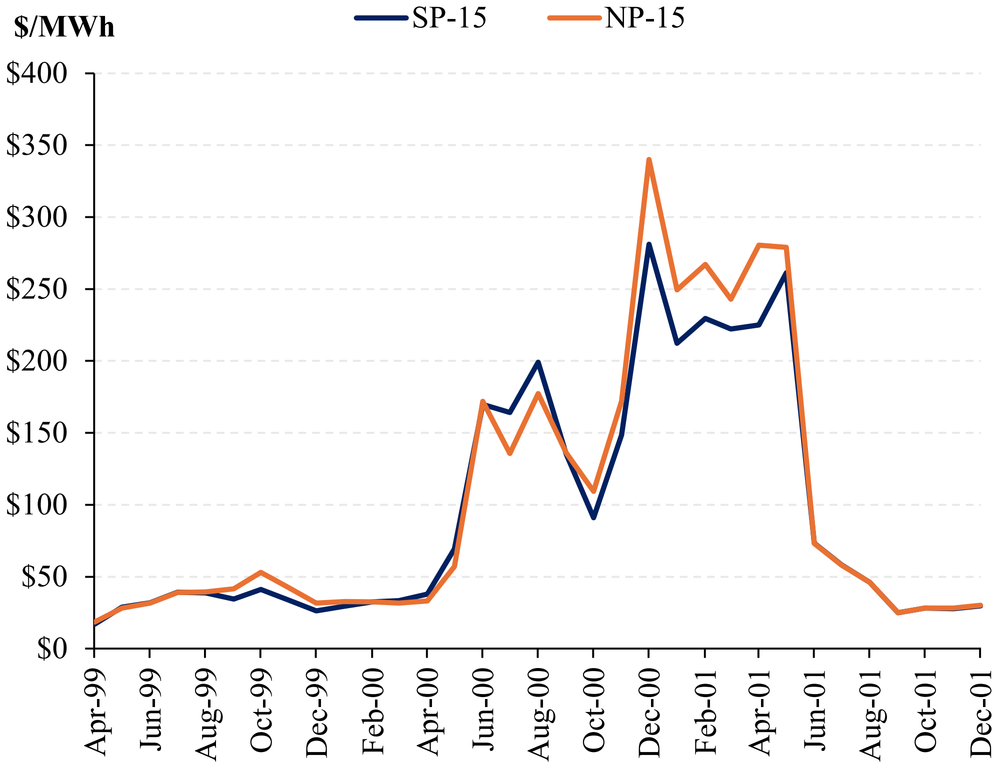
Executed the 4th day of February, 2025, in College Station, TX.

Steven L. Puller

APPENDIX A

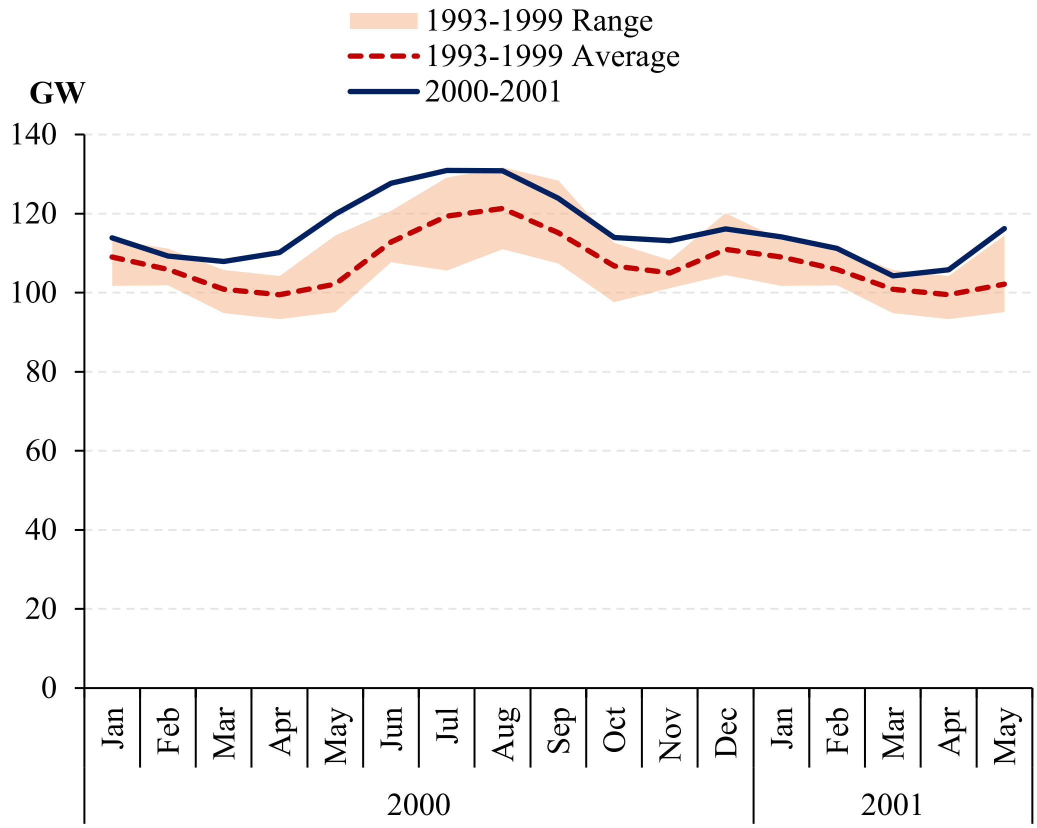
COLLECTED FIGURES FROM ANSWERING TESTIMONY OF STEVEN L. PULLER

Figure 1[1]
Average Monthly SP-15 and NP-15 On-Peak Spot Prices
April 1999 - December 2001



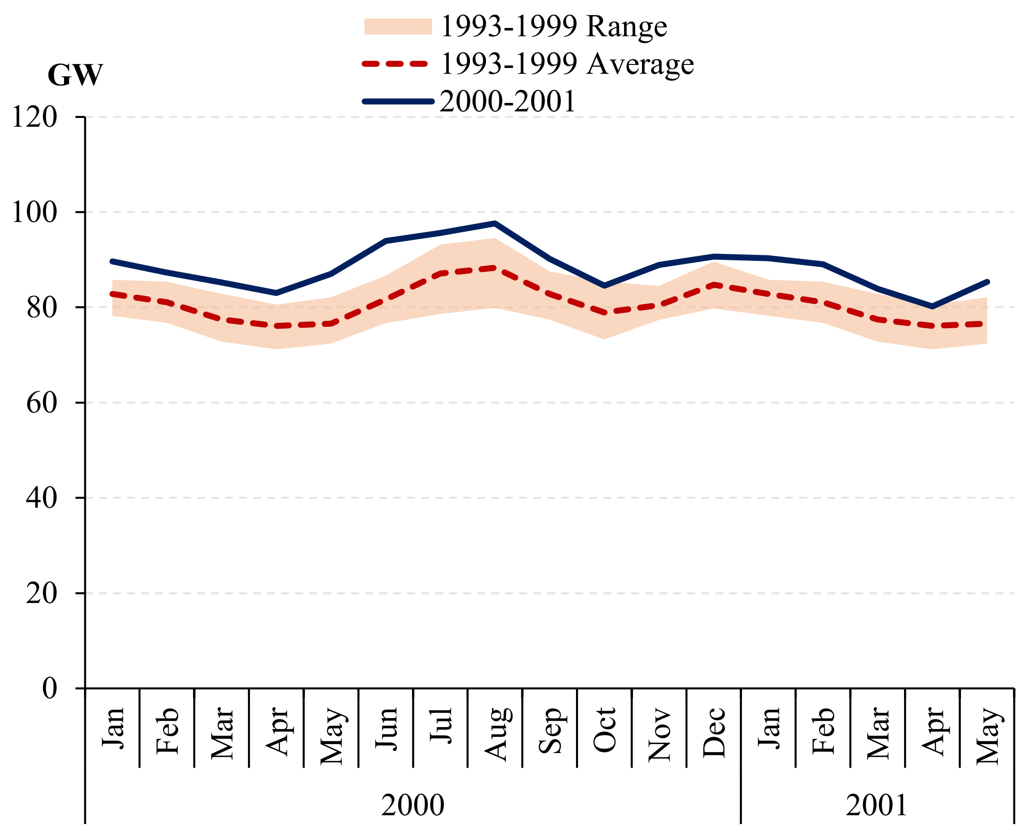
[1] Ex. TC-0018, Docket No. EL02-71-057, Table 23, at pp. 26-27.

Figure 2[2]
WSCC Monthly Peak Demand
1993-1999 vs. 2000-May 2001



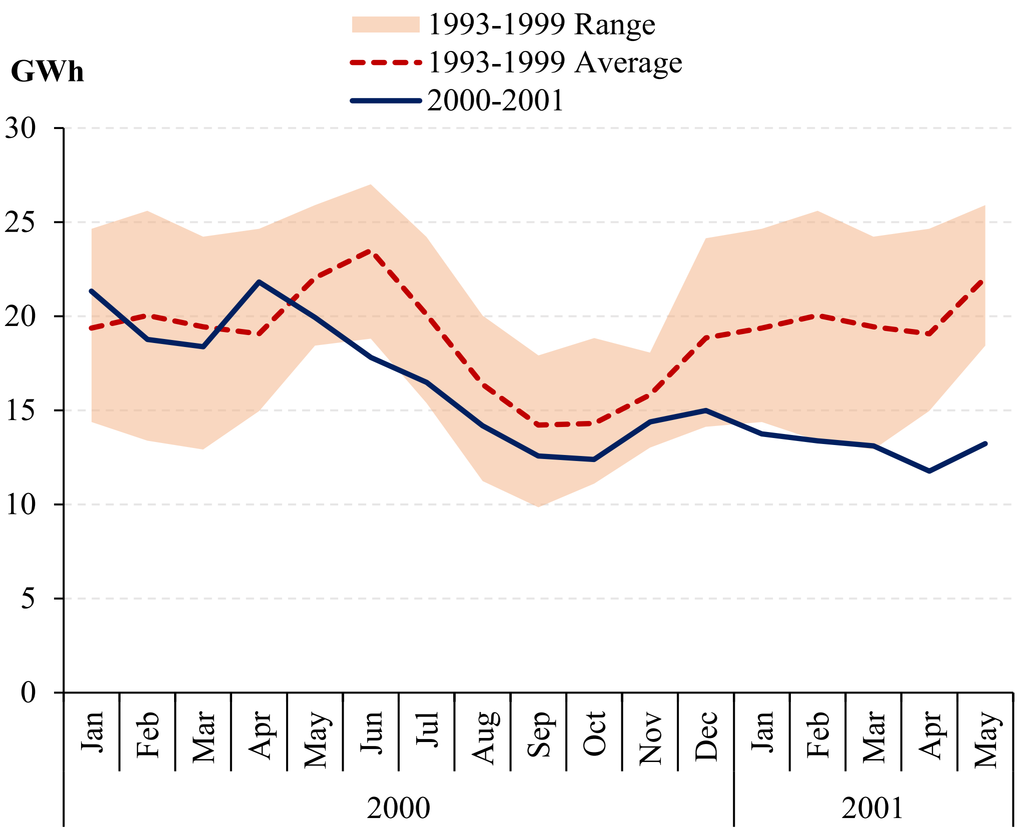
[2] WSCC 10-Year Coordinated Plan Summaries 1994-2001; WECC 10-Year Coordinated Plan Summary 2002. Peak Load is the sum of Firm Load and Interruptible Demand, and WSCC Region includes Western Canada and Western Mexico load.

Figure 3[3]
WSCC Monthly Average Hourly Demand
1993-1999 vs. 2000-May 2001



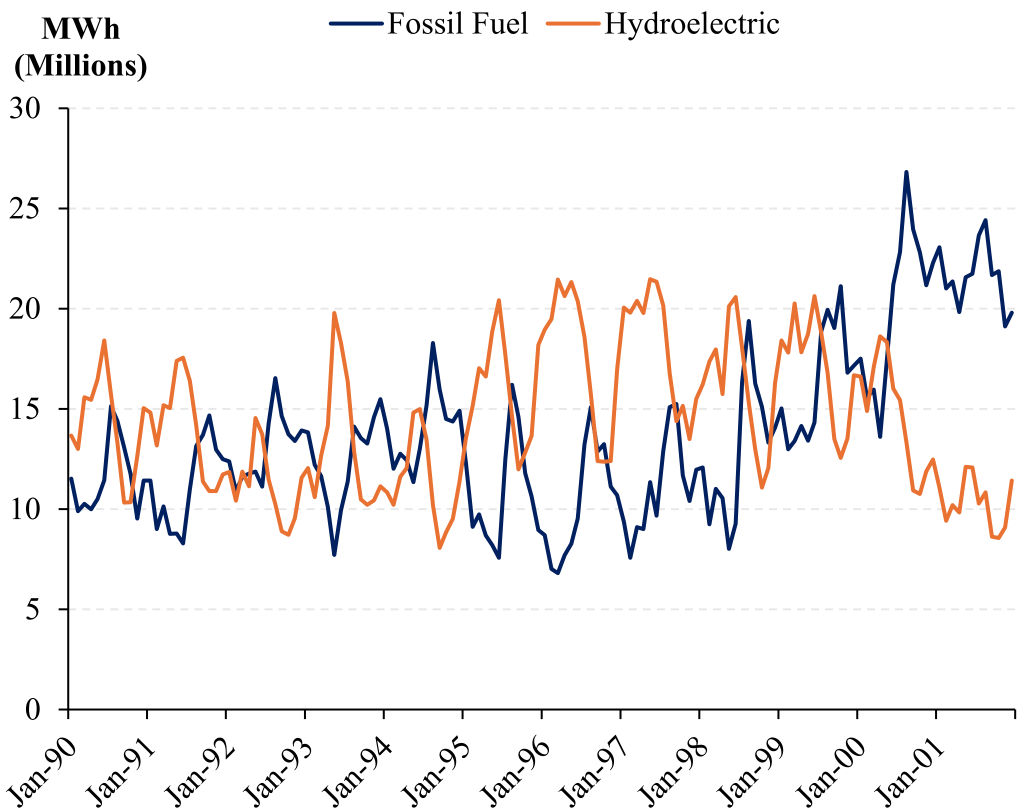
[3] WSCC 10-Year Coordinated Plan Summaries 1994-2001; WECC 10-Year Coordinated Plan Summary 2002. WSCC Region includes Western Canada and Western Mexico load.

Figure 4[4]
Western U.S. Monthly Average Hourly Hydroelectric Output (Outside CA)
1993-1999 vs. 2000-May 2001



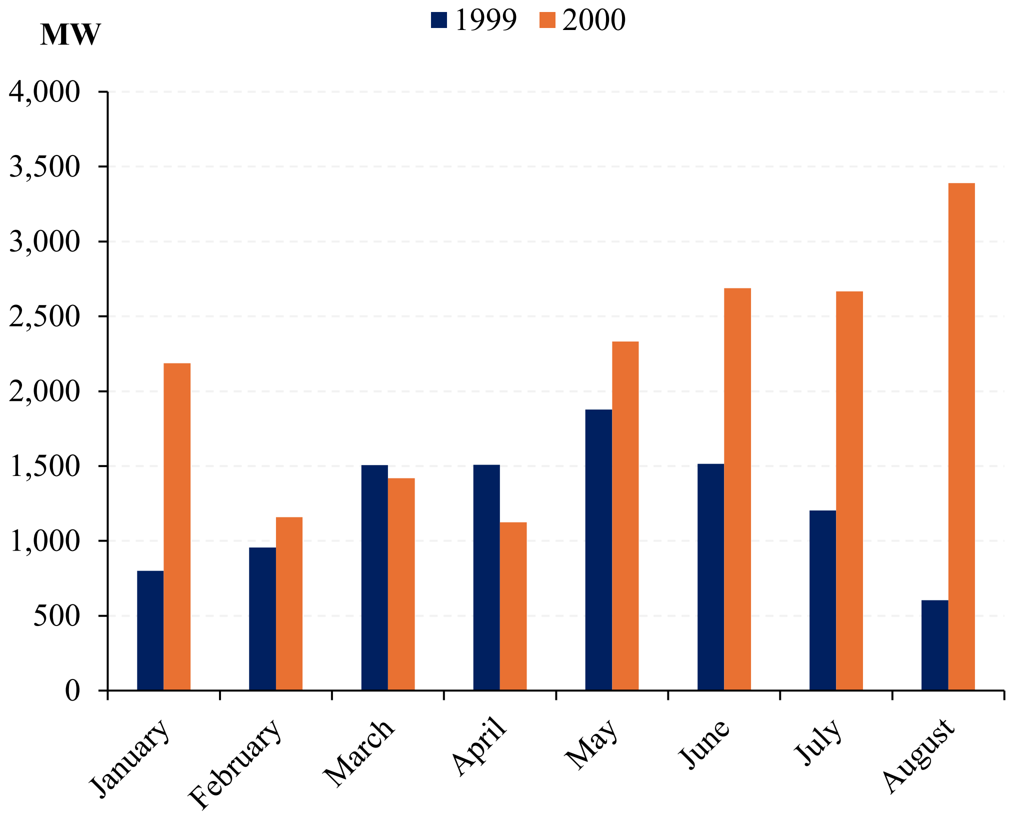
[4] Ventyx Velocity Suite data (January 1993-January 1995); EIA Electric Power Monthly, May 1996-March 2003 (February 1995-December 2001), Table 11. Western U.S. (Outside CA) generation is calculated as the sum of the Mountain and Pacific Contiguous census divisions (excluding California) as provided in Electric Power Monthly. When the regional totals in Electric Power Monthly did not equal the sum of the state totals, the table reflects the sum of individual state figures.

Figure 5[5]
Western U.S. Fossil Fuel vs. Hydroelectric Generation Output
January 1990 - December 2001



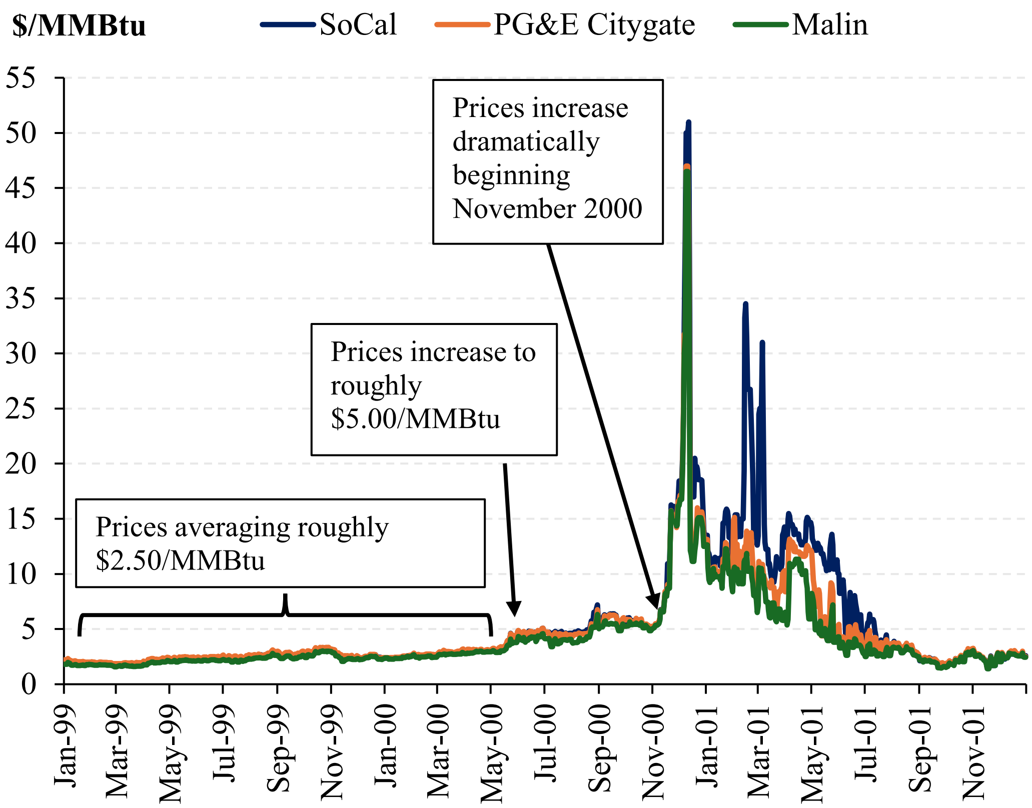
[5] Ventyx Velocity Suite data. Generation is categorized based on the 'Fuel Code Description' column in the Raw Data. Fossil generation includes generators fired by coal, natural gas, oil, jet fuel, coke, and biomass gases. Output is for Western States including Arizona, California, Nevada, Idaho, New Mexico, Oregon, and Washington.

Figure 6[6]
CAISO Average Unplanned Outages (MW)
January - August 1999 and January - August 2000



[6] FERC Report, November 2000, Figure 2-12. Comparison of Average Megawatts Out of Service in the CAISO Planned and Unplanned, 1999 and 2000, at p. 2-20.

Figure 7[7]
Daily Natural Gas Spot Prices
1999-2001



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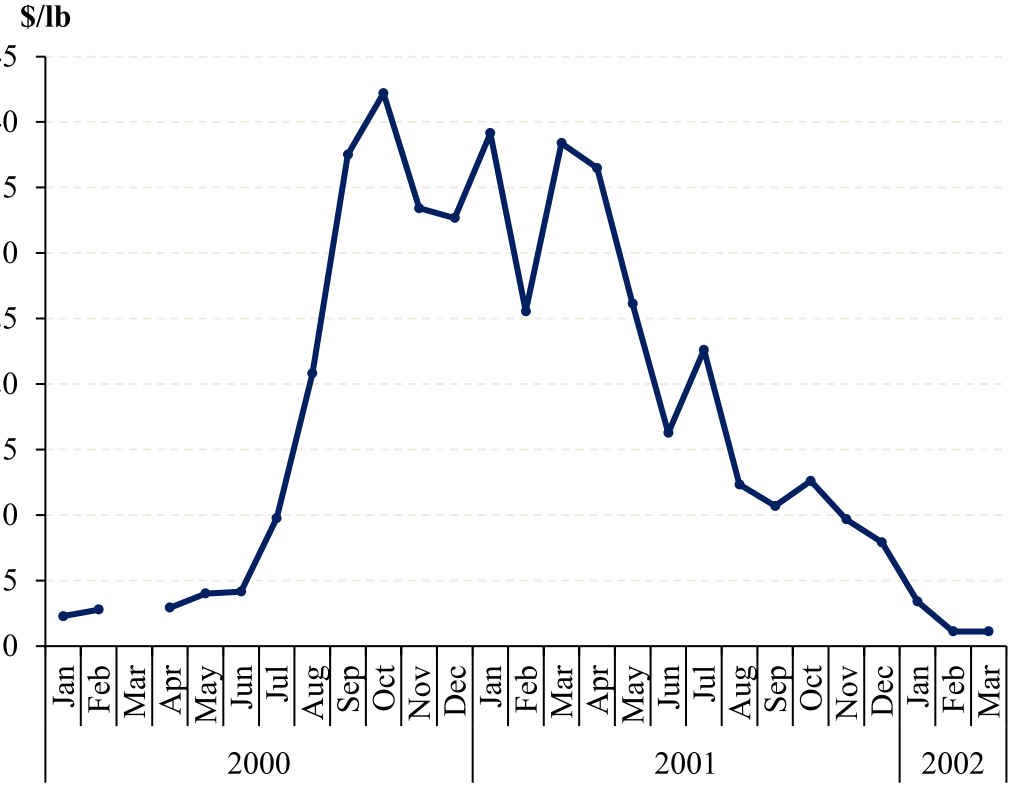
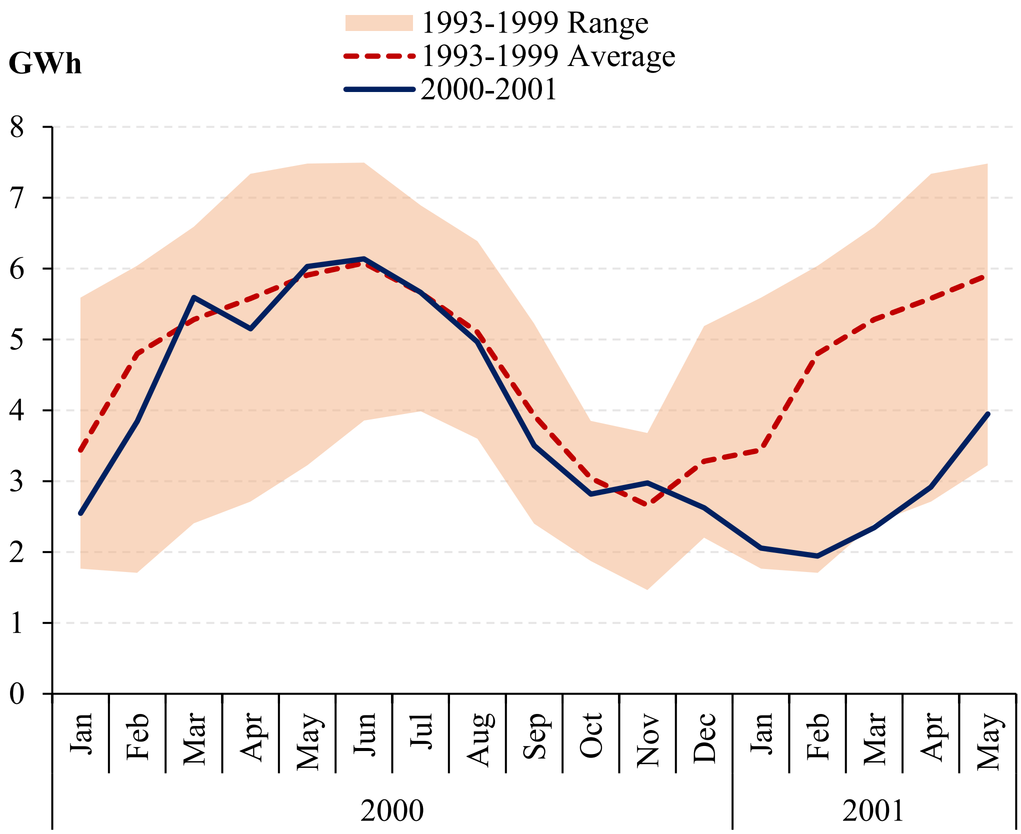
[7] Platts Daily Average Gas Data.

Figure 8[8]
Monthly Weighted Average Price of RECLAIM Program NOx Emissions Credits
2001 Vintage



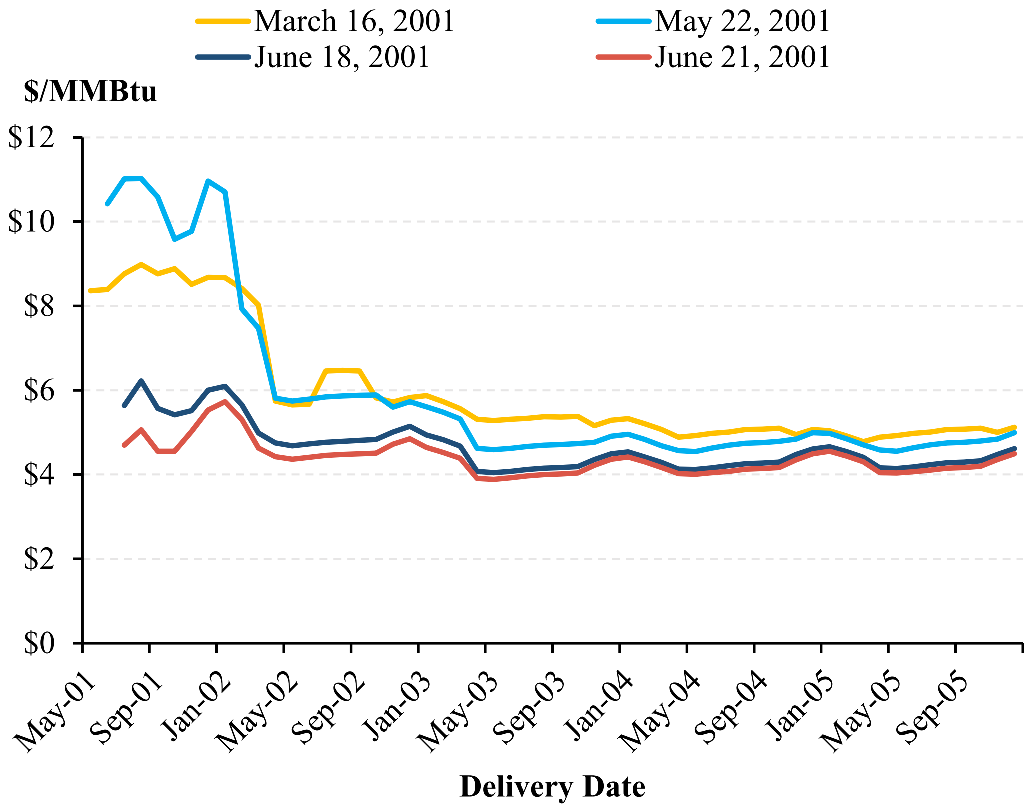
[8] SCAQMD, *Historical Trade Registrations*, available at https://www.aqmd.gov/home/programs/business/about-reclaim/reclaim-trading-credits/historical-trade-registrations. Prices are weighted by the quantity allowed by the credit. SCAQMD has two vintages per year, one expiring in June and the other in December (e.g., June 2001 and December 2001). The averages above are calculated across the June and December vintages for 2001. Prices are unavailable for 2001 vintage credits traded in March 2000.

Figure 9[9]
California Monthly Average Hourly Hydroelectric Output
1993-1999 vs. 2000-May 2001



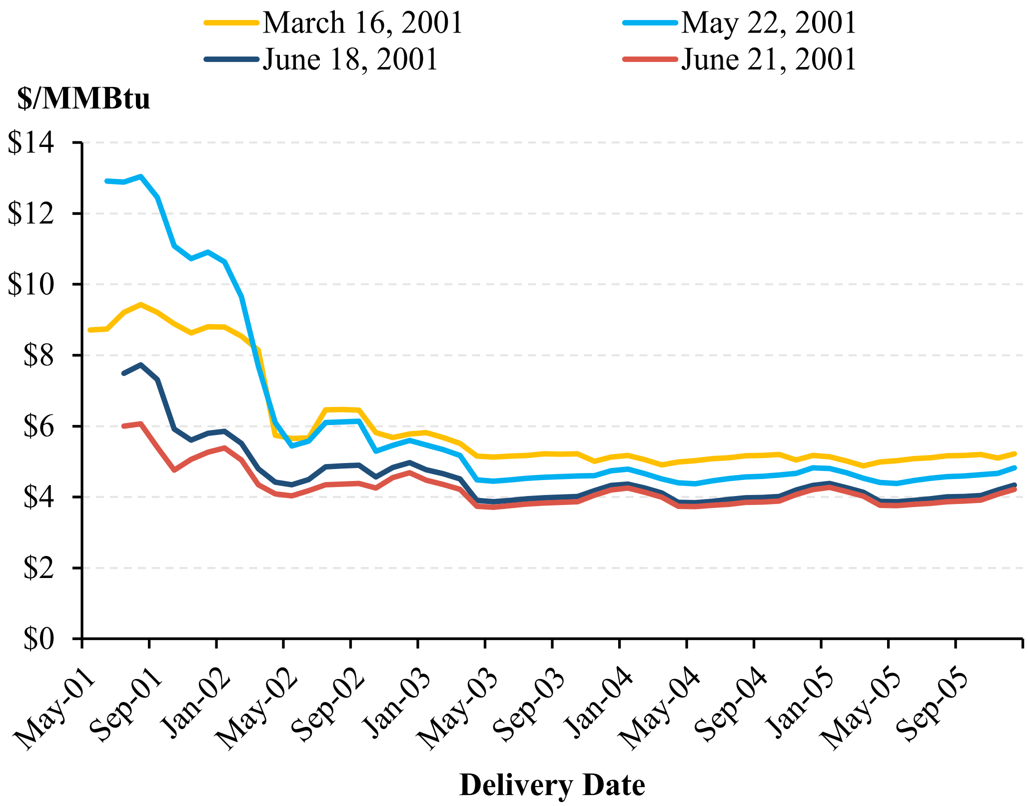
[9] Ventyx Velocity Suite (January 1993-January 1995); EIA Electric Power Monthly, May 1996-March 2003 (February 1995-December 2001), Table 11. Data include energy usage and production associated with Pumped Storage Units.

Figure 10[10]
PG&E Citygate Natural Gas Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



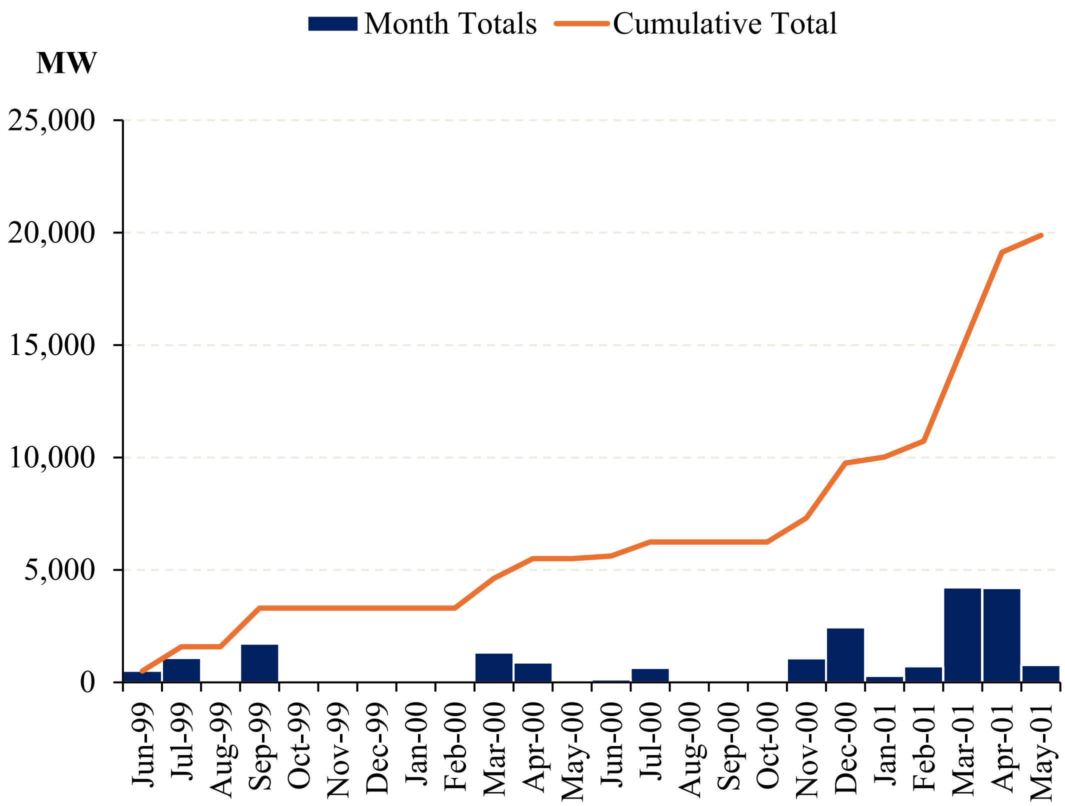
[10] Ex. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read uses PG&E Citygate Natural Gas Prices in his adjustments to NP-15 Power Prices. Mr. Read obtains natural gas prices from Enron.

Figure 11[11]
SoCal Border Natural Gas Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



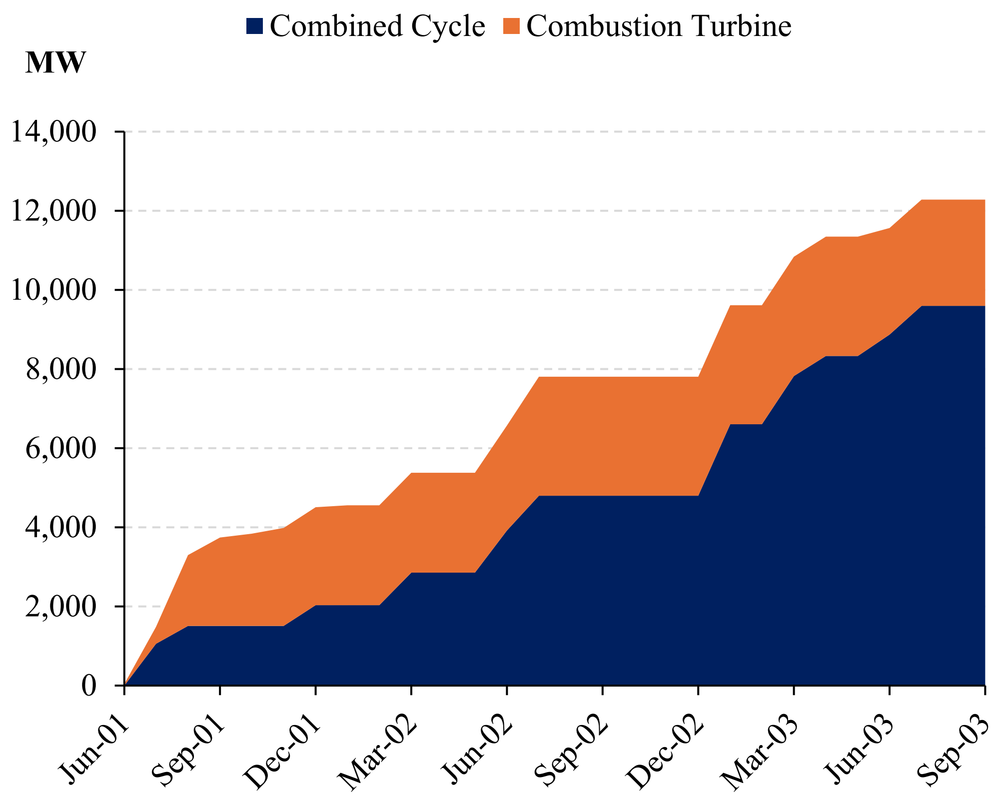
[11] Ex. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read uses SoCal Border natural gas forward prices in his adjustment to SP-15 Power Prices. Mr. Read obtains the natural gas prices from Enron.

Figure 12[12]
Cumulative Quantity of New Power Generation Plants by Construction Start Date
June 1999 – May 2001



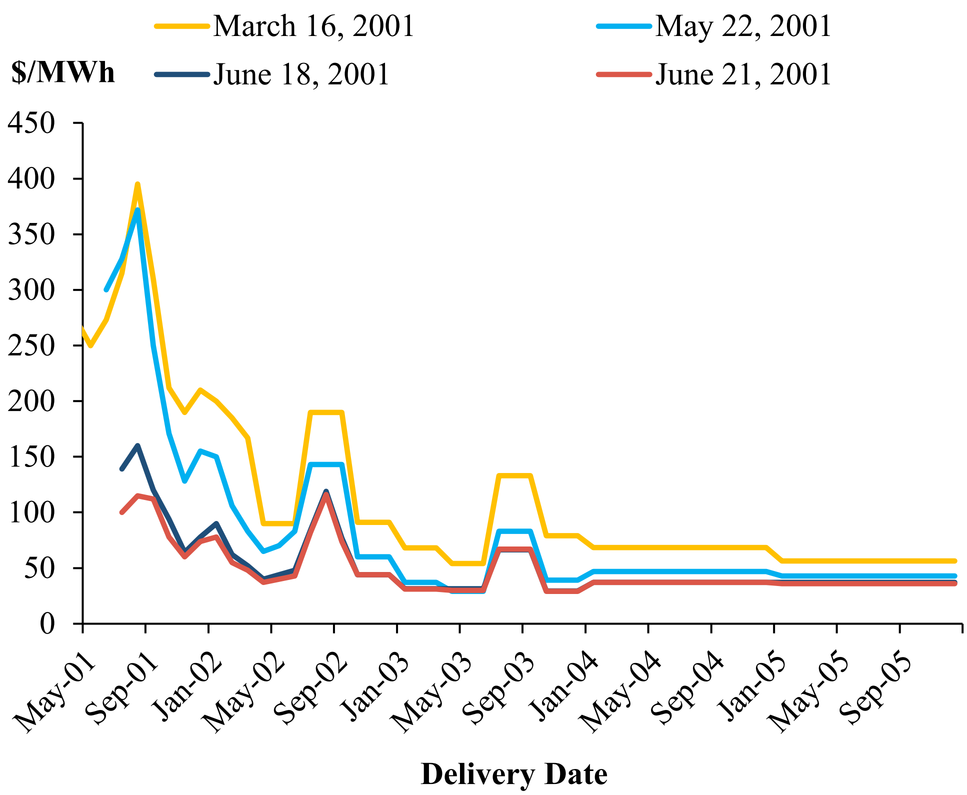
[12] Various trade press. The power plants included are located in Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, and Washington, and include only a subset of power plants constructed in these states in these years.

Figure 13[13]
CDWR Expected New Capacity Additions by Commercial Online Date as of May 18, 2001



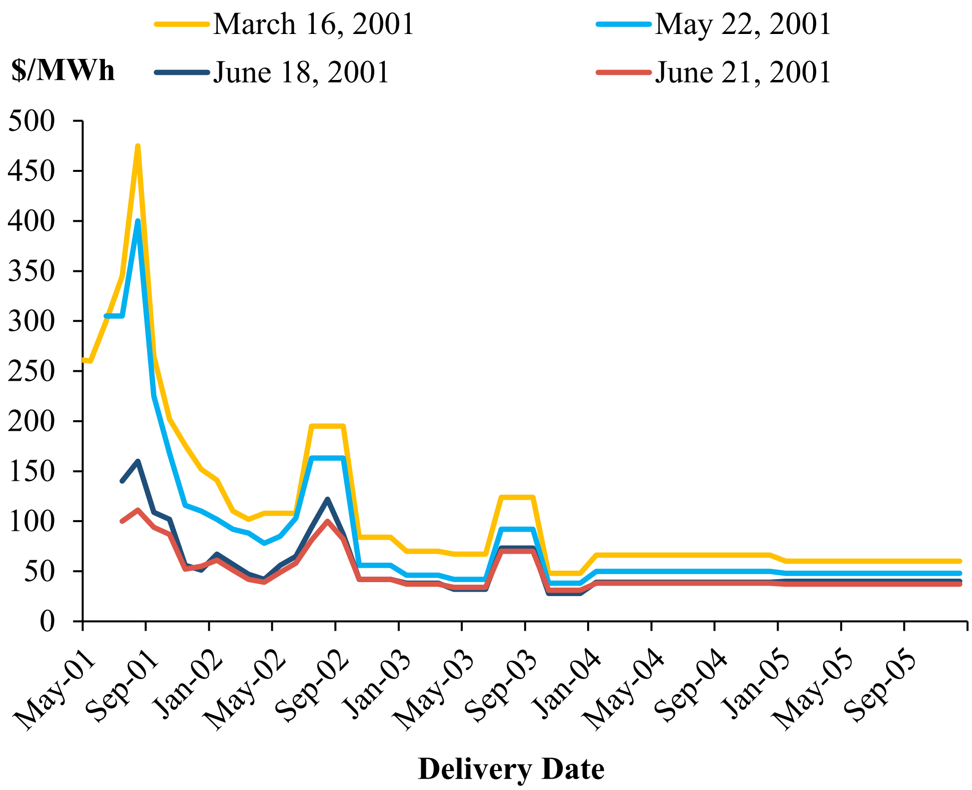
[13] "Revenue Requirement & Consultant's Report Briefing to the Staff of CEC and CPUC on DWR Energy Procurement Program," Navigant, May 18, 2001, at pp. 10-12. Data are not available for October through December 2002.

Figure 14[14]
NP-15 Power Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



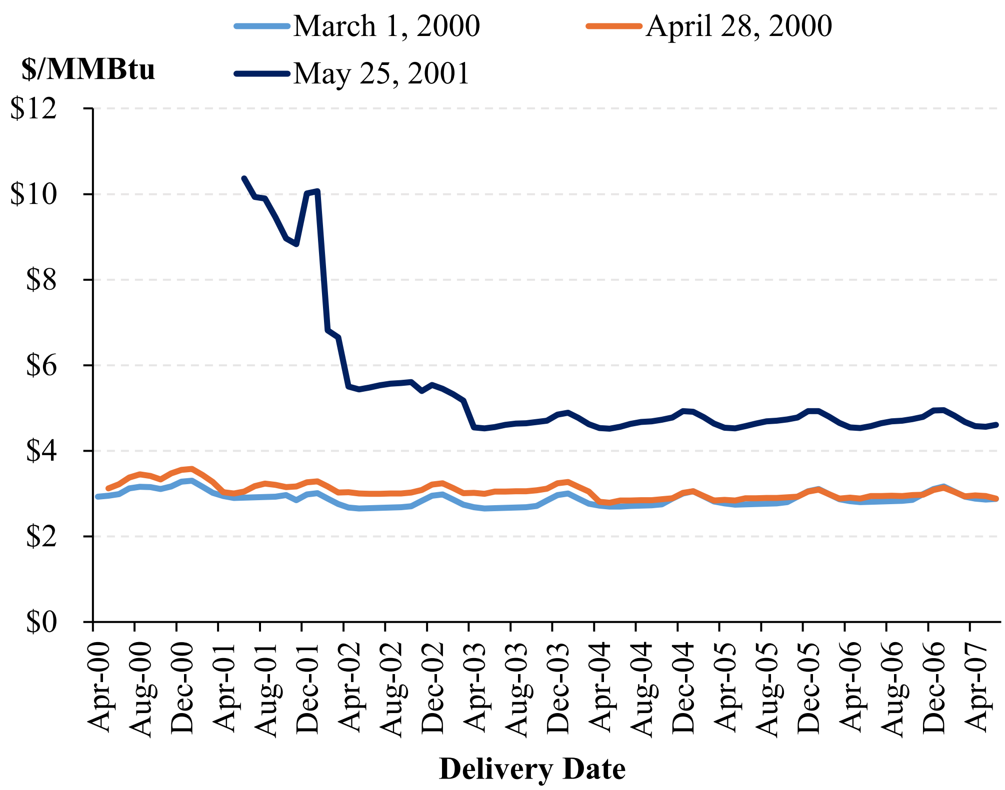
[14] Ex. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read obtains these power forward curves from Natsource fax sheets.

Figure 15[15]
SP-15 Power Forward Curves for
March 16, 2001, May 22, 2001, June 18, 2001, and June 21, 2001



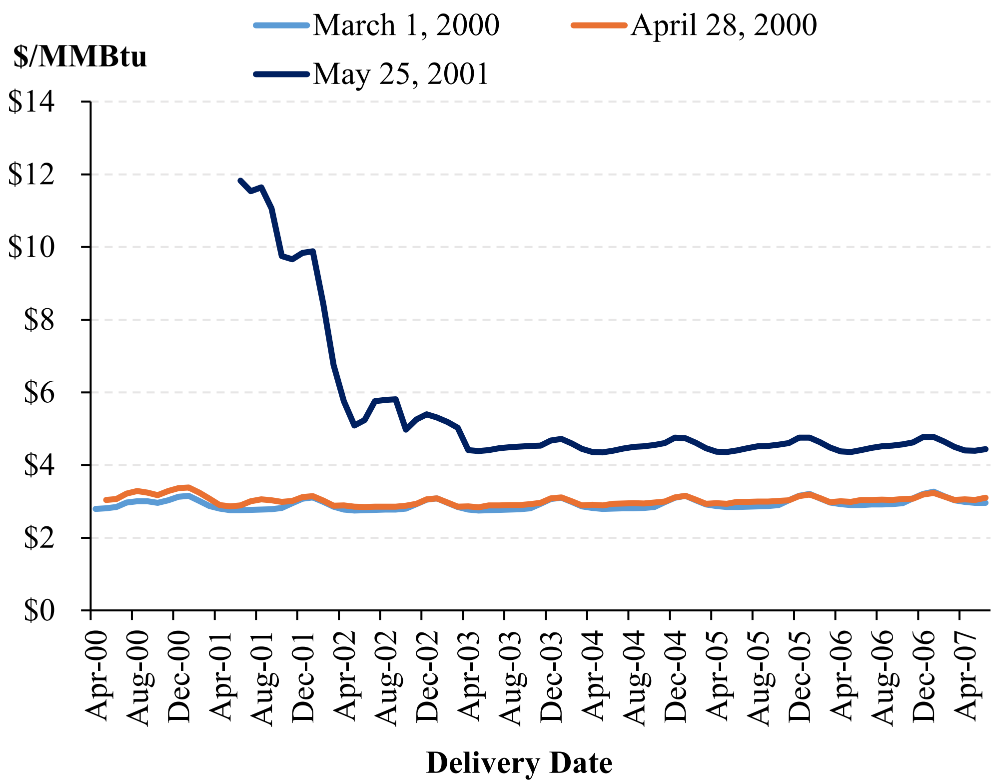
[15] Ex. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read obtains these power forward curves from Natsource fax sheets.

Figure 16[16]
PG&E Citygate Forward Natural Gas Prices
March 1, 2000, April 28, 2000, and May 25, 2001



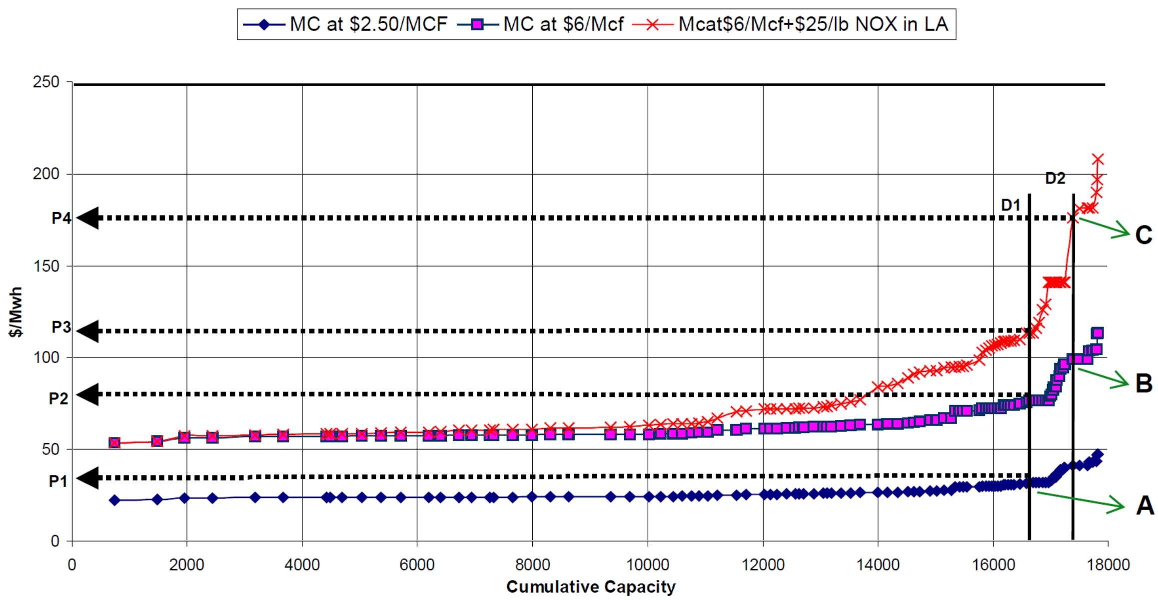
[16] Ex. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read uses PG&E Citygate Natural Gas Prices in his adjustments to NP-15 power prices. Mr. Read obtains natural gas prices from Enron.

Figure 17[17]
SoCal Border Natural Gas Forward Prices
March 1, 2000, April 28, 2000, and May 25, 2001



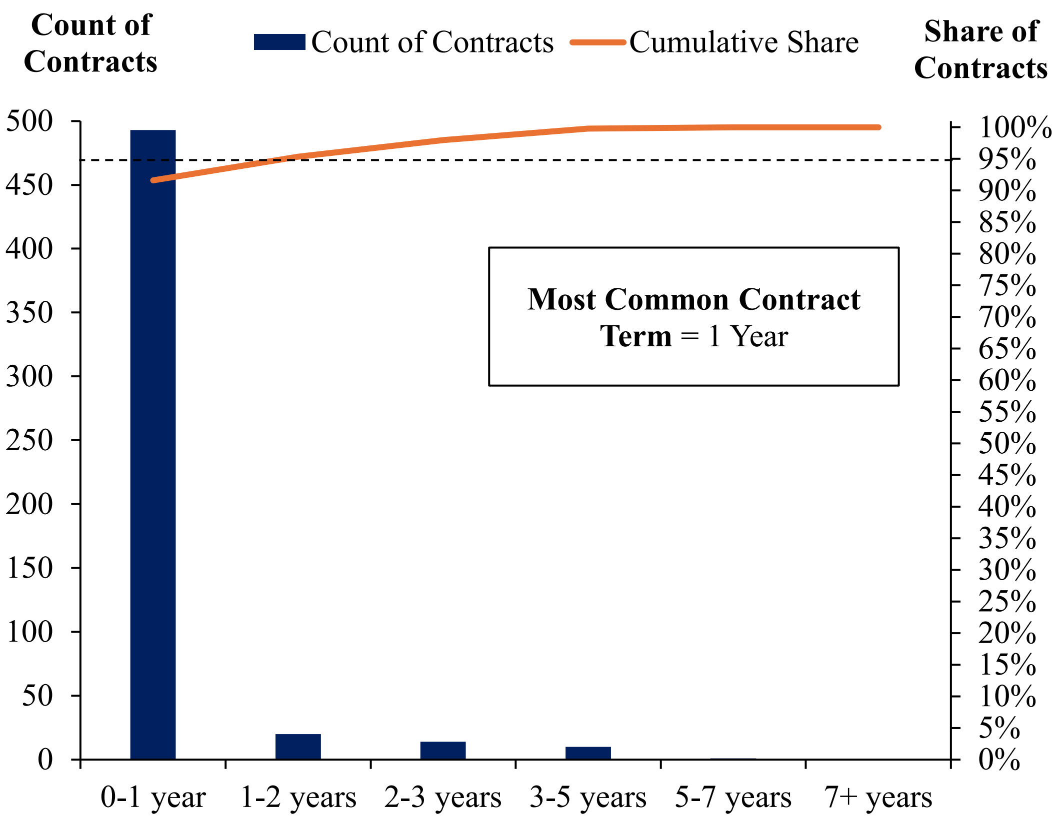
[17] Ex. CAL-00987_Inputs.xlsx, Read Workpapers. Mr. Read uses SoCal natural gas forward prices in his adjustment to SP-15 power prices. Mr. Read obtains natural gas prices from Enron.

Figure 18[18]
Marginal Cost for Gas Units



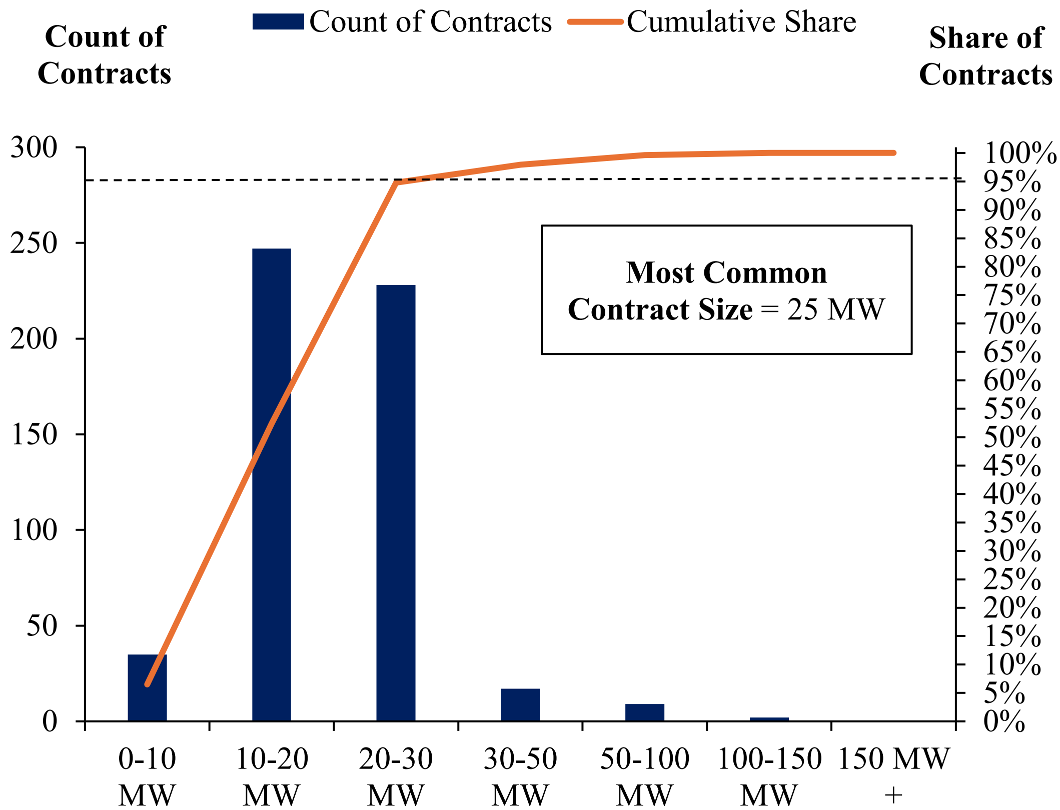
[18] Joskow 2001, Figure 3, at p. 380. I have added the indicators for points A, B, and C.

Figure 19[19]
Contract Length
Dr. Celebi's Sample of Post-Crisis Long Term Shell Contracts



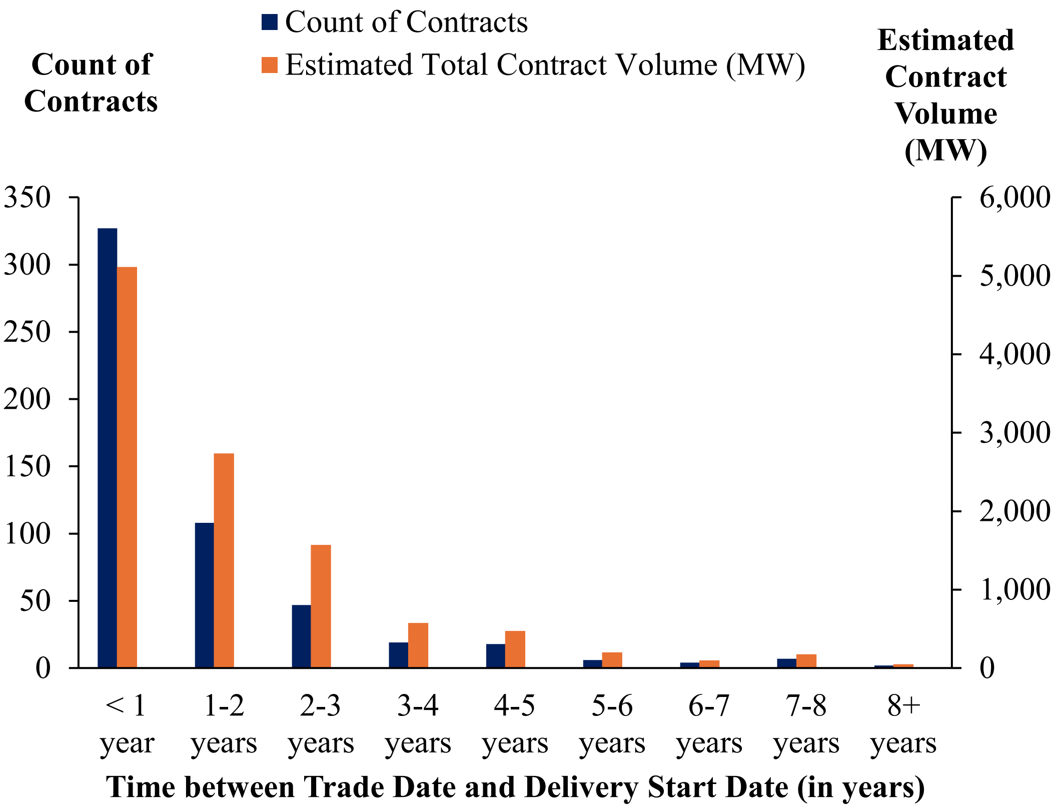
[19] Ex. CAL-00973, Celebi Testimony at pp. 17:14-18:3; CAL-00977_Other LTKs.txt.

Figure 20[20]
Delivery Volume
Dr. Celebi's Sample of Post-Crisis Long Term Shell Contracts



[20] Ex. CAL-00973, Celebi Testimony, at pp. 17:14-18:3; CAL-00977_Other LTKs.txt. I estimate the hourly contract volume by dividing the total delivered volume by the estimated number of on-peak hours during the term of the contract.

Figure 21[21]
Time between Trade Date and Delivery Start Date
Dr. Celebi's Sample of Post-Crisis Long Term Shell Contracts



[21] Ex. CAL-00973, Celebi Testimony, at pp. 17:14-18:3; CAL-00977_Other LTKs.txt. I plot the distribution of Dr. Celebi's 538 benchmark contracts based on the time between the contract's trade date and delivery start date. I estimate the hourly contract volume for these benchmark contracts by dividing the total delivered volume by the estimated number of on-peak hours during the term of the contract.

Appendix B

Table of Acronyms

TABLE OF ACRONYMS

Abbreviation	Full Phrase
CAISO	California Independent System Operator
CDWR	California Department of Water Resources
CPUC	California's Public Utility Commission
FERC	Federal Energy Regulatory Commission
IOUs	Investor Owned Utilities
LDs	Liquidated Damages
LRMC	Long Run Marginal Cost
LSE	Load Serving Entity
MBR	Market-Based Ratemaking
MMCP	Mitigated Market Clearing Price
PX	Power Exchange
QFs	Qualifying Facilities
RA	Resource Adequacy
SRMC	Short-Run Marginal Cost