

BENCHMARKING THE PRICE REASONABLENESS OF A LONG-TERM ELECTRICITY CONTRACT*

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I. INTRODUCTION AND SUMMARY

A. Background

Electric utilities in the United States have engaged in wholesale electricity trading since well before the 1978 passage of the Public Utility Regulatory Policies Act (PURPA).¹ The PURPA encouraged the development of qualifying cogeneration and small power production facilities and engendered the emergence of independent power producers.² Pre-PURPA trading was dominated by bilateral transactions largely comprised of: (1) seasonal exchanges, where a winter-peaking utility supplied energy to a summer-peaking utility that subsequently returned the energy in the winter at a preset exchange ratio; (2) sales of economy energy by a utility with surplus generation and relatively low fuel cost to a utility with relatively high fuel cost, with the transacting utilities sharing the resultant fuel cost savings; (3) reserve sharing, whereby two or more utilities, likely with differing demand patterns and plant mixes, pooled their reserves for reliability planning purposes; and (4) emergency support, where two or more utilities agreed to supply each other when one experienced a real-time operation shortage.³

These transactions were often the result of power pooling agreements among utilities.⁴ For example, the California Power Pool (CPP) was formed in 1961, with participation by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E). The CPP agreement aimed to provide for the selling, pooling, and sharing of energy sources for both reserve margins and emergency situations.

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1. Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (1978).

2. OFFICE OF COAL, NUCLEAR, ELEC. & ALTERNATE FUELS, ENERGY INFO. ADMIN., U.S. DEP'T OF ENERGY, 2 ELECTRIC POWER ANNUAL 2000 59, 85 (2000).

3. *Id.* at 60.

4. AN ENCYCLOPEDIA OF UTILITY INDUSTRY TERMS 258-262 (1985).

The key driver for transactions under (1) and (2) above was fuel cost savings. Reliability and operational benefits rationalized transactions under (3) and (4). Because these transactions delivered obvious benefits to both parties, regulatory approval at the federal and state levels was routine without the fanfare of contentious evidentiary hearings.

B. Price Benchmarking Based on Avoided Costs

The 1978 PURPA required a utility to purchase power output from a qualifying facility (QF).⁵ Section 210 of the PURPA requires that the rates paid to QFs be "just and reasonable" and "not discriminate against qualifying cogenerators."⁶ However, the rates should not "exceed[] the incremental cost to the electric utility of alternative electric energy" (i.e., the costs the utility avoided by purchasing from the QF).⁷ In general, the PURPA delegated the responsibilities of determining the utility's avoided cost and enforcing the utility's purchase obligation to the states.

Armed with this PURPA authority, a state regulator decides the rate a regulated utility pays to a QF, provided that the rate does not exceed the per-unit cost the utility can avoid as a result of the QF purchase.⁸ For example, in July 1985, the California Public Utilities Commission (CPUC) issued Decision 85-07-022 stating that the total avoided cost was the difference between the utility's total cost without the QF production and the utility's total cost with the QF purchase.⁹ Hence, implementation of the PURPA necessitates the use of a price benchmark—the buying utility's per kilowatt hour (kWh) of avoided cost due to a QF purchase. If the QF price is set at or below a utility's ex post per kWh avoided cost, which can vary continuously with actual operations, the utility's customers are a priori not disadvantaged by the QF purchases.¹⁰

However, a QF contract may have a fixed price term that lasts for a period of up to ten years in California and longer elsewhere. When a long-term QF contract price is capped at a utility's unbiased projection of avoided cost, the QF purchase should ex ante not increase the utility's expected rates.¹¹ To be sure, as the Federal Energy Regulatory Commission (FERC) observed in the preamble to its rules implementing the PURPA,¹² the QF price may result in a price higher or lower than the utility's actual avoided cost. Nonetheless, an unbiased avoided cost projection benchmark is commonly used by state regulators for capping the

5. Public Utilities Regulatory Policy Act of 1978 § 210(a).

6. *Id.* at § 210 (b)(1) – (b)(2).

7. Public Utilities Regulatory Policy Act of 1978, § 210(b)(2).

8. RICHARD F. HIRSH, *POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM* 90 (The MIT Press 1999).

9. *Pac. Gas & Elec. Co.*, 18 C.P.U.C. 2d 333 (1985).

10. See Chi-Keung Woo, *Inefficiency of Avoided Cost Pricing of Cogenerated Power*, 9 ENERGY J. 103, 105–108 (1988).

11. *Id.* at 106.

12. Small Power Production and Co-Generation Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12,214, 12,224 (Feb. 25, 1980) (to be codified at 18 C.F.R. pt. 292).

price of a long-term QF contract.¹³ Thus, QF pricing illustrates the relevant role of price benchmarking that is needed to ensure a utility's rates are just and reasonable, as required by section 210 of the PURPA.

State regulators have extended cost-based price benchmarking beyond QF pricing, thus reflecting their oversight responsibility for cost prudence. A transaction is said to be prudent if its price is below the adopted benchmark, which is often a utility's per kWh avoided cost. The types of transactions are diverse, ranging from utility-sponsored programs for conservation and demand side management (DSM) to the utility's long-term power procurement from wholesale markets.¹⁴ In October 2002, the CPUC affirmed that "[t]o justify as cost-effective an [inter-utility exchange] to reduce [residual net short] (acting as a buyer), the utility will have to demonstrate that at the time of executing the [inter-utility exchange] agreement the expected costs for the repayment was less than the avoided incremental costs at the time of delivery."¹⁵

By contrast, the FERC applies market-based price benchmarking to determine the price competitiveness of a utility's purchase from its affiliate generator. In a series of decisions to be discussed below, the FERC held that a long-term contract between a utility and its affiliated generator not resulting from competitive solicitation (e.g., auction) can still be just and reasonable if it passes a price-benchmarking test. The test aims to foreclose self-dealing behavior by the affiliated buyer, whereby the utility might attempt to offer its affiliated generator an above-market price that leads to higher rates for the utility's customers.

C. Research Agenda

This paper analyzes the approaches to price benchmarking used by the FERC and by a state regulator (exemplified by the CPUC). The authors' choice of the California example was motivated by the 2002 passage of State Assembly Bill 57 (AB 57),¹⁶ which reforms the recovery of electricity procurement costs

13. HIRSH, *supra* note 8, at 97.

The interim [Standard Offer 4] contract called for payments to QFs based on the forecasted prices of fuel and capacity for the first ten years of a fifteen- to thirty-year contract period. According to conference participant Janice 'Jan' Hamrin, director of the Independent Energy Producers Association, most people 'thought that gas and oil prices were going to the moon,' even though some fuel prices had already moderated slightly by the beginning of 1983. (While California wellhead crude oil prices had fallen from almost \$42 per barrel in 1981 to \$32 in 1983, the price of the state's natural gas, a premium fuel used in several cogeneration projects, was still heading up.) Rates paid to QFs for the first decade therefore reflected the view that fuel costs (and avoided costs) would escalate for the ten-year period. Under the terms of an [sic] [Standard Offer 4] contract offered by Southern California Edison, for example, energy payments rose from 5.6 cents per kWh in 1984 to 10.1 cents per kWh in 1993; capacity payments added another 1.42 to 2.07 cents per kWh.

Id. at 97 (footnotes omitted).

14. See Ren Orans et al., *Targeting Demand Side Management for Electricity Transmission and Distribution Benefits*, 15 *MANAGERIAL & DECISION ECON.* 169 (1994). See also Ren Orans et al., *Demand Side Management and Electric Power Exchange*, 16 *RESOURCE & ENERGY ECON.* 243-254 (1994).

15. Rulemaking 01-10-024, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*, CAL. PUB. UTIL. COMM'N 28 (Oct. 10, 2002) (Decision 02-10-062).

16. Assemb. B. 57, 2002 Assemb., 2001-2002 Sess. (Cal. 2002).

incurred by PG&E, SCE, and SDG&E.¹⁷ Implementation of AB 57 by the CPUC diminishes the need for after-the-fact reviews of transactions with price terms that pass respective benchmarks for price reasonableness. In April 2004, California Governor Arnold Schwarzenegger urged the CPUC to “expeditiously implement” AB 57. He noted that “AB 57 corrected one of the key flaws in California’s electricity restructuring effort: the inability of investor-owned utilities to develop diversified resource portfolios and enter into long-term contracts without the risk of after-the-fact reasonableness reviews by the Commission.”¹⁸

Our inquiry is substantive and relevant because, as discussed below, affiliate transactions appear to be on the rise.¹⁹ Absent long-term financing, investment in new generation evaporates. Nonetheless, a regulated utility must fulfill its obligation to serve. To meet the growing load, it may pursue a long-term contract with its affiliate seller who can lean on the buying utility’s predictable cash flow from retail sales to obtain long-term financing.

Our inquiry is also motivated by the different emphases used in the FERC and CPUC approaches. The FERC’s focus is on self-dealing. If a long-term contract with an affiliate meets the FERC’s standards for competitive procurement, the contract can be accepted as reasonable. This acceptance is irrespective of the contract’s price or other terms, thus precluding the need for price benchmarking. Otherwise, the price term of the affiliate transaction will be subject to a benchmark based on contracts that are comparable to, and contemporaneous with, the affiliate contract. To prove that the affiliate transaction has terms as favorable as those of an arms-length transaction, the sample of contracts for price benchmarking should exclude contracts between the utility and its affiliate. In addition, the utility and its affiliate must show that they do not have market power that can potentially influence market prices in general, and the price terms in the sample contracts, in particular. The FERC does not require that the price of the affiliate contract be at or below the utility’s state-set avoided cost (in cases where the state has set avoided cost). In short, the FERC’s price benchmarking is a market-price test.

In its 1994 *Ocean State II* order, the FERC distinguished the market-based approach from the cost-based one:

In the case of a market-based formula rate . . . neither the rate (which is the formula itself) nor any of its individual components has to be justified on a cost basis. Rather, if the Commission is satisfied that the rate results from competitive market forces or that the seller does not have market power over the buyer, we do not examine the underlying cost structure of the seller.²⁰

However, in the FERC’s February 2004 order in the case of Southern California

17. *Id.*

18. Letter from Arnold Schwarzenegger, Governor of California, to Michael Peevey, President of the Public Utilities Commission (Apr. 28, 2004), available at http://www.joinarnold.com/pdf/puc_letter.pdf.

19. See *S. Power Co.*, 104 F.E.R.C. ¶ 61,041 (2003); *Entergy Servs., Inc.*, 103 F.E.R.C. ¶ 61,256 (2003); *Ameren Energy Generating Co.*, 103 F.E.R.C. ¶ 61,128 (2003); *Cinergy Energy Servs., Inc.*, 102 F.E.R.C. ¶ 61,128 (2003); *S. Cal. Edison Co.*, 106 F.E.R.C. ¶ 61,183 (2004); *Elec. Generation LLC*, 101 F.E.R.C. ¶ 63,005 (2002).

20. *Ocean State Power II*, 69 F.E.R.C. ¶ 61,146, 61,546 (1994).

Edison's Mountainview power purchase agreement, discussed below, the FERC announced it would, henceforth, require that all long-term affiliate transactions, whether at cost or market, be subject to the same tests for self-dealing.²¹

The CPUC's focus is cost prudence. In compliance with AB 57, each utility must file a procurement plan for approval by the CPUC enabling the utility to fulfill its obligation to serve at just and reasonable rates and minimizing the need for after-the-fact reasonableness reviews. Specifically, AB 57 requires each utility's plan to have the following elements:

- (1) An assessment of the price risk associated with the electrical corporation's portfolio
- (2) A definition of each electricity product . . . including support and justification for the product type and amount to be procured under the plan.
- (3) The duration of the plan.
- (4) The duration, timing, and range of quantities of each product to be procured.
- (5) [Details of] [a] competitive procurement process
- (6) [Details of the] incentive mechanism, if [one] is proposed
- (7) The upfront standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to execution of the transaction. . . .
- (8) Procedures for updating the procurement plan.
- (9) A showing that the procurement plan will achieve the following:
 - (A) [U]ntil a 20 percent renewable resources portfolio is achieved, procure[ment of] renewable energy resources with the goal of ensuring that at least an additional 1 percent per year of the electricity sold by the electrical corporation is generated from renewable energy resources
 - (B) [T]he creat[ion] or maint[enance of] a diversified procurement portfolio consisting of both short-term and long-term . . . products.
- (10) The electrical corporation's risk management policy, strategy, and practices
- (11) A plan to achieve appropriate increases in diversity of ownership and diversity of fuel supply of nonutility electrical generation.
- (12) A mechanism for recovery of reasonable administrative costs related to procurement in the generation component of rates.²²

The FERC and CPUC approaches to benchmarking employ very different data. The FERC's approach uses market data on comparable and contemporaneous contracts, but ideal data are seldom readily available. Because long-term electricity contracts can have idiosyncratic terms, substantial debate can arise over whether the comparison contracts are sufficiently comparable to

21. *S. Cal. Edison Co.*, 106 F.E.R.C. ¶ 61,183 (2004).

22. CAL. PUB. UTIL. CODE § 454.5 (2004).

the affiliate contract. Depending on the liquidity of the market, it may be difficult to find contracts that are both comparable to, and contemporaneous with, the affiliate contract. Moreover, the price terms in these comparison contracts should be competitive and not influenced by the seller's market power.²³ The lack of ideal data necessitates the use of a sample of contracts determined to: (1) have terms sufficiently similar to those of the affiliate contract; (2) be reasonably close (in time) to the affiliate contract signing; and (3) have price terms not unduly influenced by market imperfections. This determination entails some degree of subjectivity and the choice of sample contracts can obviously affect the resulting price benchmark.

The CPUC's approach to price benchmarking does not require contract data. Rather, it uses publicly available cost data on generation capacity, financing, variable operational and maintenance (O&M), emissions, and fuel to calculate the long-run marginal cost (LRMC) of generation, which is the all-in per kWh cost of owning and operating new generation. The CPUC has adopted a market price referent (MPR) based on the LRMC of combined cycle and combustion turbine proxy power plants (for baseload and peaking contracts, respectively) to evaluate the reasonableness of long-term contracts in a utility's procurement plan. "Each . . . MPR represents the levelized price at which the proxy power plant revenues exactly equal the expected proxy power plant costs on a net-present value (NPV) basis."²⁴ Contracts at or below the MPR will be considered per se reasonable.

In California, published cost data and their implication are well understood by the regulator and the regulated utilities, because of their experience with avoided cost-pricing and cost-effectiveness analyses in integrated resource planning. The resulting benchmark, being cost-based, is less vulnerable to the potential price distortions caused by electricity market imperfections.²⁵ The CPUC has used this approach in determining the cap for the formerly integrated utilities' long-run avoided cost for QF pricing under section 210 of PURPA and in performing cost-effectiveness evaluations of resources.²⁶ The California Energy Commission (CEC) has also used this approach to project the long-run price in California for guiding the state's resource planning.²⁷

23. *Ocean State Power*, 60 F.E.R.C. ¶ 61,305 (1992).

24. Rulemaking 04-04-026, *Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program: Opinion Adopting Market Price Referent Methodology*, CAL. PUB. UTIL. COMM'N 6 (June 9, 2004) (Decision 04-06-015), available at http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/37383.pdf.

25. Of course, a dominant firm can manipulate a fuel price (e.g., natural gas), resulting in distortions to the benchmark electricity price. For instance, a FERC Administrative Law Judge found that El Paso Natural Gas was guilty of a "clear exercise of market power" when it withheld as much as 696,000 Mcf/day from the Western markets during the 2000–2001 winter heating season. *Pub. Util. Comm'n v. El Paso Natural Gas Co.*, 100 F.E.R.C. ¶ 63,041, 65,157 (2002) (initial decision). The case was settled before the FERC ruled on exceptions.

26. Request for Proposals, *Notice to Prospective Proposers for a Forecast of Cost Effectiveness Avoided Costs and Externality Adders*, CAL. PUB. UTIL. COMM'N (May 2, 2003), available at <http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource4.doc>; See also CAL. PUB. UTIL. COMM'N & CAL. ENERGY COMM'N, STANDARD PRACTICE MANUAL (1987).

27. CAL. ENERGY COMM'N, 2002–2012 ELECTRICITY OUTLOOK REPORT (Feb. 2002), available at

Finally, the FERC and CPUC approaches can have very different results, even though economic theory suggests that, in a competitive market with easy entry and exit, the long-run market price should converge to the LRMC.²⁸ At times of market surplus, the FERC approach can result in a price benchmark below the LRMC; at times of market shortage, the converse occurs. Hence, the choice of a benchmarking methodology can affect one's decision as to whether the affiliate contract is reasonable with regard to price and whether full recovery of the contract's cost should be allowed.

D. Overall Conclusion

Given suitable data, the FERC's approach is useful for gauging the price reasonableness of a long-term contract. However, in some instances, data difficulties may impede the empirical implementation of the FERC's approach.

Another problem is that low contract prices due to transitory surplus can discourage generation development. This occurs because the resulting price benchmark for cost recovery prevents a buying utility from offering a contract to the affiliated developer at a price sufficiently high to yield a competitive return on investment. Strict adherence to the FERC's approach can, therefore, precipitate subsequent shortages that could have been prevented by an LRMC-based benchmark. It is recommended that the FERC allow evidence of the LRMC/avoided cost approach to be considered where sufficient contemporaneous and comparable contract data are not available.

This recommendation is consistent with the CPUC's May 2003 Proposed Decision implementing the California Renewables Portfolio Standard Program, which targets twenty percent of California's generation portfolio derived from renewable sources.²⁹ The CPUC determined that long-term contracts would not provide an accurate measure of market prices for new resources for the near future because of the lack of a usable quantity of such contracts. Rather, "the [CPUC] is to determine a price based on the costs associated with new generating facilities. In theory, this price and the price established [by fixed price contracts] should converge, but . . . the electricity market in California is not in equilibrium, rendering such convergence less likely."³⁰

E. Organization

First, section II, below, illustrates the FERC's benchmarking approach with PG&E's 2001 application seeking the FERC's approval of a long-term contract with its affiliate generator as part of an initial bankruptcy reorganization plan.³¹

http://www.energy.ca.gov/electricity_outlook.

28. MICHAEL L. KATZ & HARVEY S. ROSEN, MICROECONOMICS 385-386 (Irwin/McGraw-Hill 1998) (1991).

29. Rulemaking 01-10-024, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*, CAL. PUB. UTIL. COMM'N (May 20, 2003) (Proposed Decision), available at http://www.cpuc.ca.gov/word_pdf/COMMENT_DECISION/26325.pdf [hereinafter Proposed Decision for Cost Recovery].

30. *Id.* at 17-18.

31. In April 2004, PG&E ultimately emerged from bankruptcy under a different settlement agreement,

Next, section III discusses LRMC as a benchmark for price reasonableness, using PG&E's affiliate contract as a case study. Finally, section IV summarizes the conclusions derived from this article.

II. PRICE BENCHMARKING BY THE FERC

A. Market-Based Rate Approval for an Affiliate Transaction

Under section 205 of the Federal Power Act, a generator affiliated with a (buying) utility may submit a long-term electricity contract price for approval by the FERC as a market-based rate.³² In analyzing self-dealing between the affiliated seller and the buyer who may gain at the expense of the utility's customers, the FERC established in *Boston Edison Co. Re: Edgar Electric Energy Co. (Edgar)* that it "must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and nonprice terms (i.e., that it has not preferred its affiliate without justification)."³³

In *Ocean State II*, the FERC identified examples used to identify a lack of affiliate abuse using the market value standard:

- (1) evidence of direct head-to-head competition between the seller and competing unaffiliated suppliers in either a formal solicitation or in an informal negotiation process; (2) evidence of the prices that nonaffiliated buyers were willing to pay for similar services from the seller; or (3) benchmark evidence of the market value, based on both price and nonprice terms and conditions, of contemporaneous sales made by nonaffiliated sellers for similar services in the relevant market.³⁴

According to the first criterion, the affiliate contract meets the market-based standard if it is the winning response to the buying utility's request for proposals (RFP) from competing sellers, and the RFP does not preferentially treat affiliate bidding. Implementation of a RFP by the utility may range from inviting sellers to submit sealed bids, to having sellers participate in auctions of various forms.³⁵

According to the second criterion, the seller submits evidence that the affiliated utility is not paying more than unaffiliated buyers for similar service. Thus, if an unaffiliated buyer had just signed a five year contract for X Megawatt (MW) of firm power for \$Y/MWh, an affiliate six year firm power transaction with approximately X MW in size and almost \$Y/MWh in price would pass the market-based standard.

However, benchmark evidence based on the first two criteria may not be available. With the first approach, a RFP with the affiliate seller as an invited respondent may discourage participation by other sellers who view the RFP as a sham exercise. Furthermore, preferential treatment of affiliate bidding, if

which relied on a \$6.7 billion bond, offering cash on hand and other facilities to repay creditors.

32. Federal Power Act, 16 U.S.C. § 824d(a) (2000).

33. *Boston Edison Co. Re: Edgar Elec. Energy Co.*, 55 F.E.R.C. ¶ 61,382, 62,168 (1991) [hereinafter *Edgar*].

34. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, 62,332 (1992).

35. See C.K. Woo, et al., *Avoiding Overpriced Risk Management: Exploring the Cyber Auction Alternative* 141 PUB. UTIL. FORT., Jan. 15, 2003, at 30; See also C.K. Woo, et al., *Managing Electricity Procurement Cost and Risk by a Local Distribution Company*, 32 ENERGY POL'Y 635 (forthcoming 2004).

proven, can render the RFP outcome unacceptable.

Under the FERC's second criterion, an affiliate seller with a limited resource portfolio (e.g., one 250 MW gas turbine) may not have recently signed contracts providing the necessary benchmarking evidence. As a result, the third criterion offers a feasible alternative, so long as the affiliate seller and buyer can: (1) identify comparable and contemporaneous contracts in the relevant market; (2) collect the required contract information regarding price and non-price terms; and (3) perform a benchmarking analysis of the affiliate contract.³⁶

The FERC issued the *Edgar* decision in 1991 and the *Ocean State II* decisions in 1991 and 1994, long before the widespread restructuring of the electric power industry that occurred in the late 1990s or the Western power crisis of 2000–2001. During the time of the *Edgar* and *Ocean State II* decisions, merchant power companies had yet to take shape, there were relatively few exempt wholesale generators, and the FERC had not yet issued Orders 888 and 2000 to create open access on the nation's transmission system.³⁷ In the late 1980s and early 1990s, utilities generally restricted their trading and contracting to seasonal exchanges and reserves sharing with adjacent control areas. By the late 1990s, power traded across large regions by utilities and speculators, leading to a dramatic increase in volumes and volatility. Power companies also utilized sophisticated financial hedging instruments in addition to contracting directly with physical assets. These developments point to the potential challenges in developing a comparison group of benchmark contracts and a set of unbiased assumptions.

Disputes over the objectivity of franchised utility RFP processes, where affiliated merchant generators emerged as winners, have triggered recent FERC affiliate transaction hearings in the cases of *Entergy Services, Inc.*³⁸ and *Southern Power Co.*³⁹ In May 2003, the FERC questioned eight long-term contracts signed by Entergy Services, saying that the New Orleans based utility may have given improper preferential bidding treatment to its affiliates during a 2002 power solicitation.⁴⁰ In March 2004, the FERC's staff filed testimony concluding "that numerous aspects of the design, analysis, implementation and contract negotiations of the Fall 2002 RFP conveyed undue preference toward affiliate bids. The actual affiliate abuse and instances of the appearance of affiliate abuse strongly support the need for reform of the RFP process."⁴¹ Entergy countered that its RFP process was not designed to mislead bidders or favor affiliates. The company argued that "RFP was the result of a collaborative process that included input and monitoring by an independent monitor and by

36. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, 62,332 (1992).

37. Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992). See also RICHARD F. HIRSH, *POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM* 240–247 (The MIT Press 1999). The Energy Policy Act of 1992 encouraged competition among wholesale power producers and gave states the prerogative to introduce retail competition within their borders.

38. *Entergy Servs., Inc.*, 103 F.E.R.C. ¶ 61,256, 61,948–61,949 (2003).

39. *S. Power Co.*, 104 F.E.R.C. ¶ 61,041 (2003).

40. *Entergy Servs., Inc.*, 103 F.E.R.C. ¶ 61,256, at 61,948–61,949 (2003).

41. *Id.* at Revised Ex. No. S-7, 6 (direct and answering testimony of Sabina Joe).

the Louisiana Public Service Commission”⁴² The parties attempted to settle their disputes, but have since decided to move ahead with the formal, public hearing.

Regarding the issue of Southern Company’s unregulated affiliate, Southern Power, the FERC set the case for hearing after competitive suppliers claimed that the 2002 solicitation process was biased in favor of Southern Power.⁴³ However, to avoid delays to the commercial operation of the 1040 MW of disputed generation capacity, in May 2004, Southern Company proposed that Southern Power sell the two partially constructed generating units to Southern Company’s regulated Georgia Power and Savannah Electric subsidiaries.⁴⁴ Following the sale, the power purchase agreements (PPAs) with Southern Power would no longer be effective.⁴⁵ The Georgia Public Service Commission has unanimously approved Southern’s proposal. The shift could terminate the FERC’s review of the PPAs under its market-based rate authority.

In February 2004, the FERC decided that, henceforth, the *Edgar*⁴⁶ criteria used to evaluate affiliate abuse in cases of market-based contracts would also apply to cost-based affiliate PPAs of one or more years. The FERC conditionally approved Southern California Edison’s (SCE) plan to establish a wholly owned subsidiary that would purchase and complete construction of the 1054 MW Mountainview plant and sell power exclusively to the utility under a thirty year, cost-of-service contract. At the same time, the FERC acknowledged that the electricity markets have changed significantly since the *Edgar* policy was announced in 1991, and that in some areas of the country market prices for long-term power may be below cost-based rates. The FERC stated, “In order to protect wholesale power customers and guard against potential abuse of self-dealing in a market where cost-based rates may exceed market rates, the Commission will apply *Edgar* to all future power purchase agreements involving affiliates.”⁴⁷ In fact, prior to the FERC’s decision, Calpine Corporation (Calpine) had informed the Commission that if SCE was willing to sign a fifteen-year purchase contract, Calpine could provide power at a price \$300 million below what SCE would pay under the Mountainview contract. In order to allay concerns that Mountainview would give SCE an unfair competitive advantage in the market, the FERC conditioned its approval on SCE’s acceptance that Mountainview would not be eligible to sell at market-based rates.

B. A Case Study of PG&E’s Affiliate Generation Contract Proposal

This section illustrates the challenges of applying the FERC’s price benchmarking criteria by analyzing PG&E’s 2001 application seeking the

42. 103 F.E.R.C. ¶ 61,256, Ex. No. ETR-80, 2 (rebuttal testimony of William M. Mohl).

43. *S. Power Co.*, 104 F.E.R.C. ¶ 61,041(2003).

44. See 2004 Form 8-K of Southern Company (May 7, 2004) (SEC File No. 001-03526), available at <http://www.sec.gov/edgar.shtml> (last modified Aug. 7, 2004).

45. *Id.*

46. *Edgar*, 55 F.E.R.C. ¶ 61,382, 62,168 (1991).

47. *S. Cal. Edison Co.*, 106 F.E.R.C. ¶ 61,183, 61,645 (2004).

FERC's approval of a long-term contract with its affiliate generator.⁴⁸ The affiliate contract was part of PG&E's initial bankruptcy reorganization plan, which was ultimately superseded by a new plan involving bond financing allowing PG&E to emerge from bankruptcy in April 2004. The choice of including PG&E's FERC application in this article was motivated by the significance of the case in light of the California electricity crisis that led to PG&E's bankruptcy. This was not an academic exercise, but rather an actual FERC case that served as a painful and useful reminder of the potential and actual risks of an ill-conceived market reform. The choice of the PG&E application was also motivated by the unique resource mix (hydro and nuclear) and sheer size and complexity of the 7100 MW contract, which created practical difficulties in implementing the FERC's approach.

1. Background on PG&E Bankruptcy and Affiliate Contract

Before the Western power crisis of 2000–2001, PG&E was a financially strong energy utility with an investment grade credit rating of A+ by Standard & Poors (May 2000).⁴⁹ However, beginning in June 2000, wholesale power prices rose far above the 5.47 cents per kWh that PG&E was authorized to charge its retail customers for electricity, forcing the utility to borrow billions of dollars to cover its power purchases.⁵⁰ Downgrades to below investment grade by the major credit rating agencies prevented PG&E from continuing to borrow funds, eventually leading the utility to default on various loans and, in January 2001, PG&E lost its ability to purchase power in the wholesale market. On April 6, 2001, PG&E filed for Chapter 11 protection under the United States Bankruptcy Code.⁵¹ By the time of its bankruptcy filing, PG&E had incurred \$8.9 billion of power purchase costs above the amount recoverable through rates and had accumulated billions of dollars in defaulted debts and unpaid bills.⁵²

As part of its plan to emerge from bankruptcy as a healthy, creditworthy company, PG&E initially proposed dividing the integrated utility into four separate stand alone businesses and transferring a portion of the utility's assets to each of them: retail gas and electric distribution, electric transmission, interstate gas transmission, and electric generation. The new companies were to be known, respectively, as PG&E (Reorganized PG&E), ETrans LLC, GTrans LLC and Electric Generation LLC (Gen). One of the cornerstone agreements of

48. Application of Electric Generation LLC for Order Accepting Power Sales Agreement and Interim Code of Conduct, and Waiving Regulations (2002) (FERC Docket No. ER02-456-000) [hereinafter Application of Elec. Generation].

49. STANDARD & POOR'S, CREDIT WEEK: THE GLOBAL AUTHORITY ON CREDIT QUALITY 52 (June 7, 2000).

50. PG&E's rate for generation was frozen by Assembly Bill 1890, passed in 1996, which opened the door to California's electricity market reforms. Though projected as adequate for stranded cost recovery in 1996, this rate freeze contributed to PG&E's bankruptcy when wholesale market prices surged from under \$40/MWh in 1999 and early 2000 to over \$250/MWh in early 2001. See C.K. Woo et al., *Stranded Cost Recovery in Electricity Market Reforms in the U.S.*, 28 ENERGY INT'L J. 1 (2003); C.K. Woo et al., *Electricity Market Reform Failures: UK, Norway, Alberta and California*, 31 ENERGY POL'Y 1103 (2003); C.K. Woo, *What Went Wrong in California's Electricity Market?*, 26 ENERGY INT'L J. 747 (2001).

51. *In re Pac. Gas & Elec. Co.*, 2002 WL 32071634 (Bankr. N.D. Cal. Sept. 20, 2001).

52. Application of Elec. Generation, *supra* note 48, at 6–8.

PG&E's reorganization plan was to be a long-term Power Sales Agreement (PSA) developed by Reorganized PG&E and Gen while still under the parent PG&E umbrella. According to the plan, PG&E would transfer 7100 MW of nuclear and hydroelectric generation assets to Gen, and Gen would sell all the capacity, energy, and ancillary services back to Reorganized PG&E for eleven years. For the twelfth, and final, year of the contract, Reorganized PG&E would have had rights to the capacity, energy, and ancillary services of approximately half of Gen's assets.

Assuming average water conditions and taking into consideration adjustments for forecast inflation, irrigation district contract expirations, and the fifty percent capacity phase-out in the twelfth year of the contract, Gen estimated a levelized price of electricity of \$51.90/MWh over the life of the PSA.⁵³ Capacity payments under the PSA were weighted to encourage Gen to provide the highest levels of availability during the peak summer months (July and August).

Gen submitted the PSA to the FERC for approval on November 30, 2001, and the PSA was set for a hearing. The CPUC intervened by rejecting the PSA as being price unreasonable and a vehicle used by PG&E to move the generation asset out of the CPUC's jurisdiction. Ten months after submission, the FERC issued an initial decision recommending approval of the PSA,⁵⁴ but the parties eventually set the PSA aside and negotiated a different bankruptcy settlement.

The next part of this paper analyzes the PSA against each of the FERC's benchmarking criteria from the perspectives of PG&E/Gen, the CPUC, the FERC staff, and the FERC Administrative Law Judge. These criteria include the relevant geographic market, relevant product market, contemporaneous contracts, price and non-price comparison of these contracts, and market power.

2. Relevant Geographic Market

The FERC characterizes the relevant market in geographic and product-specific terms. In its *Ocean State Power II* order, the FERC stated:

Ocean State II defines the relevant market as 'the market for delivered long-term baseload capacity and energy in New England in late 1987 through 1988.' We agree that the market for long-term bulk power—the same product sold by Ocean State II—is the relevant product market. A geographic market consists of those suppliers that can supply the relevant product to a buyer or set of buyers . . . [that] have the same supply choices as the [applicant]. The relevant geographic market is determined by sellers that could supply [the relevant] buyers⁵⁵

Given the characteristics of the PSA as a long-term contract with baseload and peaking components serving PG&E's service territory, Gen argued that, to be relevant as a benchmark, "a contract had to be deliverable on a firm basis to the PG&E service territory in Northern California."⁵⁶ This interpretation led

53. *Id.* at Ex. No. GEN-43, 5 (rebuttal testimony and exhibits of Eugene T. Meehan in response to June 12 Commission order). This price included all ancillary services that accompany the assets.

54. *Elec. Generation LLC*, 101 F.E.R.C. ¶ 63,005 (2002) (initial decision approving Gen's PSA).

55. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, 62,333 (1992).

56. Application of Elec. Generation, *supra* note 48, at Ex. No. GEN-2, 11 (direct testimony of Eugene T. Meehan in support of Gen's application).

Gen to exclude contracts in the Eastern Interconnection, eastern portions of the Pacific Northwest, and the Rocky Mountains, even if the contracts had similar product characteristics and were contemporaneous with the PSA.

The CPUC disagreed with Gen's analysis of what constitutes a relevant geographic market. The CPUC's testimony argued that "the [Gen] analysis uses too narrow a definition of the geographic market by focusing on physical deliverability of power into PG&E's service territory."⁵⁷ Since there were no comparable nuclear or hydroelectric contracts in the defined geographic market, the CPUC argued that Gen's benchmarking analysis should have included nuclear contracts from elsewhere in the United States.

To support its argument, the CPUC stated that pricing for long-term contracts was less dependent on regional factors than for shorter-term contracts. "Indeed, market prices for contracts up to five years in length in various regions around the country have tended to converge in the months since FERC issued its June 19, 2001, Order."⁵⁸ The FERC's order required nearly all sellers throughout the Western Electricity Coordinating Council (WECC) to offer to submit bids at their short-run marginal cost whenever the reserve deficiency level for California dropped below seven percent.

The FERC trial staff did not support the CPUC's case for expanding Gen's definition of the relevant geographic market. They defined the "relevant" market as "that geographic area from which sellers can deliver similar quality product to the PG&E load at a price that is lower than, equal to, or not significantly greater than the price of the PSA product."⁵⁹ Whereas, the CPUC focused on the *cost* of comparable contracts, the FERC staff's assessment emphasized the comparability of the *delivered price* that a California power purchaser would face, including transmission costs. FERC Administrative Law Judge, Jeffie Massey, in her October 2002 initial decision, concurred with the FERC staff and Gen that suppliers could not be considered part of the geographic market unless they could physically "supply the relevant product to the buyer or buyers."⁶⁰

3. Relevant Product Market

Those contracts that passed the geographic relevancy test were subjected to a product market screen. Gen considered contracts "relevant" only if they had a similar term and expected delivery pattern as the PSA. Given that the PSA is a twelve-year contract with baseload and peaking components, Gen chose to

57. *Id.* at Ex. No. PUC-1, 11 (direct and answering testimony of Gurbux K. Kahlon of the CPUC).

58. Application of Elec. Generation, *supra* note 48, at 20–21 (Kahlon testimony). Importantly, the FERC required "sellers that own generation to submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas used for generation (i.e., what the seller would pay for gas at the last minute) plus variable O&M costs." Exceptions were made for hydroelectric resources and capacity needed to meet WECC minimum operating reserve criteria for control areas. See *San Diego Gas & Elec. Co.*, 95 F.E.R.C. ¶ 61,418 (2001) [hereinafter June 19th Order]. This FERC order is significant to the proposed use of LRMC as a benchmark for price reasonableness in that the FERC already endorses the use of short-run marginal cost to remedy market imperfections that cause unreasonable price spikes. It is a natural extension to apply LRMC to gauge price reasonableness in the absence of usable data to implement the FERC market-based approach.

59. Application of Elec. Generation, *supra* note 48, at Ex. No. S-12, 12–13 (prepared direct and answering testimony of Sabina U. Joe, witness for the staff of the FERC).

60. *Elec. Generation LLC*, 101 F.E.R.C. ¶ 63,005, 63,019 (2002).

define comparable transactions as long-term bulk power contracts of ten to fifteen years in length with at least eight years of overlap with the term of the PSA period. Although Gen did not disqualify any contracts on the basis of size or technology, it did require the contracts "to have an expected delivery pattern that could equal or exceed (on a scaled basis) the expected output, based on historical averages, of the PSA."⁶¹

Gen's initial screening resulted in a comparison group of eleven contracts. Nearly all of them were long-term contracts signed by the California Department of Water Resources (DWR) in 2001, when the state's utilities were hobbled by the electricity crisis and did not have the credit strength to serve as counterparties. Recognizing that using the DWR contracts would raise concerns of market power and extraordinary pricing because many of the DWR contracts were signed at the height of the crisis, Gen specifically excluded from its comparison group "contracts signed early in [2001 that] may reflect buying panic."⁶² In response to the FERC's order setting the case for hearing, Gen revised its set of comparable contracts to include only contracts signed or amended after the FERC adopted its market mitigation plan for the spot market on June 19, 2001.⁶³

The CPUC argued that none of the contracts in Gen's comparison group had characteristics of the PSA. For example, none of the individual contracts were equal in size to the 7100 MW capacity of the PSA. The CPUC also stressed that because Gen's comparison group did not include nuclear or hydro resources and did not provide ancillary services, Gen's benchmark analysis was flawed and, therefore, invalid.⁶⁴ Instead, the CPUC proposed a portfolio of thirty-one contracts, including short-term contracts, affiliate contracts, power marketer-to-power marketer contracts, and contracts for delivery outside of California and the WECC.

Ideally, the FERC staff would have preferred the PSA to have been compared to like power projects and contracts. However, the FERC staff disagreed with the CPUC's position that the lack of a comparable 7100 MW long-term contract with a similar resource mix rendered Gen's benchmark analysis invalid. The FERC staff concluded that "[t]he principles in *Edgar* do not blindly require a one-on-one comparison of individual projects or transactions. The PSA generation profile can be viewed as a single integral product which can be reasonably compared against the output of another group of comparable projects."⁶⁵ Judge Massey sided with the FERC staff and Gen.⁶⁶

61. Application of Elec. Generation, Ex. No., *supra* note 48, at GEN-2, 11-12 (direct testimony of Eugene T. Meehan).

62. Application of Elec. Generation, *supra* note 48, at Ex. No. GEN-2, 61 (direct testimony of Eugene T. Meehan).

63. *Id.* at Ex. No. GEN-43, 7-8 (rebuttal testimony and exhibits of Eugene T. Meehan in response to June 12 Commission order).

64. Application of Elec. Generation, *supra* note 48, at Ex. No. PUC-1, 5 (testimony of Gurbox K. Kahlon).

65. *Id.* at Ex. No. S-12, 20 (prepared direct and answering testimony of Sabina U. Joe).

66. *Elec. Generation LLC*, 101 F.E.R.C. ¶ 63,005, 65,020 (2002).

4. Contemporaneous Contracts

Market conditions change constantly in the wholesale power market, driven by such factors as weather patterns, economic conditions, fuel prices, plant outages, and transmission availability. To be comparable to the PSA under the FERC's guidelines, other market-based contracts not only must serve customers in the same region with a similar type of product, but the contracts also must have been signed at roughly the same time. Based on the FERC's *Ocean State II* ruling, which defined the relevant time period for purposes of the benchmark analysis to be about eighteen months,⁶⁷ Gen researched market transactions that occurred in the eighteen months prior to its November 2001 FERC filing. The CPUC disputed Gen's definition of "contemporaneous" transactions, arguing that the PSA was not scheduled to take effect until 2003, and, therefore, was not contemporaneous with contracts that started delivery in 2001. Furthermore, it noted that the PSA was not filed until November 2001, a time when forward power prices were lower than they were when the benchmark contracts were signed. However, the FERC staff sided with Gen on the issue, and Judge Massey dismissed the CPUC's arguments.⁶⁸

5. Price Comparison Analyses

Long-term bulk power contracts are usually custom-designed to reflect the unique set of price and non-price terms agreed upon by the transacting buyers and sellers. They are not standard contracts (e.g., a 25 MW block with 6x16 firm, next-month delivery) traded on the open market; rather, they are negotiated bilaterally and are extremely illiquid. The FERC's *Edgar* decision, which rejected Boston Edison's benchmark analysis for its Edgar power plant, placed the burden of proof squarely on the applicant:

A comparative analysis such as the one submitted by Boston Edison can be complicated because of the widely varying pricing structures, operating characteristics, and nonprice terms of the numerous alternatives Moreover, because most prices are formulaic, the analysis will rely to a great extent on projections of formula variables (e.g., fuel cost, plant factors and economic indices) over the life of each project. The assumptions underlying these projections and the significance ascribed to nonprice factors are critical to the analysis.⁶⁹

To ensure that the PSA did not fall into the same trap that Boston Edison's Edgar plant did, Gen used a nominal levelized price methodology grounded in FERC's *Ocean State II* decision.⁷⁰ Gen calculated a levelized dollar per MWh price for the PSA and for each comparative contract by taking the total anticipated payments and total anticipated MWh of generation and adjusting them for timing differences using a discount rate.⁷¹ This form of present value

67. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, 62,334 (1992). The specific period defined for Ocean State was late 1987 to mid-1988 and further extended into 1989 on the theory that some commitments made in 1987-1988 would not result in power contracts until 1989. One should note that by today's standard, eighteen months is a relatively long period during which the market price might have substantially surged and dived.

68. *Elec. Generation LLC*, 101 F.E.R.C. ¶ 63,005, 65,032 (2002).

69. *Edgar*, 55 F.E.R.C. ¶ 61,382, 62,169 (1991).

70. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, 62,335 (1992).

71. Gen added a levelized charge for ancillary services to the benchmark contracts for comparability

analysis placed front-loaded contracts (with decreasing payments over time) on the same footing as back-loaded contracts (with increasing payments over time). Furthermore, Gen used a common set of assumptions for gas prices, the discount rate, the value of ancillary services, and the transmission loss adjustment. This resulted in a single metric: the levelized price in \$/MWh that Gen could use to compare prices of different contracts to the PSA individually and as a portfolio.

Gen used three separate price analyses to demonstrate that the PSA was as favorable to Reorganized PG&E as any other contract or combination of contracts that passed its criteria for comparability. In each contract price analysis, Gen compared the price of each individual contract to the price of the PSA, ignoring differences in dispatchability, availability, or delivery pattern. The PSA was superior to all but two of the contracts in every gas price scenario (low, base, and high). Only in the low gas price scenario were two of the contracts less expensive than the PSA.

Gen also conducted a least-cost portfolio dispatch analysis. Assuming that each of the comparable contracts was infinitely scalable, notwithstanding individual contractual limits on capacity, Gen constructed an optimal portfolio using only the lowest priced baseload and peaking contracts in the Comparison Group to replicate the energy pattern of the PSA.⁷² Under all gas price scenarios, Gen demonstrated that the PSA was less expensive than the optimal alternative portfolio. A third analysis, which allowed for market purchases and sales by the buyer in addition to the dispatch of the least-cost portfolio, yielded the same result as the least-cost portfolio dispatch analysis.

The CPUC rejected nearly all of the assumptions underlying Gen's benchmarking analysis and declared Gen's comparative analysis invalid. The CPUC presented an alternative portfolio of thirty-one contracts, each of which it said was less expensive than the PSA. These included short-term contracts, nuclear contracts from the Eastern Interconnection, affiliate contracts, power marketer-to-power marketer contracts, a contract with Bonneville Power Administration, and contracts for delivery outside of California. However, Judge Massey dismissed the CPUC's benchmark analysis as unpersuasive and criticized it for not being based on a careful assessment of Gen's benchmark evidence.⁷³

The FERC staff and the CPUC questioned whether the financial risks associated with hydroelectric assets, specifically, the volatility in generation output from year to year and the market valuation of the risk, had been properly accounted for in Gen's pricing analysis. The FERC staff argued that whereas Gen's benchmarking portfolio consisted of gas-fired generation with a consistent energy output from year to year, the energy from hydroelectric facilities could vary greatly, leading the market to assign it a lower value than that of a gas-fired plant. A low hydro year could expose Reorganized PG&E to enormous financial risk, because it could end up paying close to double the market price for energy,

because Gen had not included such services in the contracts, but the PSA's price did.

72. Gen did not consider two contracts in the Comparison Group to be scalable. See Application of Elec. Generation, *supra* note 48, at Ex. No. GEN-43, 10-11 (rebuttal testimony and exhibits of Eugene T. Meehan in response to June 12 Commission order).

73. *Elec. Generation LLC*, 101 F.E.R.C. ¶ 63,005, 63,032 (2002).

taking into account the full payment for capacity plus full payment for replacement energy.⁷⁴

Gen's view was that hydro flows would fluctuate over the course of the twelve-year contract, but that on average hydro output would tend towards the long-term mean used to calculate the PSA's price in the benchmark analysis. Moreover, "variations in value will be less than variations in energy" because in low water years, hydro can be stored for use in high value peak hours and used to produce more ancillary services for sale in those hours.⁷⁵ Gen concluded, with a ninety-eight percent probability, that even when using actual precipitation data under an extremely dry twelve-year hydro cycle, the PSA was as favorable to Reorganized PG&E as the optimal portfolio.

Because neither the CPUC nor the FERC staff supported their criticisms of Gen's price terms with independent analyses that quantified the meaning or impact of the price terms, Judge Massey concluded that she could not give the criticisms any evidentiary weight. Thus, Gen's position was accepted.

6. Non-Price Terms

Gen was also required to benchmark the PSA's non-price contractual terms against the comparison group. This included analyzing the assignment of responsibilities and risks and the consequences of non-performance by the parties. Gen compared the non-price terms of its PSA with those of typical, arms-length bilateral sales agreements. The terms evaluated included availability risk (a measure of reliability), fuel price risk, dispatch control, hydrologic risk, and Diablo Canyon facility security risk.⁷⁶

Gen declared that the PSA was no riskier, and in some ways less risky, than the comparison contracts entered into by the DWR. Whereas all but one of the comparison contracts were fueled by natural gas, the PSA protected Reorganized PG&E from gas price volatility through its hydro and nuclear asset portfolio. Furthermore, while some of the DWR contracts carried a risk of asset development delays, all of the assets in the PSA were operational.

The FERC staff acknowledged that nearly all of the benchmark assets face fuel price risk. In the Initial Decision supporting Gen's position, FERC Judge Massey wrote:

When taken out of context, any one price or non-price term may be less favorable than its counterpart in one or more of the Comparison Group Contracts. However, I don't believe that is what the Commission contemplated when it ordered a Benchmark Analysis in this proceeding. The PSA must be considered as a whole—almost like a living entity—its parts interact to make it what it is.⁷⁷

74. Application of Elec. Generation, *supra* note 48, at Ex. No. S-12, 24 (prepared direct and answering testimony of Sabina U. Joe).

75. Application of Elec. Generation, *supra* note 48, at Ex. No. GEN-2, 61 (direct testimony of Eugene T. Meehan).

76. *Id.* at 77–81 (direct testimony of Eugene T. Meehan).

77. *Elec. Generation LLC*, 101 F.E.R.C. ¶ 63,005, 63,029 (2002).

7. Market Power Test

The FERC's final test for abusive self-dealing in affiliate transactions examines whether the applicant or its affiliates have distorted the benchmark evidence through the exercise of market power. "In particular, when a seller . . . is seeking market-based prices for sales to one or more affiliated traditional utilities, our concern is that the transfer price—the price the seller charges its affiliated buyers for the seller's power—is too high."⁷⁸

First, Gen addressed this concern by observing that neither it nor PG&E was a party to any of the benchmark contracts. Accordingly it could not have influenced their outcomes. Second, PG&E had no incentive to artificially raise prices because it was a net buyer of power even before it sold more than 6000 MW of generation capacity in its 1998–1999 divestment. Although PG&E's parent, PG&E Corporation, did have control over independent power assets indirectly, through its wholly-owned subsidiary PG&E National Energy Group (NEG), the output of the four NEG-related power plants operating in the West was committed to long-term, fixed rate contracts.⁷⁹ Neither the FERC staff nor the CPUC presented any evidence challenging Gen's position on this issue.

C. Challenges of Applying *Edgar* and *Ocean State II* to the Current Market

The analysis in the previous section highlights the challenges of applying the market-based benchmarking enshrined in *Edgar*⁸⁰ and *Ocean State II*⁸¹ to determine whether a long-term contract between affiliates is just and reasonable. Unlike standard products with near-term delivery that are tradable on the open market, large long-term contracts are less common, usually negotiated bilaterally, and customized to particular assets and the needs of one buyer. Gen was able to find a variety of comparable contracts because many long-term contracts were executed in response to the California debacle. However, the sample of potentially comparable and contemporaneous contracts may be quite small in other situations; thus, making it virtually impossible to avoid some subjectivity and ambiguity in defining the relevant market and contemporaneous time period.

Arbitrary assumptions regarding key parameters, such as the minimum length of a "long-term" contract, can have significant effects on whether the benchmark analysis "proves" that the contract in question is at, below, or far above the market price for similar transactions. Furthermore, contract prices for the comparison group can be unduly influenced by market imperfections. Such imperfections include: poor market design as exemplified by California; market power abuse by large generators as alleged by the California Independent

78. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, 62,337 (1992).

79. On May 3, 2004, the U.S. Bankruptcy Court for the District of Maryland approved National Energy & Gas Transmission's (NEGT) Plan of Reorganization, paving the way for the company to emerge from bankruptcy. NEGT will become unaffiliated with PG&E Corp. See Press Release, National Energy and Gas Transmission, Bankruptcy Court Approves Reorganization Plan for National Energy & Gas Transmission, Inc. (May 3, 2004), available at http://www.negt.com/por_release.pdf.

80. *Edgar*, 55 F.E.R.C. ¶ 61,382 (1991).

81. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360 (1994).

System Operator and Governor Gray Davis; falsified natural gas price information, such as Williams, Dynegy, American Electric Power, CMS, El Paso Merchant Energy and Western Gas Resources have admitted to providing to energy publications;⁸² information advantage enjoyed by affiliated generators in obtaining transmission access; poor price discovery due to thin trading or lack of trading of spot energy and hedge instruments (e.g., options, futures, and forward contracts); poor risk allocation due to a lack of hedge instruments or thin trading of such instruments; and incomplete market reflected by lack of trading of long-term contracts and other hedge instruments.

The restructuring of electricity markets and rapid expansion of power trading in the late 1990s increased the complexity of the power markets and volatility of electricity prices. A fast moving market has highly volatile prices that can render meaningless a benchmark that was computed using a long sample period. For instance, the precedent set by *Ocean State II* and followed by Gen in application to the FERC for the PSA with PG&E is an allowance for an eighteen month window to cull benchmark transactions. Since the California energy crisis and the financial troubles of the merchant power sector, an even more debilitating problem has emerged—electricity trading has dwindled to such a degree that even standard products for relatively short terms lack liquidity, not to mention long-term contracts.⁸³

The result of all this ambiguity is often an inconclusive analysis, which fails to produce consensus among the stakeholders on the just and reasonable nature of the contract in question. Without reliable, comparable, and contemporaneous long-term contracts, the FERC's market price approach to benchmarking will face enormous challenges.

III. LONG-RUN MARGINAL COST ANALYSIS

A. Benchmarking and Least-Cost Procurement

The purpose of the FERC's hearing on the PSA was to evaluate whether PG&E had engaged in abusive self-dealing. The Administrative Law Judge concluded that, in light of the market-based benchmarking evidence presented, the terms of the PSA were at least as favorable as terms of comparable transactions.

The CPUC disagreed, and on several occasions attempted to insert the notion of cost into the FERC's benchmarking framework. The CPUC staff stated, "the benchmark analysis in this case should focus on measuring cost and value of the PSA relative to comparable transactions."⁸⁴

82. STAFF OF THE FED. ENERGY REGULATORY COMM'N, FINAL REPORT ON PRICE MANIPULATION IN WESTERN MARKETS (2003). See also Press Release, Western Gas Resources, Inc., Western Gas Resources, Inc. Announces Inaccuracies in Historical Price Reporting to Gas Trade Publications (Sept. 29, 2003), available at <http://www.westerngasresources.com/financial/index.html>.

83. Ken Silverstein, Trading Places, ISSUE ALERT, Apr. 25, 2003, available at <http://www.3utilipoint.com/issuealert/article.asp?id=1658>.

84. Application of Elec. Generation, *supra* note 48, at Ex. No. PUC-1, 20 (direct and answering testimony of Gurbux K. Kahlon).

Although both the FERC and state regulators agree that benchmarking is necessary for gauging the price reasonableness of long-term electricity contracts, it is questionable whether market-based comparisons are sufficient, especially when approval for full cost recovery by a state regulator is at stake. For example, although the FERC Administrative Law Judge accepted Gen's price benchmarking analysis of the PSA, it is unlikely that the CPUC, in the absence of additional information, could find the PSA prudent and qualified for full cost recovery from PG&E's retail customers within the CPUC's jurisdiction. Hence, long-run marginal cost (LRMC) analysis, which is already in use by most states, could serve as a complementary tool for price evaluation and remove much of the ambiguity surrounding benchmarking solely based on "comparable and contemporaneous" transactions.

B. Price Benchmarking beyond Edgar and Ocean State

This article proposes LRMC as corroborative evidence in support of the FERC's market-based benchmark, if there are no contemporaneous benchmark transactions available that are sufficiently comparable in both price and non-price terms to the long-term contract in question. If used as an alternative to the FERC's market-based benchmark, the LRMC approach should possess the following attributes: (1) It should be theoretically sound and backed by a history of successful case work in order to be acceptable to all parties; (2) It should be empirically conservative, generating future electricity prices that err on the low side of reasonable estimates to prevent affiliate abuse; (3) It should only use data that do not require significant manipulation; (4) Its modeling and input data should be transparent, easily verifiable, and sourced from independent sources; (5) Its cost of application error should be minimal.⁸⁵

C. LRMC Defined

It appears that LRMC has all of these favorable attributes. This conclusion is reached by first recalling the standard economic definition of LRMC: "The change in long-run total cost due to the production of one more unit of output."⁸⁶ The long-run total cost is the result of a firm making a long-run production decision using a least-cost mix of inputs to produce a given level of output. The term "long-run" refers to a time horizon whereby the firm's decision assumes all inputs (e.g., capital, energy, labor, land, and material) are variable. Because the list of inputs includes capital, the total cost includes the cost of a competitive return on and of capital.

In the context of electricity generation, the LRMC is the cost of producing an incremental output with a specific time profile. The time profile is important because electricity cannot be economically stored and must be generated in real

85. Consider a state regulator approving a contract priced below a conservatively estimated benchmark. The contract is unlikely to result in rates significantly above actual spot prices during the contract's delivery period. In other words, even if the spot prices turn out to be unexpectedly low, a contract approved on the basis of the conservative benchmark does not create unacceptably high rates that may be deemed "unjust and unreasonable" ex post.

86. MICHAEL L. KATZ & HARVEY S. ROSEN, *MICROECONOMICS* 282 (Irwin/McGraw-Hill 1998) (1991).

time in order to meet time-varying demand. An output profile with brief periods of very high production is more costly and commands a higher LRMC than one with relatively stable production.

The LRMC approach has a conceptually sound relationship to market prices for long-term contracts, especially those of ten or more years in length. In a competitive market, the LRMC is the minimum price required to yield competitive returns to investors in new supply, assuming that supply and demand are in approximate equilibrium. By contrast, shorter-term contracts (five years or less) are typically priced from volatile forward power and natural gas price curves, which reflect short-term views of the existence of surplus or insufficient capacity in the marketplace, rather than long-term fundamentals. If the input data used in LRMC estimation reflect today's market environment, the resulting estimate will provide a useful benchmark for today's minimum price for long-term contracts. To the extent the LRMC is based on conservatively developed estimates of input prices, it provides a conservative lower bound benchmark for judging the reasonable pricing of a long-term contract.

One can find contract prices that deviate from the LRMC estimates. Such deviations can occur simply because of market imbalances at the time or due to non-price terms in contracts that differ from those underlying the LRMC estimation. Price deviations from the LRMC for long-term contracts with identical non-price terms cannot persist over long periods of time due to market entry and exit by suppliers.⁸⁷ A rational supplier would not consistently enter into long-term power contracts that did not yield competitive returns. Similarly, a supplier could not consistently earn an excessive return (above the competitive level) because rational buyers of long-term contracts would seek alternative suppliers who would accept a competitive return.

D. State Regulatory Experience with LRMC

Many state public utilities commissions (PUCs), including the CPUC, have adopted the *economic concept* of LRMC to gauge the reasonableness of a utility's power procurement plan. The PUCs also have adopted empirical estimates of LRMC based on the capacity and financing costs for a suitable mix of new gas-fired plants, the fuel efficiency of that plant mix, and the long-term cost of gas used to run the plants in order to meet the non-price terms of the utility's procurement plan.

States have used LRMC to infer the long-term average price of electricity. The California Energy Commission relies on the LRMC to project the long-term average price of electricity in the state.⁸⁸ The Texas Public Utilities Commission used LRMC estimates to predict the long run market clearing prices of electricity under market competition,⁸⁹ and the resulting price prediction was used to

87. Application of Elec. Generation, *supra* note 48, at Ex. No. PUC-1, 20 (direct and answering testimony of Gurbux K. Kahlon).

88. See CAL. ENERGY COMM'N, 2002–2012 ELECTRICITY OUTLOOK REPORT (Feb. 2002), available at http://www.energy.ca.gov/electricity_outlook.

89. See Order No. 14, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule Section 25.344*, TEX. PUB. UTIL. COMM'N (2000) (Docket No. 22,344), available at

forecast the levels of "Excess Costs Over" (stranded costs) in Texas.⁹⁰ The State of Washington requires electric utilities to regularly develop and file long-range, "least-cost plan[s]" which imply the use of LRMC for electric utilities.⁹¹ These plans and the LRMC guide each utility's short-term (e.g. two-year) planning efforts and acquisition decisions, as well as help to "evaluate the performance of the utility in rate proceedings, including the review of avoided cost determinations"⁹² According to the National Association of Regulatory Utility Commissioners' (NARUC) Compilation of Utility Regulatory Policy in the United States and Canada, a majority of U.S. utilities use the LRMC as the basis for calculating avoided costs.⁹³

The CPUC uses an avoided cost/LRMC view of affiliated and unaffiliated transactions. Therefore, a transaction that passes the FERC market-based benchmark may not receive the CPUC's approval for full cost recovery. The procurement prudence review of Bear Valley Electric Service (BVES), a subsidiary of Southern California Water Company (SCWC), provides an example of a market-based benchmark not receiving CPUC approval.⁹⁴ On March 16, 2001, at the height of the California energy crisis, SCWC signed a five-year, \$95/MWH fixed price contract for fifteen megawatts with twenty-four hour-a-day delivery.⁹⁵ Even though SCWC's contract was the result of competitive responses to its Request for Offers (which would have passed the FERC's benchmark test), and the price was comparable to that of similar contracts signed by DWR, SCWC settled with the CPUC and an intervenor, resulting in a significant disallowance of the SCWC's contract cost.⁹⁶ The passage into law of AB 57 and the CPUC's requirement that California's three large utilities to submit procurement plans for the CPUC's approval should minimize future litigation over cost recovery and present a reasonable allocation of procurement risk between a utility's customers and shareholders.⁹⁷

In May 2003, the CPUC bluntly indicated its preference for cost-based benchmarking over market-based comparison. It stated, "[t]he record does not indicate that there are contracts in sufficient number or comparability to provide a basis for setting a market price. Accordingly, while the Commission will consider any such contracts in determining a market price, we cannot rely

http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=22344&TXT_ITEM_NO=256.

90. *Id.*

91. *See* WASH. ADMIN. CODE § 480-100-238(3) (2004).

92. *See* WASH. ADMIN. CODE § 480-100-238(5) (2004).

93. MICHAEL FOLEY & JESSICA O'CONNOR-PETTS, NAT'L ASS'N OF REGULATORY UTIL. COMM'RS, UTILITY REGULATORY POLICY IN THE UNITED STATES AND CANADA: COMPILATION 1995-1996 OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (1996).

94. *See* Chi-Keung Woo et al., Did a Local Distribution Company Procure Prudently During the California Energy Crisis?, ENERGY POL'Y (forthcoming 2004). Paper presented at Second Asian Energy Conference, "Energy Market Reform: Issues and Problems," at Hong Kong Baptist University (Aug. 2003). [hereinafter Woo et al.].

95. *Id.*

96. *See* Woo et al., *supra* note 94.

97. *Id.*

significantly upon them at this time.”⁹⁸ Additionally, the CPUC will not rely, in any significant way, on bids and unaccepted quotes as a basis for the market price referent.⁹⁹ Rather, it will consider the LRMC of a new combined-cycle gas turbine (CCGT) as a proxy for benchmarking the value of a baseload resource, and the costs of a combustion turbine (CT) as a proxy for the value of a peaking product.¹⁰⁰ In the absence of comparable long-term fixed-price natural gas contracts, the CPUC will use the cost of long-term gas hedges.¹⁰¹

The CPUC rejected the notion that using the LRMC of proxy plants to establish the market price benchmark was inconsistent with statutory requirements or federal law.¹⁰² The CPUC contended the FERC permits state commissions flexibility regarding the procedures selected to determine avoided costs.¹⁰³ To support this position, the CPUC quoted a 1995 FERC decision stating,

The [FERC] has not, and does not intend in the future, to second-guess state regulatory authorities' actual determinations of avoided costs (i.e., whether the per-unit charges are no higher than incremental costs). Rather, the Commission believes its role is limited to ensuring the process used to calculate the per unit charge (i.e., implementation) accords with the statute and our regulations.¹⁰⁴

The CPUC believes this means that even if the LRMC approach yields long-run prices that exceed a utility's short-run avoided cost, the FERC will not dispute the numbers.

E. LRMC in the Context of FERC's Edgar¹⁰⁵ and Ocean State II¹⁰⁶ Precedents

LRMC is a natural extension of FERC doctrines already in place. In *Edgar*, the FERC stated that “the Commission must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and nonprice terms.”¹⁰⁷ To eliminate concerns about preferential pricing, FERC applies the standard of “a benchmark of the market value of similar services based on contemporaneous data.”¹⁰⁸

LRMC forms such a benchmark for the following reasons. First, LRMC is conceptually a minimum price that a hypothetical supplier operating in a competitive market would charge to meet the non-price terms of the contract under review. If the contract price is close to a conservatively estimated LRMC benchmark, it is not the result of self-dealing. Second, the input data for LRMC estimations come from independent sources (e.g., state and federal governments). LRMC estimates do not rely on contract price data that might

98. Proposed Decision for Cost Recovery, *supra* note 29, at 24.

99. *Id.* at 17.

100. Proposed Decision for Cost Recovery, *supra* note 29, at 24.

101. *Id.* at 21.

102. Proposed Decision for Cost Recovery, *supra* note 29, at 24–25.

103. *Id.*

104. *S. Cal. Edison Co.*, 70 F.E.R.C. ¶ 61,125, 61,667 (1995).

105. *Edgar*, 55 F.E.R.C. ¶ 62,168 (1991).

106. *Ocean State Power II*, 69 F.E.R.C. ¶ 61,546 (1992).

107. *Edgar*, 55 F.E.R.C. ¶ 61,382, 62,168 (1991).

108. *Id.*

have arisen from a dysfunctional market. On the contrary, they form an objective and unbiased benchmark of the all-in cost of new generation based on the available cost data for generation equipment, financing, fuel, and emission offsets. Finally, LRMC estimates are based on assumptions reflective of the most recent input market conditions. Thus, LRMC estimates are contemporaneous with the contract in question.

LRMC estimates also accord with the criteria for benchmark evidence set out in *Ocean State II*. The relevant market considered in a LRMC estimation is the market for long-term contracts that replicates the output profile of the contract in question. The contemporaneousness of a LRMC estimation is self-evident from its use of the most recent input price data. Comparability is inherent in LRMC estimates because the estimates are based on the least-cost mix of CTs and CCGTs to meet the non-price terms of the contract to which they are being compared.

Finally, the input price data used in a LRMC estimation come from public and independent sources, preempting the possibility that the benchmark data may be skewed by market power of a contract seller or its affiliates. *Ocean State II*, in its application to the FERC, argued that a traditional cost-of-service study supported its position that it was "entitled to a higher-than-average [return on equity] because it face[d] greater risks than the average utility."¹⁰⁹

One inherently attractive feature of the LRMC approach is that the cost of error in approving a contract based on a conservatively estimated LRMC is small. For example, assume that a regulatory body approves a contract based on LRMC with an assumed natural gas price of \$4.00 per MMBTU, which is considered conservative at the time of this writing, when the spot and futures gas prices hover round \$6.00 per MMBTU. The question becomes—What is the effect of gas prices declining to \$2 or \$1 per MMBTU over the life of the contract, versus the effect of fuel or non-fuel price factors raising the spot price of electricity above the LRMC price? The unlikely gas price decline implies that ratepayers might end up paying slightly more than spot market purchasers. However, a spot price spike, such as the one that occurred in the California electricity crisis, can translate into a long-term rate increase and financial insolvency of utilities.

F. Case Study: LRMC Analysis of PSA in PG&E's FERC Application

As an illustration of how the LRMC test should be applied, this article estimates the LRMC as a supplemental benchmark to gauge the price reasonableness of PG&E's PSA. The PSA's price is said to be reasonable (from the LRMC perspective) if it is very close to the estimated LRMC using input assumptions that are reflective of the contemporaneous market environment. These LRMC estimates quantify the minimum price that a hypothetical supplier would charge for a contract with non-price terms (e.g., contract duration, annual MW and MWh profile, and delivery location) comparable to those of the PSA. This minimum price is the price at which the supplier would earn a competitive return on its investment, given contemporaneous market prices for the inputs

109. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, 62,326 (1992).

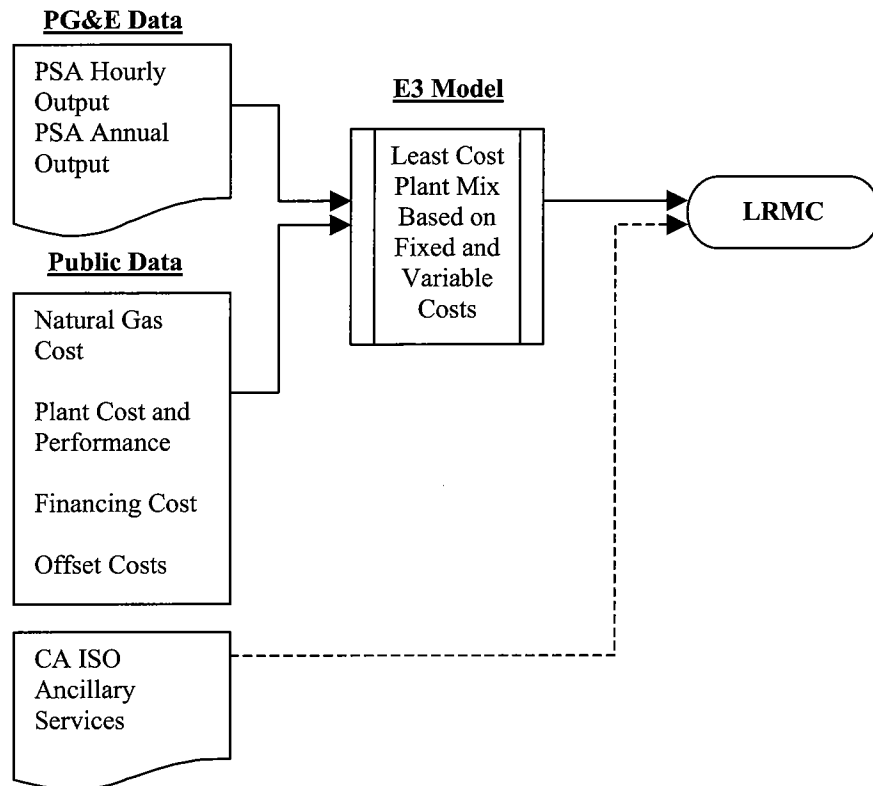
used to meet the PSA's non-price terms.

The process to quantify the LRMC by replicating the output of the assets included in the PSA involves the following steps: (1) Establish the normal hourly profile of output for the assets included in the PSA; (2) Find a suitable least-cost mix of new generators that can produce the same output profile; (3) Compute the cost per MWh of the mix, with the result being the LRMC of producing the energy from the plants included under the PSA; (4) Add the cost of providing capacity for contingency reserves and regulation to develop a final LRMC estimate; (5) Add the cost of acquiring the necessary emissions offsets;¹¹⁰ and (6) Test the sensitivity of the LRMC estimates to each of the cost input assumptions.

Figure 1 below shows how the key data assumptions are used to compute the LRMC estimate. The top of the figure shows the PSA hourly output pattern based on the 1999 recorded generation pattern (consistent with Gen's testimony) and the annual output under the PSA. Located below that are five categories of publicly available cost data used in the analysis. Using the cost data, the mix of CT and CCGT were selected to produce the least cost output profile, (i.e., the minimum sum of the fixed costs for plant purchase), financing and fixed O&M that do not vary with the MWh output of the installed capacity, and the variable costs for fuel, variable O&M and emission offset that vary with the MWh output. Additional generation plants were included to provide the ancillary services for the load that is currently served by PG&E's hydro facilities. Hence, the total long-run cost is (a) the cost of meeting the output profile, plus (b) the cost of providing ancillary services. The LRMC is this total cost levelized over the annual MWh output of the assets under the PSA.

110. Since the costs of emissions offsets vary with plant output, they are included in the dispatch analysis in step (2).

FIGURE 1: LRMC ESTIMATION PROCESS



Depending on the choice of technology cost assumptions, the estimates of the levelized LRMC of replicating the output and ancillary services self-provided by the generation assets, included under the PSA, range from a low of \$53.67 per MWh to a high of \$57.84 per MWh. In comparison, Gen estimated that the levelized rate under the PSA would be \$51.90 per MWh. This rate is three to ten percent below the LRMC values. In light of these LRMC estimates, the PSA rates are reasonable under a LRMC benchmark, because they are lower than the per MWh cost of building and operating the least-cost mix of new generation facilities capable of replicating the output profile of the facilities covered under the PSA.

IV. CONCLUSION

Price benchmarking is here to stay, irrespective of the future direction of the electricity sector. A continuation of the status quo requires benchmarking of affiliate transactions by the FERC and both affiliate and non-affiliate transactions by state regulations. An acceleration of market reform and deregulation does not remove the need for price benchmarking due to concerns of market imperfections. Reversal of market reform and deregulation expands

regulatory control and oversight, including price benchmarking.

At the state level, the price reasonableness test aims to determine procurement prudence. Whether prudence is based on an ex ante benchmark, as mandated by AB 57 in California, or an ex post reasonableness review, the LRMC at contract signing is a commonly used benchmark. As this article shows, states use LRMC for a wide range of purposes, including benchmarking avoided cost, determining the most cost-effective mix of generation resources in utility integrated resource planning, and setting renewable resource price benchmarks.

At the federal level, price benchmarking is primarily used to determine if self-dealing has occurred in affiliate transactions. Absent competitive procurement and arms-length negotiations, the benchmark is the price of the contracts that are contemporaneous and comparable to the one in question, assuming the non-price terms of the contract at issue are at least as favorable as those of similar arms-length contracts and the utility has not manipulated the benchmark through the exercise of market power. As a market-based test, it makes no direct reference to cost, including LRMC.

This article's proposal of an LRMC-based benchmark provides a clear and easy-to-understand test: If the contract's price is less than a conservatively estimated LRMC, the contract is per se price reasonable. It aligns the federal and state approaches to price benchmarking of long-term contracts.

This alignment should occur because the FERC has already shown it is not averse to using marginal cost in determining price reasonableness. In its June 19, 2001, West-wide market power mitigation order, the FERC invoked a single market clearing price with must-offer and short-run marginal cost bidding requirements for sales in the California ISO's spot markets in reserve deficiency hours, i.e., when reserves are below seven percent in California.¹¹¹ It would be but one small and natural step to extend the FERC's use of short-run marginal costs for price capping to long-run marginal costs for benchmarking a long-term contract, when the FERC's extant market-based approach is impractical due to lack of suitable data.

Today's wholesale electricity prices are highly volatile and uncertain. This also makes the FERC's market-based benchmark test for long-term contracts highly uncertain. However, for short-run contracts (less than five years), the authors concur that there is no practical substitute for the market-based benchmark, when comparable and contemporaneous contracts exist. Longer run contracts (beyond ten years) tend to have much more stable prices. In one sense, this can make benchmarking based on market prices easier if a liquid, workably competitive market for long-term contracts exists. However, if such a market is not available, a conservatively estimated LRMC can provide an effective surrogate benchmark to determine the reasonableness of long-term contract prices between affiliates.

111. *San Diego Gas & Elec. Co.*, 95 F.E.R.C. ¶ 61,148 (2001).

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