UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,	)	
	)	
Complainant,	)	
	)	Docket No. EL00-95-000
v.	)	EL00-95-045
	)	EL00-95-075
Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange,	)	
	)	
Respondents.	)	
	)	
	)	
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket No. EL00-98-000 EL00-98-042 EL00-98-063

PREPARED TESTIMONY OF
ROBERT J. REYNOLDS, PH.D.
ON BEHALF OF THE CALIFORNIA PARTIES

Index of Relevant Material Template

Submitter (Party Name)	California Parties
Index Exh. No.	CA-5
Privileged Info (Yes/No)	Yes
Document Title	Prepared Testimony of Robert J. Reynolds, Ph.D. on Behalf of the California Parties
Document Author	Robert J. Reynolds, Ph.D.
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	California Generators withheld from the market. California Generators withheld by not bidding their output into the market even though the plant was fully operational. This withholding behavior occurred during numerous system emergencies. California Generators withheld generation from the market by bidding high, and in excess of their costs, so as to deliberately price themselves out of the market. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Prices before October 2, 2000 were not consistent with Sellers' market-based rate tariffs and those of the ISO and PX.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95 and EL00-98 (including all subdockets)
Indicate if Material is New or from the Existing Record (include references to record material)	New
Explanation of what the evidence purports to	The California Generators engaged in significant levels of withholding from the CAISO real-time energy market over significant periods of time from January 1, 2000 through June 20, 2001. Utilizing the assumption

show	that the California Generators' reported outages were legitimate, aggregate withholding by those generators averaged over 1000 MW per hour during on-peak hours from May-September 2000. Using the same assumption about the legitimacy of the generators' reported outages, this evi dence shows that from May-September 2000, the California Generators' withholding exceeded 1000 MW during about 45% of the on-peak hours and exceeded 2000 MW in about 15% of the on-peak hours. These estimates are conservative (i.e. understate the full extent of withholding) for reasons enumerated specifically in the testimony. The presence of significant withholding is strong evidence of the exercise of market power by the California Generators. The California Generators frequently did not bid capacity that was available and producible at a marginal cost below the prevailing maximum allowable bid price in the CAISO real-time market. The average un-bid producible capacity exceeded 500 MW during on-peak hours in virtually all months (January 2000 – June 2001) and exceeded 1000 MW in some months. Such a failure to bid such capacity can result in withholding and reflect the exercise of market power.
Party/Parties performing any alleged manipulation	AES/Williams; Duke; Dynegy; Mirant; Reliant

* This entry is not limited to the California and Northwest Docket Numbers.

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SECTION I. INTRODUCTION AND SUMMARY

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

A: My name is Robert J. Reynolds. I am Chairman of Competition Economics, Inc., an economics research and consulting firm specializing in the analysis of competition, regulation, pricing, and financial performance, with extensive experience in many different industries. My business address is 4800 Montgomery Lane, Suite 900, Bethesda, MD 20814.

Q: On whose behalf are you offering testimony?

A: I have been retained by the Attorney General of the State of California to provide testimony on behalf of the Attorney General of the State of California, the California Public Utilities Commission, the Electricity Oversight Board, Southern California Edison, and Pacific Gas and Electric, collectively known as the "California Parties."

Q: What experience do you have with respect to matters related to your testimony in this proceeding?

A: I have experience as an economist in academia, government, and consulting to the private sector. I specialize in empirical and theoretical analysis of industrial organization, public and regulatory policy issues, and antitrust problems. I served in the Antitrust Division of the U.S. Department of Justice from 1973-1981 and was an Assistant Director of the Antitrust Division's Economic Policy Office, where I supervised research in antitrust policy and was actively involved in DOJ investigations, including serving as chief staff economist on *U.S. v AT&T* until 1978. I have also held academic positions at Cornell University, the University of California at Berkeley, and the University of Idaho, teaching courses in industrial organization, regulation, antitrust, and micro- and macroeconomic theory. I have provided expert analysis and testimony for cases in the United States and abroad. I hold a Ph.D. in Economics from Northwestern University. My background is more fully detailed in my curriculum vitae, which is attached as Exh. CA-6 (Appendix A).

Q: What is the purpose of your testimony?

A: I have been asked to assess the degree to which the "California Generators" – AES/Williams, Duke, Dynegy, Mirant, and Reliant, collectively – withheld output from the California Independent System Operator (CAISO) real-time energy market during the period January 1, 2000 through June 20, 2001.[1] My analysis does not focus on specific "crisis" hours, but rather examines whether there were significant levels of withholding over a significant number of hours during this period. As I will explain, the presence of significant withholding is strong evidence of the exercise of market power by the California Generators.

In addition, I have been asked to determine the extent to which the California Generators did not bid capacity that was available and producible at a marginal cost below the prevailing maximum allowable bid price in the CAISO real-time market. As I discuss in more detail below, under some circumstances such a failure to bid capacity can result in withholding and reflect the exercise of market power.

My testimony presents the results of my analysis in these two areas.

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[1] Notably, my analysis is limited to the ISO real-time market. I do not consider the issue of whether a generator withheld supply from the California Power Exchange (CalPX) Day Ahead or Hour Ahead markets. Unless stated otherwise, when I refer to withholding in this testimony, I am referring to withholding from the CAISO real-time market only.

Q: What documents and materials specifically related to this case have you considered in preparing your testimony?

A: In conducting this analysis, I have considered FERC orders and materials in this proceeding, various letters, papers, and reports related to California energy markets, the CAISO tariff and other CAISO documents, and certain other materials, as listed in Exh. CA-6 (Appendix B). In addition, I have relied on: (a) Dr. Richard McCann's assessment of environmental regulations affecting the California Generators' power plants and the corresponding costs related to NOx emissions and (b) Dr. Phillip Hanser's assessment of the benchmark level of forced outages for the California Generators' power plants, as described in their respective testimony submitted in this proceeding concurrent with my testimony.

Definition of Withholding

Q: How do you define withholding for purposes of your testimony in this matter?

A: I define withholding as the failure to produce energy (or commit to produce energy via ancillary services) from capacity that was capable of economically providing energy at the prevailing market prices. Withholding, as I have defined it, generally has a direct effect on market prices: i.e., withholding increases market prices.[2]

[2] Note that I have not been asked to estimate what market prices would have been but-for withholding. Technically, a small amount of withholding in a particular hour might not change the market price (i.e., if there were no change in the price of the highest bid accepted because the withholding was too small to result in a change in the marginal cost for the highest cost unit needed to meet demand).

Q: Are there different types of withholding?

A: Yes. Generally speaking, withholding can be divided into two categories: "physical withholding" and "economic withholding." I use those terms to mean the following, which I understand to be consistent with the FERC's use of those terms:[3]

- Physical withholding refers to a situation in which capacity that is available and economic at the prevailing market price is not bid into the market.
- Economic withholding refers to a situation in which capacity that is available and economic at the prevailing market price is bid at a price that is higher than both its marginal cost and the market price, so that such capacity is not dispatched.

Q: Do these different types of withholding affect the market differently?

A: For the most part, the answer is no. Each of the mechanisms of withholding has similar effects on the market. As such, distinguishing precisely between the different methods of withholding is not a critical issue from my perspective. Thus, the focus of my efforts is on the overall extent of withholding regardless of the mechanism.

Q: Can you provide some examples to illustrate your definition of withholding?

A: Yes. Figure 1 provides some simplified examples to help explain my definition of withholding.

[3] In its Notice of Proposed Rulemaking in Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (Docket RM01-12-000) (FERC SMD), FERC states: "Market power is the ability to raise price above the competitive level. [fn omitted] This can be accomplished if the generator can withhold physical power (physical withholding) or cause physical power to be withheld through inflated bids (economic withholding)." (paragraph 393).

Figure 1
Simplified Examples to Illustrate Withholding Definition
($/MWh)

Case	Marginal Cost	Bid Price	Market Price	Withholding?
1	50	100	150	No
2	50	100	75	Yes - Economic
3	50	100	30	No
4	50	None	150	Yes - Physical
5	50	None	75	Yes - Physical
6	50	None	30	No

Basically, withholding occurs when a unit is not actually dispatched, but the unit would have been dispatched if it had been bid at its marginal cost.

Referring to Figure 1:

- In Case 1, the unit has a marginal cost of $50 per MWh, it is bid at $100 per MWh, and the market price is $150 per MWh. In this case, the unit would be dispatched at the actual bid (as well as at a bid equal to its marginal cost), and there is no withholding.
- In Case 2, the market price is $75 per MWh and the unit is not dispatched at the actual bid of $100. In this case, there is withholding because the capacity would have been dispatched if it had been bid at its marginal cost.
- In Case 3, the market price is below the marginal cost of the unit. Hence, there is no withholding since the unit would not be dispatched even if it had been bid at marginal cost. Similarly, there is no withholding in Case 6 even though the unit was not bid.
- In Cases 4 and 5, there is withholding because the unit is not bid and not dispatched, but would have been dispatched if it were bid at its marginal cost.[4]

[4] In this example, I assume that the unit is not on outage.

Q: Just so I'm sure about your definition of withholding, do you consider bidding at prices above marginal costs to be withholding?

A: Bidding at prices above marginal costs, in and of itself, does not constitute withholding under my definition. The reason is that bidding above marginal costs may or may not affect the dispatch of the unit. If it does, it is withholding. If it doesn't, it is not withholding. Referring back to Figure 1, Cases 1 and 3 are examples in which bidding above marginal costs does not constitute withholding. Case 2 is an example in which bidding above marginal costs does constitute withholding.

Q: And do you consider failing to bid available capacity to be withholding?

A: Similarly to my previous answer, failing to bid available capacity, in and of itself, does not constitute withholding under my definition. Again, it depends on whether failing to bid affects dispatch. Referring back to Figure 1, Cases 4 and 5 are examples in which failing to bid does constitute withholding and Case 6 is an example in which it does not.

Q: How are outages incorporated into your definition of withholding?

A: Legitimate outages are not withholding. That is, if a unit is unavailable due to a legitimate planned or forced outage in a particular hour, that unit is not considered to be withholding in that hour. If the unit has a legitimate partial outage, the portion of its capacity on outage is not considered withholding, although there may be withholding from the portion not on outage. On the other hand, "false" outages can potentially be withholding.

Q: When does a "false" outage amount to withholding?

A: A "false" outage amounts to withholding if the unit (or part of the unit) would have been dispatched if it had been bid at its marginal cost. Otherwise, it does not amount to withholding.

Q: How have you treated outages in your withholding analysis?

A: I have considered two outage scenarios. First, I have accepted all of the outages reported by the California Generators as being legitimate. Second, I have utilized the benchmark forced outage rates developed by Dr. Hanser. Note that in this second scenario, I continue to assume that the *planned* outages reported by the generators are all legitimate.

Withholding and Market Power

Q: How to you define market power?

A: Market power is the ability to profitably maintain prices at least a small but significant amount above competitive levels for a significant period of time.[5]

[5] See, for example, Horizontal Merger Guidelines, U.S. Department of Justice and Federal Trade Commission, Issued April 2, 1992, Revised April 8, 1997, Section 0.1.

Q: What is the relationship between withholding and market power?

A: As I discuss in more detail in Section II, withholding is one of the ways in which firms exercise market power.[6] Firms with market power have the incentive to withhold whereas firms without market power do not have such an incentive. Thus, substantial withholding is strong evidence that firms have market power and have exercised that market power. For example, Scott Harvey and William Hogan stated the following:

> "A significant pattern of plants found not producing energy or providing reserves when their opportunity costs (rather than just engineering costs) were below the market price would be a powerful indicator of the exercise of market power."[7]

Summary of Conclusions

Q: Can you summarize the results of your analysis of withholding?

A: Yes. My analysis shows that, even if I accept the California Generators' reported outages as being legitimate, the California Generators engaged in significant levels of withholding over significant periods of time during the period of my analysis.

Q: Can you describe your results in more detail?

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[6] See FERC SMD, paragraph 393 (quoted earlier).

[7] Scott Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000, p. 2.

A: Yes. Although I have analyzed withholding during all hours of the analysis period, in presenting the results I focus primarily on the on-peak hours.[8] Figure 2 shows average withholding by month during on-peak hours, assuming that all of the California Generators' reported outages were legitimate. Aggregate withholding by the California Generators averaged over 1000 MW per hour during the on-peak hours in the May through September 2000 period. Figure 3 shows the percentage of on-peak hours in which withholding exceeded 1000 MW for the California Generators in aggregate. From May through September 2000, withholding exceeded 1000 MW in about 45% of the on-peak hours and exceeded 2000 MW in about 15% of the on-peak hours. As I will discuss in detail, I consider these estimates to be conservative (i.e., understate the full extent of withholding) for a variety of reasons.

[8] For purposes of this analysis, I consider on-peak hours to be hours 7 through 22 (i.e., hours ending 7 am to 10 pm), in accordance with the CAISO (see http://www.caiso.com/aboutus/glossary/).

Figure 2

Average Hourly Withholding by All California Generators During On-Peak Hours
Using Generator Reported Forced Outages

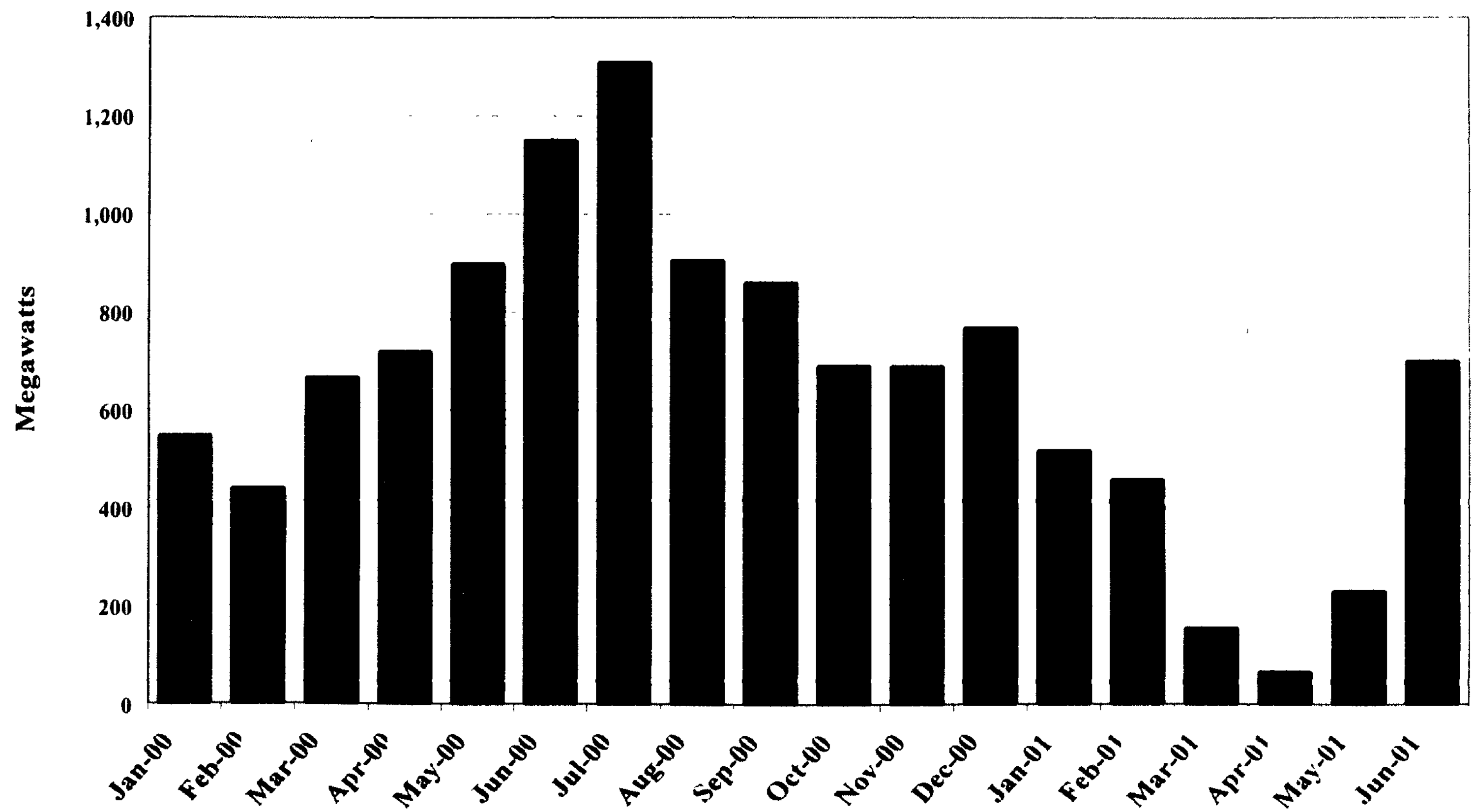
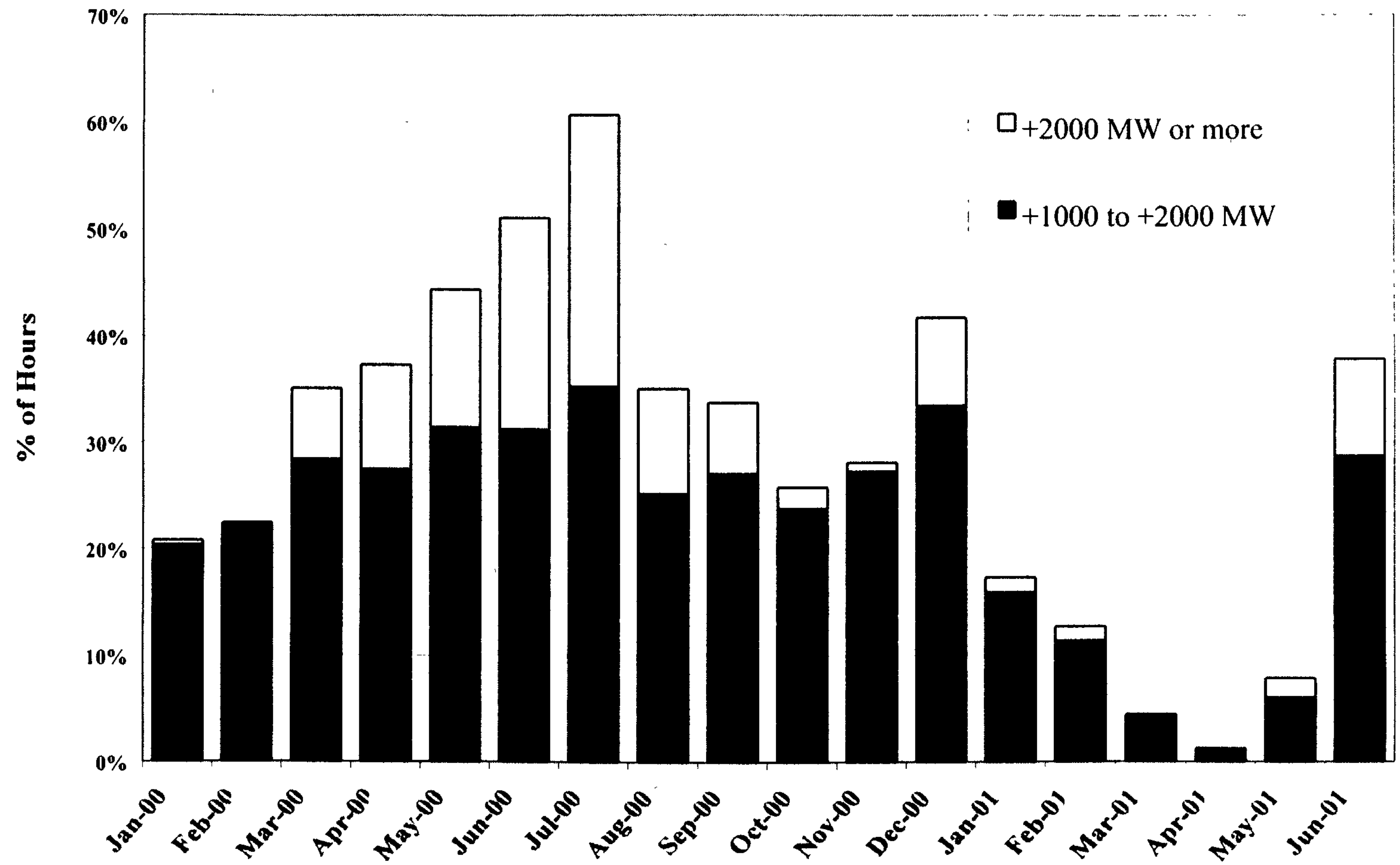


Figure 3

Percentage of On-Peak Hours in which Withholding Exceeded 1000MW
Using Generator Reported Forced Outages



Q: The results you just described assume that all of the California Generators' reported outages were legitimate. Have you analyzed withholding under any other assumptions regarding outages?

A: Yes. I have estimated withholding based on the benchmark level of forced outages developed by Dr. Hanser. In this case, I still assume that the California Generators' reported *planned* outages were all legitimate. As Dr. Hanser describes in his testimony, the forced outages reported by the California Generators were significantly higher than his benchmark group of comparable units during the second half of 2000. Dr. Hanser's analysis shows that the benchmark forced outage rates were 57% of the rates reported by the California Generators for the steam turbine units.[9]

Q: What does your analysis show about withholding using the benchmark forced outage rates?

A: Figure 4 shows average hourly withholding for on-peak hours in the second half of 2000 using alternative assumptions about the extent to which the California Generators' reported forced outages were legitimate. If the reported forced outages were all legitimate, average on-peak hourly withholding over this period was about 870 MW. If none of the reported forced outages was legitimate, average on-peak hourly withholding over this period was about 1,480 MW. Using

[9] This percentage is calculated on a capacity-weighted average basis using the EFORP/NCF measure reported by Dr. Hanser.

Dr. Hanser's results, average on-peak hourly withholding over this period was about 1,130 MW. In other words, the estimated effect of excessive forced outage reporting was about 260 MW per hour, which represents an increase of about 30% over the estimated withholding assuming that all reported forced outages were legitimate.

Q: Have you run any alternative analyses of withholding to test the sensitivity of your results?

A: Yes. I have tested the sensitivity of my results to the estimate of marginal costs. Specifically, I have estimated withholding assuming that marginal costs were 10% and 20% above my "base case" estimates. Even with these higher marginal cost estimates, I still find significant withholding.

Q: Do you have a figure that summarizes your results numerically?

A: Yes. Figure 5 summarizes the results of my withholding analysis for on-peak hours. This figure shows the following by month: (a) average hourly withholding by company and for the California Generators in aggregate, (b) withholding as a percentage of generation in aggregate, (c) percentage of hours in which withholding exceeded 1000 MW in aggregate, and (d) average hourly withholding in aggregate for the marginal cost sensitivity cases (the figure also shows average hourly un-bid producible capacity, which I discuss further below).

Figure 4

Average Hourly Withholding During On-Peak Hours

Using Benchmark and Generator Reported Forced Outages

(MW)

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Average
Reported Forced Outages:							
100% Legitimate	1,310	906	861	691	689	768	871
57% Legitimate (benchmark)	1,481	1,139	1,132	978	1,079	978	1,131
0% Legitimate (no forced outages)	1,707	1,448	1,491	1,358	1,595	1,256	1,476

Figure 5
Summary of Results for On-Peak Hours Using Generator Reported Forced Outages

	Average Hourly Withholding (MW)								Sensitivity Test Total Withholding With Increased Marginal Cost		Average Hourly Un-Bid Producible Capacity (MW)
	AES/Williams	Duke	Dynegy	Mirant	Reliant	Total	Withholding % of Generation	% of Hours Withholding >1000 MW	+10%	+20%	
Jan-00	93	38	83	219	114	547	11%	21%	454	371	521
Feb-00	81	35	46	228	50	440	9%	22%	336	212	411
Mar-00	163	101	70	303	30	666	20%	35%	400	183	643
Apr-00	160	196	31	242	91	720	22%	37%	588	424	759
May-00	265	31	93	320	189	899	14%	44%	757	636	940
Jun-00	232	42	166	418	292	1,150	12%	51%	1,058	970	1,268
Jul-00	225	57	196	532	300	1,310	13%	61%	1,246	1,171	1,191
Aug-00	76	17	193	389	231	906	8%	35%	871	844	565
Sep-00	128	31	149	299	253	861	8%	34%	827	795	679
Oct-00	56	16	101	342	176	691	8%	26%	650	616	575
Nov-00	97	22	123	152	295	689	9%	28%	627	553	608
Dec-00	268	(18)	329	(10)	199	768	10%	42%	588	348	634
Jan-01	113	32	288	28	57	518	6%	17%	291	109	447
Feb-01	119	81	149	33	77	459	5%	13%	292	157	525
Mar-01	(19)	45	7	43	80	156	2%	4%	105	58	494
Apr-01	(20)	20	10	24	33	67	1%	1%	(8)	(52)	648
May-01	2	18	106	52	53	231	3%	8%	173	119	726
Jun-01	54	45	255	262	85	701	8%	38%	635	575	899

Q: Do you consider your analysis of withholding to be conservative?

A: Yes. My analysis is conservative in the sense that it may understate the level of withholding for several reasons, including: (a) I use a conservative estimate for the capacity of the California Generators' generating units; (b) I assume that all planned outages and reserve shutdowns taken by the generators are "legitimate" in the sense that I do not calculate any withholding for the relevant units in those hours; (c) I do not consider withholding from combustion turbine units nor from certain steam units that reached their NOx emissions limits in 2000; (d) I use conservative assumptions for marginal costs (e.g., heat rates and emissions costs); (e) I give the generators credit for out-of-market transactions, out-of-sequence transactions, and positive uninstructed deviations, even though such sales may occur because resources were withheld from the CAISO real-time market; (f) I do not consider withholding through high ancillary service energy bids; and (g) other considerations as discussed in this declaration.

Q: Other than your analysis, is there evidence that the California Generators actually engaged in withholding?

A: Yes. While I have not researched this issue in detail, I am aware that in a different, but related, market FERC recently investigated reductions in the amount of capacity bid by Reliant into the CalPX day-ahead market during two days in June 2000, relative to what Reliant said it normally would have offered under the existing market conditions.[10] Such reductions, which were about 1000 MW, were taken at the direction of Reliant's Vice President for Power Trading in an effort to increase market prices. Reliant elected to perform discretionary maintenance on the generating units whose output otherwise would have been offered on these days. FERC and Reliant reached a settlement whereby Reliant agreed to pay $13.8 million to customers of the CalPX for these actions. While I have not studied this incident in detail, it does appear to be an example of physical withholding as I use the term.

Q: Have you considered criticisms of prior withholding analyses?

A: Yes. I have considered a number of issues that have been raised in other contexts. However, as discussed in Section VII, I have either: (a) directly incorporated the issue in my analysis, which renders the criticism moot for my analysis, or (b) I have concluded that the issue is either not relevant or minor relative to the magnitude of withholding that I have found. Thus, such issues do not change my conclusion regarding the presence of significant withholding by the California Generators.

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10 Order Approving Stipulation and Consent Agreement, Fact Finding Investigation into Possible Manipulation of Electric and Natural Gas Prices, FERC Docket No. PA02-2-001, Issued January 31, 2003.

Q: Can you summarize the results of your analysis of the extent to which the California Generators did not bid capacity that you would expect a competitive firm to bid?

A: Yes. My analysis shows that the California Generators frequently did not bid such capacity. I use the term "un-bid producible capacity" to refer to capacity that was not bid and was: (a) not on outage, (b) not on reserve shutdown, (c) not unproducible due to ramping constraints, and (d) did not have a marginal cost above the maximum allowable bid in the CAISO real-time market. Figures 5 and 6 show the average un-bid producible capacity by month for on-peak hours. As seen in those figures, the average un-bid producible capacity exceeded 500 MW during on-peak hours in virtually all months and exceeded 1000 MW in some months.

Remainder of Testimony

Q: How is the remainder of your testimony organized?

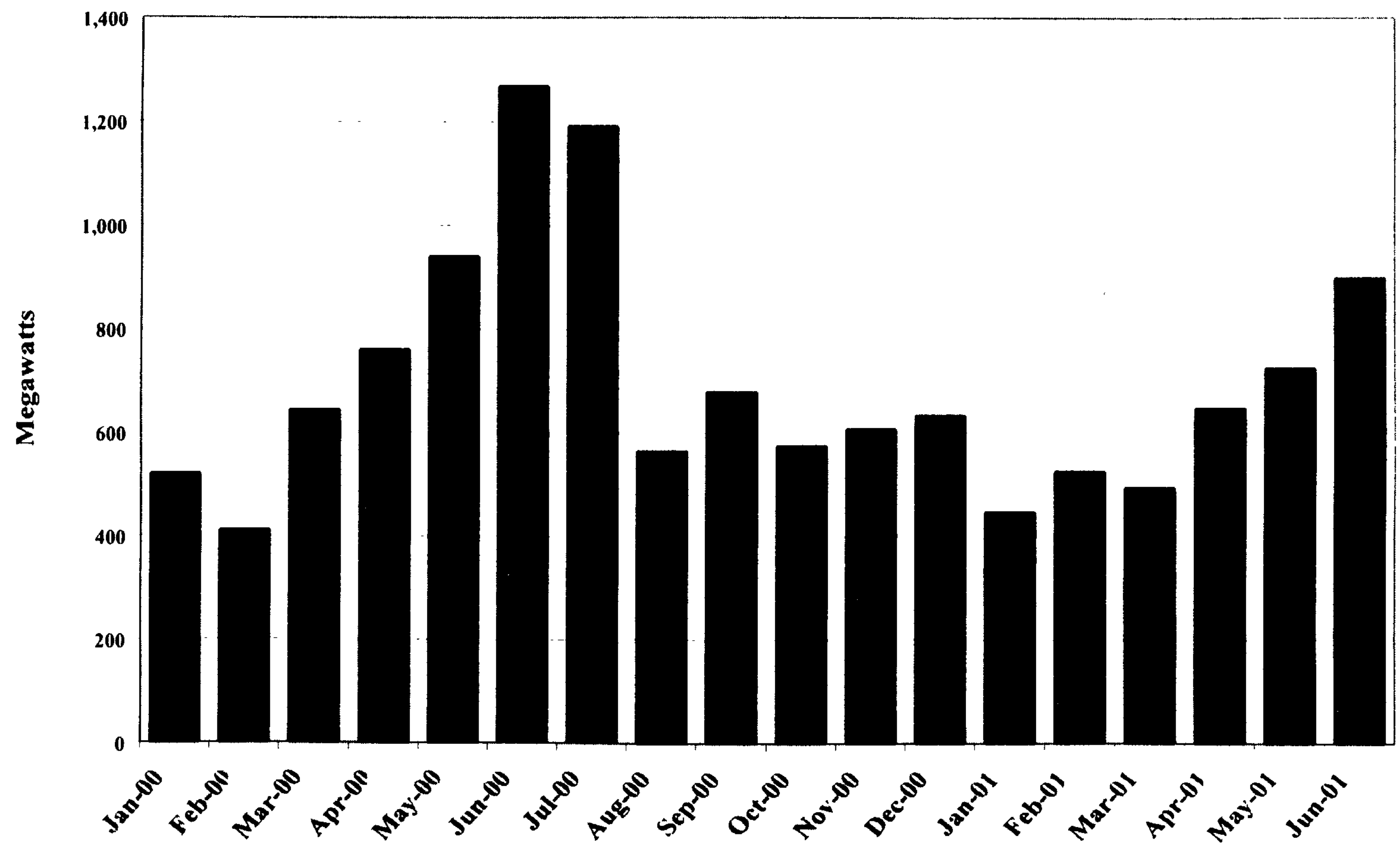
A: The remainder of my testimony is organized into six sections:

- In Section II, I provide a brief discussion of the basic economic principles of withholding.
- In Section III, I discuss the data that I used in my analysis.
- In Section IV, I describe in detail the approach that I used to calculate withholding.
- In Section V, I present the results of my withholding analysis.

- In Section VI, I present my analysis of the extent to which the California Generators did not bid capacity that was producible.
- In Section VII, I address certain issues that have been raised as criticisms of prior withholding analyses.

Figure 6

Average Hourly Un-Bid Producible Capacity During On-Peak Hours
Using Generator Reported Forced Outages



SECTION II. BASIC ECONOMICS OF WITHHOLDING

Q: What is the purpose of this section of your testimony?

A: In this section, I provide a brief theoretical discussion of the economics of withholding.

Q: What is the level of prices in a competitive commodity industry?

A: In a competitive commodity industry, competition normally drives price close to the marginal cost of the marginal source of supply (i.e., the least efficient unit required to satisfy market demand).

Q: How do firms make decisions about their output in such a competitive commodity industry?

A: Generally, when firms have different facilities with different marginal costs, they will produce output up to the point where their margin cost equals the prevailing market price. That is, firms will produce output from each facility (or portion thereof) that has a marginal cost that is less than the market price and not produce output from facilities (or portions of facilities) that have marginal costs that are above the market price. Such an output pattern will maximize the firm's profits.

Q: What could cause prices to rise above such marginal costs in a commodity industry?

A: If a firm has a significant share of a market and there are limitations on the extent to which rival suppliers can expand production, then the firm may be able to profitably restrict output at plants whose marginal cost is below the market price (i.e., "withhold") and thereby maintain price significantly above the competitive level (i.e., the firm has "market power"). In this case, prices are elevated through unilateral action by a single firm.[11]

Q: Can collusion contribute to price elevation?

A: Yes. Collusion can increase the degree of price elevation beyond that generated by unilateral decisions, including leading to price elevation when it would not otherwise occur. For example, it is possible for a group of firms, in which any one firm may not have a sufficiently large market share to profitably restrict output when acting alone, to coordinate their actions and profitably achieve higher prices by restricting output at some of their plants.[12]

Q: Are there different types of collusive behavior?

A: Yes. Collusion can be categorized as either "explicit" or "tacit," depending on whether it involves some sort of explicit agreement among the parties or not.

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[11] It is possible for more than one firm to have such unilateral market power if each has a sufficiently large market share.

[12] See, for example, Dennis W. Carlton and Jeffrey M. Perloff, *Modern Industrial Organization*, 3rd Ed., Reading, MA: Addison Wesley Longman Inc., 2000, pp. 122-4.

Tacit collusion can arise in oligopoly markets, particularly in a "repeated game" setting.[13] The California electricity markets may reflect such a setting.[14]

Q: Can you explain the considerations that lead to withholding?

A: Yes. In either the unilateral profit maximizing or coordinated interactions cases,[15] the withholding decision by a firm reflects a tradeoff between:

- The sacrifice of profits on the output that is restricted. Since output is restricted at a plant that has an incremental cost below the market price, the firm loses the margin that would have been earned on the sale of that output; versus the

- Gain in profits on the output that is produced ("residual output") resulting from higher market prices due to the restriction of output.

Q: Is the incentive for withholding the same in all markets?

A: No. The degree to which there are incentives for withholding depends on the characteristics of the market. Without getting into a comprehensive discussion of this issue, it is worth noting that California electricity markets exhibit certain characteristics that generally lead to greater incentives to restrict output, including low elasticity of demand, high firm output shares (measured in terms of price-

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[13] "(Infinitely) repeated games" is a term used in economics to refer to situations in which the same firms repeatedly compete against each other in largely the same way and either the competition continues indefinitely or the terminal date of the competition is uncertain. See, for example, Carl Shapiro, "Theories of Oligopoly Behavior," in *Handbook of Industrial Organization*, R. Schmalensee and R. Willig, eds., North-Holland, 1989, pp. 361-373.

[14] In the case of California electricity markets, the "game" (i.e., the market auction) is repeated every hour of the year.

[15] I have not attempted to delineate the relative contributions of purely unilateral actions, tacit collusion, or explicit collusion to the observed withholding.

sensitive capacity), one or more of the firms having at least some high marginal cost units,[16] and limited ability to quickly expand capacity.[17]

Q: Is the incentive to withhold the same for all firms in a market?

A: Not necessarily. The incentive to withhold may vary across firms in a market, depending on considerations such as the size of the firm, the degree to which they have high marginal cost vs. low marginal cost facilities, and the extent to which their output is contracted forward at prices that are not tied to the prevailing market price.

SECTION III. DATA SOURCES

Q: What is the purpose of this section of your testimony?

A: In this section, I discuss the sources of data used in my analysis.

Q: How is this section organized?

A: I discuss the data in the following order: market prices, capacity, ramp rates, environmental considerations, combustion turbines, marginal costs, outages, reserve shutdowns, and supply data.

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16 That is, some portions of the firm's facilities are units whose marginal cost is in the range of the market price during some portions of the year.

17 See Carlton and Perloff, *op.cit.*, pp. 126-32 and 139.

Market Prices

Q: Let's start with market prices. First, what market or markets have you considered in your withholding analysis?

A: I have focused on the CAISO real-time energy market.

Q: Why did you focus on the CAISO real-time market?

A: The CAISO real-time market is the "market of last resort" for units in the CAISO control area. In other words, this market presents the last opportunity for a generator to bid its capacity for a given hour. By focusing on this market, arguments that returns from alternative uses of the capacity for that hour must be incorporated into the marginal costs are rendered moot. This is not to say that focusing on the CAISO real-time market eliminates all alternative use issues.[18] In particular, I discuss certain inter-temporal issues in Section VII.

Q: Do you consider all hours or just a subset of the hours?

A: I consider the potential for withholding in all hours. However, in presenting my results, I focus on the on-peak hours since those are the hours in which withholding is likely to have the biggest effect on market prices.

Q: Where did you obtain market prices for the CAISO real-time market?

[18] This is also clearly not to say that withholding in the CAISO real-time market is more or less important than withholding from the CalPX Day Ahead Market.

A: I obtained hourly data on the CAISO real-time energy market prices by region from the CAISO. I note that the CAISO real-time market clears in 10-minute intervals (i.e., there are separate prices for each 10-minute interval), although bids are on an hourly basis. The hourly prices reported by the CAISO are the average of the 10-minute prices for the hour.[19]

Q: Were there any limits on the real-time prices during the period of your analysis?

A: Yes. Prior to December 8, 2000, there was a "hard cap." No bids were accepted above the hard cap. The hard cap was $750 per MWh through June 30, 2000, and then it dropped to $500 per MWh through August 6, 2000, and then dropped further to $250 per MWh.[20] From December 8, 2000 onward, there was a "soft cap" on prices. Under the soft cap, generators were allowed to bid above the soft cap, although such bids could not set the market price. If the CAISO accepted such bids, the generator would be paid its bid price, subject to potential refunds if it could not provide cost or other justification for prices above the soft cap.[21] The soft cap was $250 per MWh in December 2000 and then $150 per MWh from January 1, 2001 onward.

[19] Beginning in September 2000, there were separate incremental and decremental prices. Starting at that time, I use the average of the 10-minute incremental and decremental prices.

[20] See Initial Report on Company-Specific Separate Proceedings and Generic Reevaluation; Published Natural Gas Price Data; and Enron Trading Strategies, Docket No. PA02-2-000, Prepared by the Staff of the Federal Energy Regulatory Commission, August 2002 (FERC Staff Report), at 18.

[21] See *San Diego Gas & Electric Co., et al., 93 FERC ¶61,983 (2000)*(December 15 Order).

Capacity

Q: Let's move on to the next category of data used in your analysis, which is capacity. First, how much capacity do the California Generators own in California?

A: The California Generators own 78 generating units in California with total capacity of about 17 gigawatts.[22] Over 90% of this capacity is natural gas-fired steam turbine or combined cycle units and the remainder is natural gas-fired and oil-fired combustion turbine units. I list these units in Figure 7 (steam turbine and combined cycle units) and Figure 8 (combustion turbines).

Q: How is this capacity distributed across the state?

A: This capacity is located in three regions defined by the CAISO: NP15, ZP26, and SP15, with roughly two-thirds of the capacity located in SP15. These regions are defined by the CAISO based on transmission constraints and real-time market prices can be different across regions when there is congestion.

Q: How have you handled capacity in your analysis?

A: For this analysis I have used the lowest capacity value for each unit reported by the California Generators, either in the unit outage data that they provided in connection with this proceeding, or in materials filed by the Generators in

[22] Note that I do not include the Placerita plant, which is owned by AES, but is not part of the AES-Williams tolling arrangement.

response to other investigations of wholesale energy generation in California.[23] However, when such Generator-supplied values were not available, I have used the lowest of the various capacity values published by the CAISO.[24] I refer to this value as "effective capacity." Figure 7 and Figure 8 show my assumptions for the effective capacity of each unit owned by the California Generators.

[23] Letter from Zack Starbird, Mirant Americas, Inc. to Cal. Sen. Joseph L. Dunn, 9/26/2002; letter from Brent C. Bailey, Duke Energy Corporation to Loretta Lynch, California Public Utilities Commission, 9/26/2002; Letter from William E. Hobbs, Williams Energy Marketing & Trading Company to Cal. Sen. Joseph L. Dunn, 10/1/2002.

[24] The CAISO's capacity values have been published at various times in www.caiso.com/docs/2001/04/02/2001040211441714244.xls, under the variable "Unit PMAX (MW)," which represents the "maximum capacity of a resource."

Figure 7

California Generators' Steam Turbine and Combined Cycle Units

Company	CAISO Unit ID	Region	Type	Effective Capacity (MW)	Ramp Rate (MW/min)
AES/Williams	ALAMIT_7_UNIT 1	SP15	STNG	175	5.1
AES/Williams	ALAMIT_7_UNIT 2	SP15	STNG	175	3.3
AES/Williams	ALAMIT_7_UNIT 3	SP15	STNG	320	6.1
AES/Williams	ALAMIT_7_UNIT 4	SP15	STNG	320	6.6
AES/Williams	ALAMIT_7_UNIT 5	SP15	STNG	480	7.1
AES/Williams	ALAMIT_7_UNIT 6	SP15	STNG	480	5.8
AES/Williams	HNTGBH_7_UNIT 1	SP15	STNG	215	4.3
AES/Williams	HNTGBH_7_UNIT 2	SP15	STNG	215	4.3
AES/Williams	REDOND_7_UNIT 5	SP15	STNG	175	4.4
AES/Williams	REDOND_7_UNIT 6	SP15	STNG	175	2.8
AES/Williams	REDOND_7_UNIT 7	SP15	STNG	480	6.1
AES/Williams	REDOND_7_UNIT 8	SP15	STNG	480	4.7
Duke	MORBAY_7_UNIT 1	ZP26 (a)	STNG	163	4.9
Duke	MORBAY_7_UNIT 2	ZP26 (a)	STNG	163	4.9
Duke	MORBAY_7_UNIT 3	ZP26 (a)	STNG	337	9.0
Duke	MORBAY_7_UNIT 4	ZP26 (a)	STNG	338	9.2
Duke	MOSSLD_7_UNIT 6	NP15	STNG	750	5.7
Duke	MOSSLD_7_UNIT 7	NP15	STNG	739	5.1
Duke	SOBAY_7_SY1	SP15	STNG	146	5.1
Duke	SOBAY_7_SY2	SP15	STNG	150	4.7
Duke	SOBAY_7_SY3	SP15	STNG	175	4.0
Duke	SOBAY_7_SY4	SP15	STNG	222	3.9
Dynegy	ELSEGN_7_UNIT 1	SP15	STNG	175	5.4
Dynegy	ELSEGN_7_UNIT 2	SP15	STNG	175	4.3
Dynegy	ELSEGN_7_UNIT 3	SP15	STNG	335	6.2
Dynegy	ELSEGN_7_UNIT 4	SP15	STNG	335	6.4
Dynegy	ENCINA_7_EA1	SP15	STNG	104	0.7
Dynegy	ENCINA_7_EA2	SP15	STNG	103	2.5
Dynegy	ENCINA_7_EA3	SP15	STNG	110	2.6
Dynegy	ENCINA_7_EA4	SP15	STNG	300	5.6
Dynegy	ENCINA_7_EA5	SP15	STNG	330	7.3
Dynegy	LBEACH_2_230TOT	SP15	CCNG	180	1.1
Dynegy	LBEACH_6_66TOT	SP15	CCNG	400	1.3
Mirant	COCOPP_7_UNIT 6	NP15	STNG	335	8.3
Mirant	COCOPP_7_UNIT 7	NP15	STNG	337	9.2
Mirant	PITTSP_7_UNIT 1	NP15	STNG	150	2.9
Mirant	PITTSP_7_UNIT 2	NP15	STNG	150	3.2
Mirant	PITTSP_7_UNIT 3	NP15	STNG	150	2.5
Mirant	PITTSP_7_UNIT 4	NP15	STNG	145	4.3
Mirant	PITTSP_7_UNIT 5	NP15	STNG	312	8.0
Mirant	PITTSP_7_UNIT 6	NP15	STNG	317	4.1
Mirant	PITTSP_7_UNIT 7	NP15	STNG	682	9.2
Mirant	POTRPP_7_UNIT 3	NP15	STNG	206	4.9
Reliant	CWATER_7_UNIT 1	SP15	STNG	63	2.8
Reliant	CWATER_7_UNIT 2	SP15	STNG	82	3.3
Reliant	CWATER_7_UNIT 3	SP15	CCNG	241	7.4
Reliant	CWATER_7_UNIT 4	SP15	CCNG	241	8.4
Reliant	ETIWND_7_UNIT 1	SP15	STNG	132	4.5
Reliant	ETIWND_7_UNIT 2	SP15	STNG	132	5.4
Reliant	ETIWND_7_UNIT 3	SP15	STNG	320	10.2
Reliant	ETIWND_7_UNIT 4	SP15	STNG	320	10.1
Reliant	MNDALY_7_UNIT 1	SP15	STNG	215	4.6
Reliant	MNDALY_7_UNIT 2	SP15	STNG	215	9.7
Reliant	ORMOND_7_UNIT 1	SP15	STNG	725	24.0
Reliant	ORMOND_7_UNIT 2	SP15	STNG	750	18.6
Total				15,639	

(a) The Morro Bay units were in SP15 in Jan-00 and in ZP26 in 2/00-6/01
Capacity types are STNG = Natural gas-fired steam turbine, CCNG = Natural gas-fired combined cycle

Figure 8

California Generators' Combustion Turbine Units

Company	CAISO Unit ID	Region	Type	Effective Capacity (MW)
AES/Williams	ALAMIT_7_UNIT 7	SP15	CTNG	133
AES/Williams	HNTGBH_7_UNIT 5	SP15	CTNG	133
Duke	OAK C_7_UNIT 1	NP15	CTFO	55
Duke	OAK C_7_UNIT 2	NP15	CTFO	55
Duke	OAK C_7_UNIT 3	NP15	CTFO	55
Duke	SOBAY_7_GT1	SP15	CTJF	16
Dynegy	CRNRDO_7_NIGT1	SP15	CTNG	18
Dynegy	CRNRDO_7_NIGT2	SP15	CTNG	18
Dynegy	DIVSON_7_DIGT1	SP15	CTFO	14
Dynegy	DIVSON_7_NSGT1	SP15	CTFO	22
Dynegy	ELCAJN_7_GT1	SP15	CTNG	15
Dynegy	ENCINA_7_GT1	SP15	CTNG	17
Dynegy	KEARNY_7_KY1	SP15	CTNG	16
Dynegy	KEARNY_7_KY2	SP15	CTNG	59
Dynegy	KEARNY_7_KY3	SP15	CTNG	61
Dynegy	MRGT_7_UNITS	SP15	CTNG	36
Dynegy	OLDTWN_7_NTCGT1	SP15	CTNG	15
Mirant	POTRPP_7_UNIT 4	NP15	CTFO	52
Mirant	POTRPP_7_UNIT 5	NP15	CTFO	52
Mirant	POTRPP_7_UNIT 6	NP15	CTFO	52
Reliant	ETIWND_7_UNIT 5	SP15	CTFO	120
Reliant	GOLETA_6_ELLWOD	SP15	CTFO	56
Reliant	MNDALY_7_UNIT 3	SP15	CTFO	120
Total				1,190

Capacity types are: CTFO/CTJF = oil-fired combustion turbine; CTNG = natural gas-fired combustion turbine

Ramp Rates

Q: What is a "ramp rate"?

A: The amount of power that a unit can generate in a given hour can be limited by the rate at which it can "ramp up" to higher output levels. The ramp rate, which is generally expressed in megawatts per minute, measures the speed at which units can increase their output.

Q: Have you incorporated ramping up limitations into your analysis?

A: Yes. As I describe in Section IV, I explicitly consider ramping up limitations in my analysis of withholding.

Q: What assumptions have you made for the rate at which each unit can ramp up its output?

A: In submitting supplemental energy bids to the CAISO real-time market, generators are required to specify the maximum ramp rate that they will follow if such bids are accepted. For my analysis, I have used the average ramp rate submitted for each unit with its supplemental energy bids over the period of my analysis. The resulting ramp rates for each steam turbine and combined cycle unit are shown in Figure 7.

Q: Could such ramp rates be understated?

A: Yes, if the generators used the ramp rate submitted with their supplemental energy bids as a strategic variable (by, for example, specifying an artificially slow ramp rate as a method of withholding).

Q: Do you consider constraints on the rate at which a unit can ramp *down* its output?

A: My understanding is that there are constraints on the rate at which a unit can ramp down its output. For example, suppose that a unit operated at 100 MW at the end of hour 1 and the maximum rate that it could ramp down was 1 MW per minute. In this case, the unit could ramp down to 40 MW by the end of hour 2 and it would produce at least 70 MWh in hour 2. In effect, this means that the marginal cost for producing up to 70 MWh in hour 2 is zero (or even negative if it would take some additional cost to avoid sending the output to the grid). As such, this puts a lower bound on the unit's amount of economic capacity in hour 2. However, I have not considered such constraints in my analysis, which is another conservative assumption.

Environmental Considerations

Q: Let's move on to environmental considerations. Are the California Generators' units subject to environmental regulations that affect their operation?

A: Yes. As discussed in Dr. McCann's testimony, the California Generators' units are subject to environmental regulations that can affect their costs and/or dispatch.

Q: Have you incorporated such environmental regulations in your withholding analysis?

A: Yes. I have explicitly incorporated the relevant considerations into my analysis. In this regard, I have relied on Dr. McCann's assessment of such regulations. I summarize the relevant considerations for the steam turbine and combined cycle units in Figure 9 and discuss how I treat these issues in my withholding analysis below. Unless noted otherwise, Dr. McCann's testimony is the basis for my assumptions regarding environmental considerations discussed in this section.

Q: Let's go through Figure 9. First, why do you show NOx emissions rates in this figure?

A: The rate at which a unit emits NOx, measured as pounds per MWh, is a consideration in the operation of some of the California Generators' units. In those cases where a fee is charged per unit of NOx emission, higher NOx emissions rates lead to higher marginal costs. In those cases where there is a limit on total NOx emissions (e.g., tons) over a year or other period, higher NOx emissions rates lead to lower maximum allowable power output from the plant (MWh). I only show NOx emission rates for those units where Dr. McCann has identified that there are NOx emissions regulations which affect incremental cost or the number of hours that the unit can be run.

Q: How did you develop your assumptions for the NOx emissions rate for each unit?

A: I relied on Dr. McCann's assessment of those rates. I understand that he developed those rates based on data provided by the California Generators, if it was provided, and otherwise based on the U.S. Environmental Protection Agency's continuous emissions monitoring system (CEMS) data and CAISO generation data, or on SCAQMD Electrical Equipment Emissions Rates sheets for units that do not have CEMS equipment, as described in his testimony.

Figure 9

Summary of Environmental Considerations for Steam and Combined Cycle Units

Company	CAISO Unit ID	NOx Emissions Rate lbs MWh	SCAQMD RTC Program	Annual NOx Limit in 2000	Annual NOx Limit in 2001	Mitigation Fee in 2001	Other Consideration
AES Williams	ALAMIT_7_UNIT 1	1 07	Yes				
AES Williams	ALAMIT_7_UNIT 2	1 39	Yes				
AES Williams	ALAMIT_7_UNIT 3	0 74	Yes				
AES Williams	ALAMIT_7_UNIT 4	0 68	Yes				
AES Williams	ALAMIT_7_UNIT 5	0 07	Yes				
AES Williams	ALAMIT_7_UNIT 6	0.05	Yes				
AES/Williams	HNTGBH_7_UNIT 1	0 98	Yes				
AES/Williams	HNTGBH_7_UNIT 2	0 78	Yes				
AES/Williams	REDOND_7_UNIT 5	1 53	Yes				
AES/Williams	REDOND_7_UNIT 6	1 20	Yes				
AES/Williams	REDOND_7_UNIT 7	0 07	Yes				
AES/Williams	REDOND_7_UNIT 8	0 09	Yes				
Duke	MORBAY_7_UNIT 1	NA					Daily NOx Limit in 2001
Duke	MORBAY_7_UNIT 2	NA					Daily NOx Limit in 2001
Duke	MORBAY_7_UNIT 3	NA					Daily NOx Limit in 2001
Duke	MORBAY_7_UNIT 4	NA					Daily NOx Limit in 2001
Duke	MOSSLD_7_UNIT 6	0 67					Avg Daily NOx Limit 5/1-10/31
Duke	MOSSLD_7_UNIT 7	0 67					Avg Daily NOx Limit 5/1-10/31
Duke	SOBAY_7_SY1	0 79		Yes		Yes	
Duke	SOBAY_7_SY2	0 79		Yes		Yes	
Duke	SOBAY_7_SY3	0.99		Yes		Yes	
Duke	SOBAY_7_SY4	1.43		Yes		Yes	
Dynegy	ELSEGN_7_UNIT 1	1.81	Yes				
Dynegy	ELSEGN_7_UNIT 2	1 55	Yes				
Dynegy	ELSEGN_7_UNIT 3	0 44	Yes				
Dynegy	ELSEGN_7_UNIT 4	0 10	Yes				
Dynegy	ENCINA_7_EA1	1 62		Yes		Yes	
Dynegy	ENCINA_7_EA2	1 66		Yes		Yes	
Dynegy	ENCINA_7_EA3	1 38		Yes		Yes	
Dynegy	ENCINA_7_EA4	0 58		Yes		Yes	
Dynegy	ENCINA_7_EA5	0 24		Yes		Yes	
Dynegy	LBEACH_2_230TOT	2.11	Yes				
Dynegy	LBEACH_6_66TOT	0 85	Yes				
Mirant	COCOPP_7_UNIT 6	NA					Delta dispatch 5/1-7/15
Mirant	COCOPP_7_UNIT 7	NA					Delta dispatch 5/1-7/15
Mirant	PITTSP_7_UNIT 1	NA					Delta dispatch 5/1-7/15
Mirant	PITTSP_7_UNIT 2	NA					Delta dispatch 5/1-7/15
Mirant	PITTSP_7_UNIT 3	NA					Delta dispatch 5/1-7/15
Mirant	PITTSP_7_UNIT 4	NA					Delta dispatch 5/1-7/15
Mirant	PITTSP_7_UNIT 5	NA					Delta dispatch 5/1-7/15
Mirant	PITTSP_7_UNIT 6	NA					Delta dispatch 5/1-7/15
Mirant	PITTSP_7_UNIT 7	NA					Delta dispatch 5/1-7/15
Mirant	POTRPP_7_UNIT 3	NA					
Reliant	CWATER_7_UNIT 1	0.33		Yes	Yes		
Reliant	CWATER_7_UNIT 2	0 33		Yes	Yes		
Reliant	CWATER_7_UNIT 3	0 33		Yes	Yes		
Reliant	CWATER_7_UNIT 4	0.33		Yes	Yes		
Reliant	ETIWND_7_UNIT 1	1 12	Yes				
Reliant	ETIWND_7_UNIT 2	1 22	Yes				
Reliant	ETIWND_7_UNIT 3	0 66	Yes				
Reliant	ETIWND_7_UNIT 4	0 66	Yes				
Reliant	MNDALY_7_UNIT 1	NA					
Reliant	MNDALY_7_UNIT 2	NA					
Reliant	ORMOND_7_UNIT 1	NA					
Reliant	ORMOND_7_UNIT 2	NA					

SCAQMD = South Coast Air Quality Management District

Q: Moving to the next column in Figure 9, what is the SCAQMD RTC Program?

A: Many of the California Generators' units are located in the South Coast Air Quality Management District (SCAQMD) and are subject to NOx emissions regulations imposed by that district. During 2000 and early 2001, these units participated in the RECLAIM program, which provided for tradable permits (RECLAIM Trading Credits or RTCs) for NOx emissions. In February 2001, these plants were given the option to pay a fixed mitigation fee of $7.50 per lb. of NOx instead of participating in the RTC market. This fee was substantially lower than RTC prices at the time and three of the four affected California Generators opted for the fixed mitigation fee option.

Q: Have you incorporated the SCAQMD RTC program in your withholding analysis?

A: Yes. I have incorporated the cost of NOx emissions in the marginal costs for these units based on Dr. McCann's assessment of the relevant costs. Prior to February 2001, the market price for RTCs is the relevant cost. I understand that Dr. McCann has estimated market prices for RTCs based on transaction data collected by the SCAQMD. From February 2001 onward, Dr. McCann concludes that the fixed fee of $7.50 per lb. is the relevant cost since that option was available for each firm and was chosen by three of the four affected California Generators.

Q: Do you consider your RTC price assumptions to be conservative?

A: Yes. As Dr. McCann describes, there was a range of transaction prices at any point in time and he has used the 90th percentile (high end) of the range. Moreover, Dr. McCann states that there is evidence suggesting that RTC prices were artificially inflated during the period of my analysis. To the extent that the assumed RTC prices overstate the true cost to the generators, my analysis of withholding for these units is conservative because I use the price of RTC credits as part of the units' marginal cost.

Q: Let's move to the next three columns in Figure 9, which are labeled annual NOx emission limits in 2000 and 2001 and NOx mitigation fee in 2001. What is the meaning of those columns?

A: Those columns show units that were subject to annual limits on their NOx emissions in 2000 or 2001 and units that were subject to NOx mitigation fees in 2001. Units at three plants faced such constraints: South Bay, Encina, and Coolwater.

Q: Let's start with South Bay and Encina. What were the NOx emissions limits and mitigation fees for those plants?

A: In 2000, the South Bay and Encina plants were subject to annual limits on NOx emissions of 1,000 and 1,100 tons, respectively. Those limits applied to the combined emissions from all units at each plant. In 2001, the annual limits were removed and instead these plants paid a fee of $7.50 per lb. for NOx emissions.

Q: Did you incorporate these NOx regulations in your analysis?

A: Yes. As discussed by Dr. McCann, the South Bay and Encina plants approached, but did not exceed, their annual NOx emissions limits in December 2000. To be conservative, I have excluded both South Bay and Encina from my withholding analysis for 2000. In 2001, I incorporate the mitigation fee in my marginal cost estimates and I include these units in my withholding analysis.

Q: Does the fact that South Bay and Encina approached their annual NOx emissions limits in 2000 mean that there was no withholding from those units in 2000?

A: Not necessarily. There are several ways in which the firms owning those plants might have engaged in withholding despite being close to their annual NOx emissions limits in 2000. For example, these plants could have been run in periods when they had little effect on market prices and not run in periods when not running them would have a significant effect on market prices. Alternatively, the units at each plant with higher NOx emissions rates could have been run excessively, thereby using up more of the annual emission allowance than necessary. I have not assessed such withholding possibilities at this time.

Q: Let's move on to Coolwater. What were the relevant NOx emissions regulations on that plant?

A: Coolwater is subject to an annual limit on its NOx emissions. That limit was 1,387 tons in 2000.

Q: Did Coolwater reach its annual limit in 2000?

A: No. In 2000, Coolwater actually ran at about a 47% capacity factor,[25] and produced 864 tons of NOx emissions, which was well below its limit.

Q: Have you incorporated the Coolwater annual limit in your withholding analysis?

A: Yes. Given its emissions rate, Coolwater could have operated up to about a 76% capacity factor without exceeding its annual NOx emissions limit of 1,387 tons. To test whether the Coolwater emissions limit was "binding," I ran a withholding analysis of the plant considering only its marginal production costs and found that Coolwater's actual generation plus estimated withholding resulted in a capacity factor that was around 50%. Because this would have produced NOx emissions substantially below its limit, I included Coolwater in my withholding analysis with no adjustments to the basic marginal cost calculation.

Q: Let's move on to the last column in Figure 9, which refers to other considerations. First, please describe the regulations imposed on Morro Bay and how you handled those regulations in your withholding analysis.

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[25] Capacity factor is a measure of plant utilization. It is equal to actual output (MWh) divided by capacity (MW) times number of hours in the period being considered (e.g., 8760 hours in a year).

A: Morro Bay was limited to 3.5 tons of NOx emissions per day starting on January 1, 2001. I have conservatively excluded Morro Bay from my withholding analysis from January 1, 2001 through June 20, 2001.

Q: Second, please describe the regulations imposed on Moss Landing.

A: Moss Landing is subject to a limit on the average daily NOx emissions of 9.64 tons per day for the period May 1st through October 31st. This limit is applied from May 1st to each day in the period (i.e., May 1-2, May 1-3, May 1-4, ... May 1 – October 31).

Q: Did Moss Landing reach its limit in 2000?

A: Effectively, yes. During May-October 2000, Moss Landing was run such that its NOx emissions were below its limit during the early part of the period, but its utilization then increased so that it approximated its emissions limit in mid-September, before dropping back by the end of September.

Q: Have you incorporated the regulations affecting Moss Landing in your analysis in 2000?

A: Yes. Although Moss Landing could have been run harder in October 2000 without exceeding its emissions limit, my analysis indicates that there was not significant withholding for this facility during this period. Thus, I have excluded Moss Landing from my analysis for the entire May-October 2000 period.

Q: Does the fact that Moss Landing reached its limit in 2000 mean that there was no withholding from that plant?

A: Not necessarily. As I discussed with respect to South Bay and Encina, there could have been strategic behavior with respect to the hours in which the facility was run or the units that were run. Again, I have not assessed whether there was withholding from Moss Landing through these other mechanisms.

Q: How did you treat Moss Landing in 2001?

A: Since the utilization of Moss Landing in 2000 was below the maximum during the May-June period, but the constraint became binding later in 2000, one could not conclude that there was withholding during May-June of 2001 simply because utilization was below the maximum level during that period. As such, I have also excluded Moss Landing from my analysis from the period of May 1st through June 20th of 2001, which is another conservative assumption in my analysis.

Q: Finally, please describe the regulations placed on the Pittsburg and Contra Costa plants and how you treated those constraints in your withholding analysis.

A: These plants have cooling water discharge regulations that require a specific dispatch plan ("Delta Dispatch") from May 1st to July 15th each year. The considerations are as follows:

- The operation of Pittsburg Unit 7, the largest of the units, is not constrained by the "Delta Dispatch." As such, I have calculated withholding for Pittsburg 7 as for other units that are not affected by such constraints.[26]

- Pittsburg Unit 7 must be at maximum capacity (or on the way to maximum) before Pittsburg Units 5 and 6 and Contra Costa Units 6 and 7, the "mid-size" units at these plants, can rise above minimum load. I have calculated withholding for the mid-size units only when Pittsburg 7 was at 95% of its available capacity,[27] or would have been, taking into account withholding of that unit.

- Pittsburg Unit 7 and the mid-size units must be at maximum capacity before Pittsburg Units 1, 2, 3, and 4, the smallest units at the plants, can operate above minimum load. Again, I have calculated withholding for these smaller size units only when Pittsburg Unit 7 and the mid-size units were at 95% of their available capacity, or would have been, taking withholding into account.

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[26] Operating Pittsburg Unit 7 at full load creates an option to run the other units. While in principle the computed marginal cost of Pittsburg Unit 7 should be reduced by the value of that option, I have conservatively not reduced that unit's marginal cost to reflect the option value.

[27] I understand that the regulations do not precisely define this "maximum capacity" constraint. I have assumed that a unit must operate at 95% or more of its available capacity to satisfy this constraint. Since this constraint is based on available capacity, if Pittsburg Unit 7 has a full outage, this constraint is not applicable and if Pittsburg Unit 7 has a partial outage, its operating level must be within 5% of its effective capacity less the partial outage.

Combustion turbines

Q: Let's discuss the combustion turbines. From an economic standpoint, what is the difference between a combustion turbine unit and a steam turbine unit?

A: From an economic standpoint, combustion turbine units (CTs) generally have higher marginal costs than steam units (in particular, CTs generally have higher heat rates). In addition, CTs generally have higher NOx emissions rates than steam turbine units.

Q: Are there regulatory constraints on the operation of the California Generators' combustion turbine units?

A: Yes. All of the CTs were subject to an annual limit on the number of hours that they were permitted to run in 2000. As shown in Figure 10, such limits ranged from 200 hours to 1,300 hours. In 2001, these limits were largely replaced with fees based on hours of operation or volume of NOx emissions.

Figure 10

Annual Run Hour Limits and Actual Operation of Combustion Turbines in 2000

Company	CAISO Unit ID	Annual Hour Run Limit	Total Generation (MWh)	Capacity (MW)	Effective Operating Hours	Effective Oper. Hrs. %Limit
AES/Williams	ALAMIT_7_UNIT 7	200	19,387	133	146	73%
AES/Williams	HNTGBH_7_UNIT 5	200	21,956	133	165	83%
Duke	OAK C_7_UNIT 1	(a)	36,067	55	656	NA
Duke	OAK C_7_UNIT 2	(a)	28,344	55	515	NA
Duke	OAK C_7_UNIT 3	(a)	32,308	55	587	NA
Duke	SOBAY_7_GT1	877	12,829	16	802	91%
Dynegy	CRNRDO_7_NIGT1	877	10,215	18	568	65%
Dynegy	CRNRDO_7_NIGT2	877	6,447	18	358	41%
Dynegy	DIVSON_7_DIGT1	877	5,539	14	396	45%
Dynegy	DIVSON_7_NSGT1	877	12,389	22	563	64%
Dynegy	ELCAJN_7_GT1	877	7,206	15	480	55%
Dynegy	ENCINA_7_GT1	877	7,603	17	457	52%
Dynegy	KEARNY_7_KY1	877	11,594	16	725	83%
Dynegy	KEARNY_7_KY2	877	38,830	59	658	75%
Dynegy	KEARNY_7_KY3	877	39,855	61	653	74%
Dynegy	MRGT_7_UNITS	877	28,022	36	778	89%
Dynegy	OLDTWN_7_NTCGT1	877	7,942	15	529	60%
Mirant	POTRPP_7_UNIT 4	877	45,366	52	872	99%
Mirant	POTRPP_7_UNIT 5	877	40,668	52	782	89%
Mirant	POTRPP_7_UNIT 6	877	45,863	52	882	101%
Reliant	ETIWND_7_UNIT 5	1300	56,481	120	471	36%
Reliant	GOLETA_6_ELLWOD	200	9,929	56	177	88%
Reliant	MNDALY_7_UNIT 3	200	38,282	120	319	160%

(a) CAISO controls the operation of the Oakland units under an RMR agreement

Q: Did all of the combustion turbine units reach their annual run hour limits in 2000?

A: No. As shown in Figure 10, some of the units were at or very close to their annual run limits, but others were not close.

Q: If a combustion turbine unit did not come close to its annual run hour limit in 2000, can you conclude that it was withholding?

A: Not necessarily. While some of the combustion turbines operated for significantly fewer hours than their limit in 2000, one cannot immediately conclude that such units were withheld. For example, the level of their marginal cost relative to market price is clearly relevant.

Q: On the other hand, if a combustion turbine operated at or close to its run hour limit in 2000, can you conclude that it was *not* withholding?

A: Not necessarily. The fact that a CT operated up to its limit (or very close to its limit) does not immediately lead to a conclusion that there was no withholding from that unit. For example, as discussed with respect to South Bay and Encina, the hours in which the unit was run could have been selected to (on average) increase market prices.

Q: So, how have you treated the combustion turbine units in your withholding analysis?

A: At this time, I have not evaluated withholding from the combustion turbines in my analysis, primarily because these units amount to a small portion of the California Generators' output.

Marginal costs

Q: Let's move on to marginal costs. How did you calculate marginal costs?

A: The approach that I have used to calculate marginal costs is generally consistent with the approach that FERC has adopted for calculating the Mitigated Market Clearing Price (MMCP) in this proceeding. However, I have made a couple of modifications which result in higher marginal costs than under the FERC MMCP approach, and are, therefore, favorable to the generators in determining the extent of their withholding (i.e., using my approach to calculating marginal costs leads to lower withholding than I would get if I strictly followed the FERC MMCP approach). I calculate the marginal cost (MC), measured in \$/MWh, for each unit in each hour as follows:

$$MC = ((IHR * FUEL / 1000) + VOM + NOX) * (1 + CREDIT)$$

Q: Let's talk about each of the components of your marginal cost calculation. First, please describe "IHR."

A: IHR, a measure of fuel efficiency, is the incremental heat rate, expressed in btu/kwh. A given unit's IHR and, therefore its marginal costs, can vary with the operating level. I account for such variations by calculating the marginal cost of each unit at different operating levels. Specifically, I use the 11-point heat rate curves that FERC adopted to calculate the MMCP.[28] I calculate the marginal cost for each block of output as defined by those 11-point heat rate curves.

Q: Did you make any adjustments to the approach that FERC adopted with respect to incremental heat rates?

A: Yes. FERC allows decreasing incremental heat rates in calculating MMCP.[29] However, for determining withholding, I use non-decreasing incremental heat rates in my marginal cost calculations, which is a conservative assumption.[30] Because it increases calculated marginal costs, my use of non-decreasing IHRs is more favorable to the generators than FERC's MMCP calculations.

Q:. Let's move on. Please describe the next component of your marginal cost calculation, which is "FUEL."

A: FUEL is the price of the appropriate fuel type in the appropriate region (e.g., SP15), which is measured in \$/mmbtu. All of the California Generators' steam

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28 For discussion of the 11-point heat rate curves, see *San Diego Gas & Electric Co., et al., 95 FERC ¶61,115 (2001)(*April 26 Order) and Certification of Proposed Findings on California Refund Liability, Bruce Birchman, Presiding Administrative Law Judge in *San Diego Gas & Electric Co., et al.,* 101 FERC ¶63,026 (2002) at P 72 (2002)(Birchman Certification).

29 See Birchman Certification at P 78.

30 This non-decreasing heat rate requirement does not apply over the entire range of unit output, but is limited to outputs in excess of the final forward schedule level of output, since that is the range of outputs applicable for real-time supplemental energy bids. Thus, the incremental heat rate in any block is equal to the highest incremental heat in any block from the forward schedule output level through the block being considered.

turbine and combined cycle units use natural gas. I have used the same natural gas prices as FERC established in July 2001 as the basis for calculating the MMCP.[31] Those prices are based on the daily indices published by Gas Daily. Although some of the combustion turbines use fuel oil, the prices for fuel oil are not relevant for the analysis because I am not evaluating withholding from the CTs at this time.

Q: Do you consider your natural gas prices to be conservative?

A: Yes. Michael Harris, whose testimony is being submitted concurrently with my testimony in this proceeding, finds that there is sufficient evidence to conclude that the gas price indices used in the MMCP calculations were manipulated (i.e., artificially increased) and are invalid for purposes of calculating the MMCP. In fact, as he discusses, the FERC staff recommended an alternative approach to determining gas prices for the MMCP calculation.[32] To the extent that these indices overstate the California Generators' actual cost of natural gas, my analysis understates withholding. If the FERC were to adopt an alternative approach to developing gas prices for the MMCP calculation that yields lower prices than the indices that FERC has used, and I adopted those alternative gas prices in my withholding analysis, my estimate of withholding would be higher than presented herein.

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31 See *San Diego Gas & Electric Co., et al.*, 96 FERC ¶61,120 at 61,517-18 (2001)(July 25 Order).
32 See FERC Staff Report at 4.

Q: Please describe the next component, which is "VOM."

A: VOM is variable operation and maintenance expense, which is measured in \$/MWh. I have used \$6 per MWh for all units, as FERC has done in its MMCP calculation.[33]

Q: Please describe the next component, which is "NOX."

A: NOX is the variable cost of NOx emissions, measured in \$/MWh. The FERC does not incorporate NOx emissions costs in its calculation of the MMCP, but rather allows generators to separately recover such costs.[34] However, since such costs vary with output, they are a relevant marginal cost for assessing withholding and I have included them in my calculation of marginal cost. NOX is equal to the product of the NOx emission rate (lbs/MWh) and the relevant NOx emissions cost (\$/lb). I discussed NOx emissions rates and costs earlier in this section.

Q: Finally, please describe the last component of your marginal cost calculation, which is "CREDIT."

A: CREDIT is an adjustment for credit risk. I have adopted the FERC's approach of adding 10% to the marginal cost for credit risk from January 6, 2001 through June 20, 2001.[35] There is no credit risk adjustment prior to January 6, 2001.

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33 See July 25 Order at 61,519.
34 See July 25 Order at 61,502.
35 See July 25 Order at 61,519.

Q: Have you considered any sensitivity cases with respect to marginal costs?

A: Yes. As I will discuss in Section V, I have assessed the sensitivity of my withholding calculations to increases in the marginal cost estimates of 10% and of 20%.

Outages

Q: Let's move on to outages. First, what is an outage?

A: An outage is a situation in which a unit is not able to produce its full capacity. Outages can be "forced" (i.e., the result of an unplanned operational problem) or "planned" (i.e., the result of planned maintenance or other planned action).[36] Outages can be either full (i.e., the unit is not capable of producing any power) or partial (i.e., the unit can produce some power, but not up to its full capability).

Q: How do you treat outages in your withholding analysis?

A: I have assessed withholding under two scenarios regarding outages. First, I assume that the outages reported by the California Generators were entirely legitimate. Second, I estimate withholding assuming that the forced outages for the California Generators' units were at a benchmark level. The difference between these two cases represents the estimated effect of excessive reported forced outages by the California Generators. Note that in the second case, I

[36] I use "planned" to refer to any outage that is not "forced." Non-forced outages are sometimes broken down between "planned" and "maintenance" outages.

continue to assume that the *planned* outages reported by the California Generators were entirely legitimate.

Q: Where do you obtain your outage data?

A: For the first case, I used the outage data provided by the California Generators in response to requests from the California Parties in this proceeding.[37] For the second case, I utilized the benchmark forced outage rates prepared by Dr. Hanser, which are based on analyzing GADS[38] data for units that are comparable to the California Generators' units.

Reserve Shutdowns

Q: Let's move on to the next data item. What is a reserve shutdown?

A: A reserve shutdown occurs when an operator has chosen to take the unit offline for economic reasons, not because of an outage.

Q: Why is the consideration of reserve shutdowns important for your withholding analysis?

A: Reserve shutdowns are important for the following reason. In order for a unit to be brought online (i.e., provide power to the grid and participate in the markets)

[37] The Generators' outage data occasionally reported conflicting information about the extent of outages in particular unit-hours. In those instances, I used the outage data that reflected the largest outage (i.e., lowest availability).

[38] GADS format refers to the format for reporting outages adopted by the North American Electric Reliability Council (NERC) for its Generating Availability Data System (GADS) database.

from being in reserve shutdown, there are certain start-up costs. In addition, units in reserve shutdowns cannot be instantly brought back online, but rather require a certain amount of time to "warm up" before they can be brought online. The decision about when to start up a unit, which is part of the "unit commitment" decision, depends on the cost and time to start-up and expectations for market prices.

Q: Let's first talk about how you identified when units were in reserve shutdown. Did the California Generators provide data on when their units were in reserve shutdowns?

A: The outage data provided by four of the five generators discussed above also happened to contain data on when units were in reserve shutdowns.[39] I reviewed the reserve shutdown data provided by the four California Generators, but I ultimately decided not to use it in my analysis. The reason that I did not utilize this data is that I found that there were hours in which the data indicated that a unit was in reserve shutdown, but the CAISO data showed that the unit was generating power, providing ancillary services, and/or bidding into the real-time market. As such, I concluded that the data could not be used in my analysis without making adjustments. Furthermore, I wanted to have an approach that I could apply consistently to all of the generators and, since AES/Williams did not provide

[39] My understanding is that the California Generators were not asked to provide reserve shutdown data. AES/Williams did not provide data on reserve shutdowns with its outage data.

reserve shutdown data, I needed to develop an alternative approach to achieve that consistency.

Q: If you did not use the data provided by the California Generators, how did you identify times when units were in reserve shutdowns?

A: I used the following rule to identify hours in which units were in reserve shutdown: if a unit had no generation, provided no ancillary services, and was not bid into the real-time market for four or more consecutive hours, then I considered the unit to be in reserve shutdown during those hours.[40] I chose the four-hour cutoff because only a very small fraction of the reserve shutdowns reported by the California Generators in the data they provided were shorter than four hours.

Q: How do the reserve shutdowns identified by your rule compare with those reported by the California Generators?

A: As expected, there is a significant overlap. However, for the four generators that supplied reserve shutdown data, my rule identifies approximately 85% more unit-hours of reserve shutdowns than are reported by the generators. As I discussed, there are reserve shutdowns reported by the generators that I do not consider to be reserve shutdowns under my rule because there is some sort of activity. However, such instances are significantly less frequent than instances when my rule

[40] I used a cutoff of 0.1 MW in determining whether or not there was activity (i.e., activity that was greater than zero but below 0.1 MW was considered to be "no activity").

identifies a reserve shutdown that is not reported in the data. As such, I consider my rule-based approach to be conservative.[41]

Q: Let's now turn from how you identified reserve shutdowns to how you treated those reserve shutdowns in your withholding analysis. First, do you measure withholding during a reserve shutdown period based on your marginal cost estimates?

A: No. My marginal cost estimates do not include startup costs. It would not be appropriate to measure withholding during reserve shutdown periods without making an adjustment for such costs.

Q: So, how have you treated reserve shutdowns in your withholding analysis?

A: At this time, I have excluded from my withholding analysis all of the hours identified as reserve shutdowns for each unit using the rule I described above. I consider this assumption to be conservative since there may have been withholding during some of these periods.

Q: Did reserve shutdowns ever occur during on-peak hours during the period that you analyzed?

[41] My analysis shows that withholding based on the reserve shutdowns reported by the four generators and applying my rule to AES/Williams only is about 50% greater than withholding based on applying my rule to all five generators (based on on-peak hours from May through 2000).

A: Yes. Figure 11 shows the percentage of each of the California Generators' capacity that was on reserve shutdown during *on-peak* hours each month. As seen in this figure, with the exception of August 2000, one or more of the generators had significant levels of reserve shutdowns in all months.

Q: Have you analyzed these periods that you identified as reserve shutdowns further?

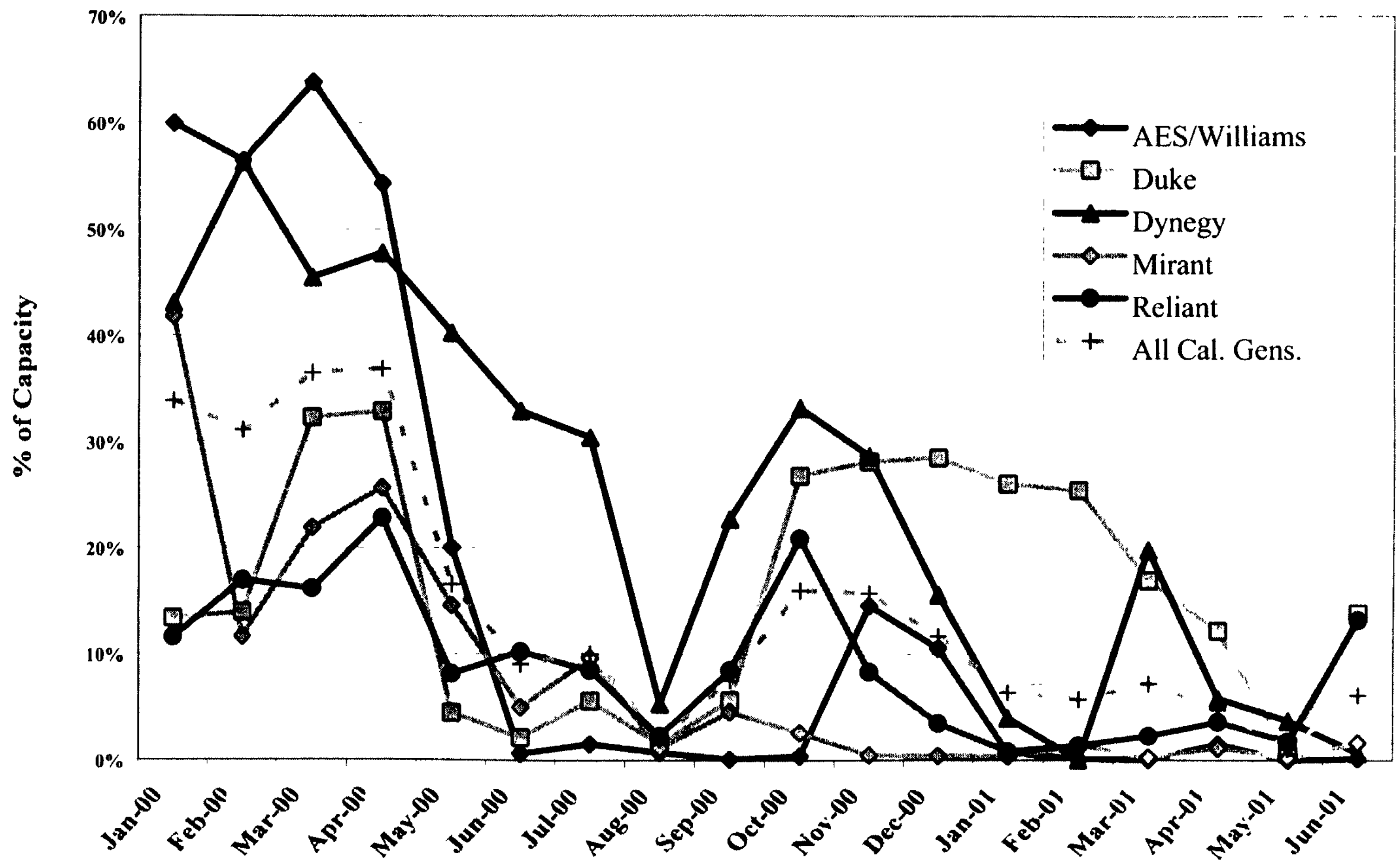
A: Yes. During the on-peak hours in May through September 2000, the California Generators' units were in reserve shutdowns for 13,886 unit-hours, which approximated 10% of the capacity during those hours. I have analyzed the "gross margin" that the California Generators could have earned if they had operated at full load during for the on-peak reserve shutdown hours in May through September 2000.

Q: How did you calculate the gross margin?

A: I calculated the "gross margin" as the difference between the market price and the marginal cost in each hour multiplied by the capacity of the unit. For this calculation, I used the average of the incremental heat rates of the blocks of capacity for each unit in computing marginal cost. Since this calculation does not incorporate unit start-up costs, it does not reflect a full analysis of the profitability of operating during the reserve shutdown hours.

Figure 11

Percentage of Capacity in Reserve Shutdown During On-Peak Hours



Q: What were the results of your gross margin calculations?

A: During the identified reserve shutdowns, the average marginal cost across all units (weighted by capacity and reserve shutdown hours) was $56 per MWh and the average real-time price was $91 per MWh, a margin of about 60%. If the units had been run at full load during these periods, they would have generated $103 million in "gross margin." Figure 12 shows the details of these results.[42]

Q: What conclusions do these calculations suggest?

A: Since such "gross margin" does not include start-up costs, I cannot conclude that there was withholding during these hours. Nevertheless, this level of potential profitability suggests that there may have been at least some withholding during those hours identified as reserve shutdown hours.

Q: How do your results compare across the individual California Generators?

A: As shown in Figure 12, all five generators could have earned positive gross margins by operating their reserve shutdown units during these hours.

42 I note that the calculations reflect the netting of margins across periods of both positive margins (+$140 million) and negative margins (-$37 million).

Figure 12

Gross Margins from Operations During Reserve Shutdowns in On-Peak Hours
From May through September 2000

Company	CAISO Unit ID	Reserve Shutdown Hours	Average Marginal Cost ($/MWh)	Average Real-Time Price ($/MWh)	Average Margin ($/MWh)	Capacity (MW)	Gross Margin (mm$)
AES/Williams	ALAMIT_7_UNIT 1	171	53	95	42	175	1.3
AES/Williams	ALAMIT_7_UNIT 2	96	40	144	104	175	1.7
AES/Williams	ALAMIT_7_UNIT 3	2	53	34	(19)	320	(0.0)
AES/Williams	ALAMIT_7_UNIT 4	40	53	46	(7)	320	(0.1)
AES/Williams	ALAMIT_7_UNIT 5	160	33	100	67	480	5.2
AES/Williams	ALAMIT_7_UNIT 6	336	35	77	43	480	6.9
AES/Williams	HNTGBH_7_UNIT 1	26	51	146	94	215	0.5
AES/Williams	REDOND_7_UNIT 5	79	64	71	6	175	0.1
AES/Williams	REDOND_7_UNIT 6	42	60	45	(15)	175	(0.1)
AES/Williams	REDOND_7_UNIT 7	85	38	186	148	480	6.0
AES/Williams	REDOND_7_UNIT 8	112	36	79	44	480	2.3
Duke	MORBAY_7_UNIT 1	256	43	49	6	163	0.2
Duke	MORBAY_7_UNIT 2	208	43	50	7	163	0.2
Duke	MORBAY_7_UNIT 4	32	59	119	60	338	0.6
Dynegy	ELSEGN_7_UNIT 1	1,418	74	94	21	175	5.1
Dynegy	ELSEGN_7_UNIT 2	1,299	74	95	21	175	4.7
Dynegy	ELSEGN_7_UNIT 3	259	46	131	84	335	7.3
Dynegy	ELSEGN_7_UNIT 4	13	43	255	212	335	0.9
Dynegy	LBEACH_2_230TOT	1,794	76	97	22	180	7.1
Dynegy	LBEACH_6_66TOT	1,208	56	81	26	400	12.4
Mirant	COCOPP_7_UNIT 6	64	44	95	51	335	1.1
Mirant	COCOPP_7_UNIT 7	111	43	54	11	337	0.4
Mirant	PITTSP_7_UNIT 1	367	49	76	28	150	1.5
Mirant	PITTSP_7_UNIT 2	387	48	88	40	150	2.3
Mirant	PITTSP_7_UNIT 3	854	47	69	22	150	2.8
Mirant	PITTSP_7_UNIT 4	790	47	86	38	145	4.4
Mirant	PITTSP_7_UNIT 5	32	39	76	37	312	0.4
Mirant	PITTSP_7_UNIT 6	90	44	103	59	317	1.7
Mirant	PITTSP_7_UNIT 7	34	45	51	6	682	0.1
Reliant	CWATER_7_UNIT 1	214	49	61	12	63	0.2
Reliant	CWATER_7_UNIT 2	19	62	86	23	82	0.0
Reliant	CWATER_7_UNIT 3	707	41	108	66	241	11.3
Reliant	CWATER_7_UNIT 4	34	32	86	54	241	0.4
Reliant	ETIWND_7_UNIT 1	988	64	84	20	132	2.6
Reliant	ETIWND_7_UNIT 2	1,027	65	82	17	132	2.3
Reliant	ETIWND_7_UNIT 3	205	66	110	44	320	2.9
Reliant	ETIWND_7_UNIT 4	270	55	88	33	320	2.8
Reliant	MNDALY_7_UNIT 1	16	45	291	245	215	0.8
Reliant	MNDALY_7_UNIT 2	30	44	183	139	215	0.9
Reliant	ORMOND_7_UNIT 2	11	33	290	257	750	2.1
Total		13,886	56	91	35		103.5
AES/Williams		1,149					23.8
Duke		496					1.1
Dynegy		5,991					37.5
Mirant		2,729					14.7
Reliant		3,521					26.3

Supply Data

Q: Finally, let's discuss supply data. What are you referring to here?

A: This refers to certain basic factual data on generation, ancillary services, and bids that I use in my analysis.

Q: Specifically, what data do you rely upon and where did you obtain the data?

A: I obtained the following data for each of the California Generators' units in each hour of the period of my analysis from CAISO:

- Metered generation: the amount of energy (MWh) produced in the hour as measured at the point the unit is connected to the transmission grid.
- Final forward schedule: the amount of energy (MWh) scheduled for that hour prior to the real-time market (e.g., scheduled in the day ahead and hour ahead markets or through other transactions).[43]
- Ancillary services capacity awarded. This includes spinning reserves, non-spinning reserves, replacement reserves, and regulation up. Regulation down is not included since it does not require that capacity be set aside. Such awards are made in advance of the real-time market supplemental energy bidding.
- Supplemental energy bids. This includes the price/quantity pairs bid as supplemental energy into the CAISO real-time market.
- Incremental and decremental supplemental energy instructed in real-time. Decremental energy refers to instruction from the CAISO to reduce output.
- Incremental ancillary service energy instructed in real-time other than regulation up and regulation down. This includes instructed dispatch of spinning reserves, non-spinning reserves, and replacement reserves. There are no decremental instructions associated with these ancillary services.

[43] Note that bids into the real-time market are due 45 minutes prior to the hour.

- Incremental and decremental out-of-sequence (OOS) energy. OOS transactions refer to cases in which the CAISO selects a bid from the BEEP stack[44] that is out of merit order (i.e., its price is higher than other bids that are not accepted). The CAISO can deviate from the merit order due to intra-zonal congestion and system reliability concerns. When the CAISO selects an OOS bid for system reliability reasons, that bid can set the real-time market price. When the CAISO selects an OOS bid for intra-zonal congestion management, that bid does not set the market price, but the OOS unit called is paid its bid price.[45]

- Incremental and decremental out-of-market (OOM) energy. OOM transactions refer to cases in which the CAISO requests additional power from a unit that was not bid into the BEEP stack. The CAISO makes such requests when there are insufficient bids in the BEEP stack.[46]

- Operating level. This measures the average operating level of each unit over the last 10 minutes each hour. I use these data in determining the ramping constraint, as discussed in Section IV. These data are only available for September 2000 onward. For earlier periods, I assume that the operating level at the end of the hour equals the average operating level for the hour.

Summary

Q: That was a lengthy discussion of data issues. Can you summarize the key points of this section before we move on to discuss your withholding analysis methodology?

A: Yes. Briefly, the key points regarding how I treat the data are as follows:

- I focus on the CAISO real-time market, which is the "market of last resort" for generators in the CAISO control area.

- I analyze withholding from the steam turbine and combined cycle units only, eliminating the combustion turbines from consideration, which is

[44] "BEEP" stands for Balancing Energy and Ex-Post Pricing. The BEEP stack consists of supplemental energy bids and ancillary services energy bids.
[45] See California ISO Operating Procedure M-403, Balancing Energy and Ex-Post Pricing.
[46] See California ISO Operating Procedure M-403, Balancing Energy and Ex-Post Pricing.

conservative. I also eliminate certain steam turbine units from the withholding analysis during certain periods due to environmental considerations, which is conservative.

- I use the lowest values for capacity of the California Generators' units that were reported by the generators themselves, which is conservative.

- I estimate marginal costs using the approach adopted by the FERC in calculating the MMCP, with two adjustments that are conservative: using non-decreasing incremental heat rates and including NOx emissions costs. In addition, I use the California gas price indices despite the evidence that such indices may have been manipulated and the FERC staff recommended an alternative approach, which would yield lower gas prices (and, thus, greater withholding) than the approach that I adopted.

- I consider two scenarios for forced outages: one in which I assume that all of the forced outages reported by the California Generators were legitimate and one in which I utilize the benchmark forced outages developed by Dr. Hanser.

- I use a conservative approach to identify times when the California Generators' units were in reserve shutdowns and I do not compute withholding during such reserve shutdown periods, which is conservative. I also do not compute withholding during planned outages reported by the generators, which is conservative.

SECTION IV. WITHHOLDING ANALYSIS METHODOLOGY

Q: What is the purpose of this section of your testimony?

A: In this section, I describe the approach that I used in my withholding analysis.

Q: For what units and time periods have you calculated withholding?

A: I have calculated withholding for the steam turbine and combined cycle units owned by the California Generators in each hour from January 1, 2000 through

June 20, 2001. As I previously discussed, I have excluded certain units in certain periods due to environmental considerations

Q: How is this section organized?

A: First, I describe the basic approach I used to calculate withholding given the outages reported by the generators. I then describe how I adapt this basic approach to estimate withholding using the benchmark forced outage rates as opposed to the generators' reported forced outages.

Methodology for Assessing Withholding

Q: Let's talk about your methodology. How do you calculate withholding?

A: Basically, withholding (WH) is equal to the difference between producible economic (PEC) and supplied output (SO). Producible economic capacity is the amount of capacity that: (a) can be produced given all of the constraints on production and (b) is economic at the prevailing market price (i.e., its marginal cost is below the market price). Supplied output is the amount of output actually supplied, including energy and ancillary services. In other words, to the extent that there is capacity that is producible and economic, but it is not supplied, there is withholding.

Producible Economic Capacity (PEC)

Q: Let's focus in more detail on your calculation of producible economic capacity (PEC). How do you calculate PEC?

A: Producible economic capacity is equal to the effective capacity of the unit if there are no constraints in a given hour. However, producible economic capacity can be limited by four factors: outages, reserve shutdowns, ramping, and costs relative to market prices. Producible economic capacity is set by the most restrictive of these constraints in each hour (i.e., it is equal to the minimum of the capacity measures derived from these four constraints). Figure 13 shows the equations that I used to calculate PEC. I note that each of the variables used in these equations is indexed by unit and hour, but I have left off those indices to keep the description from being too cluttered.

Figure 13
Equations for Calculating Producible Economic Capacity (PEC)

Producible economic capacity

PEC	=	Minimum (EFC, AVC, RLC, NSC, ECC)

Available capacity

AVC	=	EFC – POUT – FOUT (a)

Ramping limit capacity

RLC	=	OPLEVEL(-1) + WH(-1) + 0.5 * RAMP (a,b,c)

Non-shut down capacity

NSC	=	SO if unit is on reserve shutdown; EFC otherwise

Economic capacity

ECC	=	(UDASC + ECON+) if (UDASC + ECON+ >= SO);
	=	Minimum (UDASC + ECON+ + FS +INCOOM/OOS + PUDARUC, SO) otherwise
ECON+	=	Economic capacity above FS at prevailing market price
UDASC	=	Undispatched ancillary services (see calculation of SO)

Input Variables

EFC	=	Effective capacity
POUT	=	Capacity made unavailable due to planned outages
FOUT	=	Capacity made unavailable due to forced outages
OPLEVEL	=	Operating level at end of hour
RAMP	=	Ramp rate
FS	=	Final forward schedule energy
INCOOM/OOS	=	Incremental out-of-market and out-of-sequence energy

(a) EFC, AVC, and RLC cannot be less than SO; SO and ECC cannot be greater than EFC.
(b) (-1) refers to the value in the previous hour.
(c) This assumes that the unit can ramp for the entire hour without hitting a capacity limit. If it would hit such a limit, equation is slightly different, as described in the text.

Q: What is effective capacity?

A: Effective capacity is simply the capacity absent any constraints. As I discussed in Section III, I used conservative assumptions for effective capacity and, in fact, actual output exceeded effective capacity for most units in certain hours.

Q: What do you do if actual supplied output in an hour exceeds effective capacity for that unit?

A: In those cases, I reset the effective capacity for that hour to equal actual supplied output in that hour.

Q: Does this affect capacity in other hours?

A: No. I only reset effective capacity to a higher value for those hours where supplied output exceeds effective capacity. When supplied output is less than effective capacity, I base my withholding calculation on a conservative value of capacity. Thus, any calculation of positive withholding reflects the conservative capacity assumption.

Q: Now, let's go through the potential constraints on effective capacity one at a time. But first, can you provide a simple example that will help illuminate the discussion?

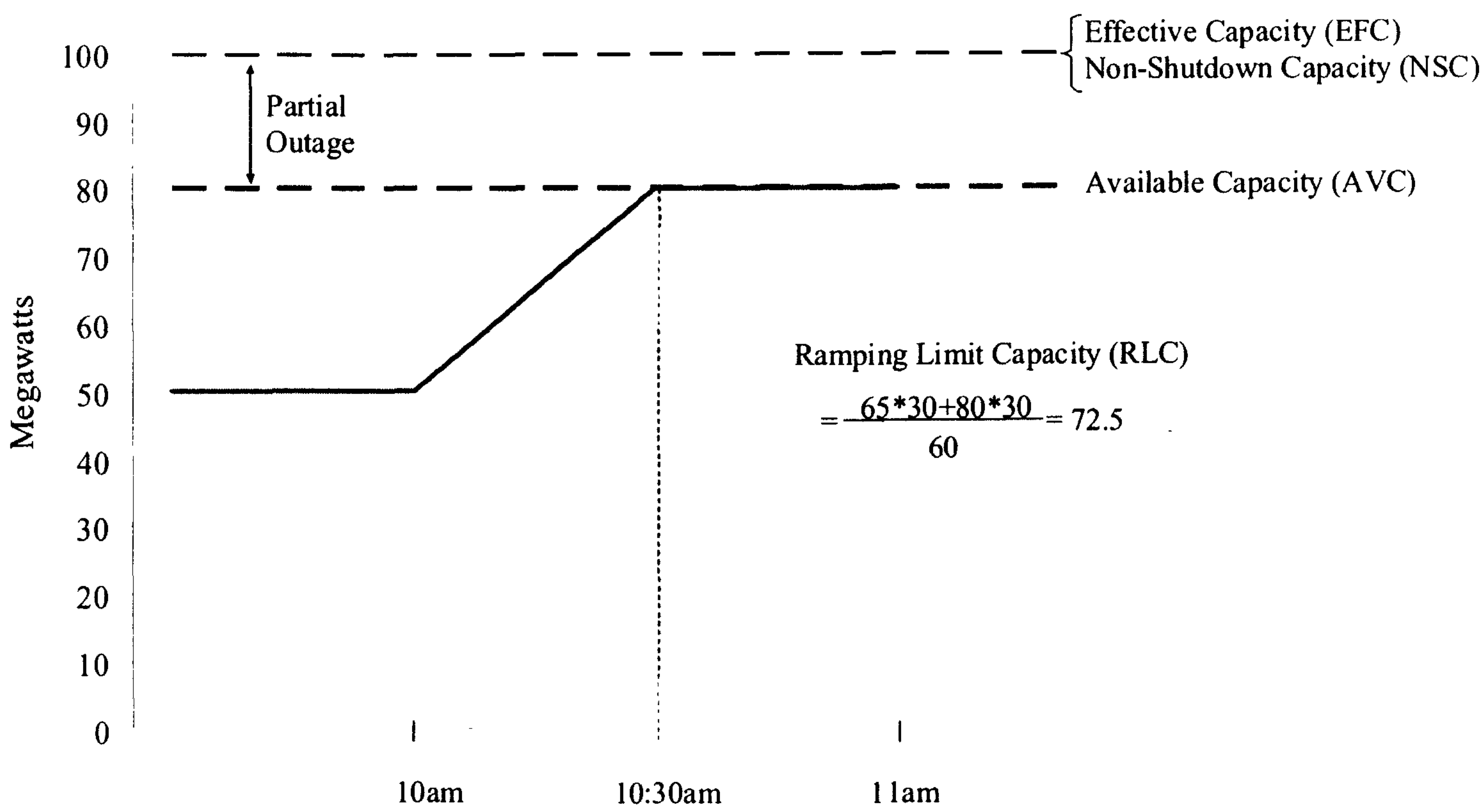
A: Yes. I have prepared Figure 14 to help explain how I calculate producible economic capacity. While this figure does not capture all of the potential complexities of the calculation, which I describe below, it does illustrate the key points. Let me set up the situation shown in Figure 14. This illustrates the calculation of producible economic capacity for a hypothetical unit for the hour 10am to 11am. The unit is assumed to have an effective capacity of 100 MW and a maximum ramp rate of 1 MW per minute. Further, it is assumed that the unit was operating at 50 MW at the end of the prior hour. As I explain each of the components of producible economic capacity, I will refer back to Figure 14.

Q: Now, using Figure 14, let's go through each of those potential constraints on effective capacity. First, please describe the available capacity constraint.

A: Available capacity (AVC) is equal to effective capacity less planned and forced outages. Planned and forced outages are input values, as discussed in Section III. In the example shown in Figure 14, there is a partial forced outage of 20 MW. As such, available capacity is 80 MW. Although it does not show up in this example, in setting available capacity, I incorporate a one hour lag to account for bid timing constraints.

Figure 14

Illustrative Example of PEC Calculation



Q: Please explain the bid timing constraints?

A: Bid timing constraints account for the fact that supplemental energy bids in the CAISO real-time market are due 45 minutes before the hour.[47] For example, suppose that a unit had a partial outage that was resolved at 9:30 am. That unit would show full availability for the hour starting at 10 am. However, that unit would not have been able to bid the capacity that had been on partial outage into the real-time market for the hour starting at 10 am because the capacity was not available at the time bids were due (9:15 am). Thus, I assume that capacity that is returning from an outage is not available for the real-time market until the hour following the hour that it returns to availability as shown in the generator's reported outage data.

Q: What do you do if supplied output exceeds available capacity?

A: Again, in those hours where actual output exceeds available capacity, I reset available capacity to equal actual output. This situation could occur, for example, as the result of the conservative approach that I used to set availability in a given hour (i.e., I assumed that if an outage affected any portion of an hour, it affected the whole hour).

Q: Is there any other degree of conservatism in your calculation of available capacity?

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[47] See Scheduling & Bidding Guidelines, Market Operations, Date Written 07/21/98, Date Modified 02/13/02, page 7.

A: Yes. The outage data provided by the California Generators provides capacity, outage, and availability levels. I use the reported outage level as opposed to the availability level from that data. To the extent that I use a lower assumed capacity than that in the California Generators' outage data, I get a lower availability level. For example, suppose the California Generators' outage data shows that the unit in the illustrative example had capacity of 105 MW and a forced outage of 20 MW, resulting in availability of 85 MW. Then, in my withholding calculation, available capacity would be 80 MW (100 – 20) as opposed to their reported value of 85 MW. In addition, to the extent that capacity did become available within the first 15 minutes of an hour, my assumed lag of one hour for bid timing considerations is conservative.

Q: Next, please describe the reserve shutdown constraint.

A: As I discussed in Section III, it would not be appropriate to measure withholding during hours when a unit is in reserve shutdown without adjusting my marginal cost measure to reflect start-up costs. Since I have not developed a "start-up" analysis at this time, I have conservatively estimated withholding by not computing any withholding during all of the hours that I identified as reserve shutdowns using the rule that I described in Section III. This is conservative since some of the reserve shutdowns may constitute withholding, as I discussed in Section III.

Q: How does the reserve shutdown constraint show up in your illustrative example in Figure 14?

A: In my illustrative example in Figure 14, the unit is not on reserve shutdown and, thus, non-shutdown capacity (NSC) is equal to effective capacity (EFC).

Q: Moving on, please describe the ramping constraint.

A: Ramping limit capacity (RLC) accounts for the fact that it takes time for a unit to increase its output level. Referring to Figure 14, the unit operated at 50 MW at the start of the hour. If it ramped as fast as possible, it would reach its available capacity of 80 MW after 30 minutes. It would then stay at 80 MW for the remainder of the hour. In this case, the maximum total energy supplied over the hour would be 72.5 MWh (65 MW on average for 30 minutes and 80 MW for 30 minutes). Thus, RLC would be 72.5 MW.

Q: Do you account for withholding in prior hours in calculating your ramping constraint?

A: Yes. The ramping limit capacity in any given hour takes into account withholding in the previous hour. That is, the starting point for the ramping constraint is the actual generation in the prior hour plus withholding in that hour. Suppose that, in the above example, there was withholding of 10 MW in the hour from 9am to 10am. Then, the starting point for computing ramping limit capacity for the hour 10am to 11am would be 60 MW (50 MW operated plus 10 MW withheld) and the unit would be able to ramp up to its available capacity in 20 minutes. In this case, RLC would be about 77.7 MW.

Q: What do you do if actual output for that hour exceeds the ramping limit capacity?

A: As with effective capacity and available capacity, if ramping limit capacity is less than supplied output, I reset ramping limit capacity (RLC) for that hour to equal supplied output.

Q: Finally, let's talk about economic capacity. Please describe that constraint.

A: Economic capacity consists of capacity that has been committed outside of the CAISO real-time market, plus additional capacity, if any, which is economic to supply at the prevailing real-time market price.

Q: What are the components of capacity committed outside of the CAISO real-time market?

A: There are four such components:

- First, units may have energy scheduled in the forward markets (day ahead and hour ahead) or through other transactions.

- Second, units may have ancillary services capacity awarded in the forward markets.

- Third, units may have OOM and OOS sales.

- Fourth, units may provide RMR (reliability must run) energy, ramping energy, and/or residual imbalance energy, which register as uninstructed deviations in the CAISO data.

Q: How do you compute each of these components?

A: The first three components are simply inputs that I obtained from the CAISO, as discussed in Section III. I describe the calculation of the fourth component in the section below on supplied output.

Q: How do you calculate the additional amount of capacity that is economic in the real-time market?

A: This capacity is that capacity, above the forward schedule, that has a marginal cost below the market price, as I discussed in Section III.

Q: What happens if supplied output is greater than economic capacity?

A: This case is different than when supplied output exceeds effective, available, or ramping limit capacity, where I reset such capacity to equal supplied output. I do not reset economic capacity to equal supplied output when it is less than supplied output. Thus, withholding can be negative for any given unit in any given hour.

Q: Why would withholding ever be negative?

A: There are several reasons, including the following:

- First, as I discussed, I use average market prices for each hour when, in fact, the market price can be different for each 10-minute interval. It is possible that a unit could be economic for part of an hour, but not be economic at the average price for the hour.

- Second, while I consider my marginal cost estimates to be conservative, there is some uncertainty in those estimates. For example, the gas price facing any given plant in any hour may be more or less than the gas price that I use. In fact, as I discussed, in Section III, there is evidence that the reported gas price indices overstated the true gas prices. If the unit's true marginal cost is lower than my estimate, the unit could be run economically even though my calculation does not show it to be economic. This would result in negative withholding.

- Third, as I discussed in Section III, constraints on the rate at which units can ramp down effectively mean that there is a certain amount of capacity that has a zero marginal cost. Since I do not consider such constraints, I effectively overstate the marginal cost of such capacity.

- Fourth, a unit may have a portion of its capacity bid at a low price in order to keep the unit operating at minimum load, thereby avoiding the costs of shutting down and restarting the unit.

Q: Is the fact that your analysis shows negative withholding for certain units in certain hours indicate that your methodology is flawed?

A: No. As I explained above, negative withholding can result from certain factors that are explainable and it does not mean that my approach is flawed.

Q: What have you done with the negative withholding?

A: I have given the generators credit for negative withholding: i.e., I have calculated net (positive less negative) withholding. This is an appropriate way to deal with the "variations" discussed above. For example, if there were some variation in actual gas prices around the reported value, withholding might be computed as positive in some hours and negative in other hours simply due to such variation.

Counting only the positive values would tend to overstate the firm's actual withholding.

Supplied Output (SO)

Q: Let's move to the second part of your withholding formula, which is supplied output. What is supplied output?

A: Supplied output measures the extent to which a unit was actually used in a given hour. Supplied output has three components: metered generation, undispatched ancillary services, and decremental instructions. Figure 15 shows the equations that I use for supplied output.

Figure 15
Equations for Calculating Supplied Output (SO)

Supplied output

SO = MGEN + UDASC – DECTOT

Undispatched ancillary services

UDASC = INCASC – INCASE – REGUPE

Decremental instructions (a)

DECTOT = DECSE + DECOOM/OOS + REGDOWNE

Uninstructed deviation, positive and negative (UD, PUD, NUD)

UD = MGEN * FGMMA – FS – INCSE – DECSE – INCASE – INCOOM/OOS – DECOOM/OOS
PUD = Maximum (UD, 0)
NUD = Minimum (UD, 0)

Regulation energy dispatched

REGUPE = Minimum (PUD, REGUPC)
REGDOWNE = Maximum (NUD, –REGDOWNC)

Positive uninstructed deviations beyond regulation up

PUDARUC = PUD – REGUPE

Input Variables

MGEN	=	Metered generation
FS	=	Final forward schedule energy
INCASC	=	Ancillary service capacity awarded (excl. regulation down)
INCASE	=	Ancillary service energy instructed (excl. regulation)
REGUPC	=	Regulation up capacity awarded
INCOOM/OOS	=	Incremental out-of-market and out-of-sequence energy
DECOOM/OOS	=	Decremental out-of-market and out-of-sequence energy
FGMMA	=	Actual transmission loss factor
INCSE	=	Incremental supplemental energy instructed
DECSE	=	Decremental supplemental energy

(a) Decremental instructions are negative.

Q: Let's talk about each component in detail. First, what is metered generation?

A: Metered generation is the actual amount of energy provided by a unit in a given hour. Metered generation includes what I refer to as instructed generation (i.e., forward schedule, real-time dispatch, and incremental OOM/OOS transactions) and uninstructed deviations.[48]

Q: Please describe the next component of supplied output, which is undispatched ancillary services.

A: I do not consider capacity that was awarded ancillary services to be withheld. Awarded ancillary services capacity is the sum of spinning reserves, non-spinning reserves, replacement reserves, and regulation up. Regulation down is not included because it does not require that capacity be set aside to provide that service. However, awarded ancillary service capacity can be dispatched in real-time. Each ancillary services bid includes an energy bid, which is considered in the ISO's real-time dispatch decisions. If capacity awarded ancillary services was dispatched in real-time, it will register as metered generation. Thus, in order to avoid double-counting, I add only *undispatched* ancillary services to metered generation.

48 Each of the components of instructed generation is an input value that I obtain from the CAISO, as I discussed in Section III.

Q: How do you calculate ancillary services dispatched?

A: Data on dispatch of spinning reserves, non-spinning reserves, and replacement reserves were provided by CAISO, as I discussed in Section III. However, regulation up energy is not directly reported by the CAISO. Therefore, regulation energy must be inferred from metered generation.

Q: How do you calculate regulation energy from metered generation?

A: First, I calculate uninstructed deviations as the difference between metered generation and instructed generation. Uninstructed deviations can be positive or negative. Regulation energy can also be positive or negative. I assume that positive uninstructed deviations are regulation up energy and negative uninstructed deviations are regulation down energy. However, I limit the amount of regulation up/down energy to the amount of regulation up/down capacity awarded. For example, if there is an uninstructed deviation of +100 MWh and regulation up capacity awarded is 50 MW, then I assume that regulation up energy is 50 MWh. Similarly, if there is an uninstructed deviation of -100 MWh and regulation down capacity awarded is 50 MW, then I assume regulation down energy is equal to -50 MWh.

Q: What could cause an uninstructed deviation to be bigger than the amount of regulation up/down capacity awarded?

A: Positive uninstructed deviations beyond regulation up can be due to: (a) energy provided pursuant to an RMR call, (b) ramping energy or residual imbalance energy, which result from the fact that generation units are never able to perfectly match output to their dispatch schedule due to ramping times, and (c) simply the unit producing more than it was scheduled to produce. Negative uninstructed deviations beyond regulation down can be due to ramping/residual imbalance energy or to the unit simply producing less than it was scheduled to produce.

Q: How do you treat positive uninstructed deviations beyond regulation up?

A: I give the generators credit for such generation since it may be due to legitimate factors. Essentially, I treat this energy in the same way that I treat incremental OOM and OOS energy (which are discussed below). This is conservative because positive uninstructed deviations might have resulted in part from "game playing," at least through September 2000.[49] Prior to September 2000, generators were paid the real-time energy price for positive uninstructed deviations. A "game" would be as follows: the generator could withhold capacity from the real-time market, resulting in a higher real-time price than if the capacity had been offered in that market, and then the generator could produce the energy as an uninstructed deviation at this higher price. Such behavior would effectively represent withholding.

[49] See CAL-ISO 2000 Report of Economic Operations, November 15, 2000, at 14.

Q: How do you treat negative uninstructed deviations beyond regulation down?

A: I do not give credit for negative uninstructed deviations beyond regulation down. That is, I do not "add back" such energy not produced to supplied output as I do with the decremental OOM and OOS transactions (as discussed below). The reason is that such deviations are not scheduled or requested by the CAISO, whereas decremental OOM and OOS transactions are at the instruction of the CAISO. As such, the generators should not be given credit for failing to meet their scheduled output.

Q: Finally, please describe the last component of supplied output, which is decremental instructions.

A: Units are sometimes asked to decrease (decrement) their output by the CAISO. Such instructions can come from the real-time market, out-of-sequence, or out-of-market instructions. In the real-time market, decremental instructions can result when excess capacity has been scheduled in the forward markets. To the extent that units were issued such instructions, it reduces metered generation. Since I do not consider power that is not produced as a result of such instructions to be withholding, I add back the amount of the decrements to metered generation in determining the extent to which a unit actually supplied power.

Q: Do you consider your calculation of supplied output to be conservative?

A: Yes, for at least three reasons:

- First, I give the generators full credit for OOM and OOS transactions, even though they may represent withholding. For example, OOM transactions arise when the CAISO procures supply from a unit that did not bid such supply into the real-time market. If that unit's marginal cost was below the real-time price and if it had been bid into the real-time market at its marginal cost, it could have been dispatched through the market and, moreover, market prices could have been lower.

- Second, I give the generators full credit for ancillary services capacity. However, Generators could put high prices on ancillary service energy bids. In awarding ancillary services capacity, the ISO may not consider the price on the energy portion of the bid. If so, undispatched ancillary services could provide a form of withholding: the generator could receive payment for "parking" reserves, recognizing that it was unlikely to ever be dispatched because of a high energy price. Thus, including undispatched ancillary services as part of supplied output is conservative.

- Third, I give the generators credit for positive uninstructed deviations even though such deviations may effectively be a form of withholding, as I previously discussed.

Benchmark Forced Outage Rates

Q: What is the purpose of this portion of your testimony?

A: In the previous section, I describe how I analyzed withholding given the California Generators' reported outages. In this section, I described how I analyzed withholding using the benchmark forced outage rates.

Q: Why do you consider the benchmark forced outage rate scenario?

A: As discussed in the Dr. Hanser's testimony, there is evidence that the forced outage rates reported by the generators were not entirely legitimate. This includes both evidence from review of specific forced outage events and the benchmark forced outage analysis.

Q: What are ways of assessing the effect of excessive forced outage reporting on withholding?

A: One way to assess the effect of excessive forced outages reported by the generators on withholding would be to go through each outage event, assess the extent to which it was legitimate, and adjust the outages for those that were not legitimate. Since that has not been done at this time, I use the benchmark forced outage levels.

Q: How do you use the benchmark forced outage rates in your withholding analysis?

A: The approach that I have adopted is as follows:

- First, I calculate withholding using the reported outage rates as described in the previous section (call that X).

- Second, I calculate withholding using the approach described in the previous section, but assuming no forced outages (call that Y). I would note that this scenario still uses *planned* outages as reported by the generators.

- Third, I calculate the benchmark forced outage rate as a percentage of the reported outage rate (call that result B/R).

- Then, estimated withholding under the benchmark forced outage rate is: $X + (Y-X)*(1-B/R)$

Q: Can you provide a simple numerical example to illustrate your approach?

A: Yes. The following numerical example illustrates my approach. Suppose withholding is 2000 MW with reported forced outages and 4000 MW with no forced outages. Further, suppose that the reported outage rate is 20% and the benchmark forced outage rate is 10%. Then the estimated withholding with benchmark forced outages would be:

$$2000 + (4000-2000)*(1-(10/20)) = 3000 \text{ MW}.$$

Q: How do you treat *planned* outages in your analysis?

A: I take the California Generators' reported planned outages as being legitimate in all cases. In other words, I am only measuring the effect of excessive *forced* outages. Thus, my analysis is conservative since the generators could have withheld capacity through excessive planned outages as well. I have not analyzed that possibility at this time.

SECTION V. WITHHOLDING ANALYSIS RESULTS

Q: What is the purpose of this section of your testimony?

A: In this section, I present the results of my analysis.

Q: How is this section organized?

A: First, I present the results of my analysis of withholding in the case where I accept the forced outages reported by the California Generators as being entirely legitimate. Second, I present the results of my analysis of withholding under the benchmark forced outages scenario. Third, I present the results of my sensitivity analysis with respect to marginal costs.

Withholding Under Generators' Reported Forced Outages

Q: Let's start with your analysis of withholding under the case in which you accept the California Generators' reported forced outages as being legitimate. Can you summarize your basic findings at a high level?

A: Yes. My analysis shows that, even if I accept the generators' reported outages as being legitimate, at least four of the five California Generators engaged in significant levels of withholding over significant periods of time (the possible exception was Duke). The levels of withholding were highest in May through September of 2000, but were also significant in other months.

Q: Let's look at your results in more detail. Have you prepared any figures that show your results?

A: Yes. I have prepared several figures that look at the results in different ways. I provide results for the California Generators in aggregate and by company. As I previously mentioned, I focus on the results for the on-peak hours.

Q: Let's go through these figures one at a time. The first one is Figure 16. Please explain that figure.

A: This figure shows the average hourly withholding during on-peak hours for each of the California Generators, and the aggregate total (which was also shown in Figure 2 in Section I). As seen in this chart, the average hourly withholding during on-peak hours exceeded 800 MW in each month from May through September 2000 and averaged over 1000 MW during this period. As mentioned earlier, at least four of the five generators have substantial levels of withholding. The numerical results underlying this figure are shown in Figure 5.

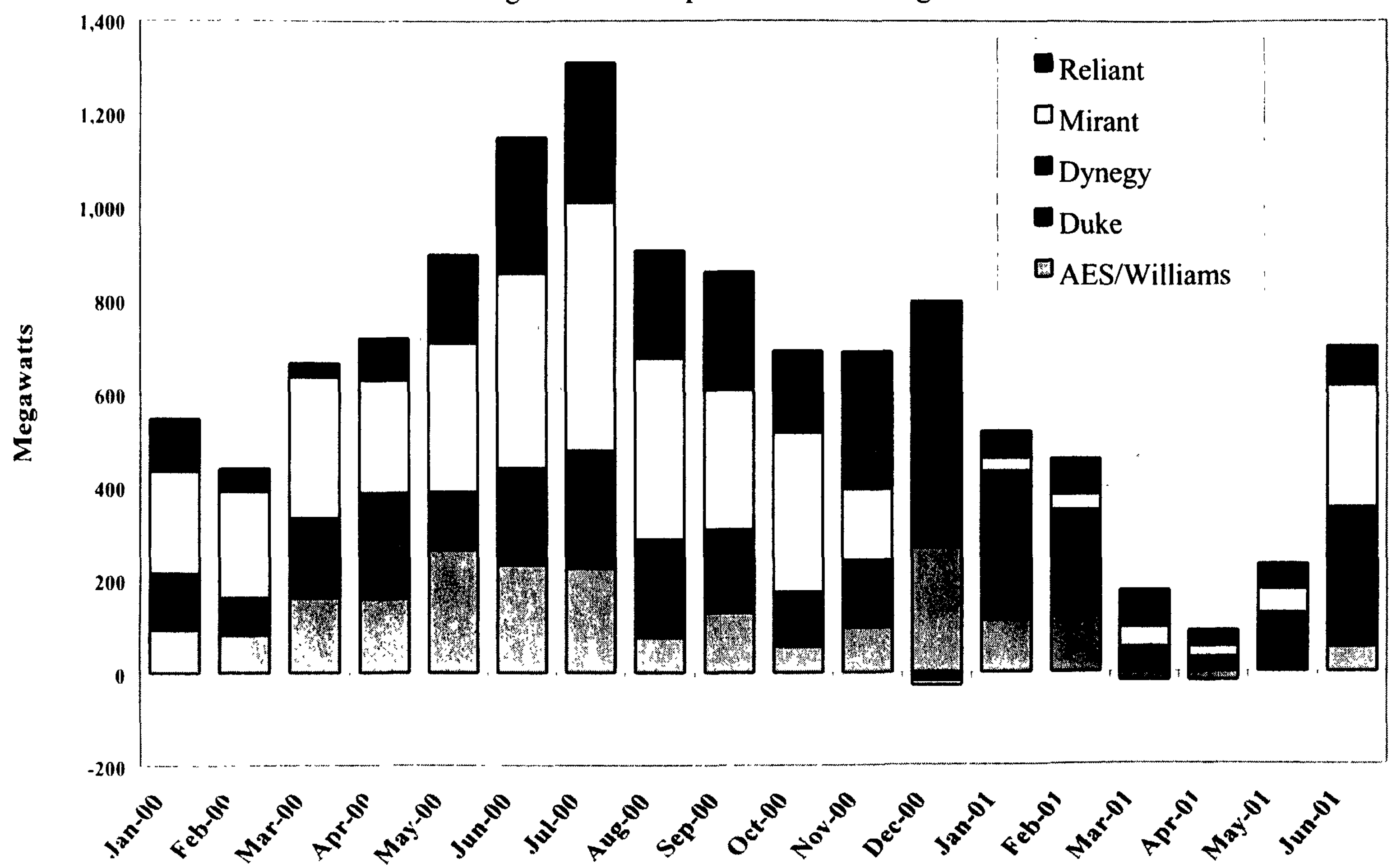
Q: Have you examined the extent of aggregated withholding by the California Generators during on-peak hours further?

A: Yes. Figure 3, shown in Section I, summarizes the percentage of hours in each month that aggregate withholding for all of the California Generators exceeded 1000 MW and 2000 MW. As seen in Figure 3, from May through September

2000, withholding exceeded 1000 MW in about 45% of the on-peak hours and exceeded 2000 MW in about 15% of the on-peak hours.

Figure 16

Average Hourly Withholding During On-Peak Hours
Using Generator Reported Forced Outages



Q: Please explain your next figure, which is Figure 17.

A: This figure shows average generation and withholding during on-peak hours for all of the California Generators. As seen in this chart, withholding equaled about 10% of on-peak generation during the summer and fall of 2000.

Q: Next is a set of figures, Figure 18 through Figure 22. Please explain these figures.

A: These figures show the company-specific results for withholding and generation, which correspond to the combined results shown in Figure 16. The results are shown for AES/Williams, Duke, Dynegy, Mirant, and Reliant in that order. One interesting point in these charts is that withholding as a percentage of generation is significantly higher at the company level in some instances. For example, during June 2000, withholding was equal to 20%, 29%, and 15% of generation for Dynegy, Mirant, and Reliant, respectively.

Withholding Under Benchmark Forced Outages

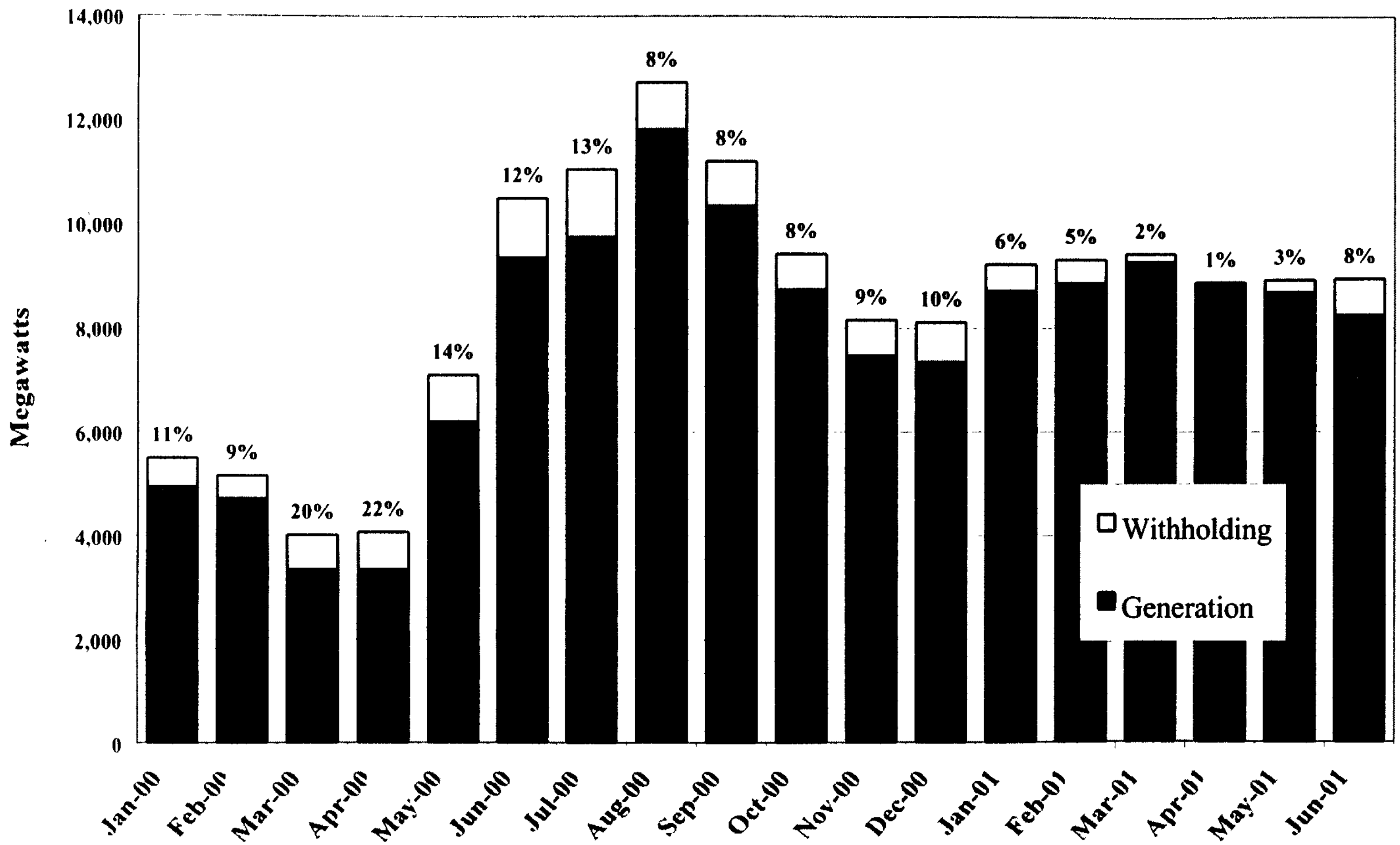
Q: Now, let's discuss your estimates of the effect of excessive forced outages. First, can you summarize Dr. Hanser's analysis of the benchmark forced outage rates?

A: Yes. Dr. Hanser found that the forced outage rates reported by the California Generators were significantly greater than the benchmark in the second half of 2000. Specifically, Dr. Hanser found that the benchmark forced outage rates were about 57% of the rates reported by the California Generators for the steam turbine units.[50]

[50] This percentage is calculated on a capacity-weighted average basis using the EFORP/NCF measure reported by Dr Hanser

Figure 17

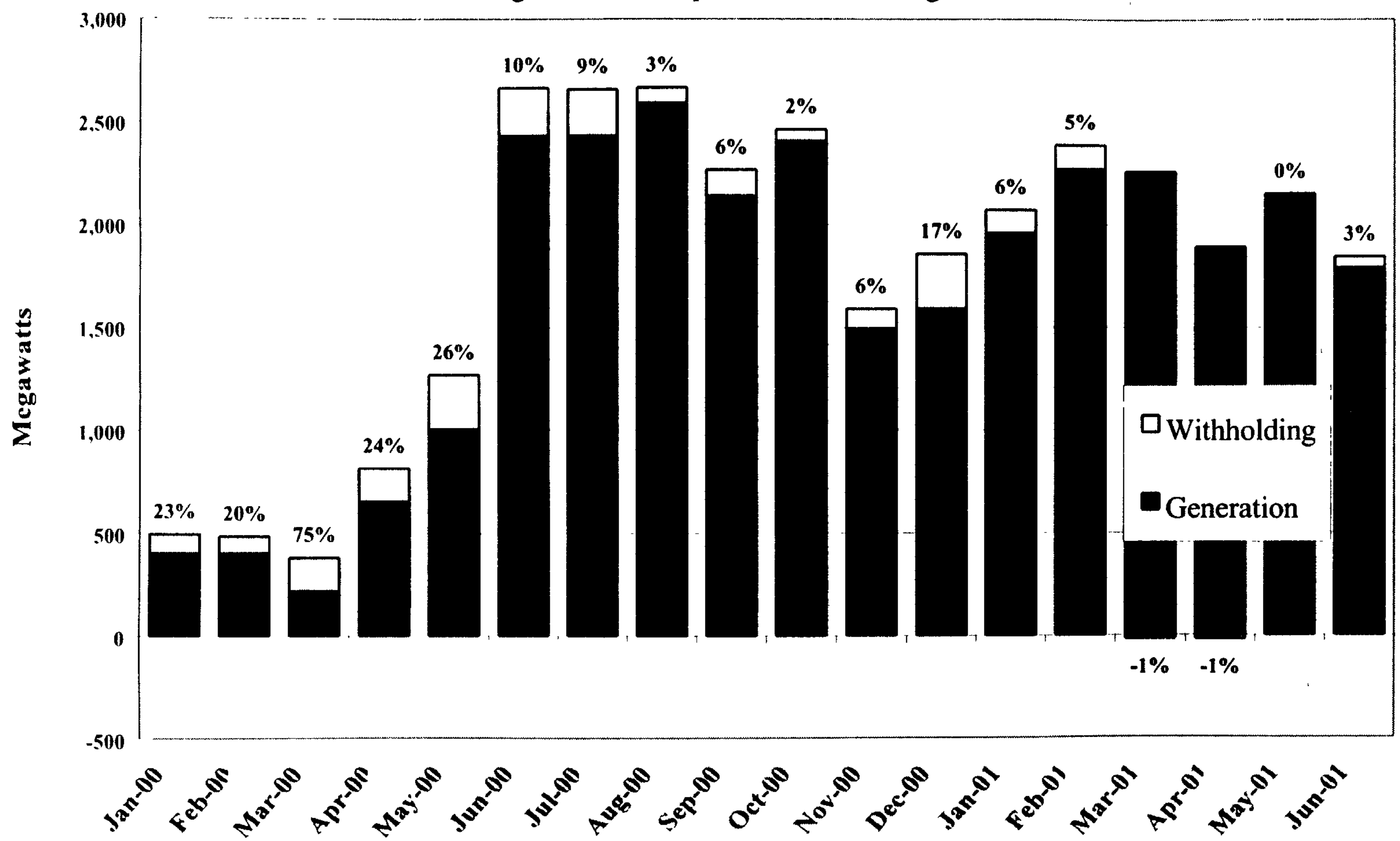
Average Hourly Generation and Withholding by All California Generators During On-Peak Hours
Using Generator Reported Forced Outages



Note: Withholding as a percentage of generation is shown above each bar

Figure 18

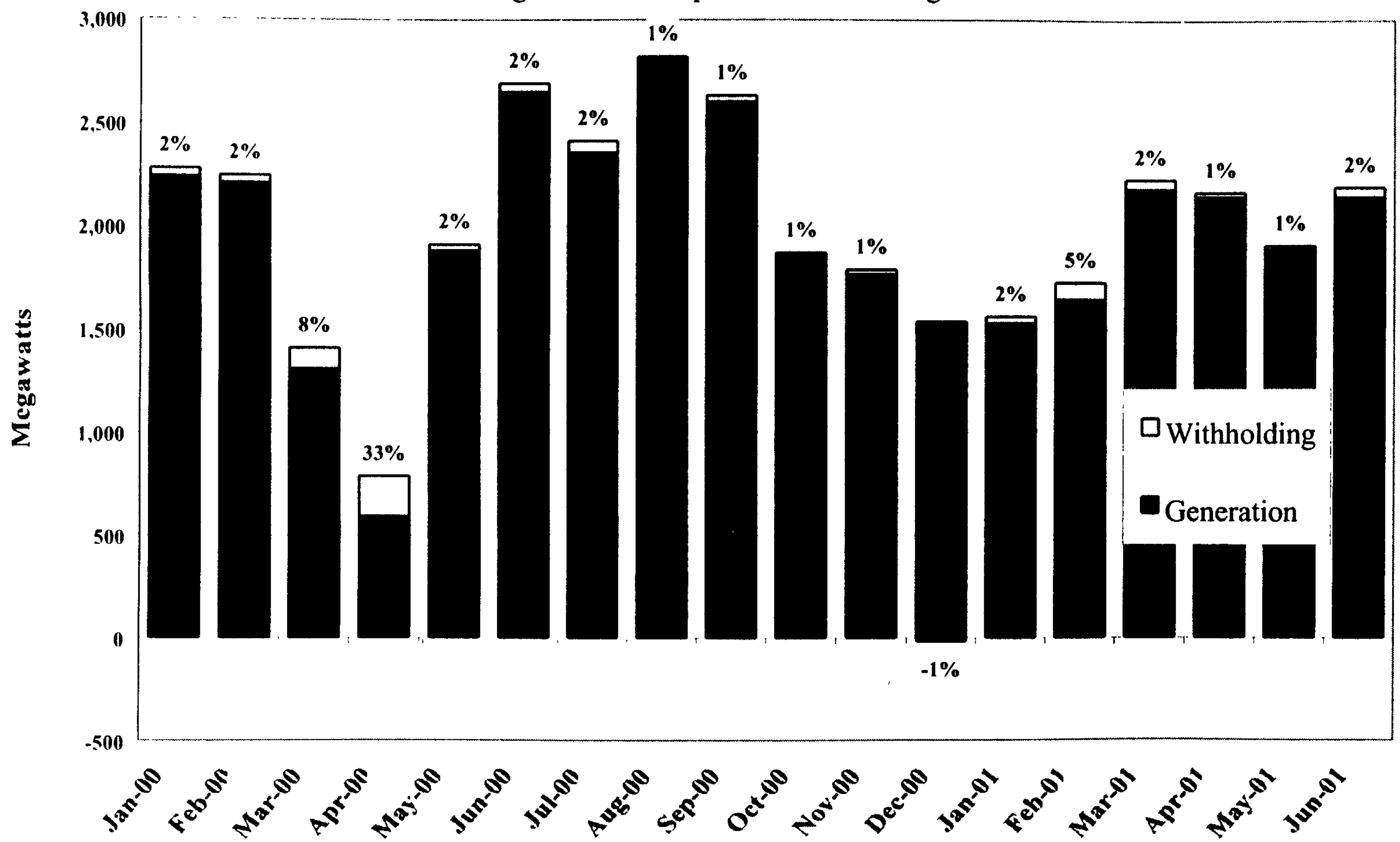
Average Hourly Generation and Withholding by AES/Williams During On-Peak Hours
Using Generator Reported Forced Outages



Note: Withholding as a percentage of generation is shown above each bar

Figure 19

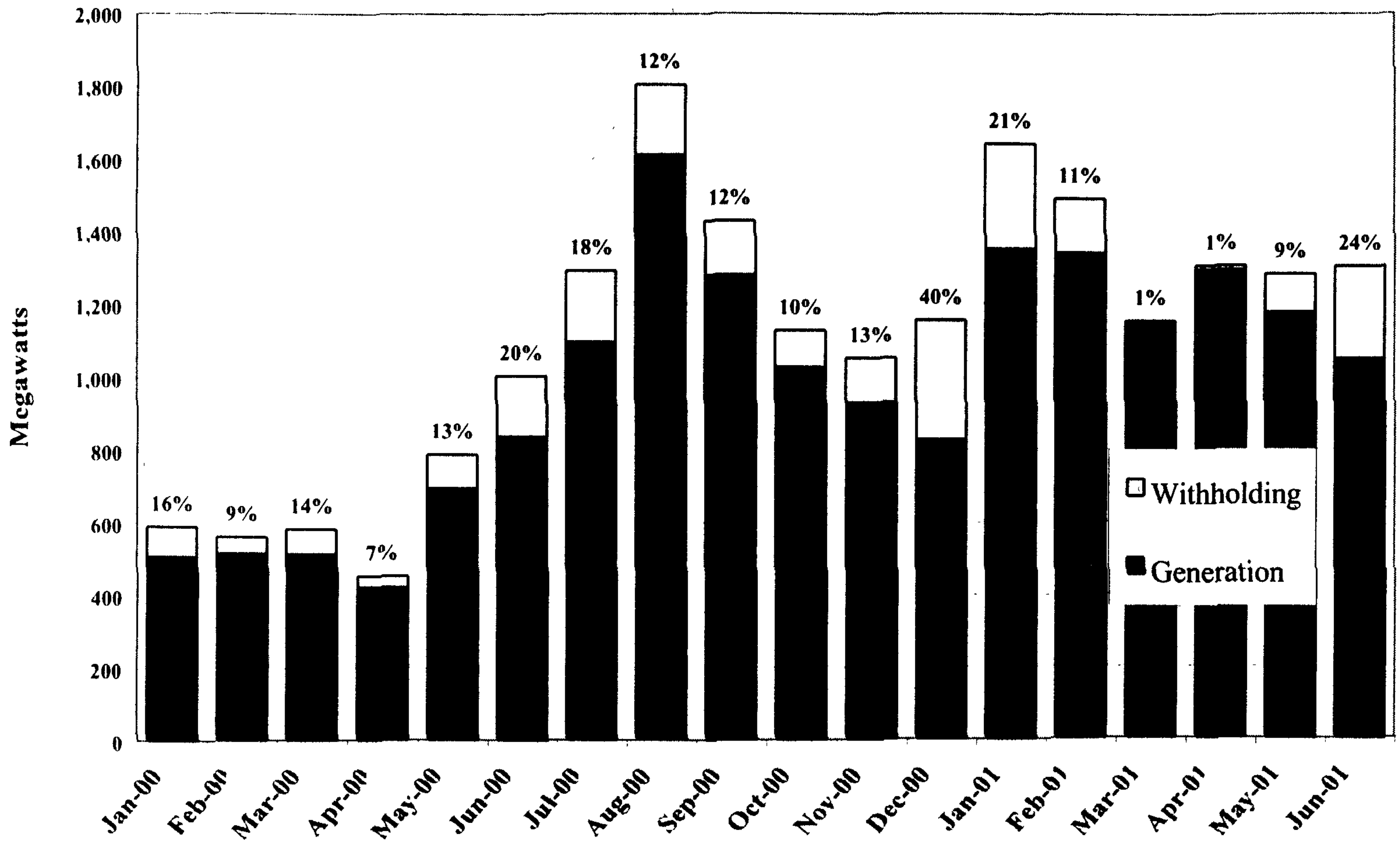
Average Hourly Generation and Withholding by Duke During On-Peak Hours
Using Generator Reported Forced Outages



Note: Withholding as a percentage of generation is shown above each bar

Figure 20

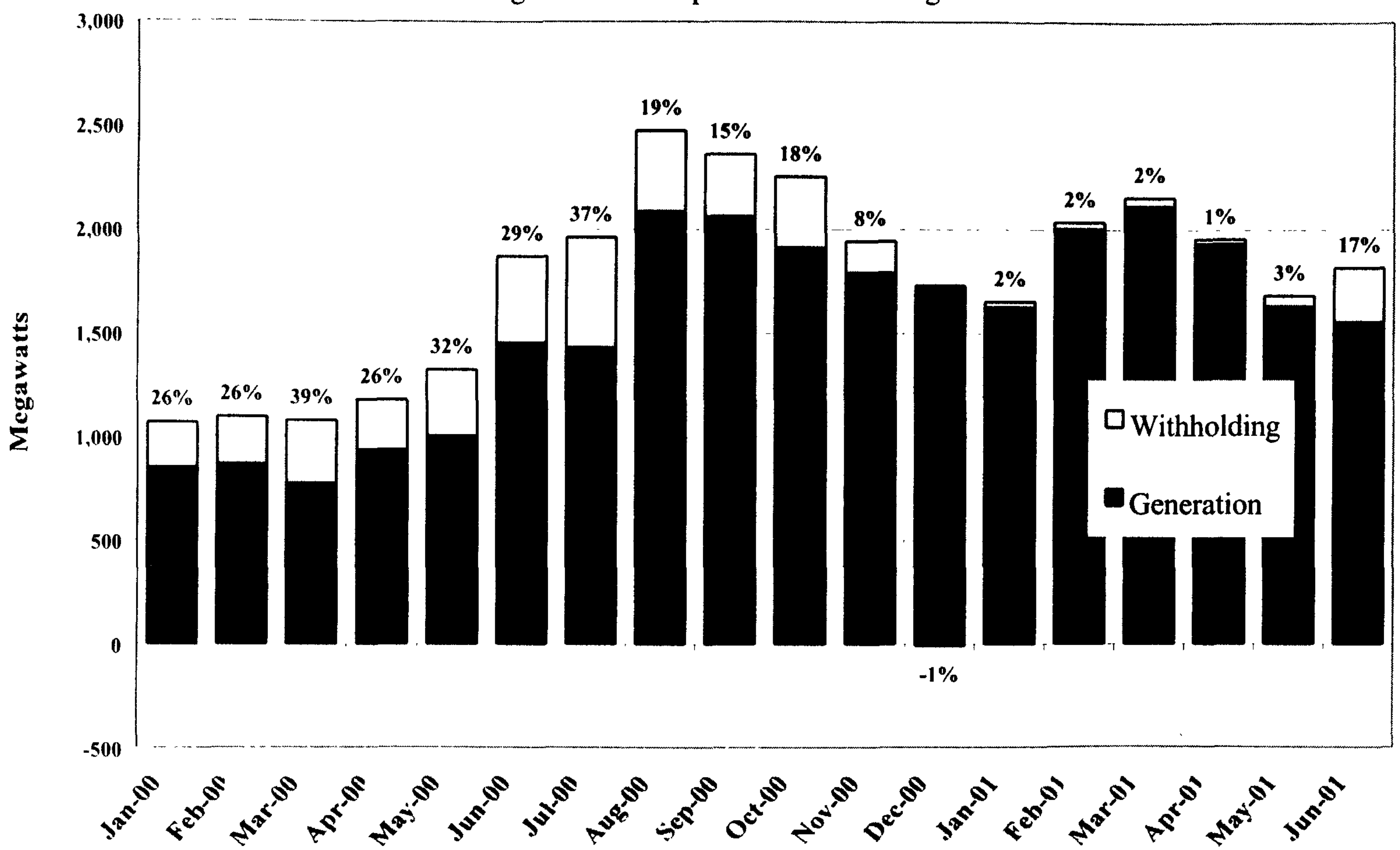
Average Hourly Generation and Withholding by Dynegy During On-Peak Hours
Using Generator Reported Forced Outages



Note: Withholding as a percentage of generation is shown above each bar

Figure 21

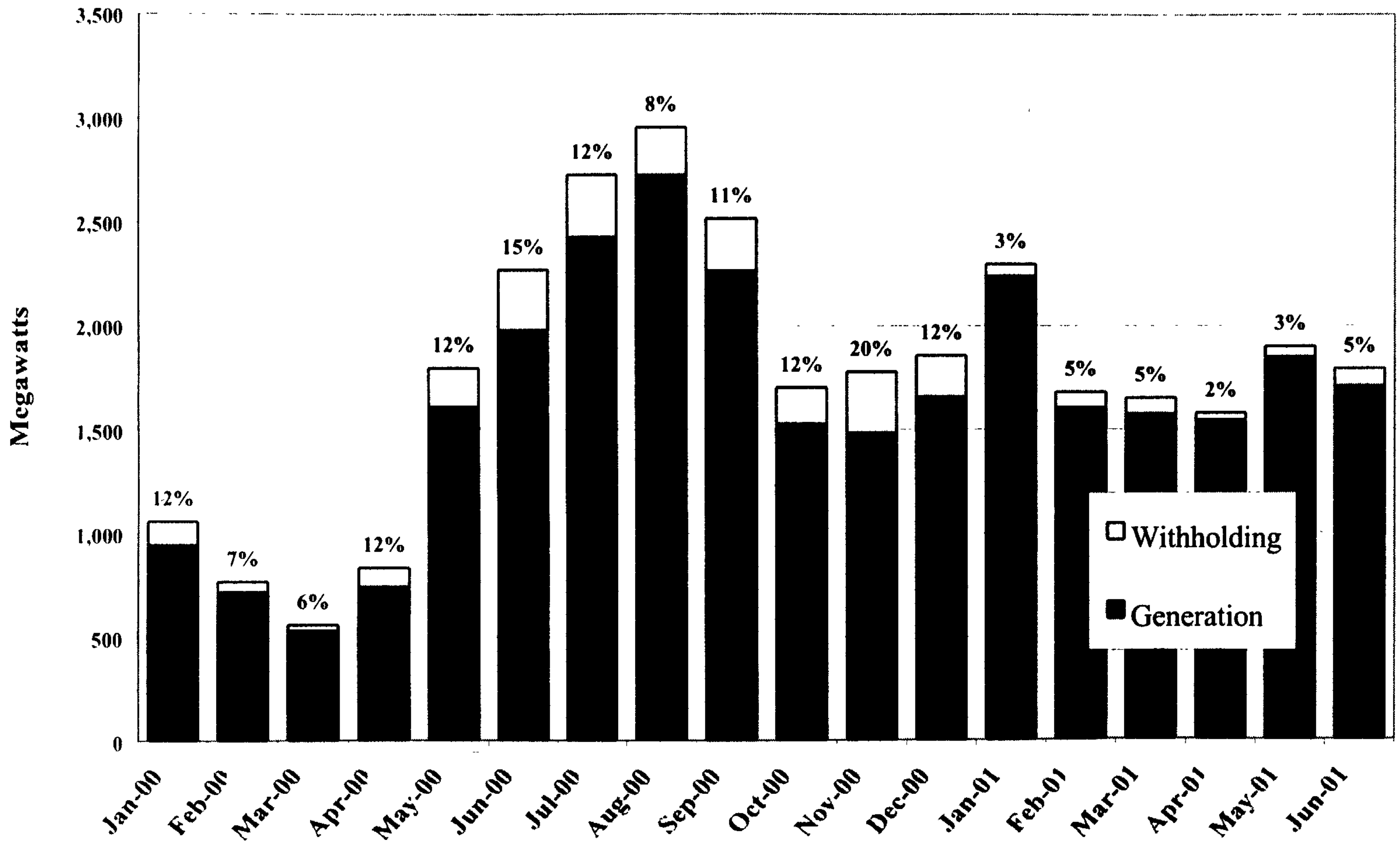
Average Hourly Generation and Withholding by Mirant During On-Peak Hours
Using Generator Reported Forced Outages



Note: Withholding as a percentage of generation is shown above each bar

Figure 22

Average Hourly Generation and Withholding by Reliant During On-Peak Hours
Using Generator Reported Forced Outages



Note: Withholding as a percentage of generation is shown above each bar

Q: How did you apply Dr. Hanser's results in your withholding analysis?

A: As I discussed in Section IV, I estimated withholding assuming (a) reported forced outages and (b) no forced outages, and then interpolated between those results based on the 57% ratio of the benchmark forced outages to reported forced outages.

Q: Do you have a figure that shows your results?

A: Yes. Figure 4 in Section I shows average hourly withholding for on-peak hours in the second half of 2000 using alternative assumptions about the extent to which the California Generators' reported forced outages were legitimate. If the reported forced outages were all legitimate, average on-peak hourly withholding over this period was about 870 MW. If none of the reported forced outages was legitimate, average on-peak hourly withholding over this period was about 1,480 MW. Using Dr. Hanser's results, average on-peak hourly withholding over this period was about 1,130 MW. In other words, the estimated effect of excessive forced outages was about 260 MW per hour during this period, or about 30% more than the estimated withholding assuming that all reported forced outages were legitimate.

Sensitivity Analysis

Q: Let's turn to your sensitivity analysis. What is the purpose of your sensitivity analysis?

A: I have run my withholding analysis using higher assumptions for the marginal costs of each unit in order to determine whether such higher costs would significantly change my results. In part, this sensitivity analysis addresses certain criticisms that have been made of withholding analyses, which I discuss in Section VII.

Q: Specifically, what sensitivity cases have you run?

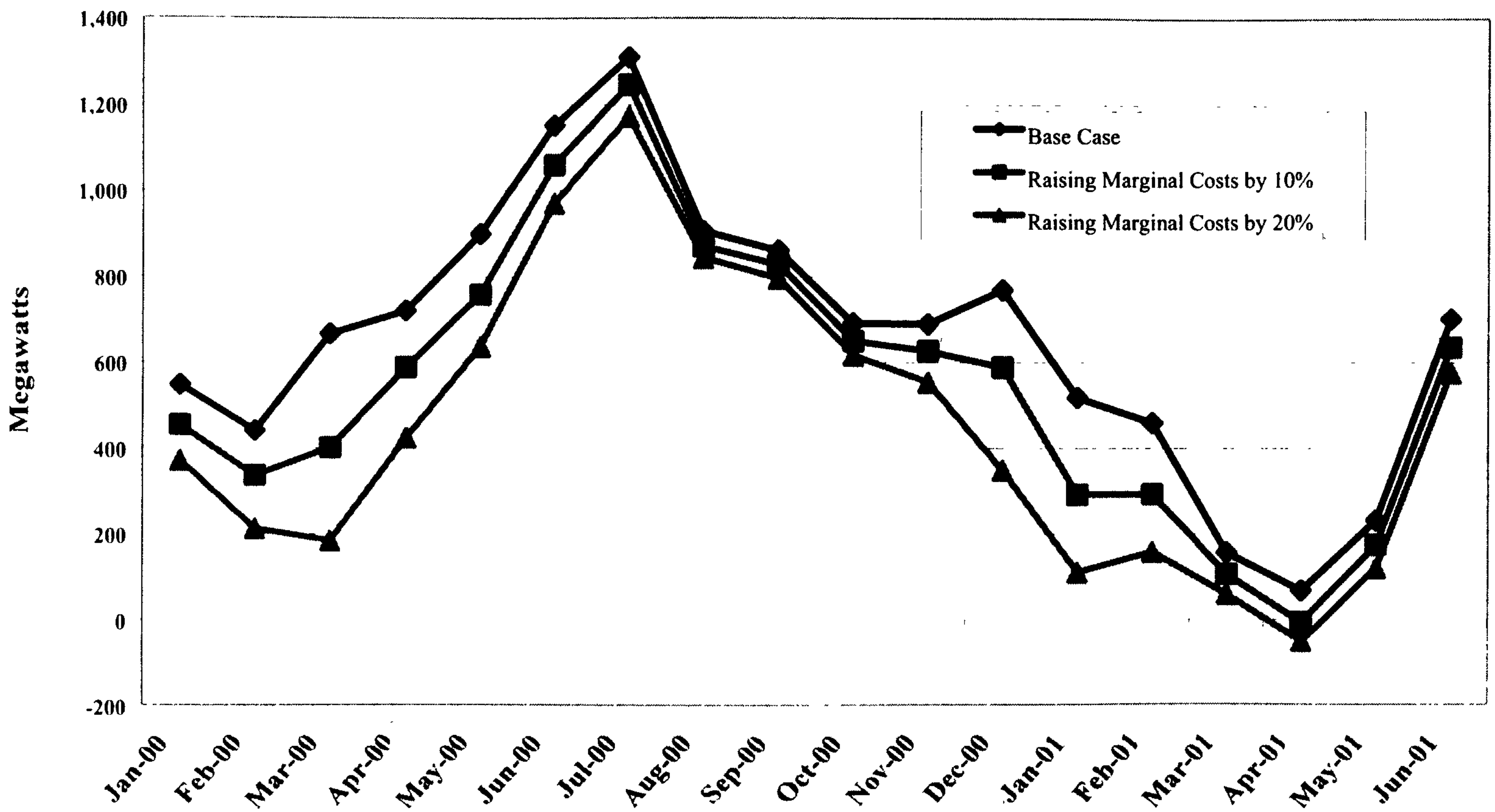
A: I have run cases in which I increase the marginal costs by 10% and 20%. In both of these cases, I used the California Generators' reported forced outages.

Q: Did you prepare a figure that shows the results of your sensitivity cases?

A: Yes. Figure 23 shows average hourly withholding during on-peak hours given the generators' reported outages under my base case marginal cost estimates and the two sensitivity cases. As seen in that figure, even increasing my marginal cost estimates by 20% does not change my results significantly and does not change my conclusion that there was significant withholding by the California Generators over significant periods of time. For example, over the May through September 2000 period, average hourly withholding during on-peak hours is 1,025 MW under my base case marginal cost estimates and 952 MW and 883 MW in my 10% increase and 20% increase cases, respectively.

Figure 23

Average Hourly Withholding by All California Generators During On-Peak Hours
Sensitivity Analysis with Marginal Costs Increased by 10% and 20%
Using Generator Reported Forced Outages



SECTION VI. ANALYSIS OF UN-BID PRODUCIBLE CAPACITY

Q: What is the purpose of this section of your testimony?

A: In this section, I describe my analysis of the extent to which the California Generators did not bid capacity into the CAISO real-time market when such capacity was producible. I term this "un-bid producible capacity." As I discussed, under some circumstances such a failure to bid capacity can result in withholding and reflect the exercise of market power.

Q: What do you mean by "producible" capacity?

A: This essentially has the same meaning as "producible" in the context of withholding. That is, producible capacity is capacity that is not on outage, not on reserve shutdown, and not precluded from production due to ramping constraints. In addition, as I explain below, I do not consider capacity that has a marginal cost above the prevailing "hard" price cap to be producible.

Q: How did you calculate un-bid producible capacity?

A: The basic equations for un-bid producible capacity (UNBID) is as follows:

$$\text{UNBID} = \text{PECCAP} - \text{SMAX}$$

$$\text{SMAX} = \text{SO} + \text{MAX}\,(0, \text{MAXSEBID} - \text{INCSE})$$

Q: Let's examine those equations. First, please explain your equation for UNBID.

A: This equation basically states that unbid producible capacity is equal to the amount of capacity that is producible and economic at the prevailing price cap (PECCAP) less the maximum supply. PECCAP is calculated in the same way that producible economic capacity (PEC) is calculated for withholding, as I discussed in Section IV, except that economic capacity is evaluated at the relevant price cap instead of at the market price.

Q: What was the relevant price cap?

A: As I discussed, prior to December 8, 2000, there was a "hard cap" on prices such that no bids were accepted above the hard cap. During this period, units with costs above the hard cap should not be expected to bid and, thus, such capacity should not be considered in UNBID. From December 8, 2000 onward, there was a "soft cap" on prices. Under the "soft cap," generators were allowed to bid above the "soft cap," although such bids could not set the market price. Thus, after December 8, 2000, there were no limits on bid prices and, thus, any producible capacity that is not bid is considered in UNBID (in other words, costs do not affect UNBID during the soft cap period).

Q: Please describe the second equation of your calculation, which is SMAX.

A: SMAX is the maximum supply offered. It is the sum of the final forward schedule (FS), awarded ancillary services capacity (ASC), incremental OOM/OOS transactions, and the maximum quantity bid into the real-time market as supplemental energy (MAXSEBID).

Q: What assumptions do you make regarding outages and reserve shutdowns in calculating unbid producible capacity?

A: I take the generators' reported planned and forced outages and the reserve shutdowns identified using the rule I described in Section III as being legitimate.

Q: Have you prepared a figure that shows the results of your analysis of unbid producible capacity?

A: Yes. Figure 24 shows the average hourly un-bid producible capacity by generator. The same results were shown for all of the generators in aggregate in Figure 6. As seen in Figure 24, the average un-bid producible capacity exceeded 500 MW during on-peak hours in virtually all months and exceeded 1000 MW in some months.[51]

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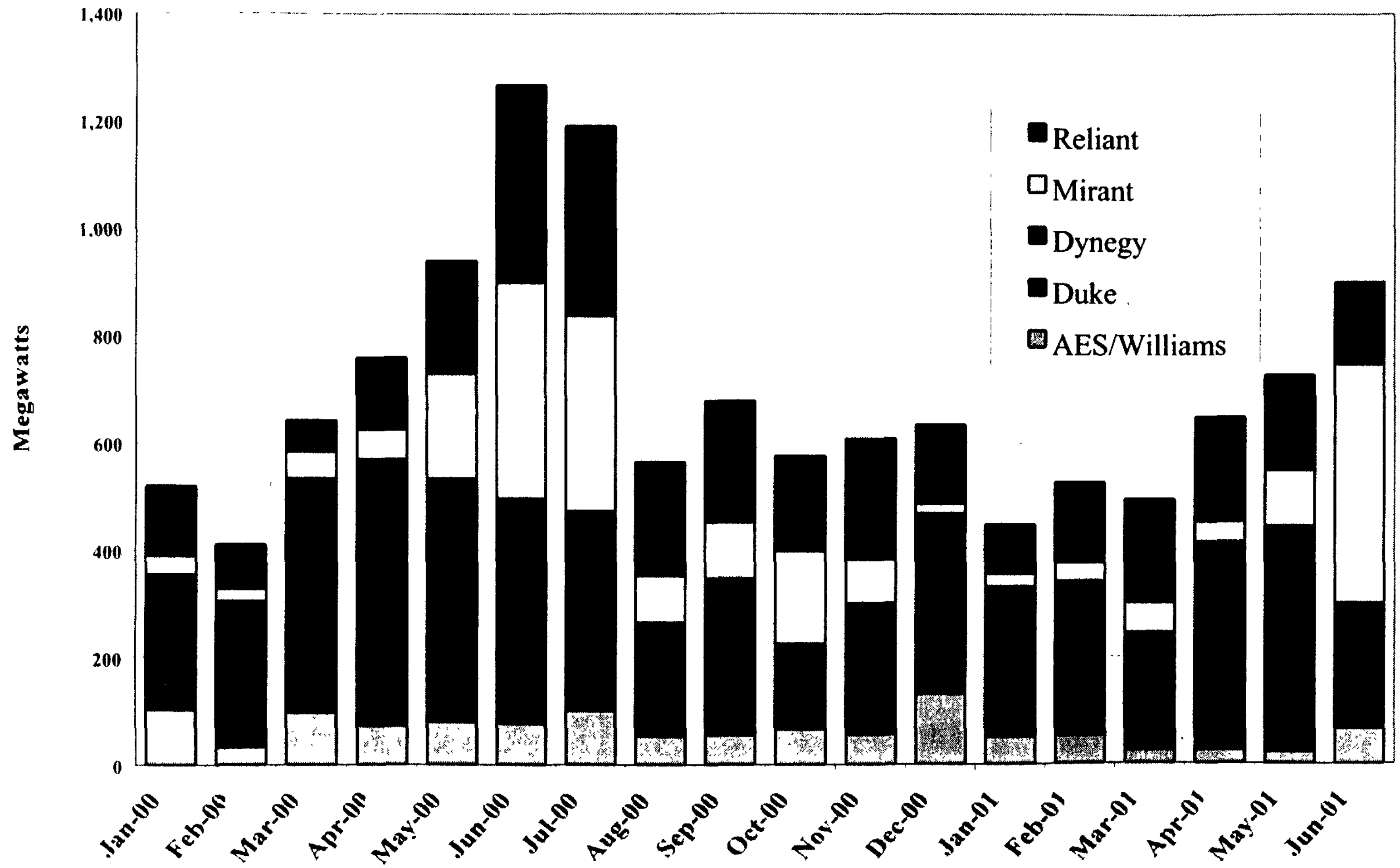
[51] If I treated the "soft cap" in the December 8, 2000 onward period as a "hard cap" for purposes of calculating un-bid producible capacity, I would obtain lower, but still significant levels of un-bid producible capacity

Figure 24

Average Hourly Un-Bid Producible Capacity During On-Peak Hours
Using Generator Reported Forced Outages



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SECTION VII. RESPONSES TO CRITICISMS OF WITHHOLDING ANALYSES

Q: What is the purpose of this section of your testimony?

A: In this section, I address issues that have been raised in other contexts as criticisms of withholding analyses. Many of these issues were raised in a series of papers by Scott Harvey and William Hogan and in responses of California Generators to the California Public Utility Commission's (CPUC's) report on the role of withholding by the California Generators in the "crisis" situations experienced primarily in early 2001.

Q: Before discussing the details, can you summarize your response to such criticisms?

A: Yes. I have either: directly incorporated the issues in my analysis, which renders the criticism moot with respect to my analysis; concluded that the issue is not relevant for my analysis at all;[52] or concluded that the issue is not significant relative to the level of withholding that I have found.

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[52] For example, Harvey & Hogan argue that the study of withholding by Joskow & Kahn is limited in a number of respects because Joskow and Kahn only had access to publicly available data and, as a result, they had to make relatively imprecise estimates of certain important factors such as outages and ancillary services (see Harvey & Hogan, "Identifying the Exercise of Market Power in California," December 28, 2001, p. 77). Such a criticism is not applicable to my analysis because I had access to the relevant non-public data from the CAISO and the California Generators that was not available to Joskow and Kahn. Harvey & Hogan also make certain bidding-related arguments that are not relevant to my withholding analysis. For example, they claim that, since the California market uses a pay-as-bid system for intrazonal congestion management, generators have an incentive to bid their assessment of the market price at their location rather than their marginal cost (see Harvey & Hogan, "Issues in the Analysis of Market Power," October 27, 2000, p 8). These arguments are not relevant to a withholding analysis because they do not involve an incentive for generators to bid above the market price.

Startup Costs

Q: Let's discuss these issues one at a time. First, what is the issue with regard to startup costs?

A: One argument is that a proper market analysis must account for start-up costs, minimum-load costs, and operating parameters such as minimum down times and run times.[53]

Q: What is your response to such an argument?

A: I agree that it is appropriate to consider these factors in assessing the decision to start up a unit or to keep the unit at minimum load. However, I have excluded from my withholding analysis all times when a unit is in a reserve shutdown, using the rule that I discussed in Section III. Thus, my withholding analysis only considers the possibility of withholding during hours in which the generator decided to start up the unit or to keep the unit operating at minimum load. Hence, start-up and minimum-load costs are not incremental to increasing output and, thus, such costs are not relevant to my analysis. Similarly, minimum down times and minimum run times are also not an issue. In fact, Harvey & Hogan endorse this type of approach as a way of dealing with these issues.[54]

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[53] See Harvey & Hogan, "On the Exercise of Market Power Through Strategic Withholding in California," April 24, 2001, at 25

[54] See Harvey & Hogan, *op cit*, April 24, 2001, at 60 ("An alternative approach to controlling for start-up and no-load costs would be to restrict the analysis to the output decisions of units that were actually on-line in real-time. Start-up and no-load costs are irrelevant for units that are actually operating, as those costs are sunk in real time")

Ramping Constraints

Q: Let's move to the next area, which is ramping constraints. What is the issue in this regard?

A: Duke claims that the CPUC report does not account for ramping times in its analysis.[55] Williams makes a similar claim.[56] Mirant also states in its response to the CPUC report that the CAISO "creates a presumed ramp rate that is substantially quicker than most of Mirant's units are capable of achieving."[57]

Q: What is your response to such issues?

A: Such issues are not applicable to my analysis since I explicitly account for ramping limitations in my analysis. Moreover, I have based my assumed ramp rates on the ramp rates provided by the California Generators with their supplemental energy bids to the CAISO real-time market.

Capacity Measures

Q: Let's move on to capacity measures. What are the issues in this area?

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55 See Letter from Brent Bailey of Duke Energy Corporation to Loretta Lynch of the CPUC, 9/26/02 ("Duke Response"), at 2.

56 See Attachment to letter from William Hobbs of Williams Energy Marketing & Trading to Joseph Dunn of the California State Senate, 10/1/00 ("Williams Response"), at 3

57 See Letter from Zack Starbird of Mirant Americas, Inc. to Joseph L. Dunn of the California State Senate dated 9/26/02 ("Mirant Response"), at 5.

A: Harvey & Hogan criticize the estimation of capacity based on maximum observed output.[58] Mirant asserted that the CPUC overestimated the capacity of its units by 111 MW.[59] Similarly, Duke asserted that the CPUC overstated the capacity of its Morro Bay Unit 3 by 6 MW[60] and Williams asserted that the CPUC overstated its capacity by 14 MW.[61]

Q: How do you respond?

A: Such criticisms are not applicable to my analysis since I have adopted the lowest capacity values put forth by the generators, including those provided in response to the CPUC report. I have not used maximum observed output in developing my capacity assumptions.

Capacity Controlled by the CAISO

Q: The next area is capacity controlled by the CAISO. What are the arguments in this area?

A: First, Duke asserts that the CAISO controlled the output of certain of its units through "automatic generation control" (AGC) and that the CAISO reduced output from Duke's plants during certain hours analyzed by the CPUC.[62]

58 See Harvey & Hogan, *op.cit.*, April 24, 2001, at 65
59 See Mirant Response, at 4.
60 See Duke Response, at 2
61 See Williams Response, at 3.
62 See Duke Response, at 1

Q: What is your response to such an argument?

A: While it is true that the CAISO directly controls the output of certain plants through AGC, that situation only arises when the plants are providing regulation up and regulation down ancillary services. Such a criticism is not relevant to my analysis since I give the generators credit for regulation down as well as other decremental instructions from the CAISO (i.e., I do not consider regulation down to be withholding).

Q: Are there other arguments along these lines?

A: In a similar vein, Harvey & Hogan criticize Joskow and Kahn's withholding analysis on the grounds that Joskow and Kahn do not account for units dispatched down by the CAISO.[63]

Q: How do you respond?

A: Such a criticism is not applicable to my analysis since I give the generators credit for all types of decremental instructions from the CAISO (decremental supplemental energy, decremental OOM/OOS, and regulation down).

Q: Are there any more arguments in this area?

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[63] See Harvey & Hogan, *op cit.*, April 24, 2001, at 60.

A: Yes. Mirant claims that all of its units are subject to RMR contracts and, as such, the CAISO had the ability to order those units to produce at any time.[64] Similarly, Duke asserts that the CAISO can order production from its units during emergency hours.

Q: How do you respond?

A: Such a criticism unfounded. It would not be practical, and would run counter to the purpose of the real-time market, for the CAISO to be constantly making RMR calls to units that withheld capacity from the real-time market.

Q: Are there any more arguments in this area?

A: Yes. Duke asserts that the CAISO controls the operation of its Oakland plant.[65]

Q: How do you respond?

A: Such a criticism is not applicable to my analysis since I recognized this situation and excluded Oakland from my withholding analysis.

Outages

Q: Let's move on to the next area, which is outages. What is the issue here?

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[64] See Mirant Response, at 5
[65] See Duke Response, at 2

A: Mirant claimed that it inherited "weakened units" due to minimal routine maintenance prior to divestiture, which affected their outage rates.[66]

Q: How do you respond?

A: Such a concern is not applicable to the portion of my withholding analysis that takes the generators' reported outages as being entirely legitimate, since those outages would take into account the supposedly weakened units.

Q: Have some generators raised a related issue of outage risk and reserves?

A: Yes. John Stout of Reliant stated at the CAISO Board of Governors meeting on June 28, 2000 that "we [Reliant] do withhold from the market every day, the day ahead market" and that one of the reasons for such withholding was that Reliant wanted to maintain a "reserve margin" equal to the size of its largest unit (750 MW) to protect itself against exposure to the risk of penalties for failing to provide its forward schedule due to a unit tripping off line.[67] Such an argument is not applicable to my analysis because I am looking at the real-time market, not the day-ahead market and Mr. Stout's alleged justification for withholding is not applicable to the real-time market.

Bid Timing Restrictions

[66] See Mirant Response, at 2
[67] See California ISO Board of Governors Meeting 28 June 2000, at 28

Q: Next is bid timing restrictions. What is the issue here?

A: Williams argues that the CPUC did not take into account timing restrictions imposed by the CAISO, which did not allow Williams to offer energy and ancillary services for up to three hours following an outage.[68]

Q: How do you respond?

A: Such a criticism is not applicable to my analysis because I incorporate a one-hour lag in available capacity to account for bid timing considerations. The fact that there is a three-hour restriction on ancillary services does not affect my analysis since capacity returning from an outage could simply be bid as supplemental energy.

Uneconomic Capacity

Q: What are the issues regarding uneconomic capacity?

A: Harvey & Hogan criticize Joskow and Kahn's withholding analysis on the grounds that they do not account for uneconomic capacity.[69]

Q: How do you respond?

A: Joskow and Kahn use a somewhat different approach than I have taken. They determine a price which they claim exceeds the incremental costs of virtually all

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68 See Williams Response, at 1

69 See Harvey & Hogan, *op cit.*, April 24, 2001, at 58-59.

of the California Generators' units and then analyze withholding from all units only for those hours when the price exceeded their threshold. Harvey & Hogan argue that the threshold that Joskow and Kahn picked for certain months was too low. In contrast to Joskow and Kahn, I examine every hour and assess whether the marginal cost of each unit exceeds the prices. As I discussed, my approach is consistent with the FERC's approach to calculating the MMCP except that I incorporate NOx emissions costs into the marginal cost. Furthermore, as I discussed in Section IV, I ran sensitivity cases in which I increased the marginal costs of all units by 10% and 20% and I still found significant withholding in those cases.

Opportunity Costs

Q: The next area is opportunity costs. What arguments have been made in that regard?

A: An argument has been made that marginal costs must include an opportunity cost representing the cost of foregoing alternative uses for capacity that might be dispatched in a given market for a given hour.[70] For example, inter-temporal opportunity costs refer to situations in which generation in one period affects the ability to generate in a later period. A common example is a hydroelectric plant

[70] See Harvey & Hogan, *op cit.*, October 27, 2000, at 2. As discussed previously, because I am examining the CAISO real-time market, arguments that selling into one market for a particular hour precludes the generator from selling into another market for the same hour (e g., selling into the day-ahead CalPX market precludes a generator from selling into the hour-ahead CalPX market or the real-time market, or selling into the CalPX market precludes a generator from selling out of state) are not relevant for my analysis. In other words, selling in the real-time market does not preclude a generator from selling in another market because it would be too late at that point to do so.

that has limited water inflow. Another example is a plant that has an annual limit on run hours or NOx emissions.[71] In these situations, generation in one hour reduces the ability to run in subsequent periods.

Q: What is your response to this inter-temporal opportunity cost issue?

A: I agree that relevant inter-temporal opportunity costs should be included in the marginal cost of generation. However, my analysis addresses the relevant inter-temporal opportunity cost issues, as discussed in Section III (e.g., I eliminated from my analysis certain plants with binding NOx mass emissions limits and units, such as combustion turbines, with limitations on annual run hours).[72] Thus, this is not a relevant criticism of my analysis.

Comparison with Historical Output Levels

Q: Let's move on to historical output levels. What arguments have been put forth in this regard?

A: In response to the CPUC's report on withholding, Mirant pointed out that it supplied 69% more power from its California units in 2001 than had been supplied on average in the previous 10 years.[73]

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[71] See Harvey & Hogan, *op.cit*, April 24, 2001, at 18-22.

[72] It might also be argued that operating a unit at high levels increases the "wear and tear" on the unit, which can lead to higher costs in the form of more forced outages, more frequent required maintenance, shorter unit life, etc. As I discussed in Section V, I ran sensitivity cases in which I increased the marginal costs of all units by 10% and 20%, and I still found significant withholding Thus, such "wear and tear" costs would have to be shown to be very substantial in order to materially change my results

[73] See Mirant Response, at 1.

Q: How do you respond?

A: This claim, as well as other assertions regarding the operating level of the units at issue relative to historical levels, is not relevant for withholding. Rather, the relevant issue is whether these units could have produced more and didn't.

Output Sold Forward

Q: What is the issue regarding output sold forward?

A: Joskow and Kahn found that Duke had the smallest "output gap" in their analysis and they found this to be consistent with the fact that Duke reportedly had sold forward a large share of its output and, thus, Duke did not have as big of an incentive to withhold as the other firms.[74] In response, Harvey and Hogan argue that, of the California Generators, AES was actually the one that had sold forward the biggest share of its output.[75] As I discussed, I agree that the fact a firm has sold forward a large share of its output at a price that is not tied to the market price has less incentive to withhold than a firm that has not done so. My findings are consistent with those of Joskow and Kahn in the sense that I find that Duke had the lowest level of withholding among the California Generators. With respect to AES, Harvey and Hogan give a false impression. The output "sold forward" by AES refers to the fact that AES entered a tolling agreement with Williams

[74] See Paul Joskow and Edward Kahn, "Identifying the Exercise of Market Power: Refining the Estimates," July 5, 2001, at 25

[75] See Harvey & Hogan, *op cit.*, December 28, 2001, at 77.

whereby Williams controls the sale of power from the units. As such, Williams, as the marketer of the capacity, has the incentive to withhold.

Q: Does that conclude your testimony?

A: Yes.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant	)	
	)	
v.	)	Docket Nos. EL00-95-069
	)	
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	)	
	)	
Investigation of Practices of the California Independent System Operator and the California Power Exchange.	)	Docket Nos. EL00-98-058

AFFIDAVIT OF ROBERT J. REYNOLDS

I declare under penalty of perjury that the foregoing is true and correct.

Executed on February 27, 2003.

Robert J. Reynolds

Robert J. Reynolds

Index of Relevant Material

Submitter (Party Name)	California Parties
Index Exh. No.	CA-6
Privileged Info (Yes/No)	Yes
Document Title	Appendices to Prepared Testimony of Robert J. Reynolds, Ph.D., including "Curriculum Vitae of Robert J. Reynolds" and Materials Considered in Preparation of Testimony
Document Author	Robert J. Reynolds (Competition Economics, Inc.)
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made r proposed	California Generators withheld from the market. California Generators withheld by not bidding their output into the market even though the plant was fully operational. This withholding behavior occurred during numerous system emergencies. California Generators withheld generation from the market by bidding high, and in excess of their costs, so as to deliberately price themselves out of the market. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Prices before October 2, 2000 were not consistent with Sellers' market-based rate tariffs and those of the ISO and PX.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95 and EL00-98 (including all subdockets)
Indicate if Material is New or from the Existing Record (include references to	New

record material)	
Explanation of what the evidence purports to show	The California Generators engaged in significant levels of withholding from the CAISO real-time energy market over significant periods of time from January 1, 2000 through June 20, 2001. Utilizing the assumption that the California Generators' reported outages were legitimate, aggregate withholding by those generators averaged over 1000 MW per hour during on-peak hours from May-September 2000. Using the same assumption about the legitimacy of the generators' reported outages, this evidence shows that from May-September 2000, the California Generators' withholding exceeded 1000 MW during about 45% of the on-peak hours and exceeded 2000 MW in about 15% of the on-peak hours. These estimates are conservative (i.e. understate the full extent of withholding) for reasons enumerated specifically in the testimony. The presence of significant withholding is strong evidence of the exercise of market power by the California Generators. The California Generators frequently did not bid capacity that was available and producible at a marginal cost below the prevailing maximum allowable bid price in the CAISO real-time market. The average un-bid producible capacity exceeded 500 MW during on-peak hours in virtually all months (January 2000 – June 2001) and exceeded 1000 MW in some months. Such a failure to bid such capacity can result in withholding and reflect the exercise of market power.
Party/Parties performing any alleged manipulation	AES/Williams; Duke; Dynegy; Mirant; Reliant

* This entry is not limited to the California and Northwest Docket Numbers.

Curriculum Vitae of Robert J. Reynolds

Chairman
Competition Economics, Inc.
4800 Montgomery Lane
Suite 900
Bethesda, MD 20814
(301) 215-9830

EDUCATION

1970	Ph.D., Economics, Northwestern University
1965	B.S., Business Administration (Finance), Northwestern University

EXPERIENCE

Dr. Reynolds is Chairman of Competition Economics, Inc., which he co-founded in 1997. Previously, he was Executive Vice President of Econsult Corporation, from 1992-1996, and a Senior Vice President of ICF Consulting Associates, which he joined in 1981. Dr. Reynolds was previously employed at the Antitrust Division of the Department of Justice as Assistant Director and Senior Economist in the Economic Policy Office, where he both supervised research in antitrust policy and was actively involved in DOJ investigations. His work at DOJ included being chief staff economist on U.S. v AT&T until 1978. Since leaving DOJ, he has specialized in statistical and theoretical analysis of industrial organization, public and regulatory policy issues, and antitrust problems. He has been engaged to do such research by both private and government clients (federal agencies and state AGs).

He has been Visiting Associate Professor at Cornell University, 1981 where he taught courses in Economics of Regulation and Microeconomic Theory. He has also been Visiting Lecturer at the University of California at Berkeley, 1976-77 where he taught courses in Industrial Organization, Regulation, Antitrust, and Micro- and Macro-Economic Theory.

He has been both Assistant (1969-73) and Associate (1973-75) Professor of Economics at the University of Idaho where he taught courses in Intermediate and Graduate Micro- and Macro-Economic Theory, and Graduate Seminars in Price Theory, Regulation, and Statistics.

SELECTED PUBLICATIONS

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OTHER RESEARCH ACTIVITIES

Dr. Reynolds has presented papers at various meetings of the Econometric Society, NBER Conferences in Industrial Organization, other professional meetings and various universities [e.g., Yale, Berkeley, Stanford, Pennsylvania, Cornell, Toronto, International Institute for Management (Berlin)].

Dr. Reynolds has served as:

- Chairman and discussant at meetings of the Econometric Society and Telecommunications Policy Research Conference.
- Member, Editorial Advisory Board, *Managerial and Decision Economics.*
- Reviewer for the National Science Foundation, *Rand Journal of Economics*, *International Economic Review*, *International Journal of Industrial Organization*, *Journal of Industrial Economics*, and *American Economic Review.*
- Invited participant in the University of Chicago Conference on Regulation, 1970; Dartmouth Conference on Regulation, 1972; University of Pennsylvania Conference on Antitrust Law and Economics, 1978; University of Virginia-MSS Conference on New Directions in Theoretical Industrial Organization, 1979; NBER (Northwestern) Conference on Information and Strategic Behavior in Economics, 1980; NBER (Berkeley) Conference in Theoretical Industrial Organization, 1980; Oxford Conference in Theoretical Industrial Organization, 1984.

PROFESSIONAL AFFILIATIONS/AWARDS

Member of:
American Economic Association
Econometric Society
Royal Economic Society
AAAS
American Statistical Association
European Association for Research in Industrial Economics (EARIE)
Society for the Promotion of Economic Theory
Mathematical Association of America
American Mathematical Association

Awards:
AT&T Post-Doctoral Grant, 1971-72

Brookings Institutional Grant to Study the Regulated Industries, 1968-69
NDEA Fellow, 1965-69
Dow-Jones (*Wall Street Journal*) Award for Outstanding Business School Graduate, 1965

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