Anticompetitive Implications of the
El Paso Natural Gas – El Paso Merchant Energy
Transaction

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I. INTRODUCTION

This report evaluates the effect of the fifteen month, 1.2 Bcf/day transportation agreement between El Paso Merchant Energy ("EPME") and El Paso Natural Gas ("El Paso") on the competitiveness of the natural gas pipeline capacity market serving southern California.[1] In doing so, the report examines concentration levels and recent market price and throughput behavior in this market, as well as EPME's incentives in both the capacity and downstream markets.

Our analysis finds that the EPME-El Paso agreement is anticompetitive and provides EPME with the means and incentive to exercise market power in the southwest gas transportation market serving southern California. Specifically, we find:

1. Gas from the southwest (San Juan and Permian Basins) constitutes the marginal (hence, price-setting) source of supply for California throughout much of the year. Supplies from Alberta via PG&E Gas Transmission NW and the Rocky Mountains via Kern River Gas Transmission ("Kern River") are "inframarginal," meaning that they are generally cheaper sources of supply, as exemplified by the fact that they generally flow into the state at very high load factors. Under these market conditions, the price of gas delivered to the southern California border on El Paso and Transwestern Pipeline ("Transwestern") serves as the netback reference price for supplies from Canada and the Rockies, thereby limiting the degree to which Canadian and Rocky Mountain supplies provide competitive discipline on the market at the California border.

2. The interstate pipeline capacity market between the southwest supply basins and the California border is highly concentrated. EPME and Southern California Gas Company ("SoCalGas") are currently the

[1] EPME also controls 156 MMcf/d of El Paso capacity released by SoCalGas (through 2006) and 65 MMcf/d of Transwestern capacity.

dominant holders of available pipeline capacity between those two locations. EPME holds 48% of the southwest capacity available to serve non-core customers[2] such as gas-fired electric generators.

3. Basis differentials between the California Border and the San Juan Basin jumped to \$0.79/MMBtu in July and \$1.01/MMBtu in August, substantially more than the \$0.18/MMBtu average for the twelve months of 1997. Similarly, California Border-Permian Basin differentials for the same months inflated to \$0.62/MMBtu and \$0.73/MMBtu, respectively, as compared to the corresponding twelve month 1997 average of \$0.14/MMBtu. While some of the increase is undoubtedly due to demand conditions in southern California, it is difficult to sort out market power from market conditions due to the relatively short time the contracts have been in effect (March-August 2000) coupled with the lack of evidentiary hearings and data responses from EPME and El Paso. Data for 1998-99, when Dynegy controlled the same block of capacity, indicate that prices at the California border were at least \$0.10/MMBtu higher than they likely otherwise would have been absent Dynegy's exercise of market power.[3] Given tightening demand conditions, the effect of EPME's exercise of market power can only be greater.

4. Given recent demand conditions in southern California and the unusually large amount of capacity controlled by EPME, perceived excess pipeline capacity into California will not serve to mitigate EPME's market power. For at least several months of a normal weather year, EPME is the marginal supplier on the marginal pipeline into the state, thereby allowing

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[2] Non-core customers are those customers that do not receive procurement services from a LDC.

[3] As discussed infra, this estimate of anticompetitive effects may be conservative in that the pre-Dynegy baseline price level itself may not have reflected fully-competitive behavior by SoCalGas and Pacific Gas & Electric ("PG&E") (the prior holder of most of NGC's capacity on El Paso).

it to directly influence the border price by its decisions to utilize or withhold capacity from the market.

5. For every $0.10/MMBtu increase in the California border natural gas price resulting from EPME's exercise of market power, annual electricity costs to Edison's customers are $34.2 million higher than they otherwise would be. This is because increases in the price of natural gas at the California border have a direct effect on the cost of delivered natural gas to gas-fired electric generating stations in southern California. Higher gas costs for these generators, in turn, results in higher electricity prices on the California Power Exchange ("PX"). This results in higher costs for Edison since under California's restructured electricity market, Edison is a major purchaser of electricity from the PX. Edison also faces higher costs on the payments it makes to Qualifying Facilities ("QFs") since under the California Public Utilities Commission ("CPUC") rules, changes in the price paid to QFs are directly linked to changes in the California border gas price.

6. Edison shareholders may also face financial exposure since higher PX prices and QF payments are not directly passed through to Edison's ratepayers. Under California's restructuring plan, Edison is permitted to recover stranded costs as the difference between the fixed prices at which Edison resells electricity to end-users and its authorized costs, including the price it pays for electricity from the PX. Therefore, as the price Edison pays for electricity increases, Edison recovers less stranded costs by the end of the transition time period. Thus, both Edison ratepayers and shareholders may be at risk for the $34.2 million per year of higher electricity costs that results from every $0.10/MMBtu increase in the California border natural gas price caused by EPME's exercise of market power.

7. Given the serious potential anticompetitive effects of the El Paso-EPME transaction on the southwest capacity market, we recommend that the

Federal Energy Regulatory Commission ("the Commission") set the matter for evidentiary hearing.

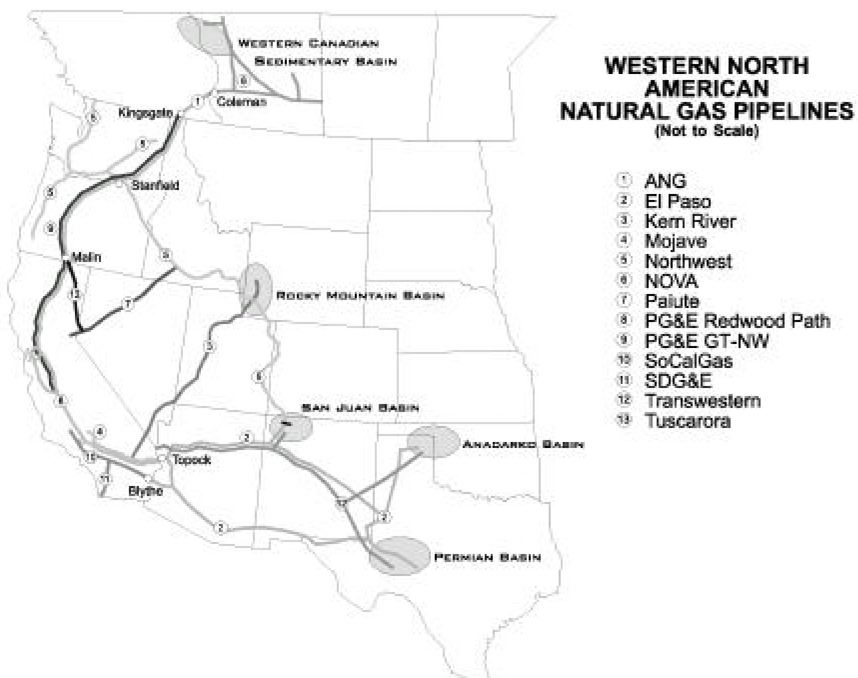
The remainder of this report is organized as follows. Section II provides a brief introduction to the California gas market, including a discussion of concentration levels in the interstate pipeline transportation market from the southwest gas producing basins to the California border. It also describes the salient aspects of the EPME-El Paso transaction**.** Section III discusses market conditions in the region since EPME acquired the capacity in March 2000. In Section IV, we discuss EPME's behavior in capacity markets and its incentives in downstream markets. In Section V, we explain the effect of EPME's behavior on Edison, through its effect on PX prices and QF payments.

II. CALIFORNIA NATURAL GAS MARKETS AND MARKET CONCENTRATION LEVELS

A. CALIFORNIA GAS MARKETS

Four major interstate pipelines deliver natural gas to California. El Paso and Transwestern deliver supplies from the San Juan and Permian basins located in New Mexico and Texas. Kern River delivers gas from central Wyoming and PG&E Gas Transmission NW delivers supplies from the Canadian Rockies. Figure 1 displays the four major interstate pipelines as well as other interconnecting interstate pipelines and the major intrastate transmission lines. The major delivery points for El Paso, Transwestern, and PG&E Gas Transmission NW are at the California Border while Kern River delivers to SoCalGas and PG&E as well as serving direct end-users in the Kern River oil fields within California.

FIGURE 1



Source: 1998 California Gas Report

Within California, the SoCalGas and PG&E networks are highly related (price-wise) yet independent systems. Both receive supplies via the four major interstate pipelines, however, the relative mix of supplies differs. PG&E's system receives the majority of its gas supply from

Canada while SoCalGas' system predominately sources its gas from the southwest basins. In addition, the ability to transfer supplies between the two LDC networks is capacity constrained. Table 1 reports interconnect capacity into the two LDC's systems.

TABLE 1
Firm Pipeline Interconnect Capacity into California LDCs

Into SoCalGas			Into PG&E		
Pipeline/Source	**Location**	**Receipt Capacity (MMcf/d)**	**Pipeline/Source**	**Location**	**Firm Capacity (MMcf/d)**
El Paso	Topock (CA Border)	540	PG&E G.T. NW	Malin, OR	1,803
El Paso	Ehrenberg (CA Border)	1,250	El Paso[3]	Topock (CA Border)	540
Transwestern	Needles (CA Border)	750	Transwestern[3]	Needles (CA Border)	300
PG&E[1]	Wheeler Ridge	380	Kern River[3]	Daggett	300
Kern River Mojave[1]	Wheeler Ridge	380	California Production	PG&E System	200
California Production[2]	SoCalGas System	297			
Total		**3,597**	**Total**		**3,143**

Notes:

1. Total capacity at Wheeler Ridge is typically approximately 760 MMcf/d. Under some operating conditions receipts at Wheeler Ridge increase to approximately 800 MMcf/d. Receipts from PG&E or Kern/River/Mojave can increase beyond 380 MMcf/d if receipts from the other source decrease one-for-one.
2. Receipt capacity on SoCalGas from California Production is equal to the maximum receipts between June 1, 2000 and August 19, 2000.
3. The combined maximum receipt capacity from El Paso-Topock, Transwestern-Needles, and Kern River-Daggett is 1,140 MMcf/d. Receipts from El Paso can increase to 1,140 MMcf/d as receipts from Transwestern and Kern River decrease.

Source: SoCalGas: The SoCalGas bulletin board.
PG&E: CPUC decision 97-08-055, August 1, 1997 and the PG&E bulletin board.

Price formation in the California gas market is determined by gas delivered to the southern California border on the El Paso and Transwestern pipelines. That is, gas delivered from the southwest is the marginal, price-setting source for southern California.[4] Suppliers to this market include shippers holding firm contracts with the two pipelines, shippers utilizing interruptible

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4 FERC recognized this point in the decision issued in Docket No. RP97-28, July 29, 1999, "The parties here generally acknowledge that Canadian producers price their gas based on the delivered price from El Paso and Transwestern at the California gateways so that the delivered price of Canadian gas is at or below that of gas delivered from the southwest fields. It is for this reason that most of the parties consider El Paso and Transwestern to be the "swing pipelines providing natural gas supplies to the California market based on shifts in demand." (page 11).

transportation – to the extent available – on the two pipes, and shippers that have acquired firm capacity rights through the secondary (or capacity release) market. Buyers at the border include marketers, non-core end-users, and the California utilities themselves (*e.g.*, San Diego Gas & Electric purchases significant quantities at the border).

One reason that the southern California border price is determined on a "net-forward" basis by supplies delivered on the El Paso and Transwestern pipelines from the southwest supply basins is that other gas supplies to the state are inframarginal to (*i.e.*, less expensive than) the supplies from the southwest. These include supplies delivered to California via PG&E Gas Transmission NW from Canada that are typically priced on a "net-back" basis from the prevailing price of gas delivered to the southern California border. Canadian gas has historically been cheap to obtain in the basin and throughput on PG&E Gas Transmission NW to California has typically been at very high load factors in most months. The other inframarginal source of supply to California is from the Rocky Mountains via Kern River. Kern River has also been operating at very high (close to 100%) load factor levels since its inception in 1992. To borrow an analogy from electric power markets, PG&E Gas Transmission NW and Kern River provide "baseload" supply to California while the pipelines from the southwest are the "swing" (intermediate and peaking) sources that determine the market price in California. [5]

A price increase at the California border will not lead to a supply response from Canada or the Rocky Mountains because PG&E Gas Transmission NW and Kern River are generally already operating at capacity. In this sense, supplies from the southwest basins delivered to the California border set the price of all gas delivered to California and transportation capacity between the southwest basins and California is a relevant market for analyzing market power concerns.

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[5] E Paso itself has acknowledged its role as the swing interstate pipeline. See El Paso's response to the Joint Parties' Data Request No. 6 in Docket No. RP97-28, "For 1998 to date, PGT, Kern River, and Transwestern have been operating at essentially full capacity. Accordingly, El Paso is the swing interstate transporter to California, as the market varies."

B. MARKET CONCENTRATION IN SOUTHWEST INTERSTATE CAPACITY TO CALIFORNIA

The southwest interstate natural gas capacity market to California has always been highly concentrated. Originally, PG&E and SoCalGas held the majority of this capacity, with their activities largely regulated by the California Public Utilities Commission.[6] However, excess capacity developed on the El Paso and Transwestern systems as a result of the excess interstate pipeline capacity created by the 1993 expansion of PG&E Gas Transmission NW. Several firm capacity holders turned back capacity on El Paso and Transwestern in 1996 and 1997 at least in part because of the excess capacity into California. Capacity turned back to El Paso ultimately totaled 1.5 Bcf/d and a settlement reached in 1996 divided the capacity into three blocks to be marketed with various restrictions on primary receipt and delivery points.

Since January 1998, an unregulated marketer has been the dominant holder of non-core-related southwest capacity. First, Dynegy (formerly Natural Gas Clearinghouse) held 1.3 Bcf/d of the turned-back capacity in 1998 and 1999. Since March 2000, EPME is the largest holder of capacity on El Paso and Transwestern with 34% of capacity (*See* Table 2 and Figure 2). In addition to the 1.2 Bcf/d EPME contracted on El Paso in March, EPME also acquired 156 MMcf/d from SoCalGas through a long-term capacity release (to August 2006) and holds 65 MMcf/d on Transwestern.

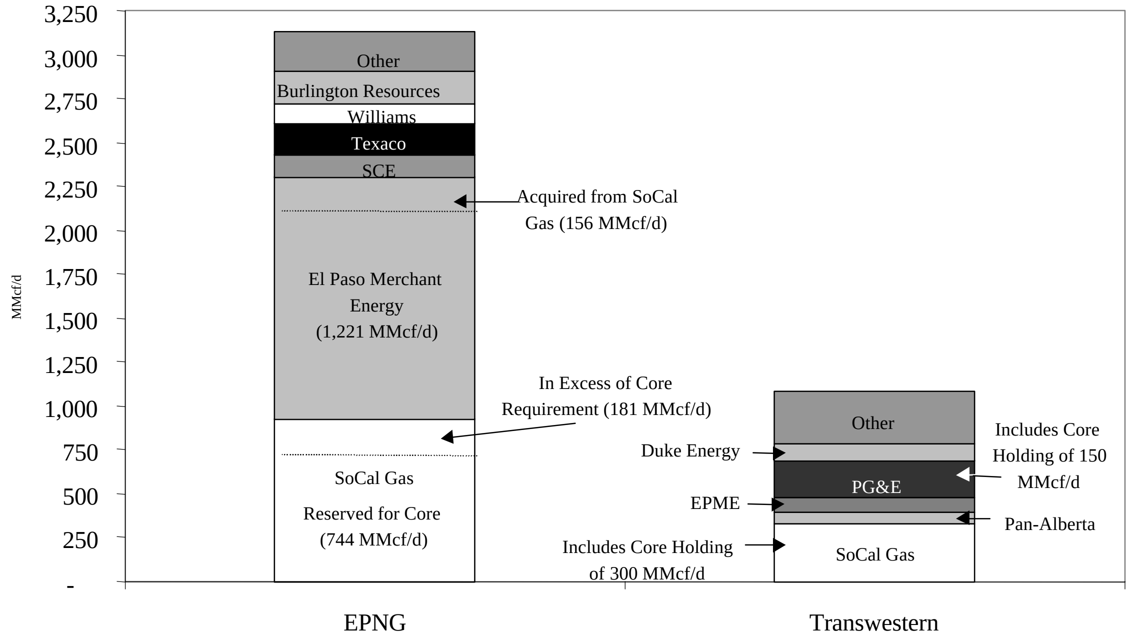
[6] The CPUC cited concerns regarding PG&E's and SoCalGas market power over southwest pipeline capacity. Evidence relied on by the California Public Utilities Commission in its "Gas Accord" Decision [D. 97-08-055] indicated that PG&E historically followed SoCalGas' minimum bids in establishing its minimum bid and minimum take requirements for its El Paso and Transwestern capacity. This evidence included internal PG&E planning memoranda, statements to the trade press, and pricing policy throughout the 1993-1996 time period. The concerns over Dynegy's market power are documented in FERC Docket No. RP97-287.

TABLE 2
HHI for Firm Capacity from the Southwest Supply Basins to California

	Capacity Out of Southwest (MMcf/d) EPNG	TW	TOTAL	Market Share (% of Total)	HHI
SoCalGas	925	328	1,253	30%	885
El Paso Merchant Energy	1,377	65	1,442	34%	1,173
SCE	130	—	130	3%	10
Pan-Alberta	—	85	85	2%	4
Texaco	175	34	209	5%	25
LADWP	36	—	36	1%	1
Southern Company	—	55	55	1%	2
Saguaro Power Company	20	—	20	0%	0
Engage	—	9	9	0%	0
US Borax & Chem	19	—	19	0%	0
Williams Energy	114	—	114	3%	7
Sacramento Mun Util Dist	—	10	10	0%	0
Mission Energy Fuel	7	—	7	0%	0
PG&E	—	211	211	5%	25
Conoco	—	20	20	0%	0
Burlington Resources Marketing	183	50	233	6%	31
Duke Energy Trading	49	93	142	3%	11
Enron	—	33	33	1%	1
Phillips Gas Marketing	—	30	30	1%	1
Amoco Energy Trading	25	30	55	1%	2
Aera Energy	20	—	20	0%	0
Reliant Energy	—	10	10	0%	0
KN Marketing (Oneok)	49	20	69	2%	3
TOTAL	**3,129**	**1,082**	**4,211**	**100%**	**2,179**

Source: July 1, 2000 Index of Customers reports for El Paso and Transwestern. El Paso contract capacity adjusted for long-term releases from SoCalGas to El Paso Merchant Energy, KN Marketing, and Duke Energy Trading.

FIGURE 2
Firm Capacity Holders to California from southwest Supply Basins (7/1/00)



Source: July 1, 2000 Index of Customers reports for El Paso and Transwestern. El Paso contract capacity adjusted for long-term releases from SoCalGas to El Paso Merchant Energy, KN Marketing, and Duke Energy Trading.

Concentration in the market for gas pipeline capacity from southwest supply basins to the California border is conformed by a Herfindahl-Hirschman Index ("HHI") value of 2,179 for that market (*See* Table 2).[7] This value is considerably above the HHI threshold of 1,800 employed by the Federal antitrust agencies in the 1992 Merger Guidelines, and the FERC in its merger policy guidelines (Order No. 592), to judge whether a market is at risk for competitive problems. The figures presented in Table 2 are based on El Paso's and Transwestern's Index of Customers reports as of July 1, 2000 and then adjusted for long-term capacity releases between parties.

EPME holds 48% of the southwest capacity available to serve non-core customers such as gas-fired electric generators. That is, when one removes the 1,044 MMcf/d SoCalGas holds for core customers – *i.e.*, SoCalGas' merchant service to residential and commercial customers – on El

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7 HHI is a measure of market concentration defined as the sum of the squared market shares of the firms in a market. Thus, a market with only one firm (*i.e.*, a pure monopoly) would have an HHI of 10,000 (100^2). A market with two firms, each with a 50% share would have an HHI of 5,000 ($50^2 + 50^2$).

Paso and Transwestern and the 150 MMcf/d PG&E holds on Transwestern for core customers, EPME holds almost half of the remaining capacity from the southwest basins to California.

C. OVERVIEW OF THE EL PASO - EPME CONTRACTS

El Paso's open season process was designed to transfer market power from the pipeline to the successful bidder. Participants were offered two alternatives, bid for their actual capacity requirements or bid for the entire 1.2 Bcf/d package. El Paso designed the award process to first evaluate any bids for the entire block of capacity relative to the aggregation of bids for smaller volumes. Thus, shippers unwilling to bid for the full 1.2 Bcf/d were dependent upon the bids for other small volume packages and then ran the risk that all small volume bids would be rejected in favor of a bid for the full block of capacity.

Twenty-four, ultimately unsuccessful, bids were received for less than the full block of capacity. Volumes bid ranged from 5,000 MMBtu/d to 193,454 MMBtu/d, with a median volume of 50,000 MMBtu/d (*see* Table 3). Prices ranged from $0.005/MMBtu to $0.175/MMBtu, with a median price of $0.043/MMBtu. Aggregate revenue from the bids was $17.6 million, not enough to satisfy El Paso's minimum revenue threshold of $37.5 million.

TABLE 3
Results of El Paso's February 2000 Open Season Partial Quantity Bids Only

	No. of Bids Rcvd	Range of Volume Bid (MMBtu/d)	Median Volume (MMBtu/d)	Range of Prices Bid ($/MMBtu)	Median Price ($/MMBtu)	EPME's Winning Bid ($/MMBtu)
Block I	7	20,000 - 100,000	100,000	0.005 - 0.035	0.020	0.040
Block II	6	20,000 - 100,000	50,000	0.020 - 0.055	0.028	0.065
Block III	11	5,000 - 193,454	50,000	0.030 - 0.175	0.100	0.141
Total/Median	24		50,000		0.043	

Source: El Paso Natural Gas Company response to CPUC data request No. 3, 1st set of data requests in RP00-241.

EPME prevailed with the sole bid for the full block of capacity. Its $38.5 million bid exceeded the minimum threshold by 3 percent.

Three contracts, corresponding to the three capacity blocks created by the 1996 settlement, govern the El Paso-EPME 1.2 Bcf transaction. All three contracts run from March 1, 2000 through May 31, 2001, with renewal rights thereafter. EPME has already indicated it plans to exercise those rights.

Table 4 summarizes the contracts. EPME acquired 462,398 MMBtu/d of Block I capacity with a reservation rate of $0.04, or approximately 11% of the maximum tariff rate. This Block I capacity has the rights to primary delivery points at Topock and Ehrenberg, but does not have any primary receipt rights.[8] EPME's second contract is for 593,122 MMBtu/d of Block II capacity at $0.065/MMBtu. This capacity only has primary delivery rights into PG&E's system at Topock but has primary receipt rights in all of the producing basins, including the San Juan basin. Block II capacity is recallable by shippers wishing to serve the northern California market if EPME is not utilizing the capacity. EPME's third contract is for 193,454 MMBtu/d of Block III capacity which has primary delivery rights at all the California border points and primary receipt rights in all the basins. Because of the added primary rights, EPME paid $0.141/MMBtu or approximately 40% of the maximum tariff rate for this capacity.

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8 The San Juan basin is generally less expensive than the Permian basin and there also exists capacity constraints to get gas out of the San Juan basin and onto El Paso's system. Therefore this capacity is less valuable without primary receipt rights in the San Juan basin than it would be if it had primary receipt rights.

TABLE 4
EPNG-El Paso Merchant Energy Contract Terms
(3/1/00-5/31/01)

	Block I	**Block II**	**Block III**	**Total or Average**
Description of Blocks				
Primary Delivery Points	All CA border points	PG&E Topock	All CA border points	
Primary Receipt Points	None	All producing fields	All producing fields	
Awarded MMBtu/d	462,398	593,122	193,454	1,248,974
Awarded Reservation Rate per day, 100% load factor ($/MMBtu)	0.040	0.065	0.141	0.082
Award Reservation Rate as a % of Max. Tariff ($0.353/MMBtu)[1]	11%	18%	40%	23%

[1] The maximum tariff from the San Juan and Permian Basins, expressed on a 100% load factor basis and excluding surcharges, is used here.

In addition to these three contracts, EPME also holds 160,000 MMBtu/d of capacity until August 2006 acquired from SoCalGas. The capacity is similar to Block III in that it has primary delivery rights to all California border points and primary receipt rights in all producing basins.

III. CURRENT MARKET CONDITIONS

A. CURRENT SUPPLY/DEMAND CONDITIONS IN THE CALIFORNIA GAS MARKET

EPME is able to exercise market power through its control of 1.4 Bcf/d of capacity on El Paso and Transwestern to California. By withholding capacity and dictating higher-than-competitive-market prices for capacity, or for gas purchased at the California border, EPME is able to profit from its anticompetitive behavior. Of course, EPME's ability to exercise market power on any particular day or month depends on demand conditions. Demand must be high enough such that EPME's capacity is necessary to meet the demand. Otherwise, other market participants can fulfill their demand from other suppliers without having to purchase EPME's capacity. Indeed, El Paso and Dynegy used this argument in 1998 as a reason why Dynegy's holding 1.5 Bcf/d on El Paso did not create a market power concern.[9]

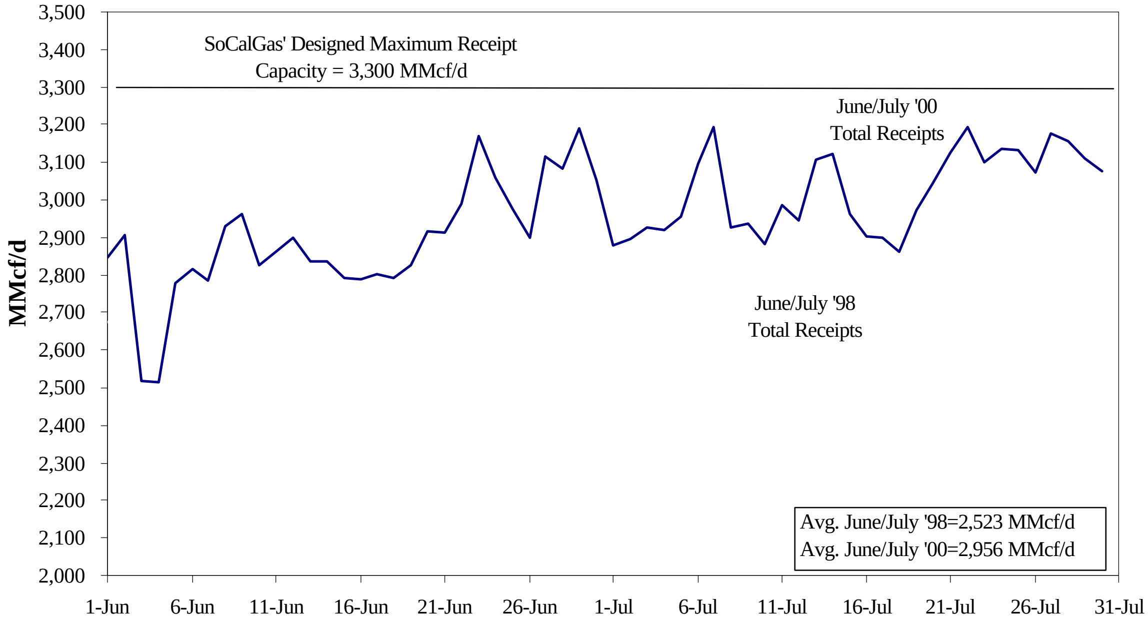
Current demand in California is at a level where EPME's capacity is required to serve the California market. The period of June and July 2000 indicates that demand in southern California is so high that deliveries on some days into Southern California Gas' system from El Paso and Transwestern are at full capacity. Spot price data for the same period indicates that capacity for transportation from the San Juan Basin to California is constrained.

Demand has increased since 1998, when Dynegy first successfully exercised market power and raised prices. Figure 3 illustrates the throughput from the four interstate pipelines serving SoCalGas' system in June and July 1998 versus June and July 2000. SoCalGas has the capacity to receive a maximum of 3.3 Bcf/d into its system and as shown, averaged throughput of approximately 2.5 Bcf/d in June and July of 1998, therefore having slack into its system of 700 – 800 MMcf/d. For June and July of 2000, throughput from the interstate pipelines averaged 3.0 Bcf/d, with peak throughput essentially equaling capacity. Demand in southern California was so high during June and July 2000, that SoCalGas reports withdrawals of 600 – 800 MMcf/d

[9] *See* El Paso's Reply Comments, Exhibit B, FERC Docket No. RP97-28, May 13, 1999.

from storage on several days at a time of the year when firms would normally be injecting into storage.

FIGURE 3
SoCalGas Interstate Pipeline Total Receipts
(June, July 1998 *vs.* 2000)

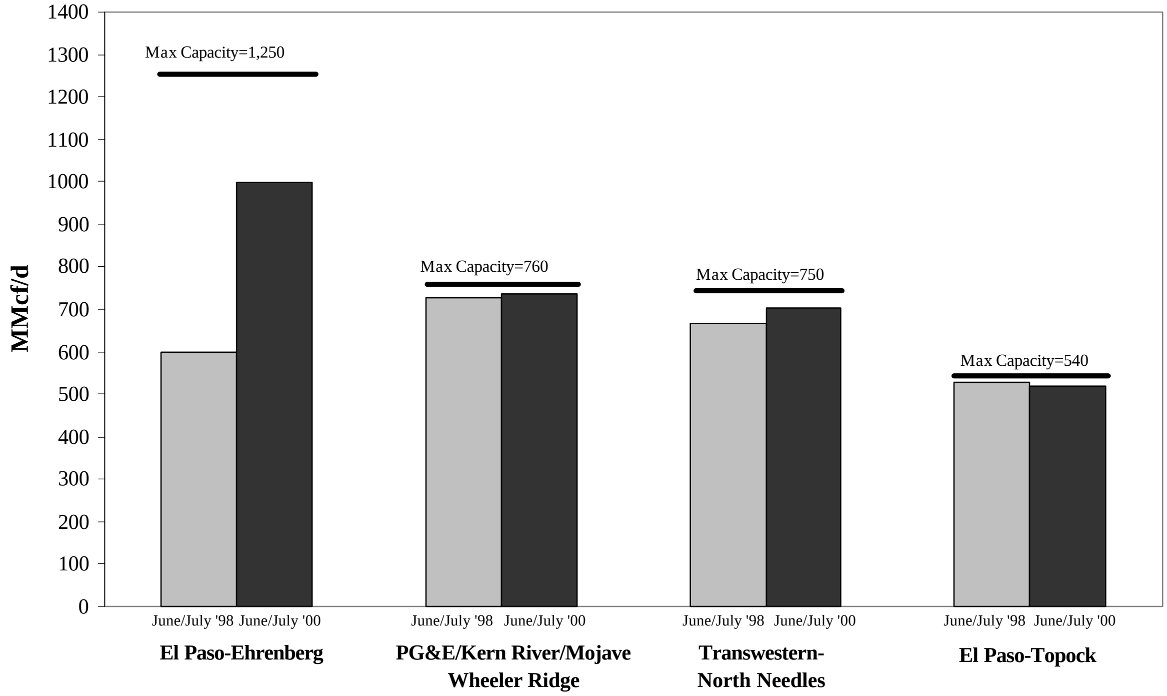


Note: SoCalGas' designed maximum receipt capacity of 3,300 MMcf/d includes maximum receipts at Wheeler Ridge of 760 MMcf/d. However, under certain operating conditions, SoCalGas is able to receive approximately 800 MMcf/d at Wheeler Ridge. It is not clear if total receipts from interstate pipelines increases as a result of increased receipts at Wheeler Ridge.

Source: SoCalGas' Bulletin Board.

The increase in demand means throughput at Ehrenberg has increased significantly from June/July 1998 to June/July 2000. Average June/July throughput relative to maximum receipt capacity is shown in Figure 4. As seen, the Ehrenberg delivery point on El Paso's system is the point where deliveries were substantially less than capacity during June and July 1998, with a load factor of approximately 50% of capacity. It is our understanding that deliveries to Ehrenberg from the San Juan Basin are limited by capacity constraints and in order for all Ehrenberg capacity to be utilized at least some gas must be flowing from the more expensive Permian Basin.

FIGURE 4
SoCalGas' Interstate Pipeline Receipts by Receipt Point (June/July 1998 *vs*. 2000)

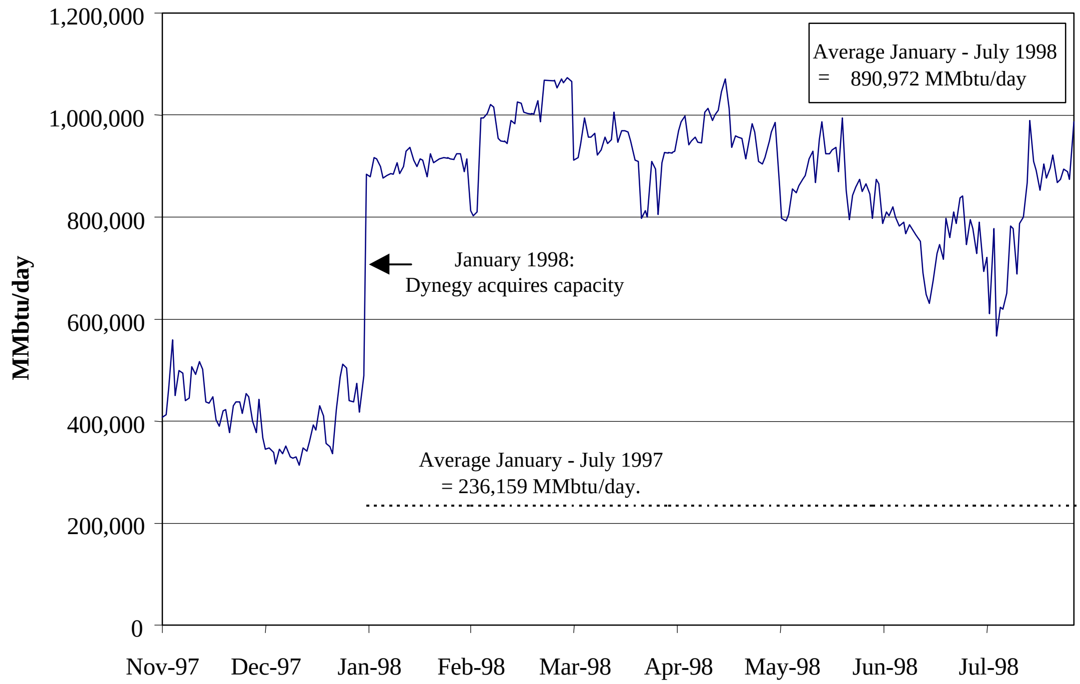


Note: Total capacity at Wheeler Ridge is typically 760 MMcf/d. Under some operating conditions receipts at Wheeler Ridge can increase to approximately 800 MMcf/d.

Source: SoCalGas' Bulletin Board

Recall that a dramatic shift in throughput away from El Paso and onto Transwestern was observed following Dynegy's acquisition of the capacity in January 1998. Because PG&E Gas Transmission NW and Kern River operate near capacity, Transwestern was the only alternative with excess capacity in January 1998 when Dynegy acquired 1.3 Bcf/d on El Paso and apparently attempted to unilaterally increase the price. The throughput data for Transwestern displayed in Figure 5 reveals the significant increase in throughput on Transwestern that occurred at the beginning of January, 1998. More recent data from Transwestern's website confirms that it is currently operating near capacity as well. El Paso is the only interstate supply source that can increase in response to an increase in demand in California.

FIGURE 5
Daily Throughput on Transwestern into SoCalGas and PG&E



Source: Throughput on Transwestern, Nov 1997 - Jul 1998, from Transwestern's bulletin board. 1997 data from SoCalGas' and PG&E's daily operating records.

The fact that EPME's capacity is needed to meet peak summer demand conditions means EPME has market power in the shoulder demand periods. Summer 2000 natural gas demand conditions in southern California may be higher than normal due to strong electric generation load. On peak days when throughput into SoCalGas is at maximum capacity, we would expect EPME to maximize throughput as it does not have an incentive to withhold. EPME does have an incentive to withhold, however, during shoulder periods such as the months of June, September, November, and February as well as relatively low demand days in the peak months of July, August, December, and January.

During shoulder demand periods, a large holder of capacity such as EPME has the ability to create an imaginary capacity constraint by withholding capacity from the market. Further, when shoulder demand is approaching a level where a true capacity constraint occurs, the substitutability of interruptible capacity for firm capacity lessens and therefore interruptible capacity does not provide a perfect substitute for firm capacity. For example, EPME can create the perception of capacity constraints among gas purchasers on SoCalGas' system by injecting into storage on SoCalGas' system. In periods when demand is just below SoCalGas' maximum receipt capacity, purchasers of gas would know EPME has the ability to utilize any potential unused capacity by flowing gas into storage, thereby creating uncertainty over the reliability of interruptible capacity and again forcing customers to turn to EPME to meet demand.

B. CURRENT PRICE CONDITIONS IN THE CALIFORNIA MARKET

Basis differentials between the California border and the San Juan and Permian basins increased significantly when Dynegy acquired the El Paso capacity in January 1998 and have increased further since EPME acquired the capacity in March 2000. Figure 6 displays the basis differential between the California border and the San Juan basin between May 1997 and the present. As reported in Figure 6, the basis differential averaged $0.15/MMBtu to $0.18/MMBtu in 1996 and 1997. The differential increased to an average of $0.32/MMBtu in 1998 and 1999 when Dynegy held the capacity, with prices at or greater than El Paso's maximum tariff rate on several days during the peak demand months of July through October 1998. 1999 was a milder summer in terms of weather, and Dynegy controlled less capacity,[10] but again daily prices approached the maximum tariff rates during November. [11]

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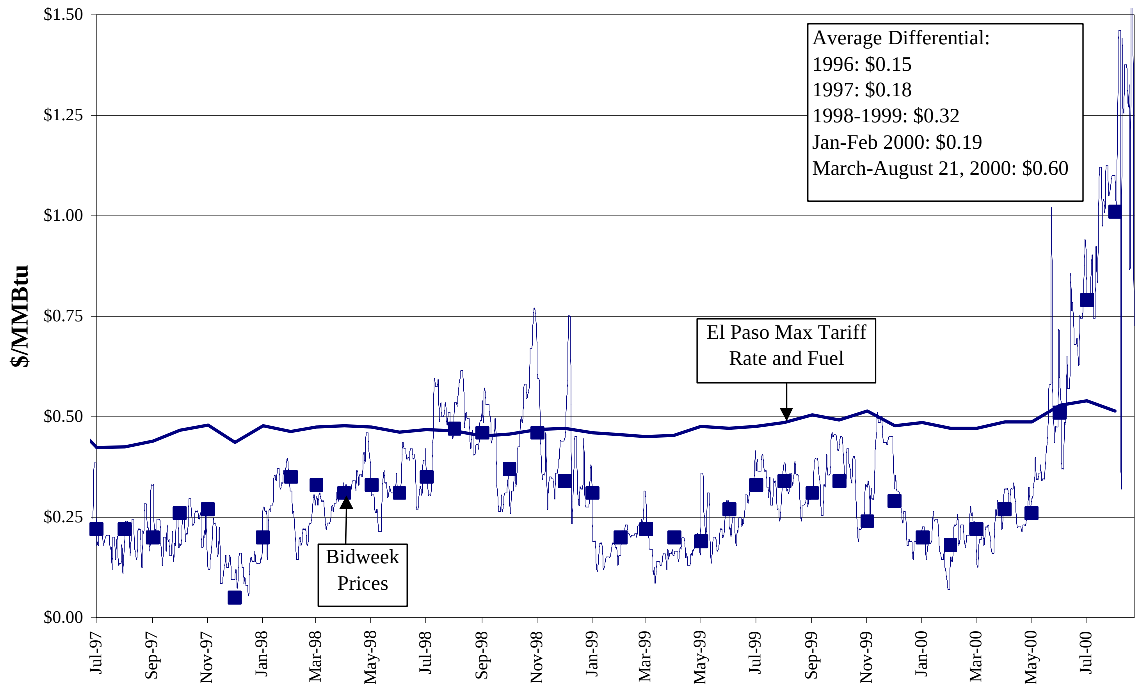
[10] Dynegy acquired 180,000 MMBtu/d from SoCalGas for 1998 that was not held in 1999.

[11] El Paso acknowledged the increase in basis differentials when Dynegy held the capacity, however, it offered weather-driven demand increases in California and a shift in demand for Southwest supplies relative to Canadian supplies (due to higher prices of Canadian gas and increased flows of Canadian gas to the Midwest) as explanations for the increase. *See* Reply Comments of El Paso Natural Gas Company, RP97-287, May 13, 1999. However, increased demand for Southwest supplies should result in an increase in the basin price, not the transportation price (basis differential) if there is substantial excess capacity as El Paso also alleges. Competition among the holders of the substantial excess capacity would keep the transportation price relatively constant and near variable cost. Therefore, the sustained increase in the basis differential indicates that there is a holder of capacity with market power and/or there is not substantial excess capacity. Some industry participants expect the commencement of the Alliance project later this year to back out Permian gas from the Midwest and lower both Permian Basin and California border gas prices from what they otherwise would be. If EPME successfully exercises market power, decreases in the Permian price may not lead to corresponding reductions in the California border price, instead it may only lead to increases in the California border-Permian Basin basis differential.

FIGURE 6
Topock-San Juan Price Differentials: Bidweek and Daily

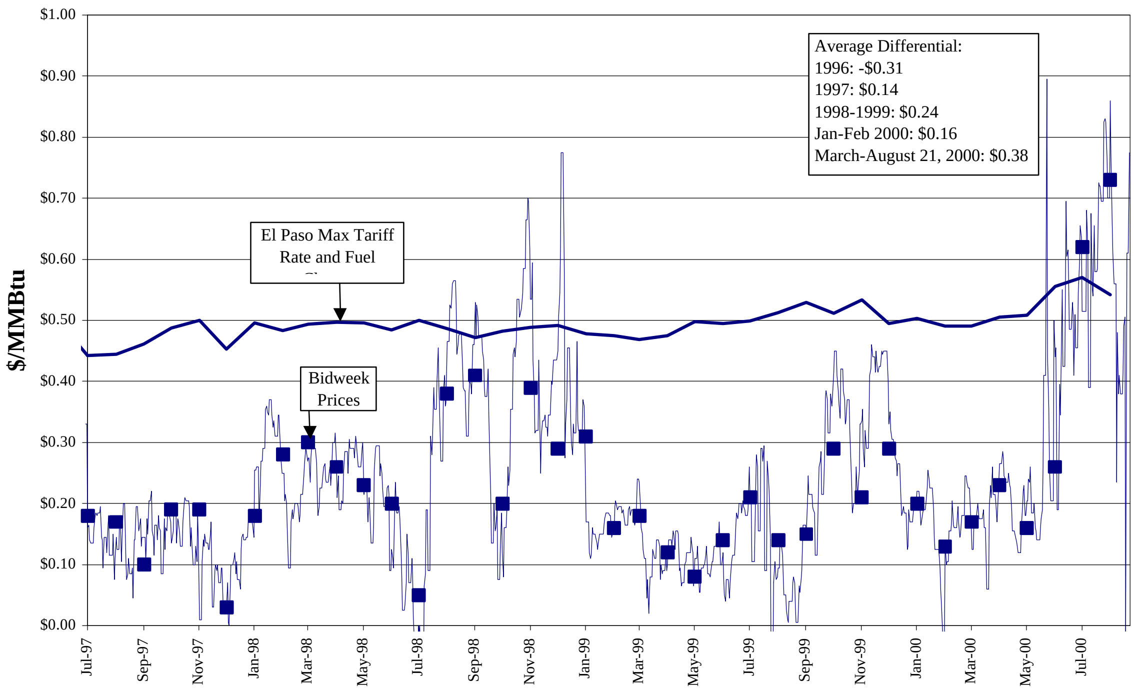


Source: *Gas Daily*

The basis differentials between the California border and the San Juan and Permian basins have increased significantly during June and July 2000 to the point where it is well above the sum of El Paso's $0.38/MMBtu maximum tariff rate[12] and its 3.88% fuel rate (at $3.00/MMBtu gas in the basin, fuel is $0.12/MMBtu = 3.88% × $3.00/MMBtu). This trend has continued into August where the bidweek differential was $1.01/MMBtu between the California border and the San Juan basin. Without discovery and evidentiary hearings, it is difficult to sort out the degree to which this unprecedented run-up in the basis differential is due to demand conditions as opposed to EPME's exercise of market power.

The basis differential between the California border and the Permian Basin displays a similar, albeit more complicated, pattern. In 1996, Permian Basin gas primarily flowed to the Midwest, as reflected in a negative basis differential with the California border (*i.e.*, gas purchased in the Permian Basin was more expensive than gas could be sold at the California border). During this time, San Juan Basin gas was typically lower priced than Permian Basin gas for California customers, causing San Juan Basin gas to flow toward California ahead of Permian basin gas. The basis differential increased in 1997 (*see* Figure 7) and further in 1998 with the daily differential exceeding the maximum tariff rate at times during the summer of 1998. As supplies from the San Juan Basin have become constrained, shippers are turning to Permian Basin supplies, causing the Permian to help determine the price of gas delivered to California. This appears to have occurred in June through August 2000.

FIGURE 7
Topock-Permian Price Differentials: Bidweek and Daily



Source: *Gas Daily*

The conventional wisdom has been that excess capacity between the Permian Basin and the California border exists on El Paso's system. If that is true and El Paso is mandated to sell interruptible transportation at its maximum tariff rate,[13] then the basis differential between the

continued

12 This rate reflects the maximum firm reservation rate at a 100% load factor plus surcharges.

13 El Paso reports that it has not discounted IT service to California in 1998 through the present nor does it have an incentive to sell discounted IT given that its affiliate holds 1.4 Bcf/d of capacity to California. *See*

continued

California border and the Permian basin should never be greater than the maximum tariff rate (plus fuel). However, as seen in Figure 7, daily differentials exceeded the tariff rate in 1998 and since June 2000, both bidweek and daily differentials have consistently exceeded the maximum tariff rate. Clearly, the conventional wisdom must be called into question – the system appears to be at capacity at least at certain times of the year.

If the system is at capacity at certain times, then there are shoulder periods when demand is high enough that an entity with market power is able to restrict capacity (by withholding it) and effectuate a price increase. The larger the volume of capacity controlled by any entity relative to the total physical capacity, the larger the range of demand conditions where market power can be exercised.

Given the relatively short period in which EPME has controlled the large volume of El Paso capacity, and the extremely high demand conditions on certain days this summer, it is difficult to sort out how much of the increase in basis differentials is due to physical capacity constraints as opposed to EPME's exercise of market power. For purposes of tracing through the effect on electricity markets and Edison, the period when Dynegy held the capacity provides a useful indication of the effect of market power on transportation price. During the period Dynegy held the capacity, the Topock – San Juan differential increased by $0.14/MMBtu to $0.17/MMBtu relative to prior, relatively unconstrained, years. To be conservative, we attribute a $0.10/MMBtu increase in the California Border price to Dynegy's market power later in the report.

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continued

El Paso's response to CPUC data request No. 18 in CPUC's Second Set of Data Requests in this proceeding.

IV. EPME'S BEHAVIOR AND INCENTIVES

A. EPME HAS MADE LIMITED USE OF ITS CAPACITY

EPME has only utilized 25% of its capacity during the first four months of its contracts. Table 5 displays EPME usage for March through June 2000.[14] EPME made very little use of its Block I and Block II capacity, particularly in March through May.

TABLE 5
EPME's Usage
(Average MMBtu/d)

Awarded Capacity	462,398	593,122	193,454	**1,248,974**
Usage	**Block I**	**Block II**	**Block III**	**Total**
Mar-00	96,034	51,094	113,094	**260,222**
Apr-00	73,348	85,549	112,154	**271,051**
May-00	45,617	78,345	98,792	**222,754**
Jun-00	233,419	169,293	110,644	**513,356**
Average Mar-Jun	112,105	96,070	108,671	**316,846**
EMPE's Avg. Mar-Jun Usage As Percentage of Capacity	24%	16%	56%	**25%**

Source: El Paso Natural Gas Company Response to CPUC Data Request No. 17-A.

Even in June 2000, when basis differentials exceeded maximum tariff rates, EPME's June usage was only 41% of its capacity.[15] The June 2000 bidweek price differential between the California Border and the San Juan Basin was $0.51/MMBtu, which is approximately equal to El Paso's maximum tariff rate plus fuel charges. This price differential indicates that market participants expected capacity from the San Juan basin to California to be at capacity. The June 2000 bidweek differential between the California border and the Permian basin was below El Paso's

[14] El Paso Natural Gas Company Response to CPUC Data Request No. 17-A in FERC Docket RP00-241.

maximum tariff rate, however, during the month the daily differentials between both the San Juan and Permian basins and the California border increased to greater than El Paso's maximum tariff rate. This increase suggests there were capacity constraints between both southwest basins and the California border. However, EPME's usage was 41% of its total capacity. Discovery and evidentiary hearings are necessary to fully understand whether these seeming inconsistencies are evidence of market power or of some unusual constraint on the system.

B. CAPACITY RELEASE VOLUMES AND PRICES ON EL PASO

A clear indicator of market power is EPME and Dynegy's practice of offering their capacity for release at prices equal to 90% of the maximum tariff rate or higher for periods of a year or more shortly after having purchased their capacity on El Paso at substantially discounted prices.

Figure 8 displays capacity release offers relative to awarded volumes with delivery points to California between February 1996 and August 2000. Such a disconnect between their offering terms (both price and release duration) and then-current market prices for capacity could only serve to withhold capacity from the market. This is confirmed by El Paso's capacity release data.

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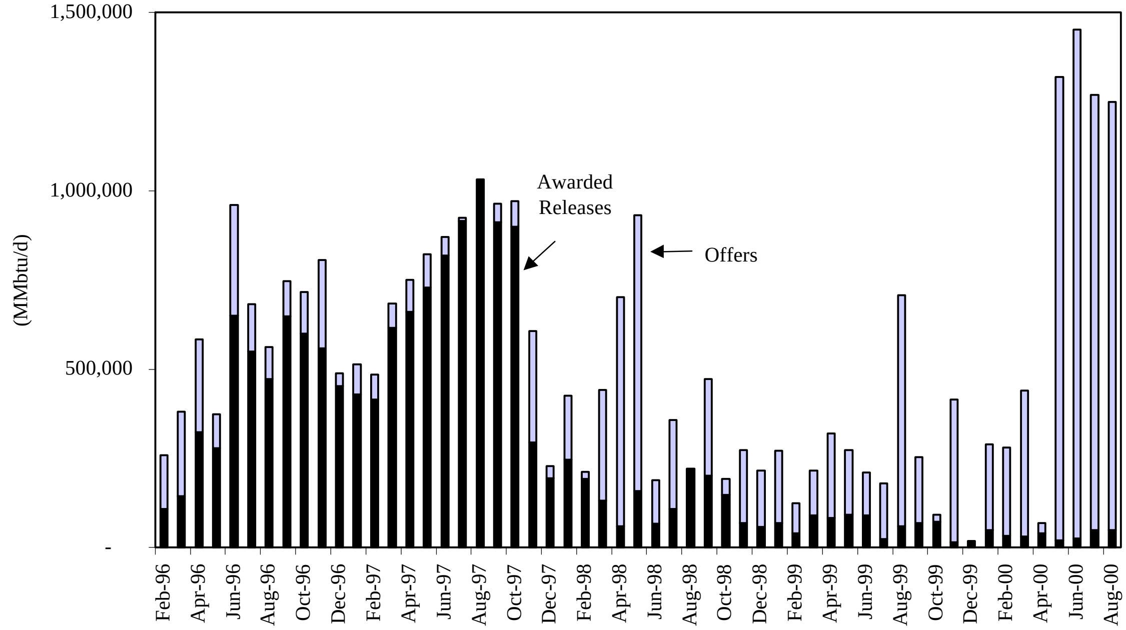
continued

[15] June usage of 513,356 MMBtu/d divided by 1,248,974 MMBtu/d of capacity equals 41%.

FIGURE 8
Capacity Release Volumes on El Paso
(Offers *vs*. Awarded Releases)



Note: Reflects offers for full months or longer. Reflects awards for full month only. Only postings for delivery to California are included. Transactions from SoCalGas at the regulatory mandated 100% maximum tariff to core aggregators' excluded. Postings by EPNG of remarketed capacity are removed.

Source: El Paso Natural Gas Electronic Bulletin Board.

As shown, awarded volumes closely tracked the offered volumes during 1996 and 1997, indicating volumes were offered at the then prevailing market price. During 1996 and 1997, the awarded volumes were between 500,000 and 1,000,000 MMBtu/d during several months. However, awarded full-month volumes decreased considerably in 1998 through the present. While the total volume offered appears to be substantial during April and May 1998 and again during May 2000 through the present, it is because Dynegy and EPME offered substantial volumes for release at rates of 90% of maximum tariff or higher, generally for release periods of a year or more. The result of Dynegy's and EPME's offering behavior was that awarded volumes for full month transactions dropped considerably, such that the awarded volumes are less than 100,000 MMBtu/d during the majority of months between 1998 and the present. [16]

The price of capacity release to California has increased substantially between 1996 and the present as the awarded volumes declined, consistent with the price behavior of basis differentials. Figure 9 displays the weighted average price of full month releases between 1996 and the present. During 1996 and 1997, capacity release prices averaged \$0.08/MMBtu/month, more than doubling to \$0.18/MMBtu/day during 1998 and 1999 when Dynegy held the large blocks of capacity on El Paso. Awarded prices during July and August of 2000 have been at El Paso's maximum tariff rate and it is out understanding that there was a recent release for October 2000 at \$0.99/MMBtu/day, approximately 300% of El Paso's maximum tariff rate.[17]

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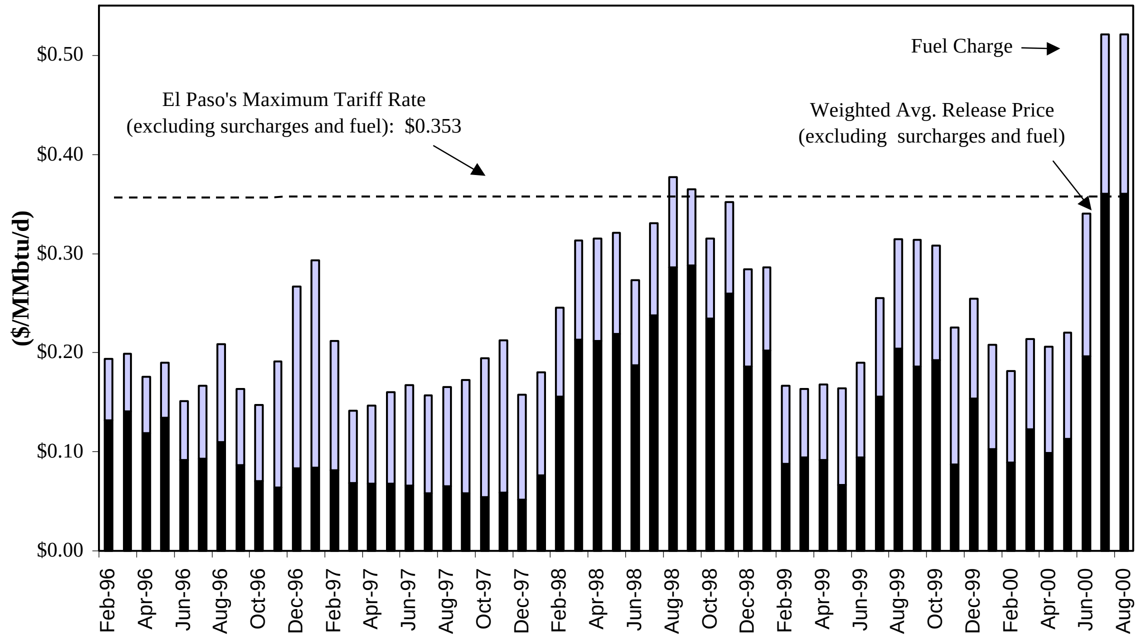
[16] Note, Figure 8 does not report multi-month awards. Nonetheless, even if those transactions could somehow be meaningfully represented in the figure, the basic conclusion would be the same: much of the offered capacity in 1998-2000 was not being awarded.

[17] EPME released 50,000 MMBtu/d to Aquila Energy on a monthly basis for July through October 2000 at the maximum tariff rate. Also, Duke Energy Trading and Marketing and PG&E Energy Trading (two shippers serving Northern California) recalled a portion of EPME's Block II capacity for July-October 2000.

FIGURE 9
Weighted Average Capacity Release Price for Awarded Volumes



Note: Only full month postings for delivery to California are included. Average prices weighted for MMBtu. 1 MMbtu = 1 Dth. Transactions from SoCalGas at the regulatory mandated 100% maximum tariff to core aggregators' excluded. Reservation rate computed assuming 100% load factor utilization, fuel charge calculated as 3.88%-5.00% of basin price based on the then current tariff. Postings by EPNG remarketing capacity are removed.

Source: El Paso Natural Gas Electronic Bulletin Board.

C. ADDITIONAL INCENTIVES OF EPME TO MANIPULATE THE CALIFORNIA BORDER PRICE

EPME has incentives to manipulate the California border price that go beyond profiting on the price of transportation between the southwest basins and the California border. These additional incentives include revenue increases at EPME's electric generation Qualifying Facilities ("QF") in California and EPME's ability to profit from financial positions taken in forward and futures markets.

EPME has an ownership interest in at least 20 QF plants in California. The plants have a total capacity of over 1,000 MW with EPME's ownership stake slightly more than 475 MW. Eleven of EPME's QF plants are gas-fired facilities acquired from Dynegy earlier this year. Ten of these eleven (with total capacity of 660 MW, of which 300 MW is owned by EPME) sell their output to PG&E. The remaining unit acquired from Dynegy (with total capacity of 41 MW, of which 16 MW is owned by EPME) sells its output to Edison. EPME acquired an additional 9 units from

CalEnergy in 1999. Eight of these units are geothermal units that sell their output to Edison; EPME owns 135 MW of the total 270 MW capacity of these units. The ninth unit acquired from CalEnergy is a 50 MW gas fired unit (of which EPME owns 50%) that sells its output to SDG&E.

Under the CPUC's short-run avoided cost ("SRAC") transition price, formulated in CPUC Decision 96-12-028, QF payments by Edison, PG&E, and SDG&E are based on formulas that incorporate changes in the price of gas at the California border. The formula that determines QF payments by Edison measures the change in the California border price relative to a base year (1995) and applies that change to the proportion of the QF payment (76%) deemed to be related to the fuel (natural gas) cost.[18] The higher the delivered price of gas at the California border, the higher the cents/kWh payment to EPME's affiliated QFs.

The increase in EPME's affiliated QFs' annual revenues from a $0.10/MMBtu increase in the California border price is $3.6 million. $1.2 million reflects increased annual payments from Edison while $2.3 million and $0.1 million reflect increased payments from PG&E and SDG&E, respectively. To develop these figures, we look only at EPME's ownership stake in each QF and assume EPME owns that stake for a full year. We derive the units' output assuming a 91% capacity factor. The increase in each unit's annual revenue is the product of its annual output and the change in the unit ($/kWh) QF payment specified in the utility-specified SRAC transition formula caused by a $0.10/MMBtu increase in the border price.

EPME can also increase its incentive to manipulate the California border price of natural gas through positions in the forwards and futures markets. This can be done using both gas and electricity markets. The correlation between EPME's gas pipeline capacity management practices and its positions in forward markets can only be determined through evidence that would be yielded by discovery and a hearing process.

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[18] *See* attachments 1-3 of CPUC Decision 96-12-028 for the exact formulas that determine QF payments by Edison, PG&E, and SDG&E. The three formulas are similar. However, PG&E's formula uses a gas price that is the average of the prices at Topock and Malin to more accurately represent PG&E's natural gas supply mix.

V. EFFECT OF HIGHER NATURAL GAS PRICES ON THE CALIFORNIA ELECTRICITY PRICE

A. RELATIONSHIP BETWEEN THE COST OF NATURAL GAS AND THE CALIFORNIA ELECTRICITY PRICE

Natural gas plays an important role in both the production and price of electricity in California. Gas-fired electric generation accounts for approximately 59% of California's total generating capacity. In the entire Western Systems Coordinating Council (WSCC), a larger electricity reliability region that includes California, gas-fired electric generation accounts for 29% of total generating capacity (*See* Figure A-1 in Appendix A). The importance of natural gas to electricity generation has been a constant theme in California's electricity markets, both before and after the restructuring of California's electricity market in 1998 pursuant to California Assembly Bill 1890 ("AB 1890").

Historically, gas-fired electric generation was frequently the "marginal" source of generation in both California and the WSCC, meaning that a gas-fired generating unit was the last unit dispatched to meet load requirements. These power plants were owned and controlled by electric utilities and dispatch was done according to lowest variable cost. As depicted in Figure A-2 of Appendix A, when measured this way gas-fired units form the majority of California's relatively elastic supply curve.

In April 1998, California commenced operation of a new institution, the Power Exchange, through which electricity in the state is now bought and sold. The PX operates two energy markets. In the day-ahead market, bids to buy and sell energy are submitted for each hour of the subsequent day. In the day-of energy market, buyers and sellers can effectively adjust the positions they received in the day-ahead market.[19] The principal buyers in this market are the utilities – Edison, San Diego Gas & Electric, Pacific Gas & Electric – who are currently required to purchase from the PX. These utilities are also among the principal sellers into the pool,

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19 Second Report on Market Issues in the California Power Exchange Energy Markets, prepared by The Market Monitoring Committee of the California Power Exchange, March 9, 1999, pp. 8-9.

through their remaining nuclear, hydro, coal, and QF resources. As part of the restructuring process, California's investor-owned electric utilities ("IOUs") have divested much of their gas-fired generation plants to third parties. The primary owners of gas-fired capacity are now AES Corporation, Duke Energy Power Services, Dynegy, NRG Energy, Southern Company and Reliant Energy.[20]

A key feature of the PX is that the market clearing price (the price paid to all generators called on to provide energy) in each hour is determined by the intersection of the buyers' aggregate demand bids and the sellers' aggregate supply bids. That is, the price is set equal to the bid of the marginal generator.[21]

Prices vary hourly and seasonally with demand under the dynamics of PX hourly pricing. Figure 10 depicts hourly PX price and quantity information for one week of each season. The graphs show the within-day trends – namely that prices increase with the level of demand. Demand and price are lowest during off-peak periods (10:00 p.m. to 6:00 a.m.) and are highest around 4:00 p.m. The graphs also show the seasonality of electricity pricing, with prices and quantities highest in July and January and generally lower in the shoulder periods of October and April.

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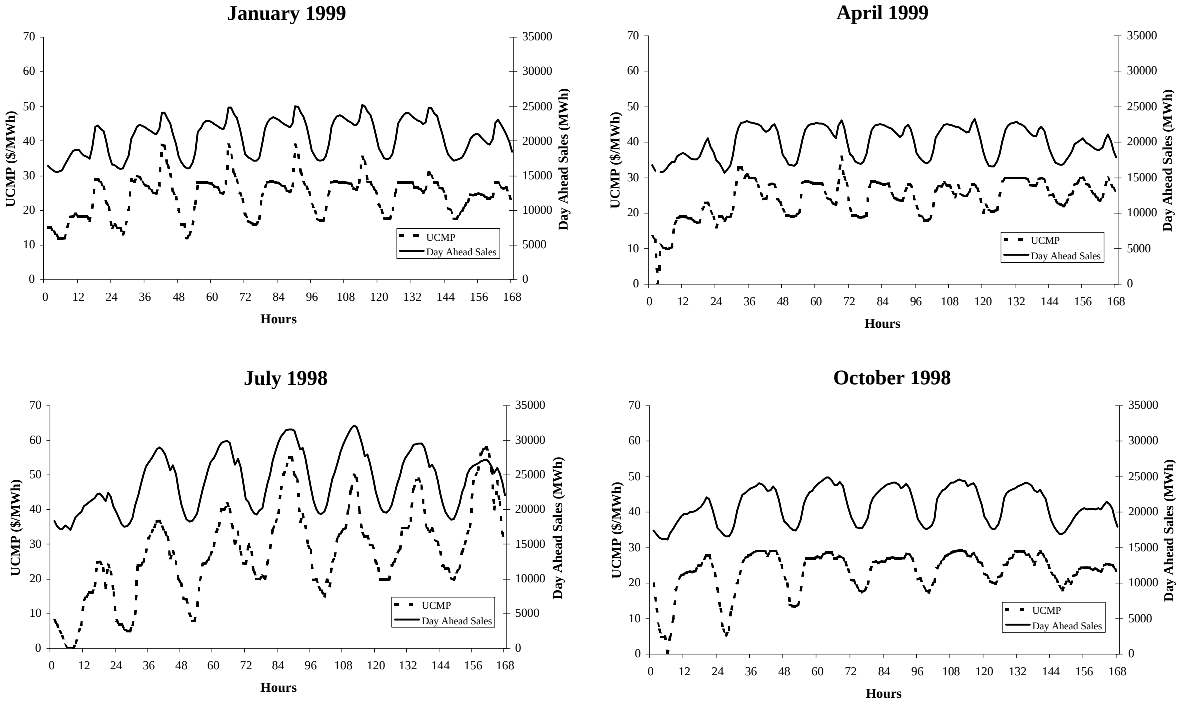
[20] Electricity Markets of the California Power Exchange, Second Annual Report to the Federal Energy Regulatory Commission, prepared by the California Power Exchange Corporation, Market Compliance Unit, July 31, 2000, pp. 89-91.

[21] This market clearing price sometimes has to be modified to account for congestion on transmission lines between California load centers.

FIGURE 10
Hourly CA PX Load and Prices for Representative Weeks



Although the Power Exchange does not publicly disclose which generating units are on the margin in each hour, there is no question that gas-fired generating units are on the margin a significant amount of time:

> It is not possible to determine exactly the marginal resource in the CalPX Day-Ahead market due to the nature of the supply portfolio bids. However, Participants owning a significant amount of conventional natural gas-fired generating units are most often the incremental supplier, thus are most likely the marginal resource influencing the market clearing price.[22]

With gas-fired generation frequently the marginal source of generation in California, the price of natural gas delivered to gas-fired generators in California has a direct effect on bids into the PX to supply electricity. Calpine Corporation, an owner of gas-fired generation in California and,

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22 Electricity Markets of the California Power Exchange, Second Annual Report to the Federal Energy Regulatory Commission, prepared by the California Power Exchange Corporation, Market Compliance Unit, July 31, 2000, p. 18.

hence, a supplier into the California PX recognizes that "the delivered price of natural gas has a direct impact on the cost of electricity."[23] Calpine elaborates:

> . . . there is a growing convergence between the electric and natural gas industries. Natural gas costs are a significant component of gas-fired generators' cost of producing electricity. The cost of natural gas directly affects the price for electricity in the restructured California market.[24]

B. QUANTIFYING THE ELECTRICITY PRICE EFFECT

We use a one-for-one effect of a change in the delivered natural gas price on the California PX price to derive a conservatively low estimate of Edison's financial interest in the price of gas delivered to the California border. As Appendix A explains in more detail, an increase in gas costs will be passed through one-for-one to the PX price in those hours when gas is on the margin and conditions are marked by perfect competition, an inelastic demand for electricity, and a high supply elasticity. Appendix A goes on to show that in those hours where gas is at the margin and some suppliers may possess market power (*i.e.,* conditions aren't perfectly competitive), an increase in gas costs will lead to at least and possibly greater than one-for-one increase in PX prices. For example, a $0.10/MMBtu delivered gas cost increase may be "marked up" as the generator bids in a price into the PX.

In the absence of public information regarding the degree to which gas-fired units are on the margin, PX hourly price data for the period April 1998 through July 2000 is used to estimate how often gas-fired units are setting the market price. A review of the hourly data as well as reports prepared by the PX[25] suggests that hours fall into one of three basic categories. In some hours, PX load and prices are low enough to indicate that gas-fired units are not setting the PX price. During these hours, the PX price is likely being set by units that either have lower variable

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[23] *Opening Brief of Calpine Corporation*, CPUC R.98-01-011, February 26, 1999, p. 9.

[24] *Id*.

[25] *See* "Second Report on Market Issues in the California Power Exchange Energy Markets," prepared for the Federal Energy Regulatory Commission by The Market Monitoring Committee of the California Power Exchange, March 9, 1999, pp. 43-49.

costs than gas-fired units or are bidding into the PX at zero cost.[26] For other ranges of prices and loads, it is reasonable to assume that gas-fired generators are setting the market price and are bidding at or near their marginal costs. These ranges are marked by mid-level loads and prices that are consistent with the cost of gas-fired generation. The third category of hours are those where loads are high and PX prices are high enough to suggest that generators are bidding above marginal cost. While the supply mix of the California market is such that gas-fired generation is on the margin during such high load – high price hours, the presumption is that generators are engaging in strategic bidding behavior.[27]

To estimate the range of hours in a typical year over which gas-fired generators are setting the market price, the minimum price for each day that a very efficient gas-fired generator would have to receive in order to cover its variable cost (principally, its delivered gas cost) is calculated. The calculations rely on estimates of delivered gas prices to southern California generators and heat rates for Edison and SDG&E's previously owned gas-fired generating plants.[28] The delivered gas price to southern California's gas-fired generation is calculated as the daily spot gas price at the California border on El Paso and Transwestern plus the SoCalGas transportation rate for electric generators.[29]

In southern California, gas-fired generating plants typically have heat rates ranging from 9,259 Btu/kWh to 11,300 Btu/kWh. Multiplying the heat rate by the delivered spot gas price provides

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[26] As described in the PX 1998-1999 Market Year Report to Californians, some generating units in California have been designated as Regulatory Must Take/Must Run units ("RMT units"). RMT units include qualifying facilities, nuclear units, pre-existing power-purchase contracts and some hydro-electric units. These units are bid into the PX at $0/MWh in order to ensure their selection. These units accounted for approximately 17,400 MW of capacity on average in each hour between April 1998 through March 1999. This is significant because for loads greater than 17,400, the PX hourly price is determined primarily by coal and gas units. *See* PX 1998-1999 Market Year Report to Californians, p.10.

[27] At least this was the presumption made by the PX in its March 9, 1999 report. While its July 31, 2000 report downplays any strategic generator behavior, it reinforces the importance of the natural gas price in establishing the PX price. Our use of a one-for-one gas price – PX price effect means that our results are not dependent upon generators engaging in strategic bidding behavior.

[28] A generating unit's heat rate measures how efficiently the unit converts fuel to electricity (how many BTUs are required to produce a kilowatthour). Thus, a lower heat rate indicates higher efficiency.

[29] Gas delivered at the California border from the southwest basins on El Paso and Transwestern sets the price for gas delivered via PG&E Gas Transmission NW and Kern River as explained earlier in this report.

an estimate of a gas-fired unit's marginal cost. For example, if a 9,259 Btu/kWh plant receives a delivered gas price of \$2.50/MMBtu, that plant's marginal cost is \$23.15/MWh. The plant would (under normal circumstances) bid its generation capacity above its minimum load requirements into the PX at no lower than \$23.15/MWH since any lower bid would result in a cash loss.

For every day of the April 1998- July 2000 period, we use the lower heat rate figure (9,259 Btu/kWh) in conjunction with the daily spot gas price to determine the lowest price at which gas could be determining the PX price. For all hours of each day where the PX price is greater than this lower bound gas-fired generation price, gas is assumed to be the marginal resource.[30] Using this methodology, we estimate that gas-fired units were setting the PX price for approximately 58% of the hours during the period April 1998 - July 2000. Figure 11 reports these estimates on a month-by-month basis.

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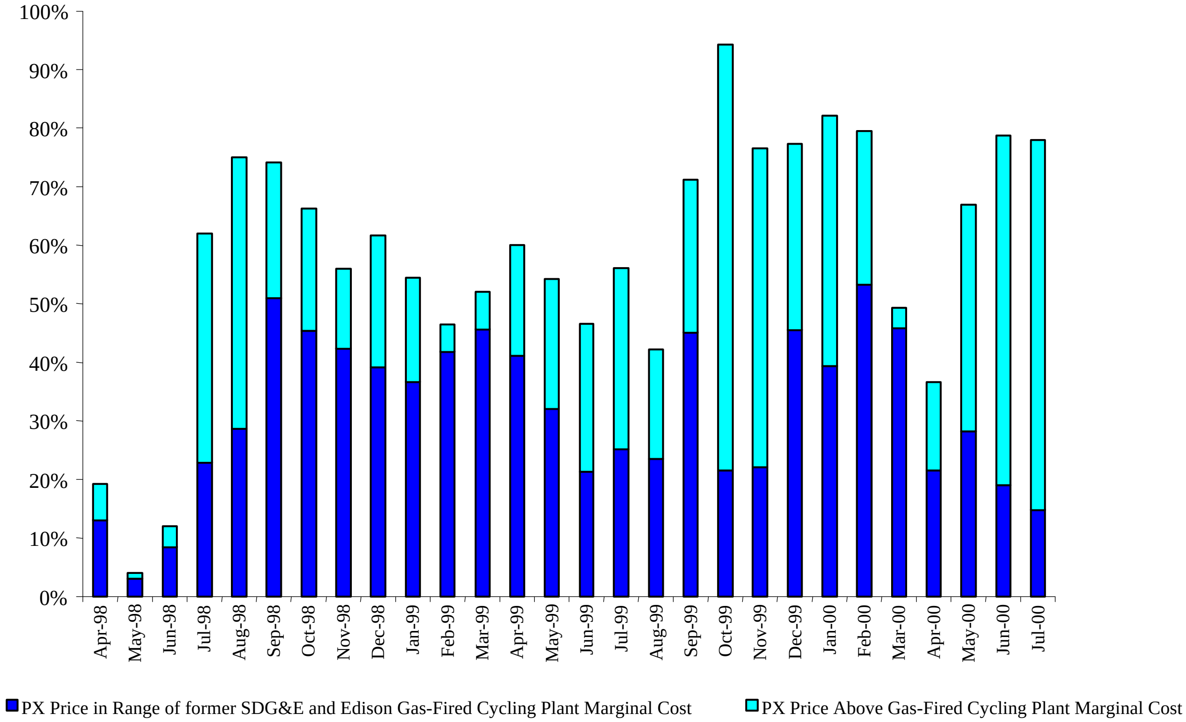
[30] An inspection of the California supply curve in Appendix A indicates that gas-fired units form a long, continuous portion of the supply chain. While it is possible that an out-of-state purchase could occasionally be at the margin above this lower-bound price, the effect is *de minimis*.

FIGURE 11
Estimates of Percent of Time Gas on Margin in the California PX



As stated earlier, there is evidence that generators may be bidding well above marginal cost in some relatively high load – high price hours. While Appendix A demonstrates that economic theory suggests that generators will price at a multiple of marginal cost in such periods, some may argue that marginal cost doesn't enter into generators' bidding strategy at such high prices. Consequently, a second calculation ignores that period entirely. This second, smaller period is comprised of those hours where the PX price falls in the range dictated by the marginal costs of the most efficient (9,259 Btu/kWh) and least efficient (11,300 Btu/kWh) gas-fired generators.[31] The bottom portion of the bars in Figure 11 report the percent of hours in each month that gas is at the margin using this more conservative definition. For the period April 1998 - July 2000, this period represents a still quite significant 31 percent of the hours.

A $0.10/MMBtu increase in the California border gas price increases annual electricity costs to Edison's customers by $34.2 million (*see* Table 6). The annual effect on Edison's PX purchases of an \$0.10/MMBtu increase in the gas price is \$13.1 million. The financial effects in Table 6 were derived as the product of Edison's hourly net purchases from the PX and the change in the PX price, summed across those hours when gas is on the margin using data from the commencement of the PX (April 1998) to the present (July 2000).[32] The financial effect on Edison's customers of higher QF payments is estimated to be \$21.1 million. The effect of \$0.10/MMBtu gas price change on the SRAC transition formula for QF payments was calculated. This effect was then applied to Edison's December 1998 through November 1999 gas-price-sensitive QF purchases to derive the \$21.1 million cost increase.[33]

TABLE 6
Annual Net Impact on Edison of Higher Gas Prices – \$0.10/MMBtu Effect
(\$ millions)

	For Period When PX Price in Range of Gas-Fired Cycling Plant Marginal Cost [1]	**For Period When PX Price Above Gas-Fired Cycling Plant Marginal Cost** [2]	**Total** [3] = [1] + [2]
PX Price Effect	\$5.9	\$ 7.2	\$13.1
QF Payment Increase	N/A	N/A	\$21.1
Total PX & QF Payment Effects			**\$34.2**

Edison shareholders may face financial exposure since higher PX prices and QF payments are not directly passed through to Edison's ratepayers. Under California's restructuring plan, Edison is permitted to recover stranded costs as the difference between the fixed prices at which Edison

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continued

31 Note that these heat rates relate to larger "cycling" units and not to gas-fired peaking units which would have even higher heat rates.

32 Edison's net purchases are assumed to include 917 MW of direct access load during off-peak periods and 1,231 MW during on-peak periods in Edison's gross purchases. While Edison is not required to purchase electricity for these customers, the implications to Edison of a PX price change for these volumes is the same as for its purchases under the rate freeze governing Edison.

resells electricity to end-users and its authorized costs, including the price it pays for electricity from the PX. Therefore, as the price Edison pays for electricity increases, Edison recovers less stranded costs by the end of the transition time period. Thus, both Edison ratepayers and shareholders may be at risk for the $34.2 million per year of higher electricity costs that results from every $0.10/MMBtu increase in the California border natural gas price caused by EPME's exercise of market power.

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continued

[33] While *Brattle* uses a $0.10/MMBtu gas price effect here, the use of a larger figure may make sense (1) as discovery and hearings yield more evidence and (2) if one is attempting to capture the effect of other factors.