ATTACHMENT C

SYSTEM ECONOMIC AND OPERATIONAL CHARACTERIZATION

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INTRODUCTION

1.1 PRIMARY QUESTION - LEVEL OF OPERATION

Pacific Gas and Electric Company (PG&E) has submitted an application to the California Public Utilities Commission (CPUC) for the sale of its geothermal power plant in the Geysers and all but one of its remaining fossil-fueled power plants within California at Pittsburg, Contra Costa, and Potrero. The primary question addressed in this system economic and operational characterization analysis is whether the divested power plants would have a tendency to be operated, maintained or repowered differently under independent ownership than under continued utility ownership. Basically, the analysis examines the economic and operational factors that could create different incentives for the new independent owners versus the utilities.

The analysis concludes that a set of general and plant-specific incentives exist which will tend to cause new owners to operate the divested plants differently than if PG&E continued to own the facilities.[1] In general, the new owners (especially any new owners that do not currently own power plants in the region) would have a strong incentive to operate the more efficient divested fossil-fueled units and/or those strategically located for "direct connect" or "over the fence" sales more than the utilities would operate them if the units were not divested.

How operations at the Geysers geothermal plant could change depends on the traits of the new owners and the specific geothermal fields serving the individual wells. PG&E currently procures steam according to two steam contracts. One contract with UnoCal, NEC, and Thermal Power (UNT) provides steam for the Sonoma County units and PG&E has recently moved to more cyclical operations for those units due to their higher costs of steam supply.[2] The other steam contract is with Calpine for the two Lake County units; the price of the steam is lower and PG&E tends to run them baseload. If the current steam suppliers, UnoCal, NEC, and Thermal Power (UNT), and Calpine, exercise their rights of first refusal and purchase the respective Geysers units, the new owners would have an incentive to operate the plant at a higher capacity factor to

1 Table C-3, at the end of this Attachment, summarizes "Key Facts, Axioms and Commonly Accepted Principles" employed in this analysis.

2 "Cyclical" or "load-following" operation is broadly defined as running a generation unit in a pattern that roughly follows the daily and seasonal electrical system demand, i.e., at highest output levels during daytime peaks, and at lowest or zero output levels during nighttime lows. "Baseload" operation is broadly defined as running a unit at a more or less constant output level, regardless of changes in loads. For most plants the most efficient level is at a maximum design output level.

the extent that localized steam reservoir conditions would permit. As owners, the steam suppliers would face effective steam prices that are well below the off-peak PX prices[3] because they would only have to recover steam production costs rather than the administered prices in the steam supply contracts. If a third party purchases the plant, it would face steam prices similar to those paid by PG&E and an insensitivity to unit-specific steam costs due to the form of steam supply contracts. In that case, the units probably would be operated in a manner similar to how PG&E does today, with some attenuation of cycling operations of the Lake County units caused by higher per kilowatt-hour transaction costs for the new owners based on the recent contract amendment between PG&E and Calpine. In addition, this new operator might consider further unit closures (as would PG&E) to consolidate operations, enhance steam supplies for single units, and reduce overall operating costs.[4]

1.2 BASIC PREMISES

There are three basic premises of this analysis. The first basic premise is that restructuring as directed through legislation and Commission decisions will lead to substantial, fundamental changes in how California's electric utility industry operates. The most dramatic changes may be deferred to the end of the transition period on or before March, 2002. At that point, the investor-owned utilities (IOUs) no longer can recover their stranded asset costs (except for specified nuclear plants and most qualifying facilities contracts). Most generators, particularly those that establish market prices, will have to recover most of their investments through power contracts or open market sales instead of through a separate regulatory-established rate of return. The incentives for choosing new generating or energy management resources and how much to run any resource will be much more responsive to consumer demands than was the case in the past.

The second basic premise is that the overall restructuring process will continue to proceed rapidly. Both the Independent System Operator (ISO) and Power Exchange (PX) are now operational, although not yet with all of the features of a fully-functioning market. This effort is being supervised by a large group of stakeholders representing all facets of investor utilities, consumers, generators, and marketer interests.

The third basic premise is that divestiture, in tandem with other facets of restructuring policies, will benefit ratepayers. Divesting power plants and disbursing them among a group of new owners will increase competition, and better ensure that the goals of restructuring will be achieved. Moving from a monopoly on generation to competition should lower prices and benefit consumers. Nevertheless, saying that divestiture benefits ratepayers is not the same as saying that a particular divestiture proposal should be approved, although it is an important factor in its favor. Other considerations, including environmental impacts of divestiture, will be

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3 During hydroelectric spill periods in the spring and at selected other periods when off-peak prices decline into the single digits, even the plants with the least incremental cost of steam supply would likely curtail production and only operate as necessary to minimize the chances of supply wells clogging.

4 Total PG&E Installed Capacity at the Geysers is 1220 MW, while firm capacity is about one half as large and PG&E has already closed several older units (i.e., Geysers 1 through 4) to marshal steam supplies and reduce operating costs. The remaining PG&E Geysers units are designated as Must Run units and as such could not be closed without ISO approval.

considered by the CPUC in deciding whether to approve the divestiture applications. It is important to note that the CPUC's stated policy objectives have nearly been achieved to date with PG&E divesting 42 percent of its fossil-fueled capacity in the first round.

Conducting any analyses about future events requires some judgment about the likelihood of various courses of action. The proposed action almost always appears more concrete than any alternative because the decisions and milestones are more clearly specified in the proposed action. For example, the expected building and activities related to a proposed office building are more likely to be clearly delineated than other alternatives for a plot of land that is currently vacant. In the case of divestiture, the sale of the plants is the identified action; what PG&E would do if it did not sell the plants is not so clearly defined. Yet through careful consideration, alternative scenarios without the specified action can be constructed and used as a baseline against which the potential impacts can be measured. This approach is the principle used in this analysis.

1.3 UTILITY SYSTEM CHARACTERISTICS

California's utility system has some key characteristics that influence how the restructured industry will operate, and in turn how owners of divested plants might change their operations from those of a large utility owner. The California electricity market has its highest overall loads during the summer air conditioning season, at which time it has large daily load swings created by warm afternoons followed by cool nights.[5] While average electricity rates are 50 percent higher than the national average, some customer-class bills, such as residential, are actually lower than the national average owing to the high penetration of natural-gas appliances and the relatively mild climate.

California's generation resources also are unique. First of all, California is the load center for the Western U.S. This creates the need for a large amount of imports from neighboring states. However, the physical limitations of the transmission network require that a number of in-state power plants must be running at all times to support these imports. As a result, the state's utilities largely import their cheapest power while running expensive plants to maintain system reliability and stability. Second, California has the largest concentration of renewable resources (other than large hydro) in any state, mainly due to a set of qualifying facility (QF) contracts called "Standard Offers" issued in the mid-1980s. In addition, California utilities operate some of the largest hydropower systems in the United States. Large amounts of utility-owned coal-fired power comes from the Rocky Mountain states and nuclear-powered electricity is generated from both in-state and out-of-state locations. Most of these resources are "baseloaded" (i.e., run constantly at their maximum output levels whenever available) and have either low operating

5 This is not true in all areas of California particularly the San Francisco Peninsula. The historic San Francisco peak is in October.

costs or "must-take"[6] contractual provisions. The result is that California must finely balance the desire to lower costs and the need to "keep the lights on."

The power plants proposed for divestiture can be put into three groups:

- The Pittsburg and Contra Costa fossil-fueled plants located on the Sacramento-San Joaquin Rivers Delta;
- The Potrero fossil-fueled plant located in San Francisco; and
- The Geysers geothermal plant.

The Delta plants are the largest being offered for auction. They provide reliability support for the entire Bay Area, and must operate within the air-quality limits imposed by the BAAQMD and the cooling water-use limits imposed by the Regional Water Quality Control Boards. The San Francisco plants (the Potrero plant and the Hunters Point Power Plant, which is not proposed to be sold) are run largely to maintain reliability within the San Francisco "island," and also are limited by BAAQMD air rules. The Geysers plant meets local reliability limits, but its operations are largely controlled by the availability of steam and the provisions in the steam supply contracts. Each of these sets of characteristics are important in assessing how the operations at these plants might change with a transfer of ownership.

1.3.1 FOSSIL-FUELED PLANTS

The fossil-fueled plants are composed of some combination of steam turbine units and combustion turbine (CT) units or a combination of the two called combined cycle units. In steam turbine units, boilers are heated by natural gas and the steam routed through a turbine generator. These units were originally designed to run baseloaded (i.e., in a constant mode) and were constructed before 1978. To operate in load-following manner as these plants do today (i.e., operating in a manner to follow changes in demand), these units must either (1) use a large amount of fuel during daily startup[7] to simply heat the boilers to a level where steam is produced and can be routed to the turbines and electricity generated, or (2) be turned down overnight to a "minimum load" level at which fuel use is relatively inefficient. In either case, the average cost per kilowatt-hour rises substantially when operating to follow load rather than at a constant output level.

The three Potrero CT units, on the other hand, each consist of twin, aero-derivative, combustion turbines that burn distillate oil and produce an exhaust that generates electricity directly. CTs are most valuable for system reliability since they can be turned on and be up to full load and

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[6] Must-take generation is generation that, for a variety of reasons, must be purchased by the local utility. Generally, reasons are contractual – such as the mandatory purchase by utilities of power produced by qualifying facilities (QFs) under PURPA – or because of the nature of the power plant, such as nuclear plants that run at full power 24 hours per day because of physical limits that prevent rapid increases or decreases of power levels.

[7] Typically equivalent to from one to two hours of full load operations.

synchronized to the electric grid in ten minutes or less. Because of high operating costs, CTs tend to be used only at times of peak demand when all other sources of supply are fully employed, during transmission system disturbances or emergencies, or when other units are forced off line. They also serve the role of supplying Black Start Capability.[8] The Potrero CTs serve the special role of increasing the transfer capability of power into the City of San Francisco by serving as a quick start backup. This is especially important in the event a transmission link goes down, which would cause the remaining transmission to overload in the absence of backup units. Because the combustion turbines to be divested tend to have limited emission control and monitoring equipment and burn more polluting distillate fuel oil, their permitted annual hours of operation are restricted to no more than ten percent by regulation of the Bay Area Air Quality Management District, to limit air emissions.

Natural-gas-fired steam boiler units throughout California including those now proposed for divestiture have similar fuel efficiencies distributed over a narrow range. Their efficiencies at maximum output generally lie within about 7 percent of the system average for on-line gas-fired units. In such a case, if a unit can lower its operating costs by a small increment, it can move up substantially earlier in the merit dispatch order; i.e., the unit will be more likely to be selected by the Power Exchange and dispatched by the ISO more frequently because of its lower cost. For example, a 10 percent cost reduction by a relatively expensive gas-fired unit can move it earlier in the merit order by 15,000 megawatts (MW).[9] Thus, if an operator can reduce costs by changing operational mode or reducing the cost of fuel by even a small amount, sales from that unit can rise substantially. This reduction in variable cost of operation could be realized by either the investor-owned utilities, if the facility were retained, or by the new owner if the facility were divested, but the incentive to do so may vary depending upon the portfolio of generation from which the individual plant owner can bid into the PX.

The Pittsburg and Contra Costa plants located on the Delta are operated to meet water quality permit limits imposed by the San Francisco Bay and Central Valley Regional Water Quality Control Boards. The cooling water use and discharge or NPDES permits require that Pittsburg Unit 7 be committed and dispatched in preference to the other Delta units during a period when sensitive fish species are present, usually from May 1 to July 15. Pittsburg Unit 7 has a cooling tower, versus once-through cooling for the other units, which minimizes the potential for losses of endangered and threatened fish species. Only one other unit may be committed until Pittsburg Unit 7 is operating at full load, at which point the remaining units may be added economically unless there are sensitive species present near the units' water intakes. PG&E has preferentially committed Pittsburg Unit 7 within its portfolio to meet this restriction; however, PG&E may not find such action economically beneficial in the restructured market.

The Potrero plant in San Francisco is largely operated to maintain system reliability criteria within the City of San Francisco. The same is true of the Hunters Point Power Plant which is not

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8 Black Start Capability is the ability of a generator to start operations independent of any outside electrical power source. Most generation units require external auxiliary power to start.

9 Sam Lovick, "PG&E Divestiture CEQA Workshop Presentation," (San Francisco, California: London Economics, Inc. June 27, 1997.)

proposed to be sold. The San Francisco Operating Criteria (SFOC) requires that certain combinations of the steam turbine units must be running at all times to ensure reliable service in case of transmission line outages into the city. (The SFOC is described in greater detail in Section 4.12 of the EIR, Utilities and Service Systems.) All of the San Francisco units operate at substantially higher capacity factors than would be the case if they were dispatched solely for economic reasons.

1.3.2 THE GEYSERS GEOTHERMAL PLANT

The remaining plant being proposed for divestiture, the Geysers geothermal plant, is fueled by geothermal steam supplied pursuant to two steam supply contracts. The contract with Calpine obligates PG&E to run Units 13 and 16 (the two units subject to the agreement) baseloaded, while providing for steam that is so inexpensive that PG&E would have an incentive to run them as much as possible without the contractual obligation to do so. The remaining units are all served by the UNT contract, which specifies a steam price that tends to be slightly below the cost of even the most efficient gas fired boiler generation. Thus, these units are cheaper on-peak but are sometimes more expensive than the market off-peak and PG&E has tended to cycle them accordingly. Superimposed upon steam price considerations is the consideration that the output and peak capacity of the Geysers units are limited by declining steam reservoirs. This decline in steam resource availability and other contractual issues have affected operational patterns. Against this background, the nature of the new owners would still have a powerful influence on how the plant would be run in the future.

Since 1960, many electric power generating units have been built on the Geysers Known Geothermal Resource Area (KGRA) to convert steam heat into electrical energy. Several dozen units now operate at the site, and the Geysers now generate more electricity than any other developed geothermal field in the world.

The wells at the Geysers emit among the purest steam of any KGRA. Very little liquid water is mixed with the steam, so Geysers generating units receive steam directly without requiring the usual "flash tanks" to remove condensate before the steam enters the turbines.[10] Also, the steam holds very low concentrations of suspended particulate matter and relatively low concentrations of hydrogen sulfide gas (H_2S). These pollutant concentrations vary significantly depending on the well and location in the field.

Currently, PG&E and several municipal electric utilities purchase or generate Geysers power, including the Northern California Power Agency (NCPA), and the Sacramento Municipal Utility District (SMUD). Two qualifying facilities (QF) developers also generate electricity from the Geysers. The majority of electricity generated at the Geysers flows onto the PG&E power system, from fifteen units supplied by steam wells operated by the UNT and Calpine Corporations.

[10] Steam turbine blades permit only a very low fraction of condensate (liquid water) or they will erode immediately. A flash tank subjects the steam/condensate mixture to an abrupt pressure drop, "flashing" much of the water vapor to steam and separating and removing the remaining condensate.

The Geysers KGRA was once touted as a geothermal baseload resource with a potential of up to 2,400 MW, and boasted 1,984 MW of installed capacity at its peak in 1989. Although all installed units were initially operated as baseload, the projected capacity was never achieved and probably never will be. It is not a "unitary" steam field; i.e., each operator is not "assigned" a percentage of the field to utilize. Instead, the more wells an operator builds, the more the operator is free and able to tap the resource, although the resource is exhaustible.[11] What ensued at the Geysers is what economists call "the tragedy of the commons;" simply, too many wells have been used to tap the KGRA. The steam resource is being unsustainably drawn upon, and the steam pressure from the field has been dropping for many years, currently to as low as 200 pounds per square inch (psi) from a peak of 500 psi. As a result, over 40 percent of installed capacity has been shut down or lost due to reduced steam pressure, and more shutdowns are expected. Another key problem is that it is not economical to pump the steam for more than about a mile from each extraction well due to thermal losses, so only nearby units offer the opportunity for consolidation. In the long term, it is thought that total Geysers dependable capacity may drop to as low as 700 MW. Except in a few cases, it no longer serves as a baseload resource.

Current dependable net capacity totals about 1,200 MW, 690 to 700 MW of which is generated by PG&E-operated units.[12] UNT supplies steam to PG&E Units 5-12, 14, and 17-20, with a combined dependable net capacity of 560 to 570 MW. Calpine supplies Units 13 and 16, with dependable net capacity of 75 MW each, or 150 MW total.

The PG&E Calpine contract calls for a steam price significantly lower than the current price paid for UNT steam which, together with other contract issues, results in a near complete take of available steam by PG&E. Both steam supply contracts share a common property, i.e., they call for PG&E to pay for steam based upon the amount of electrical generation, not pounds of steam utilized. Thus, especially in the case of the higher cost steam from UNT, PG&E has a weaker incentive to optimize steam use than it would have if it had to pay for perfection of continuing steam supply. Were the steam suppliers to assume control of the plant it seems likely that they would more efficiently employ the existing and new steam supplies to best minimize total production costs.

PG&E renegotiated its steam supply contract with UNT in 1992. Every six months, the steam operator (UNT) may open its wells to maximum for five eight-hour periods; the average resulting sustained pressure determines total "field capacity" for the next six months (625 MW on average in 1996, currently 536 to 567 MW). PG&E must accept a minimum of 25 percent of steam field production during any one month, and 40 percent for the entire year; it will otherwise curtail

11 This is consistent with California's groundwater laws in general.

12 Pacific Gas and Electric Company, "Amendments to the Must-Run Agreement between PG&E and the California Independent System Operator and Schedules for Must-Run Facilities," before Federal Energy Regulatory Commission [Washington, D.C.: January 29, 1998], Volume 1B.

generation as it finds cheaper off-peak energy elsewhere, but UNT may discount its steam to match the current price if it so desires.[13]

PG&E and UNT are currently disputing whether PG&E is required to generate at least 110 MW during minimum load conditions.[14]

REMEDIAL ACTIONS TO MAINTAIN STEAM SUPPLIES

Geysers operators have taken various steps since 1989 to stanch or mitigate the continuing drops in steam pressure:[15]

- *Baseload to load-following operation.* PG&E has changed its twelve UNT-supplied units from baseload operation (i.e., maximum operation round the clock) to a mode more closely resembling load-following operation (i.e., running the units more during peak-load periods). This change in operations resulted from a number of factors including limitations in steam supply availability and system economics as natural gas prices have fallen substantially since the inception of the original contract. Along with PG&E's UNT-supplied units, NCPA operates its units in a load-following or cycling mode.[16] PG&E's Calpine-supplied units and SMUD's SMUDGEO plant continue to use basically baseload operations. Note that a change to cycling operations increases maintenance costs, due to the higher variability of operations and/or increased corrosion in the steam wells. Reducing flow from the wells also increases cost of steam supply by accelerating the frequency of required reboring to clear obstructions in the extraction wells.

- *Additional drilling.* Some operators have drilled additional "infill" wells to supplement existing wells, which has had the effect of lowering overall pressure still further as the resource is further tapped. It should be noted that operating at lower pressure reduces overall efficiency of steam conversion to electricity. However, total steam quantity, which is most important for total generation, is maintained through this practice. Calpine in particular has maintained steam supplies for its highest revenue users, SMUDGEO and the Calpine-owned QFs through this technique.

- *Running at lower pressure.* Several turbines, particularly NCPA's and PG&E's Unit 13, have been modified to utilize lower-pressure steam, as low as 50 psi in some cases.

- *Water injection.* Most operators now capture condensed steam from their wells and pump (inject) the water back into the ground to stimulate steam production.

In furtherance of this latter technique of steam replenishment, in November 1997, a consortium of private and public agencies completed a $40- to $48-million pipeline to deliver lake water and treated wastewater from Lake County for injection into the southeastern portion of the KGRA, which geologists believe is the portion most responsive to injection. PG&E and NCPA, the

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[13] Pacific Gas and Electric Co., "Report on the Reasonableness of Operations for 1997 (January 1, 1997 to December 31, 1997)," before California Public Utilities Commission in Energy Cost Adjustment Clause, A.98-04 -, (San Francisco, California, April 1, 1998).

[14] UNT *v.* PG&E, Case No. 218780.

[15] Calpine Corporation et al., *TAC Consortium Progress Report on Implementation of the Coordinated Resource Management Plan for the Geysers* (Santa Rosa, California: Submitted to the California Energy Commission by TAC Consortium Members, September, 1992).

[16] PG&E began cycling operation with the UNT-supplied units in 1994. NCPA began cycling in 1989.

generators in this part of the field, hope that the additional injections will boost their dependable Geysers capacity by as much as 35 MW each. The Lake County pipeline is projected to add between 197 and 657 gigawatt-hours (GWh) per year, with one-third or less going to NCPA. The allocation among suppliers is contractually ambiguous, however.

A second, $100-million pipeline is under consideration by the City of Santa Rosa to inject its own wastewater into portions of the KGRA, which includes PG&E and SMUD units. Santa Rosa is seeking a place to put its wastewater, because of difficulties in discharging into the Russian River. The Santa Rosa pipeline, if approved and constructed, would send 7600 gallons per minute or 45 percent more wastewater to the Geysers than the Lake County pipeline. If the relationship of water injection to steam production is similar, then this project should add 285 to 1,000 GWh over the Lake County pipeline. UNT signed an agreement on April 20 to accept all of the wastewater delivered. UNT would supply the 7 MW of pumping needed for the last portion of the proposed pipeline.

HISTORIC AND FORECASTED GENERATION

A 1992 study forecasted that steam production in the Geysers would decline at a 7 to 9 percent annual rate. However, several key factors have changed since then, including a shift from baseload to cycling operations for a majority of units, and several unit retirements. Estimating the rate of decline in KGRA steam production is a difficult task. The individual well production data are largely confidential, and with three sets of owners, not easily compiled except in aggregate. The changes in operations by PG&E and NCPA also have affected both the apparent steam production rate, and the actual geology of the KGRA. Nevertheless, the decline rate appears to have decelerated dramatically since 1992 due to numerous efforts by both steam suppliers and power generators.

Table C-1 shows historic available and actual generation at the PG&E Geysers units through 1997.[17] "Available" generation is what could have been generated if the entire steam supply from UNT and Calpine had been accepted by PG&E; "actual" is the amount taken after economic curtailments. The annual average decline rate has been steadily decreasing, and over the 1993 to 1997 period, the rate averaged 3 percent per year. The forecasted available generation from 1998 on begins with PG&E's RMRA Contract "B" forecast, continues the annual decline trend[18], and adds PG&E's incremental share of the Lake County wastewater pipeline injection.[19] This serves as an upper bound on what PG&E could generate at its units. Note, however, that PG&E has taken substantially less than what is available since 1995. How PG&E's reduced generation levels have affected future steam production is not known at this

17 Pacific Gas and Electric Co., "Report on the Reasonableness of Operations (January 1, 1992 to December 31, 1992)," before California Public Utilities Commission in Energy Cost Adjustment Clause, A.93-04-011, (San Francisco, California: , April 1, 1993); Pacific Gas and Electric Co., "Report on the Reasonableness of Operations for 1997 (January 1, 1997 to December 31, 1997)," before California Public Utilities Commission in Energy Cost Adjustment Clause, A.98-04 -, (San Francisco, California: Pacific Gas and Electric Co. April 1, 1998).

18 The trend equation is Available GWh = $9279.6*(\text{Year}-1988)^{-0.2059}$. The equation's $R^2 = 0.9833$.

19 We assume the Lake County pipeline adds 197 GWh in the first year and grows at 2 percent per year to reflect wastewater discharge growth over the period.

TABLE C-1
ANNUAL PG&E GEYSERS GEOTHERMAL CAPACITY AND ENERGY

	Available PG&E Generation			Actual PG&E Generation	
Year	MW	GWh	CF	GWh	CF
1988	1,199	9,203	87.6%	9,203	87.6%
1989	1,079	8,053	85.2%	8,053	85.2%
1990	948	7,335	88.3%	7,335	88.3%
1991	902	6,947	87.9%	6,947	87.9%
1992	882	7,007	90.7%	7,007	90.7%
1993	791	6,491	93.7%	6,491	93.7%
1994	761	6,024	90.4%	6,024	90.4%
1995	748	6,080	92.8%	4,002	61.1%
1996	769	5,904	87.6%	4,515	67.0%
1997	712	5,739	92.0%	4,830	77.4%
1998	686	5,607	93.3%		
1999	693	5,666	93.4%		
2000	680	5,565	93.4%		
2001	669	5,474	93.4%		
2002	659	5,392	93.4%		
2003	650	5,316	93.4%		
2004	641	5,246	93.4%		
2005	633	5,181	93.4%		

time. Projecting actual generation requires simulation of California’s electric supply system and is discussed in Attachment G.

1.4 MUST RUN CONTRACTS AND AREA RELIABILITY

Electricity, unlike any other commodity or service, must be supplied in a manner that instantaneously balances with demands and it is not readily storable.[20] These characteristics impose certain physical constraints on the generation and transmission system that limit the ability to use only economic signals in dispatching generation. These rules lead to specific generating units being designated “Must Run” (Reliability Must Run or RMR) in order to prevent: 1) the extreme consequences of an electric service interruption to highly concentrated

[20] Water can be retained behind dams within specified limits .

areas, 2) overloads on generators, 3) transmission facilities overloads, 4) cascading outages, 5) voltage collapse, and total grid blackouts.

The purpose of Reliability Must Run Agreements (RMRAs) between the ISO and specific unit owners is to ensure reliability of service to customers without overpaying. If the owner of an RMR unit failed to operate when the unit was needed, then electrical service would be jeopardized or disrupted. If the owner of a needed unit were allowed to set any price, then ratepayers might be overcharged whenever the unit was needed to maintain reliable service.

All of the units proposed for divestiture by PG&E are currently designated Must Run by the ISO. As discussed below, this designation tends to diminish the differences in operational incentives for the new owners versus PG&E.

1.4.1 MUST RUN DESIGNATIONS

All 27 of the units that PG&E currently proposes to divest have been designated Must Run by the ISO. Designation as an RMR unit by the ISO does not mean that the unit literally must run or operate all the time. A unit that is designated RMR by the ISO may only be needed by the ISO for a few hours each year. It means that the owner must commit to maintaining the unit and to responding on a best efforts basis to a directive from the ISO to operate the unit. All of the units proposed for divestiture are deemed RMRs because they are all required to support either local or area reliability requirements.

The reliability criteria may cover varying regions. The Potrero Power Plant, along with the Hunters Point plant which is not being divested, is required to observe the San Francisco Operating Criteria (SFOC) for minimum levels of commitment and dispatch. Pittsburg Units 1 and 2 are needed to support the 115 kV local distribution system during the summer months. Geysers Units 5 through 8 (a.k.a. North Geysers units) are required to support 115 kV voltage in the Mendocino area and at least two units must operate at all times to support specified voltage conditions.[21] The remaining Geysers units, as well as all of the Bay Area generation slated for divestiture, plus the Oakland and Moss Landing plants already divested,[22] are required to be committed in order to observe the Bay Area Reliability Requirements. This requirement dictates that specific units be committed depending upon the peak daily temperature. More units are required as the temperature rises.[23]

1.4.2 MUST RUN GENERAL CONTRACT TERMS

There are three different versions of the ISO RMRA,[24] "A", "B" and "C". Each version is intended to serve a particular availability niche: economic and needed, uneconomic and often

[21] A transmission upgrade in the Geysers will allow Geysers Unit 11 to be used to meet this requirement in the near future.
[22] Sales agreements have yet to be finalized and possession transferred.
[23] Each of these requirements is specifically spelled out in "Operating Requirements" prepared by PG&E staff and provided to the operations personnel at the ISO.
[24] These are often titled "Master Must Run Agreements" (MMRA) or "Reliability Must Run" (RMR).

needed, and uneconomic and rarely needed. At page 36 of the Executive Summary of the March 31, 1997 ISO Tariff filing with FERC, the RMRA is described as follows.

> *The standard form of Must Run Agreement is a Master Agreement to which three different sets of conditions – A, B and C – can apply. The Master Agreement and the three sets of conditions are included in the filing as Appendix G to the ISO Tariff. Only one set of conditions can apply to a must run unit at one time. The agreement provides that all Reliability Must Run plants will be subject to the predominately market-based approach contained in the A conditions beginning on January 1, 1998.*
>
> *These conditions are in the form of an ancillary services style call contract with no penalties. Under A conditions, the ISO may call upon the Reliability Must Run unit to run up to a maximum number of hours in different months or seasons of the year based upon the ISO's forecast of its Reliability Must Run requirements. When not called upon to run by the ISO for reliability purposes, the owner may bid the unit into the PX or participate in other markets. For those periods when the ISO calls on the unit for reliability reasons, the ISO pays the owner an agreed price per MWh for capacity and energy services rendered. Agreement A conditions permit the owner to retain all revenues from sales of energy through bidding into the PX or under direct contracts.*

The executive summary describes the "B" conditions as follows:

> *Under the B conditions the unit is available to be called upon to run when required for reliability purposes. The owner is paid the fixed costs of the unit as an availability payment and the running costs when the ISO calls on the unit to run. The owner is allowed to bid the unit into the PX or other markets when not called upon by the ISO, but bids submitted to the PX are subject to a floor. If the bid is successful and the units are run in merit order, the difference between the market clearing price and the running costs is credited back to the availability payment.*

The executive summary describes the "C" conditions as follows:

> *Under the C conditions, the unit is available to the ISO to be called upon when required to run for reliability purposes. The owner is paid the fixed costs of the unit as an availability payment and the running costs when the ISO calls on the unit to run. The owner is not allowed to bid the unit into the PX or any other market, however.*

Many of the terms of the different sets of conditions are similar. Some of the more important terms are discussed below. Designation as an RMR unit is not permanent. The ISO can cancel an RMRA on ninety days notice. The owner, however, has no such right. Any unit designated as Must Run by the ISO must enter into an RMRA.

Under "A" and "B" conditions, unless dispatched by the ISO, the RMR unit is under the control of its owner. If owned by PG&E, the RMR unit must be bid into the PX until the end of the transition period. After the transition period, if PG&E still owns the RMR unit, PG&E may bid into the PX, enter into bilateral or multilateral sales, or engage in direct sales. The new owner of a divested unit may bid into the PX, make bilateral or multilateral sales or engage in direct sales.

Under the "A" and "B" conditions, the owner of an RMR unit may run the unit to its permitted maximum technical limits if the owner so desires. The contract with the ISO allows the ISO to direct the owner of an RMR unit to generate under certain conditions. The "A" and "B" conditions of the RMRA in no way allow the ISO to stop generation.

1.4.3 RELIABILITY MUST RUN UNIT OBLIGATIONS

The owner of an RMR unit is contractually obligated to fuel, operate, and maintain the units in accordance with good industry practice. The owner is required to notify the ISO of each forced outage, its expected duration, and when the unit is again available to generate electricity. The owner is required to perform routine and overhaul maintenance at times mutually agreed to by both the operator and the ISO.

When called upon, the owner must generate up to the maximum hourly commitment of the unit. The ISO can direct that the unit generate less than its maximum, but not less than its minimum, capability. For example, the ISO might direct a unit with a maximum of 200 MW and a minimum of 50 MW to generate 100 MW. In this example, under the A and B conditions, the owner could elect to generate up to the full 200 MW but the ISO would only pay for the first 100 MW and the owner would have to sell the remainder through the PX or through direct access if the owner is not PG&E or if it is after the CTC recovery period.

The ISO can only dispatch an RMR unit up to its maximum monthly generation commitment. These specified amounts under RMRA "A" are typically less than under RMRA "B" or "C". The maximum monthly generation commitment is a contractual number and does not necessarily reflect a technical maximum. The ISO is also limited in the number of annual startups that can be required of any Must Run unit. The ISO is further obligated to honor unit generator constraints such as ramp-up time, minimum run time and all other operating constraints such as the fish preservation requirements at the Delta plants. The ISO also agrees to honor any existing contractual constraints on the operation of an RMR unit.

If an owner fails to respond to a dispatch order from the ISO and does not generate the requested electricity, then the consequences stated in the proposed contracts for RMR units are: 1) no payment for missing generation, 2) requested energy amounts do not count against the maximum monthly generation commitment, and 3) if the unit started but failed to deliver, then it does not count against the maximum annual startups for the unit.

2.1 QUALITATIVE RESTRUCTURING BASELINE

This baseline analysis attempts to characterize how PG&E, as the existing investor-owned utility owner of the resources proposed for divestiture, would likely operate these plants under restructuring. The analysis focuses on the different incentives that exist in the transition and post-transition periods, and how these incentives affect both market performance and PG&E's behavior.

The analysis presented here relies, to the extent possible, on observations of how the nascent trading system is operating and, where not apparent from current ISO/PX operations, on assumptions that are conservative with respect to potential environmental impacts resulting from divestiture under a restructured regulatory regime, i.e., so as not to underestimate the possible operational changes by a new owner. Policy directives and critical dates spelled out in CPUC's *Preferred Policy Decision* and AB 1890 were used. For example, market valuation of all generation resources is assumed to occur by the December 31, 2001 deadline mandated in AB 1890. Where no guidance was given or no supporting documentation existed, the analysis assumed that the *status quo* would continue into the future to the extent that it is not changed explicitly by restructuring. An important difference in this divestiture proceeding from the initial round of sales by PG&E and Southern California Edison Co. (Edison) is that these sales are less needed to meet the CPUC's policy objectives.[25]

2.2 MARKET BIDDING AND PRICING ALTERNATIVES

The market clearing price, as reflected in the PX and the ancillary services markets managed by the ISO,[26] is likely to follow one of two paths in the future. On the first path, as described by witnesses for PG&E and Southern California Edison in the first round of divestiture, bidding behavior would follow the least incremental cost dispatch criteria used by the utilities before restructuring.[27] In this future, plant operators would only bid their incremental fuel costs for each hour to best ensure that the plant wins the auction and sells power in that hour. However, to achieve this type of pricing behavior, at least two conditions are necessary: (1) that there be ample generation supply in excess of demand, and (2) that generators are able to enter the market, both in the short-term and long-term, at little or no cost. As Dr. Joskow noted elsewhere, the electricity markets fail to meet these conditions because (1) transmission and physical plant investment limit generation availability, particularly during peak loads, and (2) start-up fuel and cycling-duty costs are significant in the short-term, and investment risks are large in the long-term.[28]

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[25] PG&E divested 41 percent of its fossil-fueled generation in the first round but is still owner of the state's largest hydroelectric system, the Diablo Canyon Nuclear plant, as well as the geothermal and fossil-fueled generation proposed for divestiture during this phase.

[26] The ISO support services or 'ancillary' services will include automatic generation control (needed to balance generation with demand for generation), spinning reserve (synchronized generating capacity that is not online but immediately available), non-spinning reserve (generating capacity with less than 10 minutes of response time), and replacement reserve (generating capacity available within 60 minutes). They will be provided through a competitive market where market participants will make bids through the PX for the necessary reserves that are required by the ISO. Other ancillary services that the ISO will provide include reactive power (to maintain system voltage), and generation black start (to provide for recovery during a major outage).

[27] Sam Lovick, "Impact of divestiture on plant operation," by London Economics before California Public Utilities Commission in Application of Pacific Gas and Electric Company for Authorization to Sell Certain Generating Plants and Related Assets Pursuant to Public Utilities Code Section 851 (U 39 E), A.96-11-020, (San Francisco, California: Pacific Gas and Electric Company, 1997); Paul L. Joskow, "Affidavit of Paul L. Joskow," before California Public Utilities Commission in Application of Southern California Edison Company (U-338-E) for Authority to Sell Gas-Fired Electrical Generating Facilities, A.96-11-046, (San Francisco, California: Southern California Edison Company, 1997).

[28] Paul L. Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives* 11, no. 3 (1997): 119-138.

On the second path, the bidders would adjust their bids to reflect the responsiveness of the market to increasing prices and to account for how operating costs in any one hour are directly linked to operating costs and levels in both previous and subsequent hours.[29] In this second future, operators would bid above incremental costs during higher load hours to recover fixed and start up costs incurred during low-load periods, and could even underbid incremental costs during low-load periods to avoid excessive cycling.

In the large-scale deregulation effort in England and Wales, the plant operators initially used marginal costs as the basis for their bids, but moved to a strategic bidding approach within a year.[30] The strategies varied depending on the characteristics of the owners and the resources controlled. For example, a large portfolio owner controlling fossil-fueled plants bid above marginal costs, while another controlling nuclear plants bid below marginal costs. A recent study of deregulating the Australian market expects similar strategic bidding to occur.[31]

The differences between these two futures have important implications. If bidding continues to simply reflect incremental costs, the market clearing price differential between on and off-peak periods will be much smaller than if bidders adjust their bids to reflect the differences in demand characteristics between the two periods. The latter pricing behavior will tend to reward cycling operations and system support to a greater extent than the former. It also could lead to higher overall bulk power costs because the higher prices would occur during the period of greatest generation, and inframarginal[32] units would earn greater net revenues while little changing their own operations and costs.

To date, the PX market price has plunged as low as zero during several late night hours. Of course, a large proportion of the fossil-fueled plants are removed from the PX market during these periods either through the RMRA or "must take" contractual provisions. Those gas-fired units that are "must run," which are virtually all of the units running during this period, are being paid start-up fuel costs to be brought back on-line each day. For this reason, these unit owners need not bid sufficient amounts into the PX to recover their full operational costs. The result is that PX prices are depressed, but all of the costs that would have been recovered through PX revenues have been shifted to the ISO. As the ISO approaches the limits on start ups for each unit, and assuming little or no FERC relief on this matter, the ISO will then have to pay the RMR units to operate overnight. In this case, the late-night PX prices are likely to be depressed even further, with more hours approaching a zero price.

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29 Joel B. Klein, *Interim Staff Market Clearing Price Forecast For the California Energy Market: Forecast Methodology and Analytical Issues* (Sacramento, California: California Energy Commission, Electricity Analysis Office, Energy Information and Analysis Division, December 11,1997).

30 Australian Bureau of Agricultural and Resource Economics, *Strategic behavior in the national electricity market* (Canberra, Australia: Prepared for Australian Competition and Consumers Commission, 1997).

31 Ibid.

32 "Inframarginal" means that the plants have operating costs below the market clearing price and therefore their operations are insensitive to how the market clearing price might change.

2.3 TRANSITION VS. POST-TRANSITION PERIODS

The effects of the restructuring reforms are being phased in during a mandated "transition period." [33] The measures implemented during this transition period, particularly including the competitive transition charges (CTCs) being imposed upon essentially all sales, and the simple inertia of existing plant and operating procedures, will act to moderate any changes in operations.

Due to the large surplus of existing generating capacity relative to demand in the western U.S., in the absence of restructuring, it is improbable that much new net capacity to serve California would be added during the transition period in the baseline.[34] Without divestiture, new firms would be further discouraged from entering the market and the IOUs would continue to be the dominant players in the generation market, while holding the lion's share of existing dispatchable capacity.

Several new plants have been announced to come on-line during the transition period, in spite of having to factor in the CTC on direct sales to existing customers and the relatively low PX price. One plant is already under construction near Boulder City, Nevada,[35] and applications for nearly 2,000 MW of generation have been recently filed before the CEC.

The bidding and dispatch rules contemplated for the PX and ISO, combined with the investment subsidy provided through the CTC, would, without divestiture, create economic incentives during the transition period for PG&E that would be little different from the dispatch rules used by the utilities before restructuring. Through the transition period, the IOUs are expected to bid only their short-run marginal costs into the PX, with no added margin of investment return, as is done today with the IOU-owned resources.[36] The CTCs will extend the existing "two-part" tariff revenue-recovery mechanism by providing a "fixed" portion of generation revenue based on the book value for IOU plants (equivalent to return on rate base), and an "operational" portion from PX revenues. Since the IOUs derive most if not all of their profits from this fixed portion, they will choose a mix of resources that will minimize their overall costs while observing required reliability standards and procedures. As a result, without divestiture, the generation patterns at least through the end of the CTC recovery period (no later than March 2002) could be quite similar to what would have occurred under today's operating regime.[37]

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[33] The CTC officially ends for a given IOU the earlier of March 31 2002 or three month after full collection of CPUC adopted CTC for that IOU. There are public assessments suggesting that PG&E will be able to complete CTC collection prior to the maximum permitted end date particularly if the divestiture sales continue to collect a premium on book value.

[34] However, local conditions, such as those in San Francisco and San Diego may dictate capacity additions sooner than 2002.

[35] The ENOVA-Houston Gas Company jointly owned combined cycle, gas fired generation plant.

[36] For example, FERC Docket Nos. EC#96-10-001 and ER#96-1663-001, *Transmittal Letter to the Phase II Filing of the Trustee for the California ISO Corp. and the California PX Corp.*, March 31, 1997.

[37] See, for example.: Rajat Deb, Richard Alpert, Hsue Lie-Long, *Modeling Competitive Energy Market in California: Analysis of Restructuring*, Draft, Los Altos California, prepared for California Energy Commission by LCG Consulting, October 3, 1996; and Marvin Feldman, (Resource Decisions) and Richard McCann, (M.Cubed), *The Effects of California Electricity Market Restructuring on Emerging Technologies*. Final Report, (San Francisco, California: Submitted to California Energy Commission Research Development and Demonstration Office, August 18, 1995.)

If the PG&E plants did not go through the divestiture process, the CPUC would determine their total outstanding asset value. These plants would then receive revenues from the PX. These revenues would cover total operating costs first; the remainder would be credited against the total remaining investment in plants excluding the CTC portion. The remainder would be the "stranded asset" amount that would be rolled into the CTC, which would "float" with the difference between the sales revenue reflecting the transition period rate ceiling and all of the other revenue requirements including the varying PX revenues. Because the IOUs are not permitted to raise rates for their customers during the CTC recovery period and are limited in how much PX margin they can credit to their CTC account (undepreciated book value of generation plus operating cost until they recover all of their stranded assets or through 2001, whichever comes first), its appears that PG&E has little incentive to bid above its marginal operating costs as long as it believes that the full CTC period provides it sufficient opportunity to recover its full CTC. To the degree it believes that the full recovery is in jeopardy and/or a commercial advantage can be gained by terminating the CTC recovery period early, it would have an incentive to bid more in hopes of increasing immediate margin.

Only utility fossil plants deemed necessary for reliability purposes have any incentive to earn revenues above operating and maintenance costs. However, because the RMRAs are specifically enforced by the ISO when the needed units are <u>not</u> selling to the PX, or if these units could exercise local market power, PG&E would have little incentive to bid above any unit's marginal operating costs during this period.

Thus, with the temporary exception of payment after RMRA start-up provisions are exhausted, the utilities have essentially the same opportunity of recovering their investment either from the PX or the CTC during the transition period. If the divested plants were not sold or "market valued" through the bidding process, they would be valued in the same manner as the remainder of the IOUs' generating systems within the transition period.

If the plants proposed for divestiture are not sold, they will have a "market value" determined by the CPUC either through an appraisal or an auction bid if such is deemed appropriate. The IOUs would then receive a CTC valuation for each plant based on the difference between the undepreciated book value and the market value. Thus, the divested plants receive a "fixed" CTC through 2001 (i.e., a single lump-sum award), versus the "floating" CTC for plants not going through the divestiture process (i.e., a payment that is determined annually after the fact and varies with actual PX prices). The IOUs will then need to recover the remaining "market value" of these plants exclusively from the PX revenues. The IOUs will want to maximize their PX revenues to maximize net generation revenues.[38] Depending on the magnitude of the market value, the IOUs will have a greater incentive to bid above operational marginal costs to recover the "market value" and to keep shareholders whole than during the transition period when any added profit would be first credited toward the CTC before shareholders saw any additional

[38] We are ignoring the issue of how this difference in the bidding strategies affects the floating CTC paid to other plants. Including additional plants requires that the IOUs optimize across both their CTC and net PX revenues.

return. Under Section 377 of AB 1890, after 2001 the IOUs may sell these plants without CPUC approval after the plants have been market-valued.

In the post-transition period, both the IOUs and the new entrants to California's power market will have to recover their generation investments directly from sales revenue.[39] Generators will bid electricity prices to the PX at rates that recover their investments as well as their operating costs, as opposed to the current practice of considering only short-run marginal costs in the dispatch rules.

HOW OWNERSHIP INFLUENCES OPERATIONAL AND INVESTMENT DECISIONS

3.1 INTRODUCTION

The PG&E plants currently proposed for divestiture operate in diverse ways. The fossil-fueled plants proposed for divestiture serve to follow load because they are some of the higher cost - sources of dispatchable generation. While the units of the Delta plants follow overall system load, the Potrero units follow and support San Francisco load almost entirely.[40] The Delta plants tend to operate most during weekdays, helping to meet the daily peak. They currently run at relatively low levels and have the potential for significant increases in generation. All of these capacity factors vary substantially and range from some of the highest to some of the lowest of PG&E gas units. All of these units are capable of increasing their capacity factors substantially.

The combustion turbine units located exclusively in San Francisco are fired by diesel fuel so they are some of the most expensive units to operate in California, being even more expensive than the state's other CTs which are generally fueled by natural gas. The San Francisco CTs run a few percent of the time and could increase their level of generation only up to a ten percent maximum level of operations as specified by the BAAQMD. The Geysers geothermal units historically operated as baseloaded. However, the decline in the steam resources and revisions in the Unocal-NEC-Thermal Power (UNT) steam supply contract have led to cycling operation to follow loads since 1994 for all but two of the units (Units 13 and 16 supplied by Calpine).[41] The Calpine-supplied units are currently run as baseloaded due to a lower-priced steam contract, but a recent settlement allows a new owner (but not PG&E) to operate in a cycling mode as well. However, the proposed steam price is below the current PX off-peak price, from which we infer that there would likely be little change in their operations.

[39] There are exceptions to this rule: (1) plants necessary for system reliability and other services which will have contracts with the ISO; (2) utility plants which could still be regulated under performance-based ratemaking (PBR) or other special agreements such as nuclear power facilities; and (3) QFs. However, for even these facilities, a certain portion of their revenues will likely be tied to the power market and their operations will affect the revenues of other facilities.

[40] See Attachment G for a quantitative examination of this point.

[41] Calpine Corporation et al., *TAC Consortium Progress Report on Implementation of the Coordinated Resource Management Plan for the Geysers* (Santa Rosa, California: Submitted to the California Energy Commission by TAC Consortium Members, September, 1992).

This section provides a theoretical analysis of the likely operation of the divested power plants under new ownership, particularly if the plants were to be purchased by entities without considerable interests in other electricity-generating resources in the region or the state. The analysis focuses on potential individual plant, unit-specific impacts, but it does address the most important system wide effects, such as changed generation at other plants. This analysis does not quantify the expected change in operations at the divested power plants. The economic and operational analysis only answers the question of whether divested power plants would have a tendency to operate differently than PG&E would if PG&E retained the plants.

3.1.1 BIDDERS' CHARACTERISTICS FROM INITIAL DIVESTITURE ROUND

A key issue in assessing the potential environmental impacts of divestiture is determining if the plants might operate differently under new ownership than under continuing investor-owned utility (IOU) control. One part of making this assessment is examining the differences in financial and structural characteristics of the new owners. For example in California, qualifying facilities (QFs) that use natural gas for fuel rarely operate in a load-following mode, and attempts by the utilities to induce such operations have not been successful to date. While this example may not be parallel, it does illustrate how two different sets of firms can have different operational approaches for meeting their financial goals.

In the first round of divestitures by PG&E and Edison, we did not have information on the firms which might bid for these plants; in the second round we now know, at least, about the six successful bidders from the first round of divestiture. We can use this information to make comparisons among this group of potential bidders and the IOUs. At the moment, the available sample of potential bidders for the fossil-fueled plants is represented by the six successful bidders from the first round.

The new owners can be separated into two distinct groups from a financial and resource ownership standpoint:

(1) The parent companies of Duke Energy (Duke Power), Houston Industries and NRG (Northern State Power or NSP) are large utility holding companies that control large utility generation plant portfolios in their service areas. In addition, Duke and Houston control large natural gas pipeline and distribution companies located primarily in the southern U.S. These three companies have financial characteristics generally similar to those of PG&E or Edison with comparable or better bond ratings, price-to-earnings (P/E) ratios and debt-to-equity ratios. While their new generation plants are isolated from their existing portfolios, these firms can be expected to make plant investment decisions that would be similar to those that might be made by PG&E.

(2) NGC (now Dynegy and parent of Destec), AES and Thermo Electron (parent of Thermo Ecotek) are merchant and cogeneration power plant developers that appear to be aggressively entering the restructured utility industry. Dynegy is perhaps better known as a natural gas supply company with the fourth-largest holdings of reserves in the U.S. AES (Applied Energy Systems) is a pioneer in the independent power industry. Dynegy and

AES each own about 5,000 MW in the U.S. beyond the divested plants in California. AES owns another 13,000 MW internationally. Thermo Electron has been more oriented to the international market with 95 percent of its 11,000 MW outside the U.S. These companies have substantially higher profit/earnings ratios than either the first group or the California utilities.[42] This characteristic typically reflects companies with higher expected profit growth rates. AES also is substantially leveraged with a 70 percent debt-to-equity ratio, suggesting more risk. Dynegy and Thermo Electron have debt structures similar to the first group.

A comparison of bond ratings for each firm is instructive in measuring the market's assessment for each of these firms. The market clearly views the second group of companies as greater risks than either the first group or PG&E. To compensate for this risk, investors will demand a higher rate of return on investment from these firms. In turn, these firms will use a higher discount or investment "hurdle" rate in choosing investments. As a result, these firms will have to tolerate greater risk in their investments in exchange for higher potential investment returns than would PG&E.

As a bidder, Dynegy presents a second important distinguishing characteristic from PG&E. Dynegy has large natural gas production capability and controls a large number of gas contracts. Dynegy markets about 8 billion cubic feet per day (bcf/d) of natural gas. In comparison, PG&E delivers about 2.2 bcf/d.[43] Perhaps more important, Dynegy has firm transportation contracts for 1.3 bcf/d on the El Paso Pipeline. Southern California Gas Co. is the next largest holder of firm capacity with 1.18 bcf/d. By controlling large gas reserves and substantial firm transportation capacity, Dynegy (or a similarly situated firm such as Enron) would face low opportunity costs for burning natural gas in its newly acquired plants. In other words, the natural gas costs for such a firm are probably well below the spot price for gas seen in the marketplace. In such a case, the firm would not find it profitable to trade off generation against the gas market price.

We can draw three conclusions about the potential bidders for PG&E's fossil-fueled plants:

(1) Some of the more serious bidders will likely fall into one of two categories: either large utility holding companies with similar characteristics to PG&E, or merchant plant developers which may possess large natural gas reserves or pipelines. The first group will have more experience and infrastructure for participating in California's power market. As a result, their transaction costs would be lower.

(2) The merchant plant developers would require higher investment returns from their acquired power plants to satisfy their shareholders, and increasing the production from acquired units is one approach to increasing the rate of return from their power plant investments.

(3) A bidder with large natural gas holding and transportation capacity would face lower costs for gas than the market spot price. This would provide incentives for them to burn more gas and generate more power in their plant.

[42] As of December 31, 1997.
[43] Within California.

3.1.2 DIFFERING INCENTIVES

Divestiture is primarily the transfer of ownership of electrical generating plants from the IOUs to currently unidentified buyers. A number of factors could motivate changes in operations and planned investment as a result of new ownership, both in timing and amount.

In the long term, the new owners of the divested plants will have to ensure a level of net revenues above operating costs to recover the investment incurred by purchasing the divested plants. During the transition period, the IOUs will be able to recover much of their existing “sunk” investment through the non-bypassable CTC, and accelerate the depreciation on these plants to ensure full recovery by 2002. The new owners will probably have a larger investment exposure created through the plant purchase, and will need to recover their investments over a longer period, which will likely be based on each plant’s remaining economic life, rather than the accounting basis now used by the utilities. For new owners, these costs are not “sunk,” but rather are “opportunity” costs represented by the value at which the plants could be resold and the proceeds invested elsewhere. This means that the new owners may bid different prices and quantities than the IOUs might have with the same facilities.

In contrast to these differing ownership incentives, those units that are designated must-run by the ISO and enter into an RMRA Contract C with the ISO will most likely operate the same under either new or utility ownership. RMRA Contracts A and B will also tend to reduce the difference in generation between restructuring without divestiture and restructuring with divestiture, although the actual effects are unknown, they are likely to be substantially less than from Contract C. All of the plants proposed for divestiture currently possess RMRA contracts from the ISO and at this point each of these is class “B”.

FOSSIL-FUELED PLANTS

The analysis conducted for this report indicates that there are three factors that could provide the new owners with incentives to operate the divested fossil-fueled power plants, particularly the more efficient ones, differently than the utilities would operate them: (1) size and nature of the portfolios, (2) gas contracting practices, and (3) selling to the direct access market.

GEOTHERMAL PLANT

Two sets of steam suppliers possess a “right of first refusal” in the sale of the Geysers. Unocal, NEC and Thermal Power which is now wholly owned by Calpine operate as an undivided partnership, called UNT, in providing steam to PG&E. Calpine also sells steam to the two remaining PG&E units pursuant to a separate agreement. Unocal is primarily a large oil and gas production, refining and retailing company, which also has developed geothermal plants internationally. NEC is a Japanese turbine producer that manufactured some of the turbines used in the PG&E Geysers plant. Calpine is a merchant plant developer with several smaller QF geothermal facilities located in the Geysers, and gas-fired plants located throughout the U.S.

How the new owners might operate the Geysers plant depends on whether the new owners are the existing steam suppliers, or a third party. A third party would face many of the same incentives as PG&E. The steam price would be established through the existing or proposed contracts, and the new owners would work with the steam suppliers to maintain the Geysers steam resource. The UNT price is sufficiently high that the new owners would continue to cycle those units to maximize the net revenues. The difference in the degree of cycling would be dependent on the relative transaction costs of participating in the PX, ISO, and direct access markets with a smaller generation portfolio. Although the contract that the new owner would assume permits cycling, little or no difference from the current baseload operation would be expected for Geysers 13 and 16 due to the low cost of the steam supply contract with Calpine.

The steam suppliers would face much different incentives if they were to acquire the Geysers units. They would base their bidding decisions on the true cost of steam production, which is lower than the contractual steam price, assuming that the contract affords the steam suppliers a profit. Thus, one would expect higher levels of operation at the various units depending upon local steam reservoir conditions. Also, the steam suppliers would no longer have to split the benefits of field development with PG&E or another generation owner. The greater total returns could encourage more field development and greater efforts to prevent steam field decline. If that occurred, the result would be greater displacement of fossil-fuel generation by geothermal in the near term and, perhaps, greater overall steam production, although generation likely would be lower in later years.

The experiences of NCPA and Calpine in the Geysers are instructive. NCPA, a joint powers agency of California municipal utilities, has an interconnection agreement with PG&E under which it is charged a relatively large amount for capacity sold by PG&E during the peak periods. As a result, NCPA has a strong incentive to maintain the capacity of its Geysers plants. NCPA is both the steam field and generation plant operator. NCPA began cycling operation in 1988 to maintain full capacity when the steam resource decline became evident,[44] and has maintained total name plate rating through steam drilling and production.[45]

Calpine operates about 80 MW of QF geothermal power in the Geysers as well. These plants have either Standard Offer Number 2 (SO2) or Interim Standard Offer Number 4 (ISO4) contracts. These contracts have afforded capacity and energy payments well above bulk-power market prices. These payments have given Calpine a strong incentive to maintain the steam supply for these plants, often averaging above 90 percent of the nameplate capacity. Since Calpine operates both the wells and plants in this case, it retains 100 percent of the benefits from developing the fields. On the other hand, the PG&E units with steam supplied by Calpine now operate at 56 to 66 percent of nameplate capacity, and their output continues to decline.

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44 Calpine, et al (1992).
45 Gregory Bazelyansky, *NCPA GEO actual generation-1993-97 (CSC @ Backbone)* (Santa Clara, California: Silicon Valley Power, City of Santa Clara, May 15, 1998).

Calpine also has purchased the 72 MW SMUDGEO plant from the Sacramento Municipal Utility District for $13 million.[46] The SMUDGEO steam price is above that paid by PG&E to UNT and SMUD projects savings of $30 to $50 million over 10 years from the sale even though it has agreed to buy the output of the plant. Calpine, by integrating supply and generation, estimates that it can realize substantial profits. The offer of $180 per kilowatt is within the range of the accepted bids in the first round of divestitures by PG&E and Edison.[47]

3.2 CAUSAL FACTORS

3.2.1 PORTFOLIO EFFECTS

The difference in behavior between the owner of a mix of power plants and the owner of a single power plant or just a few plants is the portfolio effect. PG&E owns a portfolio of power plants, which is a combination of hydroelectric, nuclear, geothermal, gas and oil-fired units. Table C-2 shows the capacity by fuel source owned or controlled by PG&E.[48] The new owners may have a portfolio of plants in the California market, although this cannot currently be known. However, a newly-created portfolio cannot possibly have the diversity of resources, nor size, available to PG&E if PG&E were to retain the plants. With more than 11,400 MW, PG&E controls almost three-fold more capacity than any of the new owners of the recently divested plants, or what is being offered in this round of divestiture.

Given the incentives discussed here, independent owners of single power plants would tend to operate their plants at a constant, efficient rate in order to minimize costs and maximize profits, while PG&E would cycle the plants if it were to retain them to maximize profits across all the plants.

THE UTILITY'S MIX OF POWER PLANTS

PG&E has lower-cost resources available to meet loads before turning on higher-cost plants to produce revenues. PG&E has hydro, geothermal and nuclear units which it will not curtail to allow a gas-fired unit to operate. In fact, the hydro and nuclear units and Geysers Units 13 and 16 are often operated in a constant or baseloaded mode. PG&E could not operate the gas-fired plants as intensively as an independent single plant owner because PG&E owns a large portfolio of plants and would run its more efficient plants first, and there would be insufficient load demand to run all of its plants at maximum load. Electricity is different from all other products in that demand must be present to allow generation; it cannot be stored for later use. The independent owner would not be constrained by overall system load behavior.

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46 Carrie Peyton, "SMUD to sell steam plant," *Sacramento Bee*, May 22 1998, B-1.
47 PG&E's plants are not likely to fetch prices as high since the SMUDGEO plant is about twenty percent more efficient than the standard Geysers design and the plant is of very recent vintage.
48 PG&E, Data Response ED-01, Q 45, March 11, 1998.

TABLE C-2
PG&E'S POST PHASE I DIVESTITURE GENERATION PLANT PORTFOLIO[a]

Type of Plant	Capacity (MW)
Fossil Steam Turbines	3,394 [b]
Fossil Combustion Turbines	253
Nuclear	2,160
Geothermal	686 [c]
Hydropower-Owned	3,910
Hydropower-Controlled	1,043 [d]
Total Portfolio	11,446

Notes:
a Assuming that the sale to Duke Energy is completed.
b Includes Gerber combined cycle cogeneration
c Available capacity, nameplate = 1,224 MW
d Hydro resources under PG&E's daily or hourly dispatch control and/or under contract.

In addition, the mix of cycling and baseloaded resources provides a larger amount of generation over which to spread the start up, cycling, and market-participation (or transaction) costs incurred by the fossil-fueled plants, which are the primary focus of divestiture. PG&E is now able to spread the costs for 3,394 MW of fossil-fueled plants over 11,446 MW of generation, thus reducing the per kilowatt-hour cost by at least two-thirds relative to a new owner who only possesses gas-fired plants.[49] As a result, PG&E does not place substantial weight on these costs because they are relatively small per unit for the entire portfolio.

Choices Facing Single Power Plant Operator

Under restructuring, a single power plant operator can choose to operate continuously at the most efficient operating level of the power plant, or to cycle the plant. To cycle a power plant is to raise and lower the output of the plant in response to market conditions. An extreme case of cycling would be to shut the plant down and produce no electricity for an extended period of time.

The basic choice facing the new independent owners of one of the more efficient plants to be divested would be whether to operate the plant in the load-following mode in which the plants are currently operating or, in the case of the more efficient units, to operate in a more constant

49 The per kilowatt-hour reduction is actually greater because most of the non-fossil generation operates at a higher average capacity factor than the fossil-fueled plants.

mode closer to their maximum capacity. PG&E has little economic choice. There is insufficient demand to justify or permit running *all* of its plants steadily at their maximum capacities. PG&E must run its lower-cost plants and idle its gas-fired units when low demand requires curtailments, or shareholders would question such unnecessary higher fuel costs.

Most of California's gas-fired units have nearly identical fuel-use characteristics, and these units will set the PX price 70 percent to 90 percent of the time.[50] As a result, a particular plant can substantially increase generation with quite small decrements in plant costs and bidding strategies.

A single-plant owner will probably shut its power plant off during the low-load spring-runoff period in the spring unless required for local reliability purposes.[51] The combination of low loads due to mild weather and abundant hydro output due to the spring runoff produces the lowest prices for electricity during the year. At these times, it is a profitable strategy to shut off a gas-fired power plant and fill any obligations to deliver electricity with purchases from lower cost producers.

During the remaining 70-percent-plus hours of an average hydro year, gas-fired power plants would be presumed to be operating. A new independent owner of a divested power plant could be in a position to operate continuously during those hours of the year. Alternatively, the new owner could cycle its plant whenever purchasing from the PX would increase its profits. However, cycling power plants and purchasing from the PX is not without its costs. These costs are significant and would tend to discourage cycling by new owners except during the very low-cost spring-runoff period.

As discussed previously in Section 2.2, the market price is likely to follow one of two courses:

(1) The market-clearing price will reflect only the incremental cost of fuel use during all but a few peak-load hours a year, or

(2) The on-peak price will rise sufficiently to recover fixed and cycling costs, and off-peak prices will fall to discourage continuous operations.

Under the first market scenario with incremental-cost bidding only, the strategy most likely to increase net revenues is to increase generation so long as the owner's forecast of the average market prices for a daily, weekly, or monthly period are above average costs for the same period. A logical goal of any new owner would be to arrange, either directly or through an intermediary,

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50 Joe Pace, "Testimony on Market Power Issues," by Law and Economics Consulting Group before Federal Energy Regulatory Commission in Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company: Application for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange, ER96-1663-000, (Washington, D.C.: Pacific Gas and Electric Company, 1996); and Paul L Joskow et al., "Report on Market Power Issues," before Federal Energy Regulatory Commission in Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company: Application for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange, ER96-1663-000, (Washington, D.C.: Southern California Edison Company, 1996).

51 The revision in the recently-signed sale of the Long Beach plant reflects this strategy. The agreement between Edison and NGC/Destec allows for seasonal operation with extended shut down periods.

to contract with high-load factor customers so that, combined with sales to the PX or another power exchange, the plants' more efficient units can be operated at or near their maximum capacities for a majority of the hours in a year. Under the second scenario, a new owner would load-follow to the extent that the apparent losses during low-load and price periods exceed the cycling, start up and transaction costs incurred by load-following.

The recent opening of the PX market gives us some evidence about the likely behavior of this market. In April 1998, the PX price was less than 22 mills per kWh in about one-third of the hours.[52] Prices generally fall below fuel costs at night and have fallen to zero.[53] With the spot price of gas at $2.20 per MMBtu or more during the month, this implies that either gas-fired plants were off-line one-third of the time in April unless they were running under an RMRA, or the owners were accepting prices which were below the equivalent of the spot-market gas price. If the latter situation is the case, this would imply that the owners of the gas-fired power plants are willing to accept short-run losses overnight to minimize cycling costs by running at as high a level as possible. The prevalence of near zero bidding has become even more apparent during the later spring melt in early June. Not only have zero or near-zero off-peak bids been very common, but peak period bids have been sufficiently low to suggest little if any discretionary gas-fired generation at any time. While it is too early to draw conclusions—the market is in transition and hydro conditions are unusual—it appears that market price does tend to discourage continuous operations.

COSTS OF CYCLING POWER PLANTS

If the power plant is shut down or curtailed in order for the owner to fully participate in the PX and to follow load based on price signals, there are additional costs beyond the apparent hourly fuel costs. Restarting or cycling a unit involves increased fuel costs for startup and ramp up, i.e., to return the plant to its optimal generation output, that would not be incurred in constant output operation Start up fuel costs typically are equivalent to one to two hours of full load operation for boilers. Operating a power plant at less than its optimal level increases the per kWh fuel cost. Each power plant has a level of operation at which it is most efficient. Producing less than the optimal level of generation increases the fuel needed to produce each kWh. If the new owner participates in the PX by reducing output below the optimal level, then the cost of each kWh that is produced will increase. In addition, maintenance costs increase, due to the increased thermal and mechanical stresses on the power plant unit from turning the unit on and off; baseload operation reduces heat stress from expansion and contraction of unit equipment. As an example, San Diego Gas and Electric Company assumes that each startup adds the equivalent of twenty

52 California Energy Commission, "Wholesale Electricity Price Review, April 1998," Sacramento, California, May 15, 1998, (http://www.energy.ca.gov/electricity/wepr/9804WEPR.HTM).

53 The "Weekly Market Watch" by the California ISO indicates a large number of hours in May when both PX and Real Time Imbalance Energy Prices fell to zero. (Market Surveillance Group, "Weekly Market Watch, May 22, 1998," (Folsom, California: California Independent System Operator, May 22, 1998).

operational hours for scheduling maintenance cycles.[54] One start per month would add about 4 percent to the maintenance costs alone for a unit on line 70 percent of the hours.

Both cycling and shut downs tend to increase forced outages, which further increase maintenance expenses and cause the operator to incur increased power replacement costs. Each time the plant is stressed with either cycling or a shut down, the odds increase for a forced outage in which a piece of equipment fails. These failures must be repaired, thereby incurring additional expense. While the plant is out of service for these repairs caused by changing the output level based on changes in the PX price, the owner may have to buy replacement power to fulfill contractual commitments to deliver electricity. Replacement power is invariably more expensive than self generation since it is produced by the power plant with highest operating costs which sets the market clearing price.

These cycling-duty costs, including startup fuel use and increased O&M expenses, must be recovered through market revenues (e.g., PX sales) as fixed costs allocated on top of the incremental fuel costs incurred from hourly operation. If a plant is a part of a large portfolio of generation resources, these cycling costs for a single plant (or a small number) can be allocated over the entire generation capacity or energy output from the portfolio. For example, if the added cost were 0.1 cents per kWh for each divested unit, PG&E could spread these costs over its portfolio, reducing the cost per kWh to 0.02 cents or an 80 percent reduction.[55] Given that many of these plants are probably inframarginal in any one hour, the portfolio can easily accommodate those startup costs. In fact, a portfolio owner can probably bid only its variable or incremental cost and recover its cycling duty costs from revenues produced by the inframarginal or baseloaded units.

However, to a single-plant owner, these cycling duty costs are significant and must be recovered solely from the revenues of that plant alone. As stated previously, the average costs for gas-fired plants in California lie within a band 10 percent above or below the average. Thus, the single-plant owner has a strong incentive to minimize those cycling duty costs. Baseload operation is the simplest way to accomplish this goal. This is one reason that QFs operate baseloaded.

TRANSACTION COSTS OF TRADING IN THE PX

In order to trade in the PX, the owner of any plant must incur a number of transaction costs. The first is the fee charged and bonding requirements by the PX for using the PX trading exchange. Also, to directly participate in the PX requires a commitment to staff and software. It is not possible to simply call up the PX and make a trade. Just as in purchasing stocks on the stock exchanges, one must either become a broker or use a broker to make trades. These are

[54] San Diego Gas and Electric Company, Data Response No. 12, SDG&E Divestiture Application No. A-97-12-039, May, 1998. PG&E has filed confidential information with the ISO which also show substantial cycling costs.

[55] Based on 20 percent of portfolio generation from steam turbines. (Pacific Gas and Electric Co., "Report on the Reasonableness of Operations for 1997 [January 1, 1997 to December 31, 1997]," before California Public Utilities Commission in Energy Cost Adjustment Clause [San Francisco, California: April 1, 1998].)

substantial costs compared to the likely difference between the cost per kWh of constant operation of one of the more efficient of the plants to be divested and the likely PX price.

While PG&E will incur similar transaction costs, it will have at least two distinct advantages over an owner of one or a few plants. First, PG&E will be able to spread these transaction costs over a large portfolio of generation resources. In fact, to gain the maximum economic benefits from its portfolio, PG&E must closely watch how the markets behave. Second, PG&E also has already made the necessary infrastructure investment necessary to participate in the market during the pre-restructuring period. PG&E always has dispatched its own system. Finally, PG&E also will participate in the PX as a buyer for its utility customers. While some of the costs between these two activities can be separated, there certainly will be synergies to PG&E's advantage. A single-plant or even multiple-plant owner will possess none of these qualities. For these reasons, the transaction costs for new owners are likely to be more significant than for PG&E.

An additional risk of PX trading is that the new owner will not know with certainty the price for electricity or gas if it elects to cease generation, buy electricity from the PX and sell gas to the spot market. The new owner will only know the clearing price at the PX. The new owner will not know the price that it will have to pay if its generation is shut down and the PX must supply the replacement electricity. The new owner only knows in advance that the price will tend to be higher, not lower. Similarly, the published gas spot price reflects the market balance. If the new owner withdraws its demand for gas and releases its supply of gas into the market, the price will tend to fall. As a result, both markets will tend to move against the new owner if it tries to replace generation with purchases. The new owner will also incur significant transaction costs to participate in these markets.

EVIDENCE OF THE PORTFOLIO EFFECT

A consulting report found that in restructured England and Wales, single station owners operate their power plants even if they have to accept some losses on days when prices are low, but portfolio owners are able to avoid doing the same. In a report to the PX Trust, London Economics stated:

> Our analysis indicates that portfolios are better able to manage the risks of trading in the PX than are non-portfolio bidders (e.g., participants that may own only a single station). It is not immediately apparent whether it is possible to develop PX rules which entirely remove this portfolio advantage; we suspect that this it may not be. This problem is not unique to California; single station bidders in other markets, most notably England and Wales, tend to have contracts to cover this type of risk. The contracts have the effect of making these generators into price takers, bidding to ensure that they are dispatched, even if they have to accept some losses on days when prices are low.[56]

[56] London Economics, Inc., "PX Auction Testing: A Report for the California Restructuring Trust," March 3, 1997, p. 20, filed as Appendix 3, "Phase II Filing," Federal Energy Regulatory Commission, in Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company: Application

SPARES AND MAINTENANCE POLICIES

The portfolio effect influences spares and maintenance philosophies. The utilities, with their mix of hydro, coal and nuclear plants, benefit from higher PX prices. PX prices will increase on average when the more efficient of the gas-fired units are out of service more frequently. The utilities, therefore, do not have an incentive to incur spares and maintenance expenses to reduce more frequent and longer duration outages at the more-efficient units. A recent study found evidence that the large portfolio generation owners in the England and Wales power pool had in fact been pursuing this type of strategy.[57]

The reason that a reduced expenditure on spares and maintenance has such a high payoff for the utilities is that, under restructuring, all of the utilities' power plants receive the highest bid price accepted by the PX. This means that if a unit costing 25 mills per kWh is the last power plant accepted by the PX, then all of the power plants owned by the utilities will be paid 25 mills. This is true even for the hydro power plants, which have zero operating costs.

If the utility skimps on spares and maintenance so that the plant generating at 25 mills per kWh is less available, then a more expensive power plant, for example at 26 mills per kWh, will set the PX price. This means that the utility will earn an extra 1 mills per kWh on all of its hydro, nuclear and coal power plants without incurring any additional costs at those plants. A new owner would have no such incentive or even ability.

An independent owner with a portfolio of one or a few gas-fired plants would have every incentive to attain a higher level of availability. The independent owner would have the opposite spares and maintenance policy from the utilities. Such a result was observed by the consultants to the PX Trust who reported:

> The incentive for the owners of divested plant in Australia to maintain high reliability, resulted in a 5 percent to 10 percent increase in power plant availability under new ownership.[58]

Under restructuring, spending less on spares and maintenance of gas-fired units will increase the profits of the utilities if they retain the plants. The higher the PX price, the greater the profit on the hydro, coal and nuclear power plants. If the utilities do not divest these plants, they cannot be expected to minimize profits by spending at the high end of the range of possible spares and maintenance expenses.

for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange, ER96-1663-000, (Washington, D.C.: Power Exchange Corp., March 31, 1997).

57 Catherine D. Wolfram, "Strategic Bidding in a Mult-Unit Auction: An Empirical Analysis of Bids to Supply Electricity in England and Wales" (paper presented at the Electricity Industry Restructuring: Second Annual Research Conference, Berkeley, California, March 14 1997).

58 London Economics, Inc. (March, 1997), op. cit.

3.2.2 PURCHASE OF NATURAL GAS

The price of gas is determined by a commodity cost and the costs of transportation. The commodity cost in the western market varies by location at the point of production depending upon the transportation options available. For example, gas that is produced in west Texas (e.g., Anadarko field) can flow both to eastern and California markets and its price varies with the market price in both regions. California source gas, on the other hand, is limited to a California market. Transportation costs include return on investment and operations of the pipelines and compressor fuel consumption. Typically, in today's market, transportation costs can represent up to one-third of the total fuel costs. These costs (and transportation costs in particular) are geographically sensitive and subject to variation depending upon special arrangements with suppliers and pipeline owners (as discussed below).

FUEL PROCUREMENT BY NEW OWNERS

If a new owner owns gas supplies or has pre-existing superior transportation capability, it would likely run the plant at a higher level than PG&E currently does, due to these fuel cost advantages. Without such advantages, it is expected that the new plant owners will nevertheless procure fuel differently than the utilities do, employing a much greater range of specialized procurement practices. These procurement practices are likely to increase gas consumption through increased power generation.

As with many commodities, purchases of natural gas can involve quantity discounts. A commitment to purchase sufficient natural gas to run a power plant steadily 70-plus percent of the hours of the year will normally draw a lower price per unit than a commitment to purchase less than half that amount—and only when demand is high for both gas and electricity. A contract to purchase natural gas for a single power plant that follows load is complex and difficult to administer. The cost of staff and risks of managing such complex contracts is another transaction cost of actively trading in the PX and following load to match incremental costs to PX prices. In contrast, a contract to purchase natural gas whenever a power plant is available (other than the spring-runoff period) is simple and easy to administer. Many gas transportation contracts are made for firm service, and sized to maximum rate of gas flow; with these contracts, very little additional cost is incurred in more intensely using the gas transportation capacity. Thus, incremental gas use can be much cheaper and would impel plant owners with such contracts to increase generation.

The new owner may not have the volume of purchases of natural gas to be an attractive firm-supply-contract customer to a natural-gas supplier if the plant follows load. The new owner may not be able to justify the cost of staff, software and telecommunications to be constantly active in the natural gas market for just one plant. The new owner may find a constant delivery-rate contract the most feasible to administer at the least cost per unit of gas.

One means to control natural gas costs would be to enter into a "net back" contract with the natural gas supplier. Such a contract (which would likely exclude the spring-runoff season) ties the price of natural gas to the price paid for electricity, whether in a bilateral contract or in the PX. This would remove any incentive for the new owner to follow load, since the owner would be indifferent to the fluctuating price of electricity. The price of gas under such a contract would rise and fall with the electricity price received by the new owner. Net-back arrangements with new power plant owners would certainly elevate the generation from the plants..

It is notable in the non-divestiture case evaluated in Edison's divestiture application,[59] the two Edison plants that were forecasted to have the highest capacity factors had special, lower-priced, gas transportation contracts. These two plants, Mandalay and Cool Water, had projected capacity factors of nearly 50 percent under continued utility ownership. In stark contrast, among the remaining plants—all of which have a common, higher cost of gas transportation—the next highest forecasted capacity factor was only about 18 percent. This behavior illustrates the extremely flat supply curve for gas-fired generation found within the state.[60] Even the slight discounts in transportation costs present for both of these Edison plants drove their expected capacity factors much higher than those of the remaining plants, which have comparable fuel efficiencies but higher gas costs. Much like Edison, in instances of cheaper gas, the new owners would not dispose of this gas on the spot market since the price discount is only on the transportation component and is quite modest in any case. Rather, the future owners would be likely to find, as Edison did, that the profit-maximizing solution involves much heavier use of these plants.

The most significant change in fuel procurement could occur if a natural gas company such as Enron or Dynegy were to purchase and operate a divested plant. A company that owns natural gas reserves and has the capability to deliver gas to its plant does not have procurement costs, but, rather, has an opportunity cost. While a procurement cost is largely fixed once a contract is signed, an opportunity cost is fluid with the market and requires a more complex assessment of the situation. Such a company can operate its power plant differently than a company that must purchase its natural gas. For example, such a company might always bid close to zero and accept the winning bid to be assured of constantly operating in order to achieve an objective in its natural gas business.

PG&E'S RECENT FUEL PROCUREMENT PRACTICES

Earlier this year, an auction was held for capacity on the Redwood Path, a natural gas pipeline between Northern California and Canada. PG&E's Electric Department was one of 46 successful bidders for Redwood Path capacity for a period of five years. PG&E was awarded 21 percent of total line capacity in 1998, increasing to over 43 percent in 2002 and averaging about 32 percent over the five years. The capacity PG&E was awarded could fuel gas-fired generation of about 8,500 GWh in 1998 to about 17,300 GWh in 2002. By comparison, total 1996 generation by the units slated for divestiture equaled about 6,000 GWh. Even in a drought year, it is unlikely that

[59] A. 96-11-046
[60] Lovick (June 27, 1997), op. cit.

PG&E would need to purchase gas beyond that available through its pipeline share in order to bid these plants into the PX throughout the year.

The auction for the Redwood Path attracted such strong bidding because the Canadian gas is currently cheaper, and has been in recent years, than gas produced in the southwest United States. The price disparity is caused in part by the difference in pipeline access to the various producing regions. Obviously, natural gas fired power plants in Northern California would prefer the lower-price Canadian gas, but as a group are unable to meet their needs due to pipeline capacity constraints.

PG&E has represented that it has no intention to keep any capacity in excess of its power needs. In addition, the PG&E Electric Department has announced that as of February 26, 1998, it had successfully released almost all of its excess capacity for the entire term, through the secondary market. Finally, PG&E has committed to releasing the rest of its capacity as divestiture further reduces its needs.

If PG&E were to retain the plants, it would have an advantageous gas price, and would have a tendency to operate its plants at a higher level than it does now. This incentive runs counter to the incentives mentioned elsewhere that new owners have to operate these units more intensively than PG&E.

3.2.3 DIRECT ACCESS MARKETS

During the transition period from 1998 to 2002, only the new owners may sell into the direct access market. Basic business strategy suggests that the new owners will attempt to enter into agreements to serve customers with the highest load factors, which have the lowest cost per unit to serve. If the new owners are successful, customers with low-load factors will be left to the utilities to serve.

The ability to select customers will separate the new owners from the utilities in a significant way during the transition period. The utilities cannot choose who to serve. The new owners can build a business based on serving only high-load factor customers or loads aggregated to support constant running of their plants. For example, NGC/Destec can sell power directly “over the fence” from the El Segundo power plant to the neighboring Chevron refinery while avoiding at least a large proportion of the transmission and distribution charges.[61] Enron has announced plans to construct a 500 MW plant in Pittsburg that would at least in part serve the USS-Posco steel mill directly, and would endeavor to sell to other local industrial customers.[62] The sets of plants both on the Delta and in San Francisco are well situated in industrial zones to serve high load-factor customers, perhaps even bypassing the utility distribution company (UDC) system.

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61 This is an extreme example of a direct-access sale or “direct connect” which avoids at least the IOU’s T&D charges, and perhaps might even bypass the CTC, depending on how the CPUC interprets Section 369 of AB1890. Such direct connect service only enhances the direct access incentive discussed here, but quantifying the difference in effect is beyond the scope of this analysis.

62 Arthur O'Donnell, “Enron would build merchant plant in Pittsburg,” *California Energy Markets*, May 8 1998, 2.

It is the more efficient of the divested units that will operate more intensively due to sales to the direct access market. These more efficient plants selling into the direct access market will probably not operate during the low-load spring run-off period, when wholesale prices are at their lowest, unless needed for reliability. Rather, these units will more likely shut down for extended maintenance when it is more profitable to buy from the PX.

3.2.4 GEOTHERMAL STEAM SUPPLY AND CONTRACTS

At the Geysers plant, PG&E and its steam suppliers are in an unusual relationship from an economic standpoint compared to other geothermal operations, which are typically integrated. PG&E has only one possible supplier of "fuel" for each of its generation units – the steam supplier that owns the wells within a mile of each unit. These suppliers are UNT and Calpine. No other competitor can enter the market and offer alternative steam supplies. For UNT and Calpine, the only feasible buyer for steam from these wells is PG&E or the new owner after divestiture.[63] Such a relationship can lead to contentious negotiations and costly litigation over contracts.[64] The parties have no alternative markets to use for bargaining and thus must use other means to gain advantage. The transaction costs of negotiating and monitoring such arrangements are often quite high. A frequent outcome that reduces these transaction costs is integration of the buyer and seller. Because no competitive market existed in the first place, such a merger cannot increase the market power held by either party in the input market–in this case for steam supply. Indeed, it may serve to lower the costs for the final product in the output market, i.e., electric bulk power, which would improve the competitive position of the merged producer. Both UNT and Calpine maintain proprietary models of the KGRA based on well production and geologic studies. These models allow UNT and Calpine to better assess the value of their steam reservoirs. PG&E is only provided a year-ahead forecast of steam availability.

A new owner that is not a steam supplier (a "third party") would assume the same relationship that PG&E now has with its steam suppliers. The new owner would have to negotiate and monitor the steam supply contracts. Because the prices must be set administratively in the contracts, and cannot easily respond to changing market conditions (unlike natural gas or coal), the new owner would be likely to continue to operate the plant in the same modes as PG&E - cycling all but the Calpine supplied units which are run as baseload. As discussed in Section 1.3.2, cycling operation can lead to increased environmental and operational problems.

A third-party owner, or the steam suppliers if they acquire the plant, might choose to shut down some of the Geysers units to reroute steam to other units for increased output, and to reduce fixed operating costs.[65] However, a previous study found that the gains in capacity and output

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63 While the steam suppliers could theoretically sell to NCPA, SMUD or the QFs, at least two practical matters basically foreclose this option: (1) steam can be moved only a short distance before it loses its effective energy (*i.e.*, a mile or less in most cases), and (2) PG&E's generation capacity dwarfs the capacity owned by all of the other generators combined.

64 Oliver E. Williamson, "Credible Commitments: Using Hostages to Support Exchange," *American Economic Review* 73, no. 2 (1983): 519-540.

65 PG&E has already shut down the oldest four Geysers plants, the Central California Power Agency has shut down the Coldwater Creek plants, and CDWR's Bottlerock plant has never opened.

would be relatively small from such actions due to the limited ability to move steam large distances and the increased well backpressure that would reduce steam production.[66] In addition, because all of the Geysers units are designated as RMR, the new owner would have to get approval from the ISO to close any of them. The ease of getting such approval would be highly dependent upon whether or not the reliable capacity of the overall reservoir would be significantly diminished.

If the new owner were also the steam supplier, the owner would be likely to compare the opportunity costs of its well operations to the gains from selling power into the power market. Given that steam well costs at selected units are likely to be significantly below steam contract prices, the steam suppliers would be likely to operate at least some of the facilities at higher capacity factors. In addition, the benefits from any well or generation plant improvements would no longer be split between the steam supplier and the generator. This should increase the incentive to make such improvements because the new owner would capture 100 percent of the benefits.

3.3 THE INFLUENCE OF MUST-RUN STATUS ON OPERATIONS

The level of potential variability of operations of the plants proposed for divestiture is significantly affected by the RMR status of the individual plants. RMR plants are eligible for special contracts (i.e., ISO Reliability Must Run Agreement [RMRA] Types “A”, “B” and “C” specially tailored to each plant) under which the plants or some individual units within the plants would be guaranteed payments that range from partial to full fixed and variable cost reimbursement in exchange for their operations being dictated by the ISO.[67] Further, pursuant to these tariffs, the ISO has the determinative authority to classify plants as RMR, though the plant owners have some discretion as to which of the RMR contracts to accept.

3.3.1 MUST-RUN STATUS DIMINISHES POTENTIAL DIFFERENCES IN OPERATIONS

Any comparison of operations before and after divestiture will vary with the RMR status of each plant. The more stringent the RMR requirements on a plant, the less variation that can arise in the plant’s operations regardless of plant ownership. At the extreme, if all of the divested plants were required to be RMR at all times (i.e., subject to RMRA “C”), then the operation of the in-state, fossil-fired generation would reduce to a single commitment and dispatch outcome without permissible variation regardless of varying ownership inclinations. All of the units being offered for divestiture are required to sign an RMRA “B.”

An important aspect of the RMRA “A” and “B” contracts is that the plant operators can essentially cause the ISO into paying the owners for at least their start-up costs, if not all of their

[66] Calpine et al (1992), op. cit.
[67] Master Must-Run Agreement and Appendices A, B, and C included as Addendum G, Independent System Operator Tariff filed as part of Phase II FERC filing by Independent System Operator dated March 31, 1997.

fixed costs. For example, suppose the unit was shut down over the weekend, but the ISO will probably need the plant at some point on Monday. Knowing this likely demand, the plant operator can put in a bid on Monday morning that would recover all of the unit's start up costs. If the bid were rejected by the PX, as is likely, then the ISO would have to pay the operator to start up the unit. With the unit started, the operator could then bid into the PX at the unit's incremental fuel cost for the remainder of the week, assuming that the unit stays up overnight. The owner can be sure of recovering almost all of its other variable costs. On the other hand, if a second unit does not have an RMRA, the owner must structure the bids throughout the week to try to recover at least the start up costs. The second unit would be at a distinct cost disadvantage compared to the first unit due to the "extra-market" start-up subsidy provided by the ISO.

The RMRA thus becomes a valuable component of the plant sale. For example, all of the plants that sold below book value in the first round of the divestiture were not designated as must run.[68] Possessing an RMRA "A" or "B" allows the plant owner the option to recover at least a portion of its cycling costs from a side-payment through the ISO. Depending on how often a plant must be called by the ISO, an RMRA can diminish the differences in incentives between independent and utility owners as the differences in recovering cycling costs diminish.

3.4 DECISION TO REPOWER DIVESTED PLANTS

"Repowering" an electric generation unit involves salvaging the useful components of an existing plant and adding new technology to enhance its efficiency, reliability and remaining life. Most repowering projects now raze the existing steam boiler and replace it with a combustion turbine (CT), which in turn fires a heat-recovery steam generator (HRSG) with its exhaust. The steam from the HRSG is routed through the existing steam turbine. The repowered combined-cycle unit typically will have fuel efficiencies or heat rates of 8,000 Btu per kilowatt-hour or better, versus heat rates (prior to repowering) that are in excess of 10,000 Btu per kilowatt-hour.

The decision to repower is based on evaluating three factors: (1) comparing the expected net market revenues from operating the old versus new facilities; (2) the costs to invest in a new facility compared to the expected investment return; and (3) the "portfolio effect." The first factor is driven by how operations would differ with changed ownership and the cost improvements from a new technology. The second factor reflects how investment "hurdle rates" will differ between smaller independent and larger utility owners. The final factor is the impetus for the portfolio owner to retain existing low-capacity-factor generation in order to preserve existing, higher PX clearing prices and maximize portfolio net revenues.

In evaluating repowering, there are three possible outcomes: (1) the unit would not be repowered within the time frame analyzed; (2) the unit would be repowered at the same time regardless of ownership; or (3) the new owners would repower earlier than a utility owner due to the difference

[68] These were Long Beach, Ormond Beach, San Bernardino and Highgrove. Coolwater is an efficient combined cycle plant with advantageous gas access. While Moss Landing or Morro Bay sold for prices above book value, which plant would be RMR was unclear, and because they were purchased as a package, we cannot distinguish their relative values to Duke Energy.

in market incentives and costs. It is PG&E's position that a large surplus exists on the Western grid and that this surplus will defer repowering, so that most repowering is likely to be delayed beyond 2013 for the vast majority of divested plants.[69] In addition, the new generation either announced or currently under construction (see Section 4.3.1) would act as a damper on repowering zeal.

It appears that several Edison plants sold in the first round of divestiture, notably at San Bernardino, Long Beach, and Highgrove, were uneconomic to operate in any manner unless they received RMRA full cost reimbursement from the ISO. These units are likely to be retired or repowered rapidly regardless of ownership status and there are early indications that current planning calls for High Grove to be repowered by 2000 and San Bernardino by 2001.[70,71]

MEETING THE SAN FRANCISCO OPERATING CRITERIA AND PLANNING CRITERIA

To serve San Francisco's growing load and to meet existing reliability requirements, it is likely that either new transmission capacity will need to be connected to the City or new power generation will have to be constructed within the environs of San Francisco.

The incentives for a new owner differ from those of PG&E with regards to repowering versus transmission upgrades. If the plants were not divested, PG&E would weigh the relative costs of each option because it bears at least the initial costs of each since it is both a generation company and utility distribution company (UDC). In fact, PG&E may be biased toward transmission because the risks of cost recovery as a transmission owner may be substantially less, given ISO ratemaking authority over transmission versus recovering generation costs in the market, and the expressed need for reliability inherent in upgrading transmission.

A new owner, on the other hand, will actually be in direct competition with the transmission upgrades. Thus, a new owner may repower as soon as possible to reduce the potential economic benefits to the ISO from approving a transmission upgrade. Also, it is unclear as to who will approve such transmission upgrades, and who will bear the costs and risks of these type of upgrades.

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69 PG&E has stated that "the large surplus capacity across the Western grid is likely to result in low wholesale prices which deter new investment. Under these conditions, we doubt that there are significant new investment opportunities that.... earn a reasonable hurdle rate." (Lovick, July 1997, op. cit.).

70 The Thermo ECOTek Corporation stated that it was repowering these two plants in May 29, 1998 motion made in A. 96-11-046.

71 Under CPUC D.97-04-042, the utilities are allowed to retire units without notifying the CPUC and still recover associated stranded assets.

SUMMARY

New owners of the divested plants are likely to differ from PG&E in at least five different ways:

- Many of the new owners will have different financial characteristics that require more rapid recovery of investment;
- The new owners will not own a large portfolio of generation resources over which to spread market participation and transaction costs, or to gain additional profits by manipulating sales from the divested plants;
- The new owners will be able to make direct access sales to selected customer groups, who either will have higher load factors which accommodate higher generation output, or in the case of geothermal, are willing to pay a price premium for "green power;"
- The new owners may make different gas purchasing arrangements, which are more likely to require higher throughput volumes relative to contracted pipeline capacity because of the lower total volume purchased for the smaller generation portfolio; and
- If the new owners of the Geysers geothermal plants are also the steam suppliers, they will experience lower steam-purchase costs, thus encouraging higher output levels.

Each of these factors tends to encourage higher generation levels by the divested owners. The need to accelerate investment returns requires either higher market prices, which are largely beyond the control of the new owners, or higher generation sales. The inability to spread transaction and unit start up costs across a broad portfolio implies that the new owners will be less willing to operate the plants in a cycling mode, so that the plants are more likely to run at a constant output level. Direct access sales to higher load-factor industries will accommodate higher sales and will allow the owners to avoid market participation costs. Premiums on green power sales will provide higher than market-clearing prices, which in turn encourages higher generation sales. Higher gas throughput means higher generation levels, since resale back into the spot gas market will incur some costs. And finally, lower steam purchase costs at the Geysers means that the steam suppliers would have an ability to bid lower prices into the Power Exchange, increasing the likelihood of winning the bid in each hour.

These changes may be attenuated by shifts in the power market price which provide incentives for the new owners to operate the divested plants in a manner similar to PG&E. In addition, the Must-Run Agreements with the Independent System Operator (ISO) may play a dominant role in the operation of these plants, and this would tend to diminish the difference in incentives between PG&E and the new owners.

TABLE C-3
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
Institutional/Restructuring Policy	
The PX and ISO began operation on April 1, 1998	Historic fact, AB 1890, Sec. 330
IOU generation plants will be market valued by December 31, 2001	AB 1890, Sec. 377
The IOUs will receive transitional costs to compensate for the stranded generation assets by March 31, 2002. The CTC account shall track accrual and recovery of costs through the period.	AB 1890, Sec. 367
Whether owned by the IOUs or independents, any “going forward” or operational costs must be recovered from the PX, through ISO contracts, or direct access sales.	AB 1890, Sec. 367
The IOUs must sell into the PX until generation plants are market valued.	PPD, col. 18.
Owners of divested plants and other non-IOU plants may sell into the direct access market beginning April 1, 1998.	AB 1890
Sales of IOU plants must be reviewed for effects on system reliability	AB 1890, Sec. 362.
System Engineering and Characteristics	
Traditional form of hourly dispatch is “merit order” by short-run fuel costs plus some portion of “variable” O&M.	PG&E ECAC
Traditional form of daily and weekly commitment is based on expectations and variance of peak demand during those periods.	PG&E ECAC
Large variations in daily loads plus inability to store electricity prevents simultaneous maximum output by all generators. Increased generation at one unit generally must cause a decrease at another.	CEC demand forecast; laws of physics
Maximum output from any thermal-source generator is limited by: temporary or intermittent derating, forced outages, scheduled maintenance, permit limitations, and transmission constraints.	CEC Electricity Supply Planning Assessment Report (ESPAR), PEA

TABLE C-3 (continued)
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
System Engineering and Characteristics (continued)	
Gas-fired steam plants must burn fuel without generating electricity to attain critical steam level before selling into the electricity market.	CEC ESPAR
Repeatedly starting up and ramping up and down plants places mechanical stresses on steam-fired generation units.	PG&E testimony in CPUC ECAC and CEC Electricity Report, SDG&E Data Response 12.
Most natural-gas-fired units in California were built for baseload operation.	CA Foundation on the Environment and the Economy, "Coal Use in California," 1982.
The incremental heat rate of a generation unit changes with its output level.	CEC ESPAR reports.
The incremental heat rates of California's natural gas plants when operating at full load fall into a narrow range.	Lovick, Workshop June 27; Joskow, FERC Filing, Fig. 1.
Gas-fired plants are the marginal resource in California at least 70 percent of the year.	Joskow, FERC Filing, May 29, 1996, p. 9.
Edison and PG&E gas-fired generation units currently operate at levels well below maximum technical and permitted output levels.	PEAs
ThermoECOTek is repowering the San Bernardino and Highgrove power plants.	ThermoECOTek filing, A. 96-11-046, May 29, 1998.
Western U.S. grid bulk power market prices are below incremental natural-gas fuel costs during the spring run-off periods during off-peak hours.	*California Energy Markets*, PX Price History, May 1998
Portfolio Effects	
IOUs possess vertical and horizontal market power in generation	PPD, FoF 29, CoL 34, 35
Owners of large generation pools in England and Wales, and Australia have exerted market power in the deregulated electricity market.	Lovick, Responses to Questions; Green, 1997; Wolfram, 1997.
Owners of large generation portfolios in England and Wales manipulated the availability of their plants to increase total net revenues by placing their most expensive plants on the margin more often.	Wolfram, POWER Conference, March 14, 1997.

TABLE C-3 (continued)
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
Portfolio Effects (continued)	
"Portfolios are better able to manage the risks of trading in the PX than are non-portfolio bidders...It is not immediately apparent whether it is possible to develop PX rules which entirely remove this portfolio advantage; we suspect that it may not be."	London Economics, PX Filing, Attachment A, March 3, 1997.
In England and Wales, single-station owners operate their plants even if they have to accept some losses on days when market prices are low.	London Economics, PX Filing, Attachment A, March 3, 1997.
Participating in a market has transaction costs to both buyers and sellers in addition to the direct purchase price of the commodity.	McCann, *Contemporary Economic Policy*, July 1996
Direct Access Market Characteristics	
Direct access contracts disconnect the contract price from those in the spot market in the England and Wales market.	Green, POWER Conference, March 14, 1997.
Large industrial and water district customers have higher load factors than the system average load factor.	CEC, Demand forecasting documents.
Large industrial customers represented by CA Manufacturing Association (CMA) led negotiations on the Memorandum of Understanding (MOU) for restructuring, which reintroduced direct access into the Proposed Policy Decision.	MOU, signed September 1995.
Association of California Water Agencies (ACWA) was one of the first groups to initiate contracting for direct access service.	ACWA Newsletters, 1996.
Natural Gas Fuel Procurement	
Several natural "gas" spot markets exist throughout the U.S.	New York Mercantile Exchange (NYMEX)
Mandalay and Coolwater generation plants had special contracts that reduced costs of gas supply.	Edison, ECAC filings; SCG, BCAP filings.

TABLE C-3 (continued)
KEY FACTS, AXIOMS AND COMMONLY ACCEPTED PRINCIPLES

	Citation/Source
Natural Gas Fuel Procurement (continued)	
Independent power plant (QF) operators currently use different gas contracting terms than those used by the IOUs.	*Public Utility Fortnightly*, Review of confidential contracts
Gas contracts and published tariffs typically have a transportation rate which is fixed over a monthly or annual period, and a commodity rate which varies with the amount of gas consumed.	Wholesale gas contracts.
"Net back" gas contracts exist where the consumer pays the producer a price equal to cost of an alternative fuel or energy source.	*Public Utility Fortnightly*, Review of confidential contracts

Acronyms Used in Table:
AB = Assembly Bill
BCAP = Biennial Cost Adjustment Proceeding
CEC = California Energy Commission
CoL = Conclusion of Law
CTC = Competition Transition Charge
ECAC = Energy Cost Adjustment Clause
FERC = Federal Regulatory Commission
FoF = Findings of Fact
IOU = Investor Owned Utility
ISO = Independent System Operator
PEA = Proponent's Environmental Assessment
PPD = Preferred Policy Decision
PX = Power Exchange
SCG = Southern California Gas Company