Introduction

Re-operation of the affected hydro facilities will result in changes to the quantity of electric energy produced, its inter- and intra-month distribution, and may change peak project capabilities. Energy production may also shift to ancillary services. Figure 1 shows a stylized result of re-operation on hydro project operation and the mix of ancillary services and energy. The relative changes in energy and ancillary services due to re-operation will depend on how project capability changes relative to the change in energy production.

Downstream, project customers will face changes in the quantity of retail electricity that must be purchased to balance the change in supply from the affected projects. This electricity will be procured from the market and delivered via the local Utility Distribution Company ("UDC") over the continued tariffed distribution system.

The change in revenues from power sales, and the change in costs to the consumer, result from the change in project operations, and the value of the power sold or bought. This section presents an estimate of the wholesale and retail power values in the restructured California electric market. Energy and some ancillary services will become competitively procured by buyers from sellers who must recover their fixed and variable costs from that competitive market. Only distribution and related UDC costs will continue to be recovered through cost of service rates.

The long run market clearing price ("MCP") is based on the all-in cost of a new combined cycle facility, while ancillary service costs are based on utility filings which are themselves cost based. This somewhat simplified MCP determination approach is consistent with the simplifications embodied in the re-operation estimation itself. Finally, retail adders are developed from a tariff unbundling filing in which the costs of generation and transmission are separated from distribution related expenses.

Estimating the Impact of Re-operation

The effects of project re-operation were estimated by the DWRSIM model. The difference between a status quo case and the various re-operation cases demonstrates the net impact of the re-operation plans on project capability and energy production.

The DWRSIM model project monthly operational changes, not diurnal changes. Thus, the impact of re-operation on on- versus off-peak power and energy production capability is not directly available. These effects, without significant additional effort, must be assessed qualitatively. Thus, rather than the effect as shown on Figure 1, the impact of re-operation as predicted by DWRSIM will be as shown on Figure 2. Since the temporal re-operation impacts are absent from the from the modeling, a non-time differentiated Power Value is also acceptable.

Power Value in the Restructured California Market

The Power Value is measured by the price a seller will receive for energy sold into the wholesale market. The California wholesale power market under the Power Exchange will operate under a single part bid method; there will be only energy bids in the Power Exchange, and no separate capacity bid. Generators will recover all of their fixed costs from the difference between their variable costs and the MCP, as adjusted for losses.

Figure 1
Hydro Project
Effect of Reoperation

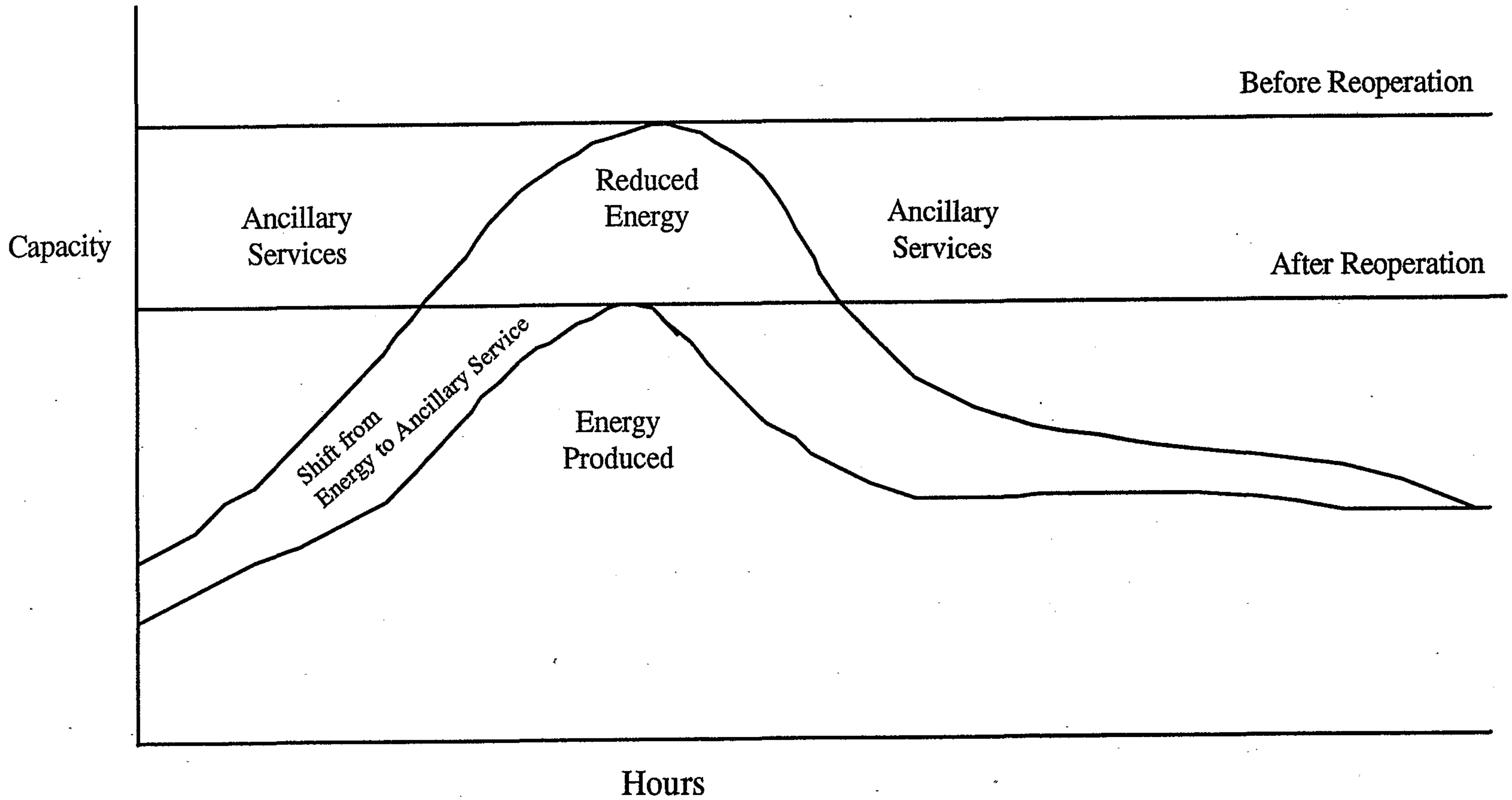

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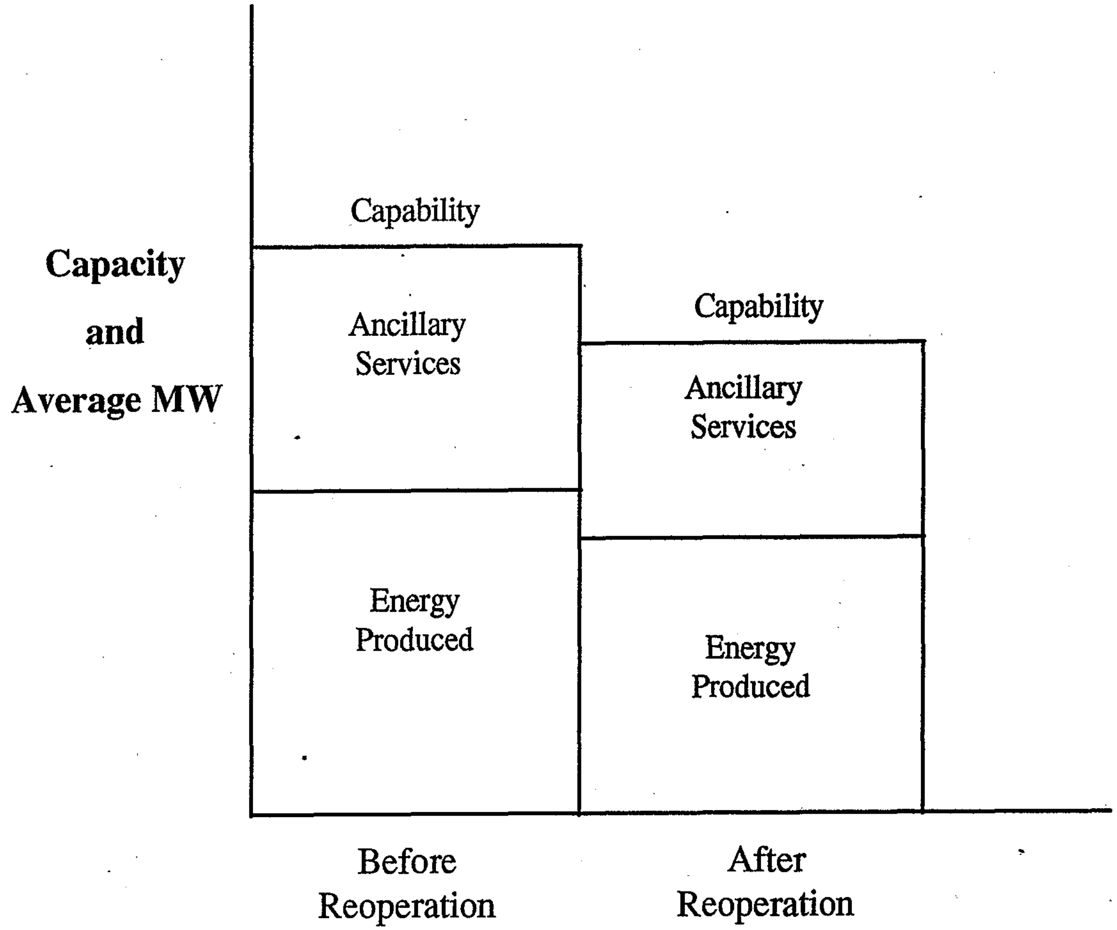
Figure 2

Hydro Project

Effect of Reoperation

Period Average Basis



Hydro projects are expected to be price takers, with variable production costs significantly less than the MCP. This assessment assumes that re-operation will not itself affect the short-run MCP, although the presence or absence of hydro energy, or the variation in available energy due to varying water conditions will affect the short-run MCP.

For power purchasers, the price paid will consist of the market clearing price for energy, plus retail adders for public purpose programs, transmission and distribution related costs, and other transaction costs associated with power provision.

In the long run, the competitive market must permit recovery of both fixed and variable costs. For the market to support new or re-powered base, or near base-load facilities, this means the long-run average market price can fall no lower than the "all-in" cost of constructing, owning, and operating the facilities that must be built to support load growth and retirement of existing facilities as they reach the end of their useful lives.

Absent detailed market assessment, the intra-year variation in market prices cannot be directly estimated. A qualitative assessment can be made based on historic seasonal variation in energy prices using the qualifying facility short run avoided cost as an index value. Table __ presents and index based on the PG&E 1995 avoided energy payments. The index represents the ratio of each monthly price to the weighted annual average price

Table __: Monthly MCP Index

Month	Price	Index
January	2.54	1.37
February	1.96	1.06
March	1.91	1.03
April	1.92	1.03
May	1.88	1.02
June	1.84	1.00
July	1.64	0.89
August	1.56	0.84
September	1.59	0.86
October	1.65	0.89
November	1.98	1.07
December	2.06	1.11
Annual Average	1.85	
Based on 1996 PG&E QF Energy Prices		

Need for New Capacity

The draft 1996 Electricity Report issued by the California Energy Commission ("CEC") forecasts a physical need for new capacity to serve the California market in about 2001 (after allowing for 2,377 MW of spot, or peaking, capacity).[1] The CEC proposes to deem

[1] Statewide surplus/deficit declines from 591 MW, to -2,520 MW between 2000 and 2003 (Page A-16). ER-96 presents data for 2000, 2003 and 2015.

"needed" up to 6,737 MW by 2007 (beyond the 2,377 MW), but without a restriction on when in the interim proposed projects may begin operation. The CEC proposes to let the market decide when that capacity should be built.[2]

Current expectations are that simple cycle combustion turbines, or gas fired combined cycle facilities will provide the bulk of the new or re-powered capacity for the foreseeable future. Environmental restrictions, fuel price forecasts, continuing pipeline availability, further technological improvement all suggest that gas-fired capacity will continue to be the preferred alternative for new California central station generatiing capacity.

Power Value Forecast

The precise timing and technology (simple or combined cycle) of new resource additions will be market driven. In the long term, base load combined cycle, for example, projects will be needed. They may also be cost effective in the near term as replacement for existing capacity. The long term power value forecast, therefore, is assumed to be the full, all-in cost of a modern combined cycle facility.

Current, "F" and "G" technology combined cycle facilities range in cost from 25 to 35 mills, including fuel, O&M, and debt service and capital recovery. The range derives from differing assumptions regarding fuel, and fuel transportation price, and cost of debt and equity. For example, the capital and O&M costs of a combined cycle facility in 1997 dollars is about 15 mills, fuel costs, including transportation in the PG&E service territory add another 17 mills, for a total of 32 mills.[3]

The CPUC has adopted a proxy market clearing price of 24 mills for use in determining CTC balances in 1998. This 24 mill value reflects an expectation about the nature of the market in 1998, and is not a representative long term value. We therefore adopt the 32 mill value for the power value analysis as a conservative estimate of the expected power value to the generator (as adjusted for losses). The loss adjusted Power Value is presented below in Table __.

Table __: Loss Adjusted Market Clearing Price

Location	Loss Factor	Loss Adjusted Power Value

[2] In fact, additional capacity may be economic beyond that which the CEC identifies. The CEC estimate is based solely on reserve margin criteria.

[3] Assuming a baseloaded facility with a $550/kW capital cost, and private financing. Energy costs based on a 6,900 heat rate and 2.42 burner tip gas price per the August 1997 CEC Revised Fuels Report.

Ancillary Services
The California market under the ISO will separately procure Ancillary Services, such as spinning and non-spinning reserves, reactive support, and black start capability. These will either be procured at cost based rates, or at market rates, if a competitive market is determined to be operating.

PG&E provided in its March 31 Phase II filing to the FERC an analysis of its cost of providing Ancillary Services.[4] These costs are shown in Table __.

Table __: Ancillary Services Forecast

Ancillary Service	Cost ($/MWh)
Spinning Reserves	7.4
Non-spinning Reserves	7.9
Reactive/Voltage Support	0.17
Automatic Generation Control	7.7
Black Start	NA

The ancillary service values are not additive since they cannot all be provided simultaneously. These are cost based rates from a combination of thermal, and hydro capital costs, and O&M costs. A representative value of 7.5 $/MWh is adopted herein for ancillary services revenues. Additional loss adjustments are made using the same loss factors from Table __.

The unique characteristic of hydro projects to ramp quickly and generally supply additional capacity for some period when needed makes them exceptionally valuable for ancillary service purposes. For this analysis, ancillary services are assumed provided from that hydro project capacity which is not supported by energy. Figure 1 shows the relationship between project capability, energy produced, and ancillary services.

Ancillary service revenues may be a significantly larger proportion of hydro project revenues than for thermal plants. New combined cycle plants will be most economic at high capacity factors, so will have relatively little remaining capability to provide ancillary services. To the extent the combined cycle plant is off-line it may be configured to provide operating reserves, but the dominate product will still be energy, and therefore from where most project revenues will derive.

Retail Consumers
After 2001, retail consumers will pay the market clearing price for energy, and the additional distribution system, metering, public purpose, etc. charges. In addition, generators must pass on their ISO/PX transaction costs, and transmission access charges levied for the transmission owners. A one mill transactions fee to cover grid management and Scheduling Coordinator costs is assumed. PG&E has proposed a 3.53

[4] Pacific Gas and Electric Company, Tariff and Prepared Direct Testimony, Volume 1, Appendix IV, March 31, 1997.

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mill transmission access charge.[5] Location specific losses must also be applied, as well as distribution system losses that depend on delivery voltage. A total power value of 37 mills, plus losses, is therefore used for the retail energy.[6]

Table _: Retail Generation and Transmission Charges	
Product	Value (Mills)
Long Run Market Clearing Price (w/o Generation losses)	32
Transmission Access Charge	4
Transaction Fee (Grid Management & S C)	1
Total	37

The level of distribution and other charges has not yet been presented in the PG&E or Edison pro-forma direct access tariffs. PacifiCorp, on the other hand, has presented its unbundled tariffs for its California customers.[7] For service with demands between 100 and 500 kW, the distribution and non-FERC related transmission costs, plus public purpose and other adjustments are shown on Table _.

Table _: Retail Services Costs	
Service	Cost (mills)
Distribution Demand 1/	.326
Non-FERC Transmission 1/	.026
Public Purpose and Adjustments	.148
Energy (Distribution, Transmission, and Delivery	26.830
Total	27.330
1/ at 70 percent load factor See PacifiCorp DIAP, June 30, 1997 Preliminary Statement, Part D, and Schedule A-36	

Total retail charges are then 27 plus 37 mills, or 64 mills. This value is used for retail power value analyses.

Application of the Power Value Forecast

Power Producers

Power Purchasers

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[5] Pacific Gas and Electric Company, Tariff and Prepared Direct Testimony, Volume 1, Appendix II, March 31, 1997. The transaction and access charges are shown as a retail expense, since it is assumed the generator will pass those costs through bid price to the consumer. The costs therefore net out for the seller.

[6] Plus location specific losses.

[7] PacifiCorp Direct Access Implementation Plan, June 30, 1997.