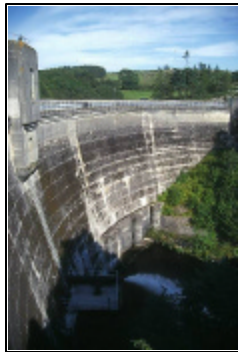


The Economics of Electric System Municipalization

Infrastructure Acquisition and its Effect on Consumer Rates



Bay Area Economic Forum

A Partnership of the Bay Area Council
And the Association of Bay Area Governments

October 2002



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**Project Supervisor
R. Sean Randolph**

**Economic Analysis
Bill Roberts
Helen Chin
Economic Sciences Corp.**

October 2002

Foreword

This report is the fourth in a series of five analyses by the Bay Area Economic Forum on the California power crisis and its impact on the state and Bay Area economies. The first, *The Bay Area – A Knowledge Economy Needs Power*, in April 2001, examined the causes of California's power crisis and options for near-term solutions. The second, *California at a Crossroads*, in October 2001, examined the experience with competitive power markets in other jurisdictions, and the potential for reforming California's power markets to restore competition and consumer choice. A third analysis of the state's power sector, presenting an integrated framework for power market reform, will be released in November 2002.

Because of the renewed interest from many cities in municipal power that resulted from the power crisis, the Economic Forum undertook a more focused analysis in October 2001 of the economics of creating new municipal utilities for electric power. That report, *The Economics of Electric System Municipalization*, examined the historical record of California's municipal utilities in delivering low cost power to consumers, and the issues that cities in the region and the state must address when considering that option. The report that follows is a sequel to the 2001 municipal power analysis, and examines in greater detail both the determinants of consumer rates for municipal utilities and investor-owned utilities alike, and the tradeoff between infrastructure acquisition costs and power production costs that will ultimately determine whether the municipalization of power will produce consumer benefits. It focuses exclusively on the economics of electrical power municipalization, and does not address other possible social or political benefits.

This report was prepared with the support of Bill Roberts and Helen Chin of Economic Sciences Corporation, who developed its economic analysis and models. Reviewers from the fields of regional economics, energy economics, investment banking and law provided valuable comments and perspective.

Reliable and cost-effective power is essential to the operation of any economy and to its future development. Cumulatively, these analyses examine the economics and policy choices affecting the development of energy infrastructure in the Bay Area and the state, sufficient to ensure a reliable supply of reasonably priced power to both business and residential consumers.

The Bay Area Economic Forum is a partnership of regional leaders representing business, government, universities, labor and the community, sponsored by the Bay Area Council and the Association of Bay Area Governments. A non-profit public-private organization, the Economic Forum works to foster a dynamic and competitive economy in the Bay Area, through focused analytical reports and by facilitating dialogue and action by the region's leaders on key economic issues.

The Economics of Electric System Municipalization: Infrastructure Acquisition and its Effect on Consumer Rates

Executive Summary

The California energy crisis revived and broadened interest in the conversion of regulated investor owned utility (IOU) electric distribution systems to publicly owned and controlled municipal utilities (MUs). This report examines the potential effects of municipalization on retail electric rates. It describes how key electric service cost components differ under MU versus IOU utility structures and sets out the System Average Rate (SAR) as a measure for comparing pre and post-municipalization electric service costs. The traditional cost of service formula is used to construct a model for calculating and comparing IOU and MU SAR's under varying assumptions about key factors.

When a public takeover of an electric system occurs, the valuation of various costs change and the tabulation of costs switches from IOU to MU accounts. For example, the valuation of the distribution system assets that are purchased by the MU will change from the IOU's book value to the price paid to acquire the asset, which in an involuntary takeover will likely be higher than the IOU's net book value. A higher asset valuation will produce higher financing costs for the MU, and higher depreciation charges.

While the amount to be financed will be larger, the MU will be able to use debt-only financing (versus an IOU's combined equity and debt financing), and thereby lower its average cost of capital. A new MU cannot issue tax-exempt bonds to finance the take-over of IOU assets, but can issue tax-exempt bonds for financing future expansion and improvements. Changes in tax treatment will also occur with a take-over, which will generally reduce MU costs. IOUs pay federal and state income taxes, local property taxes, and local franchise fees while MUs do not. Communities can avoid state & federal income taxes. However they would have to continue covering local non-income taxes through electric rates or other new local replacement taxes to maintain local budgets.

Operation and maintenance expenses will also change with municipalization. Power supply costs will change when MUs replace IOU power sources and contracts, and MUs may be more or less efficient in managing other O&M costs (distribution, customer service and administration and general costs). When all of these changes are accounted for, the bottom line for consumers is the new MU SAR, which can be directly compared to the IOU SAR.

The key cost components that will determine whether a new MU's rates will be higher or lower than the incumbent IOU's rates are: 1) the combination of the income tax exemption and debt-only capital structure, both of which lower MU rates relative to IOU rates; 2) the premium over book paid for the distribution assets, which will increase MU rates relative to IOU rates; and 3) the MU's cost of generating or purchasing power, which is a wild card that could increase or decrease relative MU/IOU rates. All other O&M cost components will likely have a small effect on the overall economics of the municipalization. Since the tax

exemption and capital structure rules for MUs are set in legislation, economic analysis of a proposal for public takeover of existing IOU distribution infrastructure should focus primarily on the MU's plans for obtaining power and for acquiring (pricing) the distribution infrastructure assets.

To explore the relative cost implications of municipalization, a Cost of Service Comparative Model was developed for this report to reflect the differences between IOU and MU cost structures. The model was applied, as a case study, using data specific to the San Francisco portion of PG&E's distribution system.

The City of San Francisco faces a complex and uncertain energy future as described in the City's *Electricity Resource Plan*. It will be an uphill task to resolve its immediate transmission constraints and local generation/conservation issues and avoid power shortages. Overlaid on this difficult situation is Proposition D, which will be decided this November.

Proposition D will essentially authorize the San Francisco Public Utilities Commission (SFPUC) to establish a full service or vertically integrated municipal electric utility. It does not directly mandate the City's takeover of PG&E's distribution system, but leaves the option to be decided by the SFPUC, without further voter approval. This is a very significant decision, with economic implications for San Francisco residents for decades to come. However, the basic information needed to rationally evaluate the implications of the Proposition is not available. The sources and costs of the City's power supply portfolio have not been identified and the valuation of the City's electric distribution system has not been determined.

In the absence of needed power cost and distribution system valuation estimates, several scenarios were developed for this report to explore the trade-offs between the key SFMU cost determinants: power supply costs and system acquisition costs. The first scenario simulation showed that if the SFMU could match PG&E's power supply costs, and could purchase the distribution system for less than or equal to 176% of book, then the SFMU SAR's could be below or equal to PG&E's SAR's. Variations in power production/purchase costs and system acquisition costs will produce different impacts on consumer rates.

The charts developed from the scenarios give a visual snapshot of the constrained options that will be available to all SFMU. The fundamental conclusion from this scenario analysis is that finding a combination of power supply, and premium-over-book acquisition cost that will not increase rates and be acceptable to PG&E or the courts, will be a formidable task.

There is scant evidence at this point that lower consumer rates will be reliably achieved through municipalization of the San Francisco distribution system. In addition to exposing San Francisco customers to the risk of higher rates from unknown power costs and system acquisition costs, severance from the PG&E system will also subject San Francisco customers to amplified financial risk through increased exposure to gas and wholesale electricity market volatility, and to higher transmission congestion charges. Addressing these issues will require more substantial analysis, including a clear power supply plan and system valuation study.

Contents

Foreword	iii
Executive Summary	v
I. Introduction	1
II. The California Energy Crisis and Diverging IOU/MU Rates	2
III. Municipalization Studies and Initiatives	4
IV. IOU/MU Comparative Cost of Service Framework	6
V. Applied Analysis - San Francisco	11
VI. Conclusion	17

I. Introduction

This report is a sequel to the Bay Area Economic Forum (BAEF) report entitled *The Economics of Electric System Municipalization* published October 2001¹, and is the fourth in a series of analyses of power infrastructure issues brought on by California's power crisis. The 2001 BAEF report examined the issue of whether the conversion of regulated investor owned utility (IOU) electric systems to new publicly owned and controlled municipal utilities (MUs), will reliably reduce electricity cost and consumer financial risk. It provided a historical review of the legislative/regulatory foundations of the differing IOU and MU business structures and compared the average electric rates for California's 3 largest IOU's and 21 largest MUs for the period 1990 through 1999. The data showed that average electric rates for IOU's were about 30% higher than the average MU electric rates for the period. However, the data also showed a wide variation in cost performance across municipal utilities and that some MUs had consistently higher rates than IOU's throughout the period. Moreover, over the decade reviewed, the average rate differential between MUs and IOUs had diminished, reflecting the diminishing proportions of low cost federal power in the MU resource bases.

Looking forward, the 2001 report suggested that some key economic advantages that were endowed on *existing* MUs (such as exemption from paying federal and state income taxes and, debt-only capital structures), would continue to be available to *new* MUs, but access to low cost federal power would not be available, nor would the unrestricted use of tax exempt securities.

To explore the question of whether the conversion of an IOU electric distribution system to a newly formed MU would benefit consumers, the 2001 report constructed a simple analytic model based on the conventional cost-of-service formula (which aggregates the different components of electric service cost). Model simulations demonstrated that the key issues determining the economic success of a new MU are: 1) the magnitude of the premium-over-book acquisition cost of the IOU's distribution assets, and 2) the MU/IOU relative cost of power supply. The analysis demonstrated that the amount of premium-over-book that a community can afford to pay for IOU assets (without increasing rates) depends heavily on the MU/IOU relative cost of generating and acquiring power. The 2001 report concluded, "Whether lower costs will be realized by a community depends primarily on the ability of municipalization organizers to develop a firm plan for securing low cost power supplies and obtaining electric system assets as close to book value as possible."

Since the issuance of the 2001 BAEF report, the prospects for moderating IOU electric rates and for reliable service have not improved, and interest in exploring the potential for municipalizing local electric systems has gained traction.

The objective of this report is to extend, refine, and demonstrate the application of the general analytic model presented in the previous report, in order to provide communities with a simple framework for examining the economic implications of municipalization proposals. For demonstration purposes, the model has been applied to estimate the rate implications of municipalizing PG&E's distribution system in the City of San Francisco.

The following section of this report (II. The California Energy Crisis and Diverging IOU/MU Rates) offers a discussion of the unbalanced impact of the California energy crisis on IOUs versus MUs, which has amplified the interest of citizens and municipal officials in exploring the options for, and potential benefits of, converting IOU services to local public ownership and control.

The third section of this report (III. Municipalization Studies and Initiatives) reviews recent efforts by Northern California Communities in pursuing interests in municipalization.

The fourth section of this report (IV. IOU/MU Comparative Cost-of-Service Framework) discusses the components of the cost of service formula for setting electric rates for both IOUs and MUs, and presents a model framework for comparative cost analysis.

The fifth section of this report (V. Applied Analysis - San Francisco) applies the cost of service comparative model to San Francisco as a case study, to estimate the trade-offs among the key cost factors in determining pre and post municipalization electric rates.

The sixth section of this report (VI. Summary) briefly summarizes the key issues that need to be considered in evaluating potential municipalization projects.

II. The California Energy Crisis and Diverging IOU/MU Rates

The State's DWR contracts have burdened IOU customers with above-market costs

Assembly Bill 1890, which restructured California's electricity industry, focused primarily on the IOU's that were regulated by the California Public Utilities Commission (CPUC); its provisions were not applied to the publicly-owned and locally controlled MUs. Key provisions of the restructuring rules required IOUs to divest legacy power plants, sell power from any retained plants through the wholesale spot market, and purchase all energy requirements from the spot market. The subsequent meltdown of California's wholesale electricity markets resulted in unprecedented losses in service reliability, soaring electricity costs, and the virtual financial ruin of California's regulated IOUs.

While the IOUs were suffering through the crisis, most of the State's MUs continued to provide reliable, relatively low cost service. Although the MUs were not restructured in the same way as IOU's, MUs with short power supply positions (i.e., that bought spot power and/or committed to high cost long term contracts) were also negatively impacted by the high wholesale prices, while those with long power supply positions actually benefited financially.

At the height of the energy crisis, the IOUs credit standing weakened to the point that the State Department of Water Resources (DWR) stepped in and bought power for the IOUs' customers. In an attempt to avoid extremely high spot prices for electricity, the DWR negotiated long-term (10-20 years) power supply contracts (on behalf of the IOU customers), at prices lower than the then current spot prices, but 2-4 times historic averages. With those

long-term contracts, Federal Energy Regulatory Commission (FERC) intervention, and significant energy conservation across California, the wholesale power market stabilized at prices consistent with historical averages and actual power production costs.

As a result of the DWR's purchases, the State has burdened the IOU customers with long-term obligations to buy electricity at prices that are significantly higher than any reasonable expectation for future electricity production costs. While some of the contracts have recently been renegotiated, the changes appear to have been mostly in reducing the length of contract terms while retaining high prices, leaving the present value of the IOU customers' burden essentially unchanged.

The immediate impact of the energy crisis on IOU retail electric rates was small relative to the scale of wholesale price changes. Despite skyrocketing wholesale costs, IOU electric rates remained frozen until near the tail end of the crisis, when the CPUC added surcharges averaging about 40%, which only partially covered the then-current high power costs. The wholesale power costs not covered by retail rates were absorbed first by the utilities (PG&E was pushed into bankruptcy), and then by the State. Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) avoided bankruptcy and are now collecting revenue to cover prior losses through CPUC-approved retail rates (the legality of which is being tested in the courts). The extent of customer obligations for paying off PG&E's losses is also currently being worked out in the courts.

The State intends to recover its power purchasing costs by issuing bonds that will be paid off by IOU electricity consumers. The total magnitude of the IOU and State costs for power purchases after October 2000 may be somewhat reduced by future FERC decisions concerning refunds from power generators and traders. However, the exact extent of market manipulation and its impact on power costs has not yet been established, and the FERC has not determined the amount of reparations due. And, regardless of what the FERC might decide, the financial condition of the trading and generation firms concerned may foreclose significant refunds actually being paid.

In summary, California's attempt at power market restructuring has burdened IOU electric customers with a long-term financial overhang that includes obligations to pay:

- 1) Above-market prices for an extended period for ongoing power purchases.
- 2) The cost of bonds for the State's prior power purchases.
- 3) Some or all of the IOUs' prior power purchasing losses (some amounts remain to be determined by the FERC and the courts).

The actual amounts of these obligations are currently unknown, but it is reasonable to expect that the CPUC will hold IOU rates well above ongoing costs for at least several years until these legacy obligations are paid down. In contrast, it is reasonable to expect that MU rates will converge to levels consistent with the ongoing cost of generation. Of course, those MUs that made spot and long term wholesale purchases during the energy crisis will also have above current cost rates until their legacy obligations are paid down.

Given the relative IOU/MU short and long term financial impacts left behind by the California energy crisis, it is tempting for IOU customers to contemplate seeking refuge through municipalization. However, it is highly unlikely that municipalization will actually provide IOU customers an escape from these legacy obligations. Should municipalization of a portion of an IOU's distribution system become a reality, it is reasonable to expect that exit charges or some other unavoidable charge will be assigned to all departing load by the CPUC and/or the courts, to avoid compounding the financial burden on the remaining IOU customers. Therefore, while the unbalanced burden of the energy crisis has understandably increased interest in municipalization, municipalization may not provide the hoped for shelter.

III. Municipalization Studies and Initiatives

Current Northern California municipalization proposals do not offer reliable estimates of consumer costs, benefits or risk

In the aftermath of California's energy crisis, at least three Northern California communities have taken initiatives to convert portions of PG&E's distribution infrastructure to local public ownership and control.

Davis

The City of Davis has commissioned Navigant Consulting, Inc. to assist it in understanding the options, risks and rewards associated with establishing a locally controlled electric utility. Navigant issued its Phase-1 Report entitled *Municipal Utility Options Analysis* in May 2002. This report gives a broad overview of optional utility structures and issues, but does not provide estimates of the potential for rate savings through municipalization. The study envisions a comprehensive set of four additional reports which include: a phase-2 options analysis, an engineering study, a legal feasibility study, and a financial feasibility study.

East Bay Municipal Utility District

The East Bay Municipal Utility District (EBMUD) commissioned R.W. Beck to study the feasibility of EBMUD developing a role in providing energy services including, taking over PG&E's distribution system in its district. Beck issued its report entitled *East Bay Municipal Utility District Potential Roles as an Electric Utility* in February 2002. The report provided a broad discussion of key issues, identified several possible business models for EBMUD, and discussed possible benefits and risks associated with the various business models, using pro forma business plan tables to illustrate their implications. For the vertically integrated utility business model, the Beck study estimated that the likely range of cost changes for EBMUD customers could be as much as -\$400 million to +\$400 million, indicating a high level of uncertainty as to customer impacts. More detailed and definitive studies were recommended, depending on EBMUD's choice of business model.

After taking public comments, the EBMUD Board's decision concerning the full service utility option (including takeover of the distribution system) was as follows:

"Given the high costs and high risks and the limited customer interest to date in EBMUD pursuing this role, we will not commission a business plan now. However, we will work with energy service experts to identify events that could lead to further future study of EBMUD becoming an electric service retailer. Due to the regulatory and legal complexities of retail electric services, experts estimate a takeover of PG&E's system in the East by EBMUD could cost up to a billion dollars and take a decade or more to move through the courts with no guarantee of success." (*EBMUD Public Power* on the EBMUD web site)

San Francisco

The idea of municipalizing the local electric system has been promoted by various groups in San Francisco for many years. In 1996, the San Francisco Public Utilities Commission hired the Economic and Technical Analysis Group (ETAG) to prepare a feasibility study to determine the economics of the City's takeover of electric service. The ETAG study resulted in an extensive report entitled *Final Report on the Feasibility of Electric System Municipalization in San Francisco* in February 1997. It estimated that municipalization would most likely yield consumer savings of less than 5% relative to PG&E's rates. However, the ETAG report also suggested that it is possible that the municipal rates could deviate from PG&E's rates by as much as plus or minus 10%.

In November 2001, the voters of San Francisco rejected (by small margins) two ballot measures that would have created local publicly owned electric utilities. This year, the San Francisco Local Agency Formation Commission (LAFCO) funded an additional municipalization study by R.W Beck, Henwood Energy Services, and Flynn Resource Consultants. The study entitled *Final Report, Energy Services Study (ESS)* was prepared in July 2002 and provided a broad discussion of San Francisco electricity issues but did not provide estimates of municipalization cost savings.

This November the San Francisco voters must again decide on an electricity municipalization proposal. The San Francisco Board of Supervisors has placed a City Charter amendment on the ballot, Proposition D, that will essentially authorize the San Francisco Public Utilities Commission (SFPUC) to establish a full service or vertically integrated municipal electric utility. Proposition D does not directly mandate the City's takeover of PG&E's distribution system, but leaves the option to be decided by the SFPUC, without further voter approval.

IV. IOU/MU Comparative Cost of Service Framework

Power generation and purchasing costs, and distribution system acquisition costs, are the key determinants of whether customers of new MUs will pay higher or lower rates

The fundamental economic issue to be resolved in deliberations concerning the public acquisition of existing IOU distribution systems is whether a newly formed MU can reliably achieve cost savings for MU customers. This section outlines the various components of electric service costs, explains how these costs may vary under MU versus IOU utility structures, and sets out a model framework for comparative analysis.

Cost-of-service, for both IOUs and MUs, is the total of all costs incurred by a utility in providing electric service. In traditional rate making, cost of service is also the total revenue required by the utility to pay all operating and capital costs, and electric rates are set to meet this requirement. The total electric revenue that a utility collects from its customers divided by the total volume of electricity delivered is the System Average Rate (SAR). The SAR is the broadest measure available for comparing electricity costs across utilities. The comparison of a post-municipalization SAR against the pre-municipalization SAR (other things equal), provides a simple test of whether the municipalization was economically beneficial to customers. Similarly, comparing estimated future SARs provides a basis for projecting the economic implications of planned municipalizations.

The composition of service costs differs between IOUs and MUs but their aggregate revenue requirements and SARs are directly comparable². When a public takeover of an electric system occurs, the valuation of various costs changes and the tabulation of costs switches from IOU to MU accounts. For example, the valuation of the distribution system will change from book value to the price paid for the asset.

Also, the financing basis for the system will convert from a combination of debt and equity to all debt (since MUs don't have shareholders or issue stock), and income tax costs will be eliminated. When all of the changes are accounted for, the bottom line for consumers is the average electric rate. Therefore, the cost of service formula, expanded to include the detailed cost categories of both IOU and MU accounting, provides a model structure for estimating the SAR impacts of municipalization³. A discussion of the cost categories used for estimating pre and post municipalization SARs follows.

Power Supply Cost

Power supply (generation plus purchased power) is the largest component of electric cost-of-service, typically making up 50-60% of the total cost⁴. Due to the relatively large contribution that power costs make to SARs, the power supply arrangements of new MUs relative to those of incumbent IOUs, will be critical determinants of whether municipalization will lead to electricity cost savings or added cost burdens to consumers. For cost analysis it is useful to decompose power supply cost into: 1) generation, and 2) purchases.

Generation

Under the provisions of California's market restructuring, IOUs were required to divest much of their generation assets, to preclude them from exercising power in the wholesale markets. While most of their gas-fired units were sold, the IOU's have retained their hydro and nuclear generating units, which are currently regulated by the CPUC. This retained generation covers about one third of IOU load. These units generally have the lowest or near lowest operating costs in the region, which works against the economics of municipalization. Even the best new efficient gas fired generation units will not produce power cheaper than the hydro and nuclear units retained by the IOUs.

Since new MUs will not have access to low cost federal power (which has been available to existing MUs) , they will have extreme difficulty replacing the IOU retained generation with lower or equal cost power, particularly in the short run. Over time, comparable cost replacement generation might be accomplished by the new MU by building new combined cycle units and possibly distributed generation heat and power units. Most likely, if the MU builds or buys generation facilities to replace IOU retained generation, they will be natural gas based, which will expose the MU customers to a higher degree of gas price risk than customers under IOU service.

In analyzing potential municipalization plans in the PG&E service territory, it should be noted that PG&E's retained generation cost advantage could be significantly affected by the outcome of its bankruptcy proceedings. This issue will be discussed in Section V. below.

Purchases

California's IOU utilities currently acquire the balance of their customer's load requirements from three sources: long term Qualifying Facility (QF) contracts⁵, long-term DWR contracts, and small quantities of short term wholesale market purchases through the ISO. It is reasonable to assume that a new MU would be required to assume a prorated portion of the IOU's long term QF and DWR contracts. These are generally high cost contracts that could represent about two thirds of both IOU and new MU load requirements, the cost of which would continue to be borne by future MU customers in the same manner as they are now carried by IOU customers.

Initially, a new MU will most likely acquire about one third of its requirements (replacing the IOU's retained generation) in the spot and long-term wholesale markets. Under normal conditions, the wholesale power costs will probably be in the range of \$30-\$45 per MWh. However, these prices can be very volatile, varying with changes in gas prices, regional weather conditions, transmission and generator outages, etc.. In other words, going to the wholesale market to obtain replacement power for IOU retained generation, will expose MU customers to increased financial risk.

The cost of purchased power can also be affected by the specific location of the buying MU. This is because of differences between MU area and IOU system load shapes, the area cost-averaging policies of the CPUC, and transmission capacity constraints. All IOU customers

of the same rate class currently pay the same rates regardless of location. However, the power costs of serving customers with relatively high consumption during high-cost periods are higher than for serving customers with relatively low consumption during high cost periods. The new MU's power purchase costs will reflect the load shape of the MU service area, which may differ from the IOU system load shape.

Transmission congestion costs (applied to electricity commodity charges) could also affect the power cost advantage (or disadvantage) of new MUs, depending on location. New MUs served by congested transmission lines could experience increases in congestion charges relative to the average IOU congestion charges, while new MUs served by non-congested transmission lines could experience decreases. Since congestion costs are affected by weather conditions and outages, the electric customers in high congestion areas will also experience both increased average electricity cost and increased volatility in electricity costs.

Transmission

Transmission expense (the cost of transporting power over high voltage lines) represents only about 1% of the total cost of electricity. These costs should not be expected to change substantially when converting from an IOU to a MU.

Distribution

Distribution O&M expenses represent only about 4% of the total cost of electricity. Both IOUs and MUs make claims of greater efficiency in distribution operations and maintenance in the debate about municipalization. There are differences in the cost of maintaining rural versus urban distribution systems, which under CPUC area cost averaging may cause city consumers to subsidize rural consumers and municipalization would allow city consumers to recapture that subsidy. However, the potential difference in distribution costs is not large enough to be determinative in the debate over municipalization. For example, a ten percent reduction or increase in distribution O&M costs would only change the SAR by about one half mill per KWh.

Customer Services

Customer services O&M expenses represent less than 4 % of the total cost of electricity. As with distribution charges, arguments about relative efficiency are not significant determinants of the value of MU conversion.

Administration

Administrative and general O&M expenses represent only about 5% of the total cost of electricity and are not a significant determinant of the MU conversion value.

Depreciation

Depreciation charges vary with the scope and age of the utility plants in service, and currently account for about 7% of the total cost of electricity. Also, the magnitude of depreciation charges can vary across utilities because of the adoption of different depreciation methodologies. Therefore, to assure comparability, it is essential that common rules be applied so that the only differences in depreciation between IOUs and MUs result from changes in the underlying rate base that occur because of the sale of the electric distribution system. For example, if a new MU acquires distribution assets owned by an IOU, at a price that is 50% higher than the IOU's book value for the asset, then the MU's depreciation charges will be 50% higher than the IOU's depreciation charges for the same assets.

Amortization of Development Costs

The costs of developing the MU such as study costs, litigation costs and the costs of severing the MU system from the IOU system should be amortized and added to the MU revenue requirements. When amortized, these costs are most likely small relative to other costs components and are not likely to affect municipalization decisions.

Income Taxes

IOU's pay state and federal income taxes while MUs do not. Income taxes for PG&E for 1999 represented almost 8.5 % of the cost of electricity, so tax rules give MUs some cost advantage over IOUs. The conversion of a portion of an IOU's electric system to a MU will shift a similar portion of the IOU's state and federal income tax burden from the MU consumers to taxpayers at large.

Non-Income Taxes

IOUs also pay local property taxes and franchise fees while MUs do not. When the electric system property is transferred to a public entity, these IOU tax payments will cease. To maintain public revenues, replacement funds must be provided for locally, either from the MU or from other local taxation. Therefore, it is reasonable to assume that there is no real MU cost advantage related to non-income taxes and for this analysis non-income taxes are retained as a part of the MU cost of service and included in electric rates.

Capital Costs

The capital costs associated with an electric system asset will change as a result of municipalization because of differences in capital structure and because of changes in rate base. Since the capital structure of IOUs is typically about 50% debt and 50% equity, while the capital structure of the MU is 100% debt, the IOU will have a higher average cost of capital (the average of the long-term interest rate and the return on equity). Therefore,

(assuming equal credit standing for the IOU and the MU) the MU should have lower capital costs per dollar of rate base. However, any premium-over-book paid by the MU for the assets will increase the rate base. Capital costs will therefore be reduced or increased depending on the asset acquisition price.

Debt financing for MU acquisition of existing IOU distribution systems does not qualify for use of tax-exempt debt. Tax-exempt debt may be used, however, for subsequent financing for system upgrades and expansion.

To the extent that the city considering the takeover of an IOU's distribution system has a higher credit standing than the IOU, the MU could obtain lower interest rates on its debt financing. Conversely, if the city's credit standing is lower than the IOU's, then the MU could end up paying higher interest rates.

Distribution System Valuation and the New MU Rate Base

In setting electric rates, regulators normally set charges for the use of the IOU electric system assets on the basis of a "rate base" that is valued at the net book value (or simply book value) of the assets (original cost less accumulated depreciation). Over time, excluding new investment, the rate base will decline according to the depreciation schedule adopted by the regulators. While the rate base will gradually decline, the market value of the electric system assets will vary according to changes in market factors such as the income potential of the assets and the cost of their replacement. In recent years, the market value of electric system assets has generally been above book and consumers have been shielded from paying rates on the basis of the higher market value. However, when assets are sold, they are re-valued at market value (transaction price). In other words, the rate base of the new owner will be higher than that of the original owner.

The magnitude of the system acquisition cost is a major component of a new MU's cost structure and determines both the level of depreciation charges and interest payments. The magnitude of the transaction premium-over-book paid for the IOU electric system assets that is negotiated or set by the court in the process of municipalization is one of the key determinants of the economic viability of a newly created MU. The higher the premium-over-book paid for distribution assets, the greater are the reductions required in other costs to avoid increases in rates relative to those of the incumbent IOU.

Summary of Key Comparative Cost Analysis Issues

The primary source of MU cost *advantage* is a combination of the income tax exemption and capital structure. The primary source of MU cost *disadvantage* is a combination of the premium over net book value that the MU must pay to acquire the distribution assets, and possibly higher power production costs. Other differences in O&M costs that may be realized by the MU will most likely have a small effect on the overall economics of the MU conversion. Therefore, analysis of the economic impact of a proposal for public takeover of existing distribution infrastructure should focus primarily on the plans for pricing the distribution infrastructure assets and for obtaining power supply. The cost-of-service

formula provides a convenient computational framework for estimating and comparing pre and post-municipalization SARs. Alternatively, the formula can combine estimates of power purchasing costs and other costs, and calculate the maximum amount that can be paid for the distribution assets, without increasing MU rates above IOU rates or any other target rate.

V. Applied Analysis - San Francisco

Applying this methodology to San Francisco, and with actual power production and infrastructure acquisition costs still unknown, there is insufficient evidence to reliably predict that municipalization will lower consumer rates

For the second year in a row, San Francisco voters will be casting votes on whether to municipalize PG&E's distribution system within the City. In November 2001, San Francisco voters rejected (by small margins) two ballot measures that would have created local publicly-owned electric utilities. This November, the San Francisco Board of Supervisors has placed Proposition D (a City Charter amendment) on the ballot that will authorize the San Francisco Public Utilities Commission (SFPUC) to establish a full service or vertically integrated municipal electric utility. Proposition D does not directly mandate the City's takeover of PG&E's distribution system, but leaves the option to be decided by the SFPUC, without further voter approval.

The City of San Francisco faces some difficult power reliability and cost issues, which were described in a joint report by the City's Public Utility Commission and Department of Environment entitled, *Electricity Resource Plan, Choosing San Francisco's Energy Future*, published in August 2002. In effect, the City will soon face the prospect of inadequate power supply. Local generating capacity consists of old, polluting plants at Hunters Point and Potrero Hill, and transmission capacity from outside the City is not adequate for importing replacement power. During peak usage periods only about 60% of demand can be imported, so the City must rely on continued use of its aged generating units. Plans are underway to build a new larger plant at Potrero Hill (Mirant Corporation) and to expand transmission capacity (PG&E & CAISO) but there are no assurances that either will occur in time to avoid significant outages when the old plants are shut down in 2005. To reduce the City's vulnerability to these circumstances, the City's *Electric Resource Plan* promotes increased conservation and the quick siting of small generating units within the City (especially renewable resource based). The *Electricity Resource Plan* does not address the benefits or costs of municipalization but does suggest that the passage of Proposition D would help facilitate the implementation of the City's program. However, the plan also acknowledged that most measures could be implemented whether Proposition D passes or not.

Unfortunately, the information available to San Francisco voters concerning the potential implications of Proposition D is very limited. The Energy Services Study (ESS) undertaken for the San Francisco Local Agency Formation Commission did not reach the stage of offering conclusions concerning the rate impact of municipalization. The ESS Report provides a broad discussion of the City's energy service options, hints at possible economic advantages for municipalization, but leaves detailed economic analysis of the options for future studies.

Although detailed economic analysis of municipalizing the San Francisco distribution system to create a vertically integrated public utility (SFMU) is not yet available, some general insights about the potential economic impact of municipalization can be obtained using the Cost-of-Service Comparative Model. The model's logic incorporates the differences in PG&E/SFMU taxation and accounting, and permits an assessment of the implications of expected comparative performance in key cost-determining activities such as power production. The model provides a convenient computational framework for estimating and comparing pre and post-municipalization SAR's. It can also combine estimates of power purchasing costs and other costs, to calculate the maximum amount that can be paid for the distribution assets without increasing SFMU rates above PG&E's.

Following is a brief discussion of the key economic issues relevant to the takeover of PG&E's San Francisco distribution system by an SFMU, and the potential impact of such a takeover on retail rates. As stated above, the primary source of SFMU cost *advantage* over PG&E is a combination of the income tax exemption and capital structure. The primary source of SFMU cost *disadvantage* relative to PG&E, is the premium over net book value that the SFMU may have to pay to acquire PG&E's distribution assets. The wild card in determining whether consumers will be better off or worse off after municipalization is the relative SFMU/PG&E cost of power supply (generation and purchased power). Other differences in O&M costs that may (or may not) be realized by the SFMU will most likely have only a small effect on the overall economics of the SFMU conversion and can be ignored for first iteration analysis.

SFMU/PG&E Power Supply Cost

Although power supply costs will play a key role in determining the economics of creating an SFMU, there is no detailed electricity supply plan available for the City that describes the sources and costs of power. The ESS report offered rough estimates of SFMU energy commodity costs to be in the range of 3.9 cents to 4.1 cents per KWh (excluding exit fees that may be charged related to legacy DWR obligations), compared to an estimated PG&E tariff of 5.7cent per KWh. It also indicated that the exit fees would likely be set to increase the SFMU supply costs to PG&E's tariff costs. At the same time, it contained charts suggesting an SFMU cost advantage from avoidance of portions of the legacy cost obligations of IOU customers who become SFMU customers.

This report assumes that the legacy obligations of SFMU customers will be unavoidable. To assume otherwise would imply that regulators and the courts would allow legacy cost shifting among customers when creating an SFMU, at the expense of the remaining IOU customers. Such cost shifting is highly unlikely.

This means that the costs of a portion of an SFMU's power costs will be identical to PG&E's until the legacy obligations have been paid off. PG&E's recent portfolio of power sources has included about 65% of its load from DWR and QF contracts, and about 35% from retained generation. Therefore, it can be expected that the SFMU will be obligated to also take its prorated share (65%) of its load from DWR and QF contracts, or make financial payments to cover its portion of over-market costs included in those contracts, through exit fees or some other charge.

The SFMU will then need to cover the remaining 35% of its load requirements with wholesale power purchases and/or generation from City-acquired plants. In effect, this 35% portion of the SFMU load will be replacing power supplied by PG&E's retained nuclear and hydro generating plants, which are some of the lowest production cost units in California. PG&E's average generation cost is under \$20/MWh while the wholesale price of electricity delivered to NP15 has been hovering around \$30/MWh⁶. For the foreseeable future, the SFMU will face a very difficult task in obtaining replacement power priced below PG&E's retained generation cost. Over time, comparable cost replacement generation might be accomplished by the SFMU building new local high efficiency combined cycle units, and possibly distributed generation heat and power units. At some point, it may also be possible for the City to negotiate expanded use of to its Hetch Hetchy hydroelectric power.

It may also be the case that PG&E's bankruptcy workout plan will change the valuation of its retained generation. If the CPUC reorganization plan prevails, PG&E's retained generation will be under cost based CPUC regulation. On the other hand, if PG&E's reorganization plan prevails then pricing of the retained generation could change. Specifically, PG&E is seeking to move its retained generating units into a FERC regulated subsidiary that would sell the power back to the regulated IOU under a fixed price contract of about 5.1 cents per KWh, which is higher than current retained generation production cost⁷. The uncertainty surrounding the ultimate outcome of the bankruptcy proceeding also translates into uncertainty about the consumer cost impact of municipalizing PG&E's distribution facilities.

In addition to facing potentially higher power production costs in replacing PG&E's retained generation, SFMU customers may be exposed to the risk of being assessed significant transmission congestion charges in getting the power to San Francisco. This point was raised in the ESS report and should be seriously considered. It was pointed out that under PG&E tariffs, congestion charges are spread, by rate class, across the entire service area. Given the City's severe transmission constraints, the severance of the its distribution system from PG&E could expose City consumers to substantial congestion charges. This exposure could be exacerbated when the California Independent System Operator (ISO) moves to Locational Marginal Pricing (LMP). LMP distinguishes the incremental cost of supplying power at specific locations. Until the transmission constraints are relieved and/or efficient new production capacity is operating in the City, LMP could imply the risk of very large power cost increases to SFMU customers.

In replacing PG&E's retained nuclear and hydro generation, the SFMU will also be increasing the proportion of natural gas-fired electricity used in the City, which will increase the City's relative exposure to gas price volatility. As was demonstrated in the energy crisis, generation cost varies directly with the price of natural gas.

Distribution System Valuation

The magnitude of the system acquisition cost will be a major component of the SFMU cost structure and determines both the level of depreciation charges and interest payments. However, the value of the San Francisco portion of PG&E's distribution system is an open question. Data on PG&E's net book value is only available in FERC reports on a system-wide (not city-by-city) basis. A major study would be required to isolate the portion of the

system that would be taken over by the City in forming an SFMU. Once the scope of the San Francisco system is identified and its book value is determined, then the transaction valuation must be determined by negotiation or by the courts. Since there have been few IOU/MU conversions during the past two decades, there is not much actual experience to rely on in estimating the transaction valuation. The 1997 ETAG Report calculated San Francisco system valuations, using three different methodologies, to be in the range of 160% to 317% of book. Stone and Webster reviewed the ETAG valuations and suggested valuation figures in the range of 367% to 455% of book.

Scenario Analysis

Multiple scenario calculations were developed to explore the trade-offs between the key cost determinants, power supply costs and system acquisition costs. For the first set of scenarios, various combinations of relative MU/IOU power supply costs versus premium over book distribution asset prices (that are consistent with an SAR of \$11.27 per MWh⁸, a projection of PG&E's future average rate) were calculated. The base case for this set of scenarios is as follows:

Scenario A (SAR = \$11.27):

Assumption – SFMU and PG&E power supply costs are identical

Results – SFMU can pay up to a premium over book of 76% for the distribution system without increasing rates

A visual interpretation of this scenario and other related scenarios is shown on the chart entitled, *Premium Over Book vs Relative Power Cost, San Francisco*, Figure 1. The downward sloping line (isoquant) shows the combinations of SFMU/PG&E power supply costs and San Francisco distribution system asset prices relative to PG&E's net book value for the system, that are consistent with a constant average SAR of \$11.27 per MWh. The Scenario A base case results can be read from the chart. The vertical line from 100 on the horizontal axis (indicating MU power cost at 100% of IOU power costs) intersects the isoquant line at approximately 76% premium-over-book, on the vertical axis. The isoquant line summarizes all combinations of relative power cost and premium-over-book that are feasible without increasing rates above the projected \$11.27 per MWh. Suppose for example, that the MU's power cost is expected to be 120% of IOU power cost; then the chart shows that an SFMU could not afford to pay more than book for PG&E's San Francisco distribution system without raising rates above the \$11.27 SAR. This analysis was based on a projected PG&E average SAR of \$11.27 but similar analysis can be performed using other projections of PG&E's average future SAR's as shown below.

For the second set of scenarios various combinations of relative MU/IOU power supply costs versus premium over book distribution asset prices (that are consistent with SFMU customers paying an average SAR of \$13 per MWh) were calculated. The base case for this set of scenarios is as follows:

Scenario B (SAR = \$13):

Assumption – SFMU and PG&E power supply costs are identical

Results – SFMU can pay up to a premium over book of 210% for the distribution system without increasing rates

For the third set of scenarios various combinations of relative MU/IOU power supply costs versus premium over book distribution asset prices (that are consistent with SFMU customers paying an average SAR of \$15 per MWh) were calculated. The base case for this set of scenarios is as follows:

Scenario C (SAR = \$15):

Assumption – SFMU and PG&E power supply costs are identical

Results – SFMU can pay up to a premium over book of 365% for the distribution system without increasing rates

A visual interpretation of all of the above scenarios and other related scenarios, is shown on the chart entitled, *Premium Over Book vs Relative Power Cost, San Francisco*, Figure 2. This chart shows an isoquant line for each of the three SAR values. In effect, for any assumed SAR level, an isoquant line can be calculated from the Cost of Service Comparative Cost Model, which displays all combinations of relative power cost and premium over book that are consistent with the given SAR level. The entire map of isoquants will also show the SAR implied by any combination of relative power costs and asset valuation. For example it can be seen from Figure 2 that the combination of MU power costs at 120% of IOU power costs, and a premium over book of 290%, would imply an SFMU average SAR of \$15/MWh.

A fourth set of scenarios was developed to show the implications of the SFMU paying different wholesale prices for its net short power requirements (or load not covered by the DWR and QF contracts). For these scenarios D & E, it was assumed that all O&M costs (except the net short power supply costs) are identical for PG&E and for an SFMU. For these scenarios, low and high wholesale electricity prices are assumed and the model solves for the implied premium-over-book, consistent with an average SAR of \$11.27/MWh.

Scenario D:

Assumption – SFMU will purchase its net short at *low* wholesale prices averaging \$32/MWh.

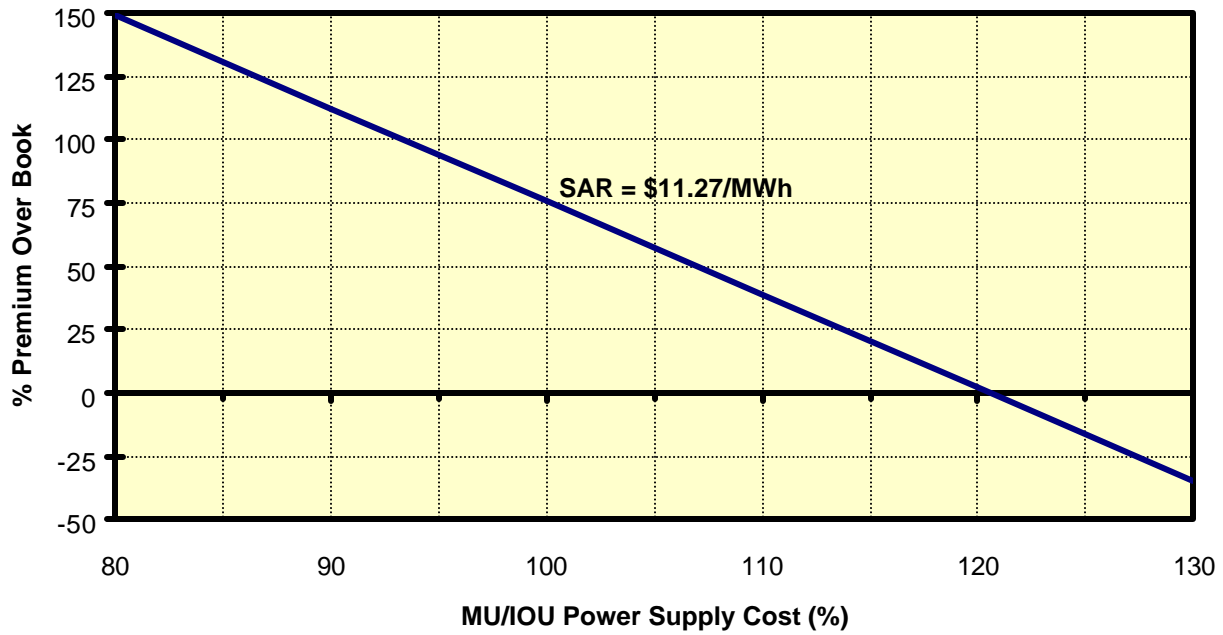
Results – SFMU can pay up to 50% premium over book for the distribution system without increasing rates

Scenario E:

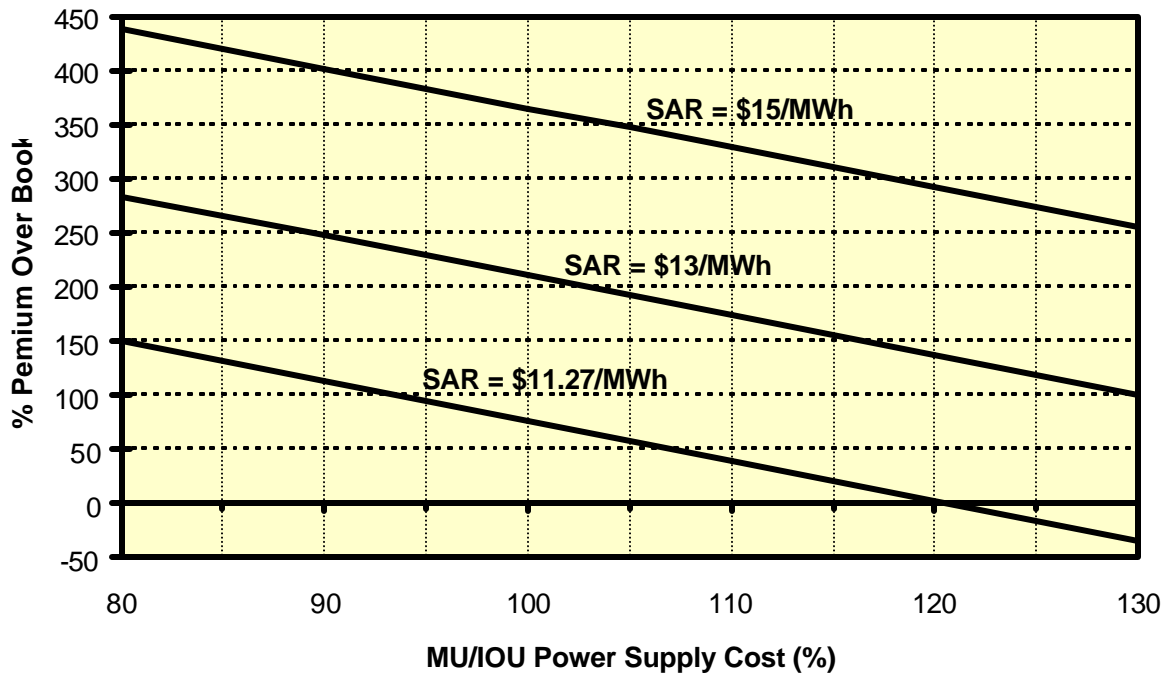
Assumption – SFMU will purchase its net short at *high* wholesale prices averaging \$38/MWh.

Results – SFMU can pay up to 32% premium over book for the distribution system without increasing rates

Premium Over Book vs Relative Power Cost
San Francisco
Figure 1



Premium Over Book vs Relative Power Cost
San Francisco
Figure 2



IV. Conclusion

This report has examined the issue of whether the conversion of regulated California investor-owned utility electric systems to new publicly owned and controlled municipal utilities will reliably reduce electricity cost and consumer financial risk. To explore the relative cost implications of municipalization, a Cost of Service Comparative Model was developed to reflect the differences between IOU and MU cost structures. The model was applied, as an example, using data specific to the San Francisco portion of PG&E's distribution system.

As shown in this report, California MUs have on average delivered lower cost electricity than IOUs. While relative MU/IOU costs were converging prior to the California energy crisis, the restructuring rules and market meltdown that occurred in 2000-2001 imposed greater cost burdens on IOU customers than on MU customers. This has prompted new interest in the potential benefits of converting IOU electric systems to public ownership and control. However, historical conditions no longer prevail, and the analysis of potential economic costs and benefits must be performed in the context of current and future conditions.

This report confirms that a new MU will be endowed with the key cost advantages of avoiding the payment of income taxes and using a debt-only capital structure. Working against these advantages is the fact that a new MU will face the necessity of buying the distribution system for its service area from an existing IOU at a premium over its net book value. The other critical factor in determining whether consumer costs will be reduced by municipalization is the cost of MU power relative to the cost power for an IOU. Unlike existing MUs, new MUs will not have access to low cost federal power, and also face the task of replacing the IOU's low-cost retained generation.

With adequate information on the distribution system's expected acquisition price and a new MU's expected cost of power, the rate implications of municipalization can be calculated. Without these figures for a specific municipalization proposal, its economic costs or benefits cannot be reliably estimated.

Both a clear power supply plan and a system valuation study are needed to establish a rational foundation for municipalization decisions. The primary focus of that analysis should be on developing a firm MU plan for obtaining power supplies (i.e., an integrated resource plan), and on estimating the distribution asset price relative to the book value that would likely be accepted by the incumbent utility or set by the courts. Once the costs of power and premium-over-book that can be paid for the distribution system have been established, implied MU rates compared to projected IOU rates can be estimated, to determine whether municipalization will result in rate increases or decreases.

San Francisco offers an enlightening case study. The City of San Francisco faces a complex and uncertain energy future as described in its Electricity Resource Plan. It will be an uphill task to resolve its immediate transmission constraints and local generation/conservation issues and avoid power shortages. Overlaid on this situation is Proposition D, which will be decided this November.

Proposition D will essentially authorize the San Francisco Public Utilities Commission (SFPUC) to establish a full service or vertically integrated municipal electric utility. Proposition D does not directly mandate the City's takeover of PG&E's distribution system, but leaves the option to be decided by the SFPUC, without further voter approval. This is a very significant decision, with economic implications for San Francisco residents for decades to come. However, the basic information needed for rationally evaluating the implications of the Proposition is not available. The sources and costs of the City's power supply portfolio have not been identified and the transaction valuation of the City's electric distribution system has not determined. Various valuations relative to book have been suggested but these cover a broad range, from 160% of book to 455% of book.

In the absence of the necessary power cost and asset valuation estimates, several scenarios have been developed to explore the trade-offs between the key SFMU cost determinants: power generation and purchasing costs, and system acquisition costs. The first scenario simulation showed that if an SFMU could match PG&E's power production costs, and could purchase the distribution system for less than 176% of book, then SFMU rates could be below or equal to PG&E's rates. Other scenarios examined the effects of varying power and system acquisition costs.

The charts developed from these scenarios give a visual snapshot of the constrained options available to an SFMU. As can be seen, finding a combination of power supply, and premium-over-book that will not increase rates and be acceptable to PG&E or the courts, will be a formidable task. There is scant evidence at this point that lower consumer rates will be reliably achieved through municipalization of the San Francisco distribution system. In addition to exposing San Francisco customers to the risk of higher rates, resulting from unknown power costs and system acquisition costs, severance from PG&E's system will also subject San Francisco customers to amplified financial risk through increased exposure to gas and wholesale electricity market volatility, and to transmission congestion charges. Addressing these issues will require more substantial analysis, including a clear power supply and system valuation study.

Footnotes:

- 1) The Report is available on the BAEF web site www.bayeconfor.com.
- 2) The ETAG Report argued that the MU SAR's should be adjusted upward to compensate for the equity over debt risk premium that is paid to IOU owners but not to MU customer/owners.
- 3) The Cost of Service Comparative Model utilizes the cost of service equation (which specifies that revenue requirements must cover all costs of providing service: operating expenses, depreciation, taxes, and return on capital investment) to organize comparable IOU and MU financial models. Discussion of the cost of service equation can be found in, Roger Morin, *Utilities cost of Capital*, published by Public Utilities Reports, and in *Resource: An Encyclopedia of Energy Utility Terms*, published by PG&E.
- 4) The cost related figures shown in this and subsequent sections were developed from the FERC Form 1 filings of the utilities.
- 5) A QF is a small power producer that meets certain guidelines set by the FERC concerning fuel type, efficiency, etc.
- 6) Source - Bloomberg Daily Power Reports
- 7) Materials related to the PG&E bankruptcy proceedings are available on PG&E's web site www.pge.com.
- 8) The average SAR estimate of \$11.27 was developed from California Energy Commission, Electricity Price Forecasts by Sector (7/19/02). The CEC forecasts of PG&E's SAR were, re-benched by the authors to be consistent with SAR data reported in PG&E's 2001 FERC Form 1 filing. The CEC forecasts are available on the CEC web site www.energy.ca.gov. PG&E's FERC Form 1 report is available on PG&E's web site www.pge.com



Bay Area Council

Sunne Wright McPeak, President & CEO
200 Pine Street, Suite 300
San Francisco, CA 94104
Phone: (415) 981-6600
Fax: (415) 981-6408
E-mail: info@bayareacouncil.org
Website: www.bayareacouncil.org



Bay Area Economic Forum

R. Sean Randolph, President
200 Pine Street, Suite 300
San Francisco, CA 94104
Phone: (415) 981-7117
Fax: (415) 981-6408
E-mail: info@bayeconfor.org
Website: www.bayeconfor.org



Association of Bay Area Governments

Eugene Y. Leong, Executive Director
101 Eighth Street
Oakland, CA 94607
Phone: (510) 464-7900
Fax: (510) 464-7970
Website: www.abag.ca.gov