SAN FRANCISCO
LOCAL AGENCY FORMATION COMMISSION
ENERGY SERVICES STUDY

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INTRODUCTION: REPORT PURPOSE AND ROLE OF SF LAFCo

Report Purpose

Reliable, reasonably priced electric service is vital to the economic health and public welfare of the City of San Francisco (City). During the past year, City residents and businesses have experienced unprecedented instability in the costs and reliability of their electric services. Given the bankrupt status of the City's current electric service provider and the uncertainty associated with the state's electric market structure, there exists public doubt as to the ability of PG&E and its state and federal regulatory authorities to properly meet the future electric service needs of the City.

Role of SF LAFCo

The SF LAFCo was formed in August 2000 as a result of an initiative petition to create a municipal utility district for the City and County of San Francisco and the City of Brisbane. Although this measure was narrowly defeated at the polls, the Commission determined that public hearings should be held to gather information from energy experts regarding the current utility service needs of San Francisco and the various options that may be available to increase service reliability, efficiency and cost effectiveness. These hearings are consistent with LAFCo's primary purpose which is to review public service needs, including utility service, and to determine whether new government entities should be created or changes in existing governments should be made to address the needs of its citizens.

From February 2002 until April 2002, the San Francisco LAFCo conducted a series of public hearings. The information provided through the hearings is available through the LAFCo Executive Officer. Representatives from the following public entities and private organizations provided presentations:

- SFPUC
- State of California Consumer Power and Conservation Authority (California Power Authority)
- CPUC
- PG&E
- Sacramento Municipal Utility District (SMUD)
- The Cities of Anaheim, Palo Alto, Roseville, San Jose, and Pasadena, California, and Austin, Texas
- Onsite Energy Group (specializing in cogeneration development and operation)

- The Utilities Reform Network (T.U.R.N.)
- Northern California Power Agency

The Commission has taken the results of that public information process, and has commissioned this study, utilizing a number of electric energy experts, for the purpose of exploring the various alternatives of the City to receive its vital electric services, and in particular, to discuss how each alternative might address the following three key issues that affect electric service in the City:

- High energy prices
- Reliability (shortages and outages)
- Local versus statewide control to address energy issues and services

"Electric Service" involves a range of activities, including generation, power purchases, load forecasting, transmission and distribution, energy efficiency and conservation, metering, and retail customer services. Basically, there are only two vehicles or alternatives for providing these services: i) private companies (e.g. PG&E, its subsidiaries and other private companies); or, ii) municipal entities (as a utility, district or as a city).

This Study will identify how each of these three key issues might be addressed by private companies or through one of the municipal forms (municipal utility, municipal district or city). The study will also assist the Commission in identifying the relative merits of pursuing some or all of these electric services through PG&E and other private companies, or, as an alternative, through some municipal form.

Finally, it should be noted that the matter of whether or not a particular electric service should be undertaken by a municipality, and in what manner, requires a complicated technical, legal, and financial analysis, involving a variety of factors beyond the scope of this study. This study does not go into the level of detail that would be necessary to conclusively evaluate the cost and revenues related to the various electric service activities (i.e. generation, power purchases, load forecasting, transmission and distribution, energy efficiency and conservation, metering, and retail customer services). Rather, this study discusses the relative level of expected costs and benefits of selected alternatives, and identifies areas in which further exploration is warranted.

More detailed economic studies would be needed after an appropriate municipal vehicle is selected (if one is selected), and after a governance body is established to oversee the scope and direction of such feasibility studies.

ENERGY SERVICES STUDY CONCLUSIONS

This is the final report of the San Francisco Local Agency Formation Commission (SF LAFCo or the Commission) Energy Services Study (the Study). It follows several working drafts that were reviewed by the Study Task Force and one public draft that was the subject of a public hearing and on which written comments were received.

Without regard to ownership and operation of the electrical system within the City and County of San Francisco, there are very definite risks and opportunities that are identified within this Study

San Francisco is Uniquely at Risk

Unlike the other major cities in California, the electrical system in San Francisco is uniquely at risk because of a combination of limited transmission to load center and limited local generation. Consequently, the loss of local generation or transmission capacity due to normal risks, such as scheduled maintenance or due to unforeseen risks (especially since September 11) can place the residents of San Francisco at risk almost any given day of the year. The California Independent System Operator (CAISO) concluded in its San Francisco Peninsula Long-Term Transmission Planning Study–Phase 2 Study Plan (see Appendix B) that:

> "The need of the Project (Jefferson – Martin 230 kV Transmission Project) is based on the inability of PG&E's existing transmission system to serve the project load in the San Francisco Peninsula Area beyond 2005, even with reinforcements to the 115 kV system north of San Mateo substation."

Even more troublesome is the lack of a coordinated effort to address these vulnerabilities. PG&E is currently in bankruptcy and, in that proceeding, is advocating the break-up of its parent company to allow for the separate ownership of its distribution, generation, and transmission facilities, with the generation and transmission companies to be effectively unregulated. Until the PG&E bankruptcy and corporate structure issues are resolved, it is unclear as to how the unique energy problems of San Francisco can be coordinated and resolved. It is also unclear as to how long and to what extent the residents of San Francisco will face reliability and economic penalties resulting from lack of effective transmission and generation planning and implementation.

Consideration of the existing generation at Hunters Point Power Plant and Potrero Power Plant Unit 3 is also warranted. While these generation facilities are needed to support reliability in the San Francisco area, their continued operation beyond 2005 cannot be considered without addressing the necessary upgrades that would be required for either of these plants, each at least 35 years old, to meet NO_x limitations. Thus, the long-term cost-effectiveness of investing additional dollars towards upgrading these plants over the development of alternative facilities will need to be considered. To ensure that there are adequate facilities to meet load in the San Francisco Bay Area by 2005, decisions must be made within the near future about the combination of new transmission, new generation, emissions reduction equipment, and/or conservation or load management resources that will be pursued.

San Francisco's Competitive Advantage

Despite the significant electric system risks that the City faces, it possesses significant competitive advantages, such as:

- Hetch Hetchy Water and Power (HHWP)
- Broad public support for:
  - Renewable resources
  - Conservation and efficiency
  - Local involvement

San Francisco's Options

The Study outlines several options for consideration by SF LAFCo that include:

- Ownership or participation in local generation and power supply markets with one or more of the following potential objectives:
  - Increasing local generation
  - Substitution for existing generation to obtain reduced emissions and enhanced reliability and efficiency
  - Serving retail load
- Ownership or participation in expanded transmission to:
  - Enhance reliability
  - Offset the need for some local generation
  - Reduce the potential for congestion price effects on retail rates
- Provide energy-related retail services via:
  - Aggregation as a Facilitator
  - Aggregation as an ESP
  - Community Aggregation
- Provide integrated retail electricity services, such as:
  - Full municipalization of the distribution system
  - Spot municipalization
  - Services to loads adjacent to SFPUC facilities

- Increase efforts in conservation, energy efficiency, renewable, and distributed generation.

These options are not mutually exclusive. In other words, SF LAFCo could decide to select one or more for further review or implementation, depending on the objectives of the community. Rough estimates of time and cost for further review and implementation are contained in Section 6.

The following table provides a matrix showing attributes of ownership type for the four elements of electric utility services as they affect each of the key issues, Rates and Pricing, Reliability, and Local Control.

Key Issues	Generation: PG&E	Generation: City Utility	Transmission: PG&E	Transmission: City Utility	Distribution: PG&E	Distribution: City Utility	Conservation, Energy Efficiency, Renewables: PG&E	Conservation, Energy Efficiency, Renewables: City Utility
Rates/Pricing	■ Lack of generation in the City forces reliance on energy markets ■ PG&E wants to pass along short term market risks and costs to customers ■ Market prices are often volatile and expensive, especially when shortages exist. ■ City will have little say in how high market prices get passed on ■ Energy market risks will be managed by PG&E to benefit shareholders not necessarily the City	■ The City could develop local options to deal with market exposure and risks, including long term contracts or City owned generation (power from Hetch Hetchy may also be available) ■ Retail prices and energy costs would be decided by the City ■ The City would control an average of 70% of the final retail price of electric service ■ Direct access must be renewed for aggregators, exit fees will likely apply ■ The City may need to compete with other energy providers	■ Transmission into San Francisco is limited and critical as the City does not have enough local generation to meet demand. ■ Given the CAISO proposed market rules, fees charged to manage transmission congestion are likely to increase ■ Transmission costs represent about 5% to 10% of retail rate and are regulated by FERC	■ The City may avoid CAISO fees by creating its own Control Area. This option would be expensive as the City would need to have sufficient City owned transmission and generation resources to balance supply and demand ■ The City could build new transmission and join the CAISO. This option would help relieve congestion while being cheaper than a City-wide control area ■ New transmission could be planned along with generation and distribution resources to minimize cost and maximize reliability	■ Distribution represents 15% to 20% of retail rate that is regulated by the CPUC ■ PG&E pays taxes and profits to shareholders that increase distribution rates	■ Purchasing the PG&E distribution system could be costly and contentious ■ Distribution ownership would avoid taxes and profits and have lower financing costs ■ Unique San Francisco characteristics (downtown network, average use and density) would affect distribution rates ■ Spot municipalization could be done in conjunction with redevelopment or water system improvements but would be costly and difficult to coordinate with PG&E	■ California law dictates funding levels ■ CPUC and CEC determine how program revenues are spent	■ The City is currently recognized as a leader in conservation and renewable generation development ■ Governing Board would determine the amount of funding and the programs that get funded ■ Money collected locally could be spent locally
Reliability	■ Financial conditions may affect reliability ■ Hunters Point and Potrero are inefficient, unreliable and environmentally constrained	■ The City could ensure loads are fully resourced either with new generation or energy contracts ■ Renewable or distributed generation resources could improve reliability ■ The City could tailor generation resources to meet local reliability needs	■ PG&E is proposing transmission expansions that should improve reliability ■ Short-term transmission will likely be congested and reliability could suffer	■ Developing own control area would likely enhance reliability ■ Building new City-owned transmission would enhance long-term reliability	■ Status quo would likely prevail ■ PG&E may get performance incentives	■ Long-term reliability would likely be the same as PG&E ■ Reliability could suffer with spot municipalization	■ PG&E has little incentive to improve reliability through distributed or renewable generation or energy efficiency	■ Reliability could be enhanced through application of conservation, distributed generation, or energy efficiency
Local Control	■ Influence over energy service issues and costs would be limited to interventions in CPUC or FERC regulatory cases ■ Shareholder motives drive energy policy	■ Governing Board determines customers to serve, contracts signed, and final pricing offered ■ Citizens have a voice in determining how to pay for City Utility energy costs ■ The City would determine how to offer energy service: various aggregation options or targeting specific loads	■ Constituents have little control over transmission prices, expansion plans, or operating policies	■ The City would determine when and where to build new transmission ■ Pricing would be controlled by the City, unless the City joined the CAISO	■ Limited to interventions in CPUC rate cases ■ Shareholder concerns will drive distribution policy	■ Distribution reliability, service options, as well as costs, rates and interconnection policies would be controlled locally ■ The City would determine how to best meet local needs with distribution resources	■ CPUC and CEC typically control key policy issues	■ Public would have control over funding, programs, policies, and program evaluation

Report Purpose and Industry Structure

Purpose

Since electric industry restructuring was first implemented in 1998, residents and businesses in San Francisco have witnessed or been affected by opportunities to participate in customer choice (Direct Access), the bankruptcy of the Pacific Gas and Electric Company (PG&E), wholesale electricity price volatility, retail electricity tariff increases, and unprecedented rotating blackouts. This Study has been prepared to support the development and evaluation of options available to San Francisco to better manage three key elements of electricity service:

- Rates and Pricing
- Reliability (shortages and outages)
- Local Control

This Study focuses on options available to San Francisco in regard to business roles and methods of service delivery that could have a material impact on the three elements listed above. The Study is primarily qualitative rather than quantitative. A quantitative evaluation cannot commence until policy options have been agreed to, scenarios and financial assumptions developed, and preliminary or prefeasibility analyses undertaken.

The Study contains sections that address the following electric services and issues:

- Wholesale Power Market Costs and Risks (Section 2)
- Transmission Issues (Section 3)
- Electric Energy and Distribution Service Issues and Options (Section 4)
- Conservation, Energy Efficiency, and Renewable Resources (Section 5)
- Next Steps and Issue Responses (Section 6)

Readers should understand that, even though the restructured electric industry has been unbundled in much this same way, there is significant linkage between these business components. As an example, the addition of new transmission can reduce the need for local generation; also, aggressive conservation and energy efficiency programs can offset the need for transmission, generation, and distribution facilities.

The services and issues are reviewed in relation to their impact on rates and pricing, reliability, and local control. Governance and ownership options are also discussed and presented in terms of three alternative service providers:

1. PG&E
2. San Francisco Public Utilities Commission (SFPUC)
3. A new San Francisco municipal utility (City Utility)

Where practical the authors have looked at the effects on price, reliability, and local control for each service provider option. This will be particularly evident in sections on transmission, distribution, and conservation and energy efficiency.

Industry Structure

The full Study provides a high-level view of the changes that have taken place since California began the process of restructuring the electric industry. That outline of how we got to where we are is useful, but not critical to the choices that San Francisco is considering. What is critical is an understanding of outstanding legislative and regulatory issues, the progress of new power supply resource additions (particularly in and around San Francisco), and the uncertainties that decision-makers will face as they consider policy alternatives. Important activities to follow include:

- PG&E is in bankruptcy. Two competing plans have been approved by a creditors committee that will be considered by the bankruptcy judge. Each would have very different outcomes with regard to PG&E's business structure, regulatory jurisdiction, and electricity tariffs.
- The Federal Energy Regulatory Commission (FERC) is considering issues such as rebates from generators and marketers for excessive power supply costs in 2000 and 2001; market restructuring to mitigate market gaming; transmission ownership, operation, and control; and price cap extensions. Decisions on each of these issues will affect the options available to San Francisco, including the Status Quo option. All three of the key elements of service will change as a result of FERC rulings.
- The California Public Utilities Commission (CPUC) and the California Legislature are considering ways to reinstate Direct Access. Decisions will affect the types of service delivery available for San Francisco's consideration as well as the exit fees or non-bypassable charges that could effectively financially block the implementation of these choices.

As these issues are resolved and more certainty in industry structure develops, stakeholders will make choices on investment in generation and transmission; electricity customers will be able to better evaluate their choices to invest in conservation, energy efficiency, demand management, renewable, and distributed generation; and new entities will evolve to take advantage of new market opportunities.

It has been eight years since California began to consider electric industry restructuring. Implementation has resulted in electricity cost penalties that will persist for the next 10 to 15 years. San Francisco policy-makers will be deliberating during a period of regulatory and legislative uncertainty, electricity price instability, periods of compromised reliability, and rapid industry evolution.

Power Supply

Since the federal government encouraged competition in wholesale power markets through the Energy Policy Act of 1992, there has been a proliferation of new players (Independent Power Producers and Energy Merchants) in wholesale power markets. Independent Power Producers are building power plants and offering the power to load. Energy Merchants buy the rights to output of power plants and resell power. These players also provide numerous physical and financial options to load serving entities for purposes of ensuring reliability and hedging risks. Transmission access rules are also going through major overhaul, as FERC attempts to ensure that there is optimum ability for competing supplies to reach electric loads.

Last Year's Problem

Following deregulation, wholesale power supply prices throughout California remained within a predictable range until May 2000. Then a combination of the following factors caused severe price excursions:

- During the decade of the 1990s, growth was occurring and generating reserve margins were declining.
- Above-average hydro conditions masked the effect and kept prices somewhat depressed.
- Developers were reluctant to pursue new projects due to these economics and the difficulties in permitting new generation projects.
- PG&E and other Investor-Owned Utilities (IOUs) were, for a variety of reasons, highly dependent on short-term spot-market energy purchases.
- Retail rates were frozen and not linked to wholesale energy prices, effectively discouraging any demand response to price increases.
- Hydroelectric generation in the West declined markedly in the summer of 2000.
- Natural gas storage was low and a major pipeline into California failed just as the demand for gas to fuel thermal power plants escalated.
- Natural gas costs make up a predominant share of the cost of units that were required to meet margins on the peak. This drove up generating costs.
- Energy traders may have been manipulating gas and electricity markets, exacerbating the situation.
- Soft price caps were not effective in controlling price excursions

Near-Term Outlook

Today's outlook for wholesale power prices in the next few years is more positive. Wholesale power prices have been moderate, if not depressed during the past year. This price downturn is the result of the concurrent economic downturn, retail rate increases, significant consumer conservation, return to normal hydro conditions, and the completion of new generating plants to increase supply. Regulatory response to charges of market manipulation, including the short-term continuation of price caps, should help moderate prices as well.

The conclusion is that:

- Wholesale prices are likely to remain stable and slightly depressed throughout the Western Electricity Coordinating Council (WECC) region.
- Comfortable reserve margins will be maintained for the foreseeable future.
- Considerable uncertainties will persist.

Long-Term Outlook

Key regulatory issues of specific concern to San Francisco include:

- The potential imposition of Locational Marginal Pricing (LMP) that could increase costs due to transmission constraints and the fact that local generation is insufficient to meet local demand.
- Environmental risks associated with local gas-fired generation.
- Technological change, such as more efficient new generation, expanded use of distributed generation, and electricity storage.

In the WECC region, power supply and demand balance is predicted until about 2009. In San Francisco, by 2003, supply from local generation (650 MW) is expected to meet only two thirds of the estimated 960 MW of demand at the best of times assuming all generation is available. Any deficiencies will have to be imported over transmission into the Bay Area and the City of San Francisco. Reserve margins, considering only resources located within the City of San Francisco, are forecast to be −32.3% in 2003 and worsen to −44.4% by 2012. Hence, there is a clear need to provide for more resources (and/or conservation) within the City of San Francisco and ensure the importation of power supplies over the transmission lines.

Wholesale Generation Market Risk Factors

To the extent that the SFPUC or a new San Francisco municipal utility takes on any obligation for energy supply, whether through some form of aggregation or distribution service, it will need to consider the following risk factors:

- Integrated planning will be required to balance power supply commitments and loads.
- Volatility and market uncertainties will carry very significant risks.
- Forward contracting will be essential.
- Long-term risks will affect the economic viability of market participants. Relevant risks are demand uncertainty (including loss of customers), supply risk, fuel price risk, market and environmental regulatory uncertainty, and technological change.

- Short-term market price fluctuations will be driven by weather, seasonal hydroelectric potential, fuel price, generating equipment outages, and transmission availability.

Developing a portfolio of electricity supply sources for a load that fluctuates hourly, daily, monthly, and annually is a complicated undertaking. Only through a detailed Integrated Resource Plan (which adequately addresses load and power supply risks) will it be possible to identify an appropriate portfolio of supplies and determine the cost of the commodity to consumers. An effort has been made to provide a rough estimate of generation costs to meet loads in the San Francisco Peninsula area. The three scenarios analyzed and rough costs are:

Electricity Supply Alternatives	Approximate Cents per kWh
1. 100% Purchases From Spot Markets	3.9¢ + Exit Fee
2. 50% Long-Term Contract, 50% Spot Market	4.1¢ + Exit Fee
3. PG&E Tariff (Utility Generation + CDWR)	5.7¢

The numbers presented above do not reflect "exit fee" ramifications and therefore, one should not infer from this table that the PG&E tariff costs[1] more than either Scenario 1 or Scenario 2. In theory, since the exit fees are calculated to make the utility and CDWR indifferent to customers going to direct access, then the exit fee that would be added to Scenarios 1 or 2 would increase the generation cost component of those scenarios to roughly that of Scenario 3. The CPUC is in the midst of the process of determining exit fees for Direct Access customers. The outcome of this proceeding can impact the cost under each of the three scenarios. In order to evaluate any City Utility role in power generation or contracting, it would be necessary to add exit fees to Scenarios 1 and 2 and to update CDWR and other exit fees in Scenario 3.

Power Supply Options for San Francisco

Options for San Francisco include:

- Continue to rely on PG&E and the CAISO to effectively address transmission constraints, offsetting the need for local generation.
- Continue to invest in and to escalate programs for renewable and distributed resources in San Francisco.
- Rely on developers to replace and expand insufficient and unreliable power plants with new technology-efficient and low-emission generation.
- Invest in transmission upgrades into San Francisco.
    - Create a Control Area and retain operational control.

[1] PG&E Tariff Costs are based on data presented in the CEC's 2002-2012 Electricity Outlook Report modified to reflect Henwood's assessment of the CDWR contract costs. Many new proposals have and are being evaluated since the publication of the CEC report; hence, data in it may not accurately reflect current assumptions.

  - Invest in and turn transmission upgrades over to CAISO to enhance revenue recovery.
- Invest in new generation at the airport or other appropriate sites. Revenues can be recovered using a variety of mechanisms, such as:
  - Sell into the market.
  - Bilateral contracts.
  - Retail sales through aggregation of fully integrated distribution.
  - Supplement and firm up Hetch Hetchy supplies; sell balance.

Ownership of generation would allow a City Utility to avoid price volatility, market abuse by entities that have excessive market power, and to control the amount of renewable resources contained in the resource mix.

Transmission Issues and Options

The existing transmission into San Francisco is planned according to standards that are equal to or higher than those used elsewhere in California. Unfortunately, electric consumers in the city continue to obtain less reliable transmission service than other parts of the state due to continued reliance on old, unreliable and emission-limited generation at the Hunter's Point and Potrero Power Plants.

PG&E is planning on building new transmission into and within the Bay Area. If completed, this will increase reliability and may reduce costs to San Francisco customers. Cost reductions would take place under current regulations that spread the costs of transmission additions over a large service area, whereas avoided congestion charges are proposed to be recovered locally. Still, the transmission additions by PG&E may not fully mitigate San Francisco's potential exposure to congestion charges.

Because of the potential of continuing transmission constraints under PG&E, local generation and conservation will be important to improve reliability and reduce exposure to high energy prices for San Francisco. City Utility-controlled generation within the city would provide similar benefits to new transmission, and potential City investments in generation should be evaluated in an integrated manner that considers the relationship between transmission, generation, conservation, and energy efficiency.

Transmission Opportunities

The City has many opportunities to influence or participate in the creation of an integrated solution to reducing the cost and improving the reliability of San Francisco's power supply. Three of these opportunities are listed below and each could be pursued by a City Utility.

- The City Utility could develop new transmission, turn it over to CAISO for control, and recover its investment from CAISO payments. This may be the most economic solution.

- The City Utility could create a separate control area to increase local control, particularly with regard to improving reliability and reducing exposure to rotating blackouts. This solution is likely to be more expensive to San Francisco's electricity consumers than using CAISO-controlled transmission.
- The City Utility could explore targeted transmission projects that could result in an attractive revenue stream, providing benefits to all City consumers, as well as to specific customers connected to the City Utility's transmission facilities.

Electric Retail Service Issues and Options

San Francisco currently receives distribution services from two utilities: Hetch Hetchy Water and Power (HHWP) and PG&E. HHWP is a support bureau of the SFPUC and serves most City loads either with City-owned distribution (such as at the airport) or employing PG&E distribution through an interconnection agreement with PG&E. PG&E provides retail distribution service to all of the other residential and business customers in San Francisco.

The obligation to provide power supply transferred from PG&E to CDWR in January 2001, although a portion of the power supply is provided by generation that is still owned by PG&E and power purchased under contract by PG&E.

Service Options

There are four options that have been considered for supplying retail service in San Francisco. They include two types of Aggregation (Facilitator of Aggregation and Aggregator as an ESP), Community Aggregation, and Integrated Distribution Service. Each of these is discussed in the Study.

Aggregation

Aggregation can take two forms:

- **Facilitator of Aggregation**. This is the low-risk version where the City Utility would, through their procurement process, select one or more Energy Service Providers (ESPs) and develop standard pricing and service terms that would be available to San Francisco customers. Using the standard terms, customers would contract directly with the ESP such that the City Utility has no financial risk. This is similar to the business model used by the Association of California Water Agencies for their aggregation program.
- **Aggregator as an ESP**. This is the higher risk approach where the City Utility would become an ESP. This is similar to the business model adopted by the Association of Bay Area Governments for their aggregation venture. The City Utility would be responsible for building or contracting for power supply resources, arranging for transmission, scheduling, etc., to meet the load requirements of customers who participate. The City Utility then takes on the risk of price competition, customer departure, stranded investments, and adequacy of

supply. In both of these approaches, marketing would be required to attract and retain customers in what is expected to become a very competitive market.

Community Aggregation

Community Aggregation is much like the high-risk aggregation model with the risk level lowered by employment of an “Opt-Out” strategy. This means that if the City Utility became a Community Aggregator, all customers would automatically transfer to the City’s ESP services unless they opt out. This reduces marketing costs, transfer costs, and greatly enhances the potential for financial success.

Integrated Distribution Services

One of the commonly proposed alternatives to PG&E is the purchase of the distribution system by the City, allowing the provision of fully integrated service. The first option available to San Francisco is to maintain status quo, that is, full service from PG&E. This option is compared in the Study with two full-service municipalization governance options. The two governance options include either the SFPUC or the formation of a new and independent San Francisco municipal utility. Since in most cases these are only minor differences, these two governance approaches are often combined and discussed as “the City.” The following table details the major generic similarities and differences between PG&E’s and the City’s options.

Table ES-1
Comparison of Distribution Services between Public Utilities and PG&E

Service	Public/Muni Distribution Services	PG&E Distribution Services
Electric Design, O&M	■ Similar design standards and construction practices. O&M can depend on budget allocations and be affected by distribution system conditions.	
Reliability	■ Similar standards, both measure System Average Interruption Frequency Index and System Average Interruption Duration Index indexes and attempt to minimize outages.	
Safety	■ Both adhere to CPUC's General Orders 95 and 128 standards.	
Financing	■ Financing comes mainly from tax-exempt bonds.	■ Typically a higher cost of capital that is composed of bonds as well as common and preferred stock. ■ Has limited access to tax-exempt debt. ■ Financing cost and access can be volatile and unpredictable.
Rates/Pricing	■ Historical prices have averaged 20% below IOUs for similar customer segments.	■ Already have unbundled prices for all customer segments. Usually more pricing options than Muni.
Taxes	■ Publics are exempt from income taxes, some property taxes, and most franchise fees.	■ IOUs pay income taxes, property taxes, and franchise fees.
Regulation	■ Self-regulated by a locally elected or appointed governing body.	■ Regulated by at least the CPUC and FERC
Public Benefit Programs	■ Usually more emphasis on low-income programs, (with community involvement) in mix of public benefit programs.	■ Provides public benefit programs with CPUC oversight.
Resource Mix	■ Usually have more federal hydro power than IOUs.	■ IOUs have limited and declining access to federal hydro power.

The benefits of public ownership have generally been lower rates, historically averaging 20% lower, and the opportunity for local control. Distribution reliability has historically been about equal for public and private ownership. The potential for rate savings under fully integrated electric services is likely to start small and grow over time. The decision to consider this approach may be influenced by the importance of integrating planning that can only be fully implemented when the energy supplier also distributes that energy. In turn, integrated planning is the key to effective balance of generation, transmission, conservation, and energy efficiency. Without this balance, it will be more difficult to rebuild a reliable electric supply system for San Francisco.

A more in-depth discussion of public and private ownership of electric utilities is contained in Section 6.

The biggest risk to municipalization is the likelihood of contested acquisition of the PG&E distribution facilities. Due to geographic circumstances, severance (often a significant part of acquisition costs) would be relatively small for San Francisco.

Spot Municipalization

Spot municipalization is a subset of Integrated Distribution Services and avoids the need to acquire PG&E distribution facilities. Under this approach, a City Utility would provide distribution services only in redevelopment areas or new developments where new distribution facilities are installed as part of the development. After installation of its required share of the electric infrastructure, the developer would turn the facilities over to the City Utility instead of PG&E, as is the current practice. Because the City Utility would not pay income taxes, the developer would save the 34% gift tax they would otherwise have paid to PG&E. From a benefit and risk perspective, this approach is attractive in that it avoids the difficulty of acquiring PG&E facilities and it saves the 34% cost to the developer of deeding facilities to PG&E. However, the costs of operations and maintenance (O&M) will likely be higher, as the City Utility has to serve non-integrated pockets around San Francisco, reliability may be compromised because of the difficulty of providing alternative or back-up connections to the PG&E distribution grid, interconnection costs with PG&E will add to the cost of service, and different residents and businesses will be provided with different service standards and rate structures.

Other forms of Spot Municipalization include:

- Parallel construction of electric conduits and cables when replacing or installing new sewer and water pipelines.
- Acquiring facilities from PG&E at the time of overhead-to-underground conversions.

In both cases, detailed feasibility studies would be required to assure cost-effectiveness and practicality considering legal and reliability issues.

Impact of Alternatives on Key Considerations

The service delivery options are all somewhat differently impacted with respect to the key considerations, depending on ownership and governance structures. This Study addresses these differences for each service option and key considerations.

Energy Services Only (Various Forms of Aggregation)

Aggregation Facilitation, Low-Risk Model

Aggregation of this type is dependent on reinstatement of Direct Access. The City Utility would select and negotiate standard pricing and terms with one or more ESPs. The customers would contract directly with the ESP, relieving the City Utility of supply and cost risk.

- **Rates and Pricing**. One would expect very little difference in rates or pricing from those offered by other competitors. The melding of Hetch Hetchy power is not assumed in this case. The only economic advantage that would be passed on to the customer is a lower marketing cost due to a trust factor that many potential customers may feel towards a public agency, as compared to large energy companies that have, as a group, developed a tarnished image.

- **Reliability**. Since PG&E would be providing distribution services, there should be no change in delivery reliability. If rolling blackouts were to return, the fact that PG&E is delivering the power means that City Utility energy customers would share the same rolling blackout risks as PG&E full-service customers.
- **Local Control**. There would be local control in the selection process of ESPs and some potential influence on pricing and terms available to retail customers. However, market competition is likely to be the dominant factor in service costs and terms, minimizing the effect of local control.

Aggregator as an ESP, High-Risk Model

This is also dependent on reinstatement of Direct Access. The City Utility would become the ESP and have the obligation for sufficient power supply and the risk associated with matching that supply to the aggregated loads (minute by minute). Competitors would include PG&E bundled service and any other aggregator.

- **Rates and Pricing**. Since the City Utility would have no market energy purchasing advantage and maybe even some disadvantage versus large national ESP firms, its only competitive advantages will be the ability to integrate some low-cost Hetch Hetchy power and the “trust factor,” as described above. Any potential melded energy cost advantages will depend on the size of the aggregated load. The bigger the program, the lower percentage of Hetch Hetchy power and the lower the discount, as limited Hetch Hetchy supplies are spread farther and farther.
- **Reliability**. No change form PG&E bundled services.
- **Local Control**. The Aggregator as an ESP would have the ability to structure rates, rules and regulations, and public benefits programs differently than those offered by PG&E. However, the state-mandated public benefit expenditures are financed by charges on the distribution system (PG&E). Any additional programs or any subsidy by one customer class of another customer class would likely lead to the loss to another competitor of that class doing the subsidizing. As a result, although local control would exist, its effective use may be limited by economic considerations.

Community Aggregation

Community aggregation is still only a concept and depends on the passage of legislation, such as California Assembly Bill (AB) 117 (Migden), to even become an option. Under the current concept, the only potential provider would be the City Utility or a Joint Powers Authority with San Francisco as a member. The key advantage of community aggregation, as compared to other forms of aggregation, is that on implementation, all customers not opting out would transfer to City Utility energy service.

- **Rates and Pricing**. The City Utility would be competing with regulated bundled services from PG&E or, if Direct Access is reinstated, with other ESPs and aggregators. The product served would be energy only. The financial advantages held by the City Utility would be access to some low-cost Hetch Hetchy power and lower marketing costs due to the "opt-out" provision that defines this concept. Under AB 117 (as amended on June 5, 2002), customers would be obligated to pay the equivalent of exit fees to protect PG&E debt and to pay a share of CDWR power cost obligations. From the standpoint of the cost of purchasing wholesale energy, the City Utility would have no market advantage. Any competitive edge would depend on the percentage of the melded energy resources that are available from Hetch Hetchy or other San Francisco-owned resources. Without below-market cost resources, the City Utility would have little, if any, competitive price advantage.

- **Reliability**. Reliability issues are the same as for the other forms of aggregation, i.e., no change.
- **Local Control**. This is the same as for Aggregator as an ESP. Local control would exist but the requirement for competition would dampen its effectiveness.

Distribution Services

Full Municipalization

The City Utility would acquire the PG&E distribution system and provide fully integrated electric service.

- **Rates and Pricing**. Rate differences would depend on several key factors, including the cost of acquisition, severance costs, power supply costs, and any obligations to pay exit fees or other non-bypassable charges. Over time, exit fees and similar charges will diminish and finally go to zero. From the standpoint of price competition, it should be noted that PG&E rates will reflect the same changes in price related to declining exit fees and non-bypassable charges.
  - **PG&E**. PG&E, as an investor-owned distribution utility, is regulated by the CPUC. Rate levels are generally set on a Rate Base concept where PG&E is allowed to earn a Return on Investment (ROI) on distribution and customer service facilities and to recover its costs of O&M. The allowed ROI is established periodically based on a weighted cost of capital, including the melded cost of common stock, preferred stock, and debt. PG&E's weighted cost of capital can be expected to be relatively high due to its financial difficulties, including a reduction in its stock value and the downgrading of its debt. Most PG&E debt is taxable, although it has issued tax-exempt pollution control bonds.

    PG&E pays property taxes and a franchise fee (normally 1% of gross revenues). They also pay federal and state income taxes that are paid before distribution of dividends to stockholders.
  - **SFPUC**. It is assumed that the SFPUC would incorporate the distribution business within the Hetch Hetchy enterprise activity, allowing it to integrate some below-market cost hydroelectric power with bundled electricity services. Bundled rates would, therefore, reflect the following:
    - Lower costs of distribution due to a PG&E burden of 30% for combined taxes and profits. Since distribution makes up about 20% of the total

power bill, this translates to a 6% advantage in melded costs for a publicly-owned utility that had built its own distribution system. These savings can be offset by purchase of a distribution system at a highly inflated price.

- Unknown higher costs of facilities, depending on costs of acquisition and severance.
- Any power supply cost benefits from Hetch Hetchy.
- Potentially higher transmission costs due to higher San Francisco transmission costs versus PG&E system average.
- Higher average distribution costs due to the high cost of the downtown network no longer being averaged over the PG&E system.
- Lower residential distribution costs than average due to service area density. This may be offset in terms of cost per kilowatt-hour by the relatively low use per average residential customer.
- Lower costs due to synergy between electric service and other SFPUC utility services. Examples include overheads, customer systems, metering, and billing.
- Somewhat higher costs of starting with an existing set of restrictive policies and procedures, work rules, and union agreements.
- Somewhat lower costs by starting with an existing work force and infrastructure.

It cannot be determined without in-depth analysis how all of these pluses and minuses work out in the short term. However, in the long term (30 years), if San Francisco is like other public power communities, it is likely to obtain a net cost advantage that has historically averaged about 20%.

- **New San Francisco Municipal Utility**. It is unclear whether a new and independent San Francisco municipal utility would obtain the benefits of below-market cost Hetch Hetchy power. For purposes of this discussion, it is assumed it would not. Bundled rates would, therefore, reflect all of the points noted for the SFPUC, with the following exceptions:
  - No power supply cost benefits from Hetch Hetchy due to existing contracts.
  - No value of synergy with other utility services.
  - A need for a new customer care system.
  - The costs of setting up a new organization and infrastructure but with the benefits of starting from scratch.

  As with the SFPUC discussion, there is no certainty as to the net effect of all the pluses and minuses. It should be noted that the pluses of the SFPUC approach could be maintained, while the minuses are reduced by reforming the SFPUC in light of the needs of competition in the electric industry. Some reforms have been proposed in a Charter Amendment set [scheduled?] for vote in November 2002. The largest potential differentiator between the

SFPUC and the San Francisco municipal utility approaches is the ability to make below-market cost Hetch Hetchy power available to San Francisco consumers.

- **Reliability**. Investor-owned and publicly-owned distribution utilities in California follow the same CPUC-approved construction standards and report service interruptions using industry standard indices. There have been instances where CPUC rate regulation has resulted in PG&E reductions in O&M expenses (with attendant outage frequency increases). In the long term, it should be expected that overall distribution system reliability from PG&E would be equivalent to that which would be available from a San Francisco municipal utility.
- **Local Control**
  - **PG&E** is regulated by the CPUC, which is headquartered in San Francisco. The CPUC establishes rates, rules, and regulations for the entire PG&E service territory. Several years ago it eliminated the distinctions between service zones such that rural and urban communities pay the same rates even though their costs of service differ because of load density and weather-related customer load characteristics. Currently, about 2.3% of PG&E's total revenues, including those collected on behalf of the CDWR, are committed to public benefit programs. The allocation of these revenues to each of four program categories was set by the Legislature. The further allocation of the revenues to specific programs is regulated by the CPUC or the California Energy Commission (CEC).

    If a customer has a service or billing complaint that is not satisfactorily addressed by PG&E, their primary recourse is the CPUC. Although housed in San Francisco, the process of filing a complaint and ultimately being heard by the CPUC is lengthy and somewhat intimidating.
  - The **SFPUC** is regulated by a commission that is appointed by the Mayor, resulting in a regulatory body that is one step removed from the voting public. (The draft Charter Amendment would change who appoints and establishes qualifications for appointees.) Although still addressing local problems and local solutions, there may be a perception that an appointed body is not as responsive to the public as would be an elected governing board. Other issues, such as historical experiences with water and wastewater services, joint cost allocations between enterprises and political concerns, may all play into the effectiveness of this form of governance.
  - A **San Francisco Municipal Utility** could be an independent agency with its own elected or appointed governing body. The use of an elected body would provide the opportunity for the highest level of local control. Constituents can directly communicate with their elected representative to address matters of community concern.

Conservation, Energy Efficiency, and Renewable Resources

The issues surrounding the responsible use of energy and the environmental impacts of electricity generation are of extreme interest and have a high level of community awareness in San Francisco. As a result, San Francisco is already doing more than most other communities in terms of promoting energy efficiency and in the development of renewable resources. Current City programs go beyond those funded with public benefit funds collected by PG&E in connection with distribution services. The issue of local control over public benefit fund expenditures is addressed in connection with elements of distribution system ownership. The most relevant consideration affecting the City's role in the electric business in connection with energy efficiency and renewable resources is the opportunity to assure integrated planning for all elements of electric service. Integrated planning would allow evaluation of trade-offs between local central station generation needs, transmission capability, distributed generation, distribution system design, rates, rules, and regulations. As a fully integrated utility, the City could make integrated planning a foundation for all future facility additions and service standards. PG&E, as an unbundled distribution utility, is not ever again likely to be able to establish that type of foundation.

Conclusions

San Francisco is uniquely at risk with regard to the cost and reliability of its power supply. Risk factors include:

1. Limited transmission into the Bay Area and San Francisco.
2. Old, inefficient, unreliable generation with insufficient capacity to provide self-sufficiency.
3. A changing electric industry regulatory structure that:
   - has resulted in, and will continue to allow, wholesale electric price volatility, and
   - will likely change retail pricing to more closely track wholesale costs and to penalize San Francisco for the combination of insufficient generation and transmission congestion.

San Francisco has the SFPUC that provides municipal electric utility services through Hetch Hetchy and owns hydroelectric generation and transmission that may not be used to its maximum economic value for San Francisco consumers. San Francisco also has the opportunity to employ other municipal approaches to providing energy services in San Francisco.

Expansion of municipally-provided electric service and reliability can be achieved through the SFPUC or other forms of organization and governance. Business roles and services that can be considered include:

- Ownership or participation in local generation and power supply markets with one or more of the following potential objectives:
  - Increasing local generation
  - Avoiding market price volatility and market power abuses
  - Substitution for existing generation to obtain reduced emissions and enhanced reliability and efficiency
  - Serving retail load
- Ownership or participation in expanded transmission to:
  - Enhance reliability
  - Offset the need for some local generation
  - Reduce the potential for congestion price effects on retail rates
- Provide energy-related retail services via:
  - Aggregation as a Facilitator
  - Aggregation as an ESP
  - Community Aggregation
- Provide integrated retail electricity services, such as:
  - Full municipalization of the distribution system
  - Spot municipalization
  - Services to loads adjacent to SFPUC facilities
- Increase efforts in conservation, energy efficiency, renewable, and distributed generation.

Each of these roles and services are discussed in this Study as they relate to rates and pricing, reliability, and local control.

Section 1
ELECTRIC INDUSTRY STRUCTURE: YESTERDAY AND TODAY

Electric Industry Yesterday

In response to the excesses of 19th century monopolies and trusts, the California Constitution in 1879 established a regulatory body known as the Railroad Commission to regulate certain essential utility services such as privately owned railroads, heat, light, power, water, and telegraph companies (*Calif. Const. Art. 12, Sec. 3*). This commission later became known as the CPUC. In exchange for receiving monopoly service territories, these regulated "public utilities" were allowed to charge "reasonable" prices for their services, as approved by the CPUC, that would allow these private companies to earn a "reasonable return on investment". The "regulatory covenant" became the centerpiece of the relationship between the regulated (*i.e.,* the public utility) and the regulator, the CPUC.

At the same time that the Railroad Commission was created, the California Constitution also provided an important alternative. Article 11, Section 9, granted California cities the constitutional right to provide their own utility services (light, water, power, heat, transportation, or means of communication). To fully implement this constitutional right, municipalities were also given the full statutory power of condemnation. *Code of Civil Procedure Section 1240 et seq.* Thus, if regulation of a public utility failed to produce reasonable rates, the municipality could exercise its constitutional right to form its own municipal utility to provide that same service.

By the middle of the 20th century, there were three dominant private electric utilities in California, each regulated by the CPUC: PG&E, the Southern California Edison Company (SCE), and the San Diego Gas and Electric Company. These large utilities owned the vast majority of the transmission facilities in California and up into the Northwest. In the 1960s, they began looking to nuclear power as a new source of meeting the increasing power demands of a rapidly growing California.

During that same time period, there were approximately 30 municipally-owned electric utilities, ranging from very small utilities like Biggs and Gridley to large ones like the Los Angeles Department of Water and Power and SMUD. In the mid-1960s, many of these municipal utilities made important choices as to their sources of energy. Some turned to the private utilities as their primary wholesale power suppliers, while others made long term commitments to purchasing their power from the federal government's hydroelectric facilities pursuant to "preferential rights" under federal law.

By the mid 1970s and 1980s, many of the municipal utilities became disillusioned with the prospect of purchasing their power supplies from the large private utilities to meet their entire or supplemental needs, and formed joint power agencies for the purpose of sharing risks in the construction of new power plants and transmission facilities, and in otherwise meeting their future power supply needs. This proved to be a prudent decision on the part of such independent-minded municipal utilities, as the differential in utility rates between the private utilities and municipal utilities began to widen in favor of the municipal utilities.

By the early 1990s, there was growing ratepayer dissatisfaction with high energy bills from the private utilities, especially compared with the national averages. There was also mounting disillusionment with the "regulatory covenant" and the ability of the CPUC to assure reasonable utility rates. Electric industry restructuring had already been initiated in some other countries and California followed suit with its own programs for regulatory change. At the same time of this regulatory reform for private electric utilities, municipal utilities around the nation were aggressively seeking access to the growing wholesale power markets through transmission reform at the FERC and at the state CPUC. The ability of the private electric utilities to forestall wholesale competition with municipal utilities by virtue of their monopoly ownership of the transmission grid was rapidly eroding.

Electric Industry Restructuring

In 1994, large commercial customers in California began a campaign to "deregulate" the electrical supply industry in an effort to reduce the cost of electricity and ultimately lower their production costs. California was in the midst of an economic downturn and energy-intensive businesses, such as aerospace and manufacturing, were moving out of state. In 1996, State Assembly Bill 1890 (AB 1890), authored by State Senator Steve Peace (D-El Cajon), was unanimously passed by the Legislature and signed into law by Governor Pete Wilson. AB 1890 was touted as the means to transition from a regulated, vertically-integrated, utility environment to unbundled electricity supply, transmission, and distribution markets, with the goal of reducing costs by creating competitive markets. Among other things, the legislation:

- Allowed PG&E customers to be able to purchase their energy from ESPs.
- Required PG&E to collect their stranded cost investment through a Competition Transition Charge (CTC), or fixed energy component, on all customers' bills, even those being served by a new ESP.
- Established the CAISO and the California Power Exchange (PX) for transmission management and market trading.
- Strongly encouraged the IOUs to divest at least 50% of their thermal power plants through financial incentives.
- Required the IOUs to sell all output into the PX.
- Required the IOUs to purchase all needs from the PX day-ahead (and later, block forward) market and the CAISO's hourly real-time market.

The legislation was signed by Governor Wilson on September 23, 1996. Groups as diverse as utilities, consumer advocates and large business organizations supported the bill. IOUs were promised full recovery of stranded generation assets, consumers were given promises of rate decreases, and industrial customers were given the promise of lower rates and service provider choice.

The Transition Period

At the outset of restructuring, the supply of generation available to California exceeded the demand by a fairly wide margin. Rather than selling off only 50% of their thermal power plants as encouraged by potential economic penalties in the law, the IOUs divested nearly all of their thermal power plants. Wholesale electric prices were low but retail customers saw little difference in their bills due to the mandatory fee on their bills (the CTC). Few residential or small commercial customers made use of their ability to switch providers, since the CTC prevented them from achieving any real savings on their bills. However, about one-third of industrial customers exercised their option to switch ESPs because they were able to obtain discounts from ESPs anxious to establish a foothold in one of the country's first, and largest, restructured electric markets.

Between 1996 and 2000, the economy in California rebounded, creating new load growth (such as communications providers, dot-com companies, and internet service providers) that was not forecast. Supply did not increase as fast as demand because of a variety of factors: low market prices inhibited investment, the state siting and permitting process was new to many developers and took time, and power plant construction took up to two years once permitting was completed. Growth and electricity demand in other Western states had accelerated, particularly Nevada and Arizona, that California had relied on for their excess electricity generation, leaving less power available for export to California. These changes initiated an imbalance between supply and demand for power that the new electricity market was expected to solve.

Much of the economic expansion fueled by the new dot com industry of the late 1990s occurred in San Francisco and the south Bay Area. The dot-coms brought new jobs, population, housing, capital investment, and electricity demand growth to these areas. All of the growth caused San Francisco's electric system to be taxed and transmission lines feeding the area to be congested. While utilities, the CAISO, regulators, generators, and customers had no reason to doubt that San Francisco's electric system could handle the new growth, the entire California electric system was being primed for failure.

Problems Develop In 2000

Problems inherent in the implementation of deregulation began to surface in the summer of 2000. Sempra (San Diego Gas and Electric Co.) was the first IOU to recover its stranded cost, eliminate the CTC from its bill, and allow retail rates to reflect spot-market (PX and CAISO) prices. Prices remained relatively low until May

2000 when wholesale prices began to dramatically increase as shown in the graph below that contains average monthly PX prices beginning in January 2000.

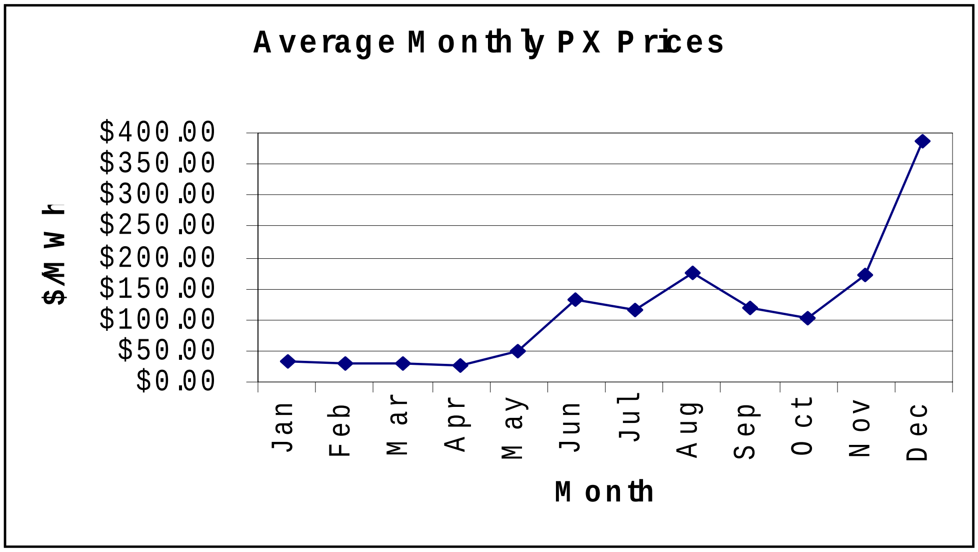


Figure 1-1: Average Monthly PX Prices

Customers of SDG&E had their monthly bills double and triple almost overnight. State legislators passed legislation that limited the generation component in San Diego's rates to $65 per MWh. The CAISO experimented with price caps that varied anywhere from $150 to $750 per MWh. The price caps failed to hold since the CAISO, on a real-time basis, purchased power well above the cap at almost any price in order to avoid blackouts. In the meantime, the debt of the other IOUs (SCE and PG&E) mounted rapidly. With their rates still frozen by AB 1890, they were not able to recover the cost of power they purchased from the PX/CAISO.

Given the high market prices and mounting utility debts, California turned to the FERC for help. FERC responded by ordering changes to PX bidding, permitting IOUs to enter into bilateral contracts and giving IOUs the freedom to trade through markets other than the PX. However, FERC refused to act on refunds California had requested or establish firm regional price caps in the Western U.S. Prices continued to rise and IOUs facing mounting debts and a lack of revenue began to default on payments to power suppliers, bond holders, and creditors. Eventually, PG&E's power purchasing debt led it to seek bankruptcy protection and SCE's debt left it without investment grade ratings and with major cash flow problems. In spite of orders from the U.S. Energy Department, sellers were reluctant to sell either electricity or gas supply into California for fear of not being paid. In addition, a large number of existing power plants were not operating during this time; sellers claimed that the offline plants were undergoing repairs, others accused them of intentionally reducing the supply available to California. Finally, there were numerous accusations of market "gaming" and fraud. The investigations into market behavior that began in the end of 2000 are ongoing at the local, state and federal level. The crisis peaked when, for the first time since World War II, power was involuntarily curtailed on two days in January as the state's demand exceeded the available supply.

San Francisco endured rotating outages ordered by the CAISO during these two days in January, 2001. With less than 30 minutes of warning, two sections of the city were the first to be blacked out for up to 90 minutes. The outages affected businesses and homeowners in San Francisco and stopped traffic at numerous major intersections. Critical public safety services, like hospitals, fire departments, and police stations were exempted from the blackouts, however not all were exempted in practice.

Throughout the state and the city, the crisis triggered emergency conservation efforts. Many citizens and businesses started conserving energy. At the Embarcadero Office Center, lobby lighting was reduced, elevator service was curtailed during power alerts, and pumps in the ornamental fountains were shut off. Altogether, the City was able to reduce electric demand by up to 20% on critical days. On January 23, 2001, Mayor Willie Brown stated, "(the blackouts) already had a profound effect on the city. We budgeted a certain number of millions of dollars for power, and in six months, that millions of dollars have disappeared. I am so worried about it that I am toying with the idea of putting the City and County of San Francisco in the energy generating business beyond its capacity currently."

In an attempt to respond to the electrical hysteria caused by blackouts and the price of power, the Governor declared a State of Emergency and authorized the CDWR to purchase power for delivery to the PX/CAISO. Today, the CDWR is the buyer of electricity for most IOU customers.

After enduring many months of high priced spot market power, some publicly-owned utilities had to raise rates. In addition, the CPUC granted both PG&E and SCE temporary rate increases averaging 4¢ per kWh. Even with the increases, reliability was still a major concern. Customers throughout California endured more rotating blackouts as supply and demand remained out of balance.

During the summer of 2001, when most utility experts were expecting the worst, a number of factors converged to mitigate the problem, avoiding additional blackouts. These factors included an economic downturn and aggressive conservation that reduced load by 10 to 15%, regional price controls implemented by FERC, the signing of long-term power supply contracts by the state, substitution of state borrowing ability for the IOU's lack of credit, and completion of new generation facilities. Prior to deregulation, there were fundamental differences between public and private ownership of electric utilities. The unbundling of the IOUs, as compared to the retention of fully integrated services by the publicly-owned utilities, has resulted in even greater demarcation. The following table summarizes the new environment created by these changes:

Table 1-1
Comparison of IOU and Muni Services

Issue	IOUs	Munis
Vertical Integration	Still own distribution and transmission resources but have divested many generation assets	Are still vertically integrated, controlling generation, transmission, and distribution
Obligation to Serve	Do not serve 100% of native load with own resources	Serve 100% of load in service territory with Muni managed resources
Reserves/Debt	Still have debt of about $12 billion, although have collected substantial reserves from rate surcharges granted by CPUC	Most have created reserves to pay down debt and any stranded costs
Direct Access	New Direct Access contracts were suspended by the CPUC	Can still offer Direct Access if choose to do so
Restructuring Costs	Continuing debt obligation for rate reduction bonds through 2007. Have continuing CTCs for power purchase contracts and nuclear decommissioning	Some are preparing to lower rates in the near future funded with stranded investment reserves and expiration of high priced energy contracts
CDWR Responsibility	Must bill customer for power provided by CDWR, with excess costs estimated by CDWR at 2.39¢ per kWh	None

Outstanding California Issues

There are a number of issues in California that need to be resolved before a stable electric service environment can be expected. These include:

- The role of the CAISO and its survival is in question. FERC is pushing for Regional Transmission Organizations (RTOs) that would merge the transmission authorities or ISOs of several states into one organization. Some California publicly-owned utilities, in an attempt to avoid unfair and escalating CAISO charges, are seeking to form their own control areas. FERC ruled on January 29, 2002, that the governance structure of the CAISO was not satisfactory in that it was not sufficiently independent and that it would have to be modified.
- FERC is considering and implementing market surveillance and reporting mechanisms so that past price abuse is not repeated in the future. At this point, it is unclear if price controls will remain in place beyond September 2002, or if FERC will order refunds for past abuse.
- In June 2002, the Government Accounting Office has found that FERC has not been an effective regulator of power markets and questioned FERC's competence to control electricity markets.
- The CAISO has proposed a Comprehensive Market Design that could have major implications for the delivered cost of power to Bay Area consumers, and could affect the viability of some municipal energy services options.

- The status of Direct Access is uncertain. The date by which a Direct Access customer had to be signed up for Direct Access may be revised to July 1, 2001 (now September 20, 2001), because of concerns about the amount of load that is purported to be exempt from non-bypassable charges (14%). Additionally, Direct Access may be reinstated for certain types of customers, for some percent of all customer loads, or made available if Direct Access customers pay a surcharge to compensate for the stranded cost portion of CDWR power purchase commitments
- The CPUC is currently investigating a means to return the obligation to serve 100% of native load to the IOUs. The expected date of implementation is January 1, 2003.
- There will need to be a resolution of how and to what extent the IOU debts, the high cost of CDWR power supply purchases, and remaining stranded investment and AB 1890 transition costs will be recovered.

Section 2
WHOLESALE POWER MARKET COSTS AND RISKS

Introduction

This portion of the study provides the following information to inform SF LAFCo's study for the potential provisions of energy services to the City:

- Overview of the wholesale power market
- Identification of wholesale market risk factors facing Load Serving Entities and opportunities to mitigate those risks
- Position Report for the CAISO-defined San Francisco area
- Assessment of wholesale power market costs for the City of San Francisco under three supply portfolio scenarios

WECC Wholesale Power Market – Background

Before the City can determine how to meet its electricity service needs, it must understand the issues related to the wholesale power market in a broad context. Not only do the issues need to be addressed from a California perspective, but also from a perspective that considers the electrically interconnected western North America.

This larger interconnected area in North America is referred to as the Western Interconnect. The WECC, one of 10 electric reliability councils in North America, is responsible for coordinating and promoting electric system reliability in the Western Interconnect. The Western Interconnect and the WECC encompass the same geographic area. The WECC is the second largest of the three interconnected grids in North America. The WECC encompasses 1.8 million square miles and includes all or portions of 13 western states, two Canadian provinces, and a portion of Mexico. With some limitations, generation from any area of the WECC can be used to meet electric load in any other area of the WECC. The transmission ties between the sub-regions of the WECC are good, albeit not perfect. Historically, wholesale electricity spot prices have been highly correlated across the WECC. California is a geographic portion of the Western Interconnect and its load makes up about 39 percent of the total electric load in the WECC.

Figures 2-1 and 2-2 provide key characteristics and price drivers of the WECC. Figure 2-1 provides an overview of the WECC and the current status of project development.

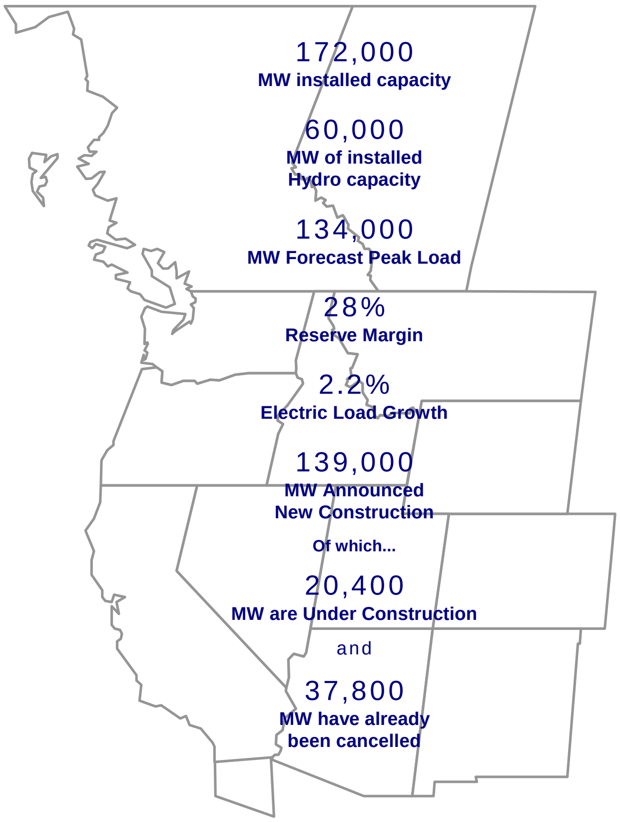


Figure 2-1: WECC at a Glance

The generation mix in the WECC is shown in Figure 2-2. The hydroelectric generation portion in WECC is higher than the national figure. At the present time, hydro accounts for 36 percent of the installed capacity. While hydro is cheap and renewable, it does have its problems. From an electricity standpoint, the amount of power coming from hydro electric generators in each hour, day, month and year is driven by a number of factors. Rain and snowfall are the lifeblood for hydroelectric supply. If it is a wetter than normal year, hydroelectric generation is better than expected. If there is a severe drought, generation supply in the west can become very tight. Hydro generation is also subject to a number of non-power constraints including flood control, irrigation, recreation, fish needs, etc.

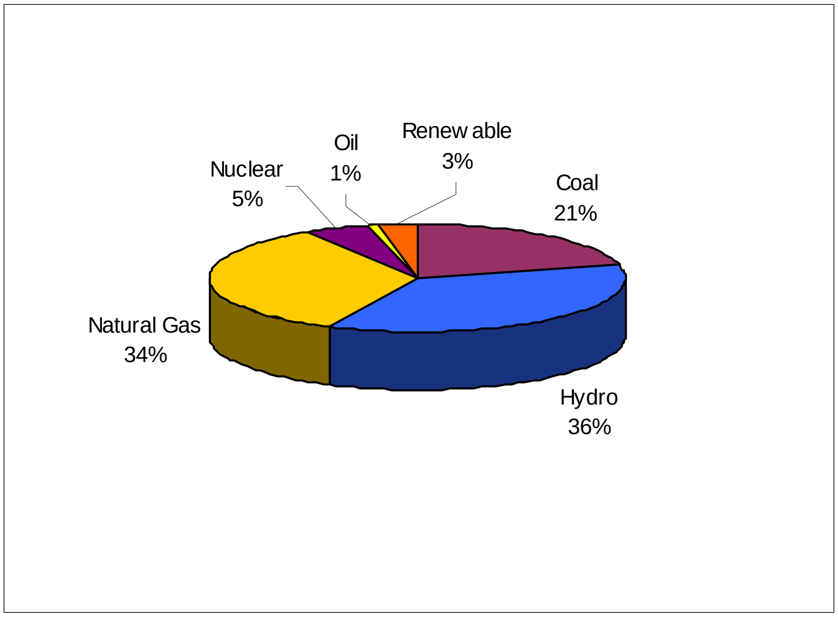


Figure 2-2: WECC Installed Capacity by Fuel Type - 2001

What went wrong in 2000 and 2001?

There were many factors that contributed to the recent electricity crisis in California and the Western United States. AB 1890 promised to achieve a number of goals for California energy consumers including lower electric bills and choice of generation providers. A key to realizing these goals was a continued adequate supply of electricity and a properly functioning market. Unfortunately, the Western United States ran into a severe shortage of electricity and investigations are ongoing regarding market manipulations and other broken aspects of the market. This caused severe problems for California and the WECC. Some of the key aspects that created those problems were as follows:

- **Lack of new resources**: The WECC experienced robust economic growth in the last decade, resulting in increasing demands for electricity. For a number of reasons, construction of new power plants did not keep up with demand growth. The developing supply shortage was masked for a few years by the fact that hydroelectric generation supplies in the late 1990s were more plentiful than normal because of abnormally high precipitation and snow pack.
- Figure 2-3 below provides an overview of new construction since 1991.

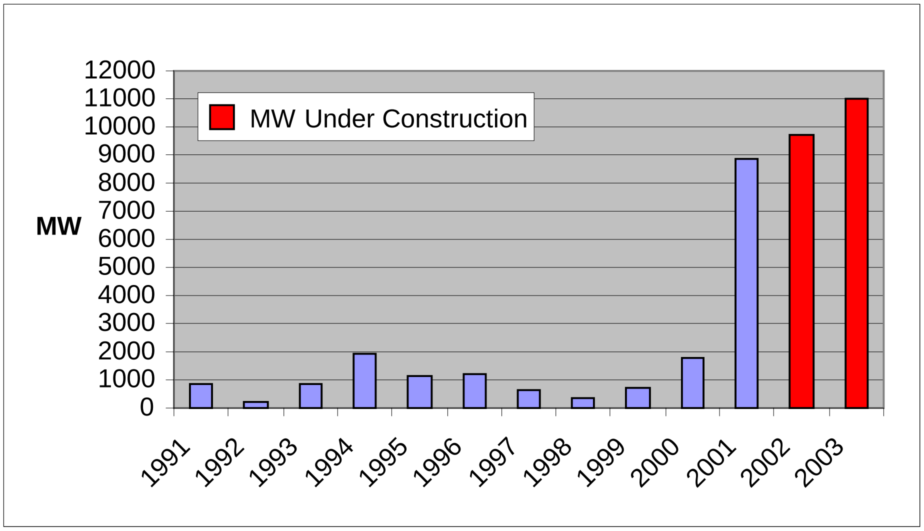
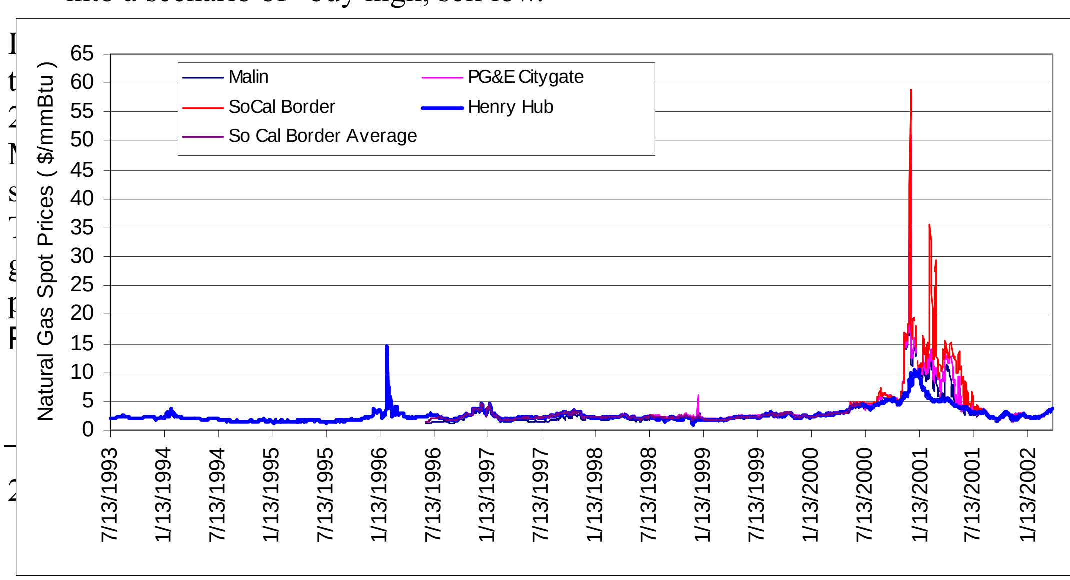


Figure 2-3: Construction of New Generating Resources in the WECC

- **Large exposure to Spot Market power**: Throughout the history of power markets in the WECC, the bulk of wholesale power was produced under arrangements that resulted in long-term fixed prices. However, under the California AB 1890 legislation, the California private utilities were required to sell large quantities of their long-term stable price resources and substitute power that would be procured in spot markets. With such a large proportion of the private utilities' power being purchased from the spot market, the utility financial costs for purchased power was dependent on that key assumption of low and stable prices.

- **Retail rates frozen at low levels**: In passing AB 1890, California legislated a 10 percent rate decrease for California retail electric customers of the IOUs and required that the rates be frozen at these lower levels until the earlier of (a) the date the IOU had fully recovered its stranded costs, or (b) until March 2002. This retail rate cap had two effects. First, it resulted in few customers changing their generation provider. Second, in conjunction with the requirement that IOUs be exposed to spot market wholesale power prices, the retail rate cap set up the possible scenario where wholesale purchases could be very high priced while retail prices would be capped at low rates. In essence, the IOUs could be forced into a scenario of "buy high, sell low."



The result of this combination of events was historically high wholesale power prices, as shown in Figure 2-5, below:

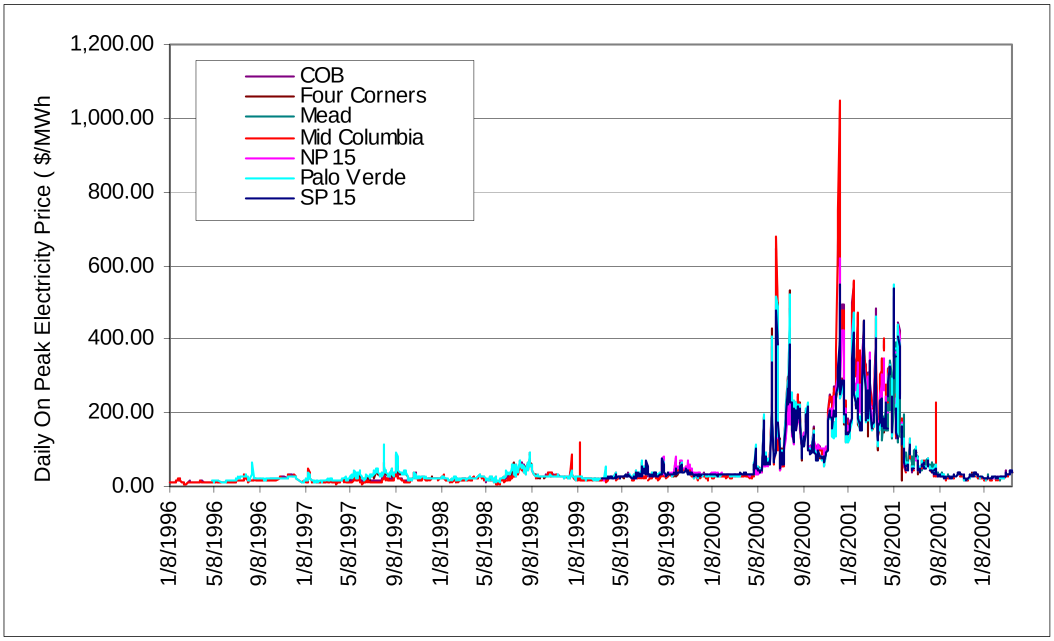


Figure 2-5: Daily On Peak Prices for WECC Market Areas, $/MWh

Exacerbating the fundamentals that led to high prices may have been manipulation of the electricity and gas markets. The FERC is examining now-bankrupt Enron's role, as well as the role of over a hundred other trading firms and utilities outside of California, in the soaring electricity prices experienced in California and the Northwest.

Near-Term Outlook

Compared to California's 2002 experience, today's outlook for the supply of electricity at reasonable prices is very different and positive. The severe supply shortages plaguing the WECC in 2000 and 2001 are history. The region has now returned to more than adequate reserve margins driven by the competitive market forces that responded to the shortage of energy and capacity. Increasing supply, the impacts of recession and customer conservation that lowered demand, and the return to a normal hydro year have pushed wholesale electricity prices substantially downward, prompting many developers to cancel, defer, or postpone projects previously announced and/or under construction.

Despite recent project cancellations and a worsening liquidity crisis affecting developers, more capacity is now under construction than nine months ago. There is a significant amount of capacity in the pipeline, which will be completed during the 2002-2004 period. Nonetheless, the impact of competition in the wholesale power markets has dramatically reduced the reaction time for market correction in the current boom and bust cycle.

As the market works off the surplus margins caused by so much new construction and as loads return to more normal levels, the capacity surplus is expected to disappear by 2009 and market prices will stabilize at more long run equilibrium levels.[2]

However, against this background of current healthy reserve margins and depressed prices, price volatility is expected to remain a permanent fixture of the competitive market, creating risks for load serving entities (LSE). This has created significant opportunities for traders and generators offering hedging and/or long-term, fixed price contracts. Many LSEs are now attempting to reduce their risk exposure by relying on a mixture of long-term and spot market options, appropriately hedged against rising prices.

A recent study of the WECC contained several conclusions and insights regarding wholesale electric prices in the future. These include:

- wholesale electricity prices in the WECC region will likely remain *stable* and *slightly depressed* in the short run under reasonable assumptions;
- there will be a *comfortable reserve margin*—for the foreseeable future;
- there could be sub-regional capacity shortages;
- there will be *considerable uncertainties* which can affect projected prices depending on assumptions about economic and load growth in the region, hydro conditions, availability and price of natural gas, the amount of new resources that may come on-line; and regulatory and policy issues affecting transmission and market design.

Wholesale Market Risk Factors

The City of San Francisco, if it chooses to operate as an independent load serving entity will need to immediately begin exploring its options for reliably serving the growing load of the City consistent with the need to minimize costs without taking on an inappropriate level of risk. Other load serving entities in the west have learned the hard way that if they do not have an integrated resource plan for managing both load and resources in their system, they can easily become over-exposed to market volatility and incur huge financial losses – either by having too much dependence on the spot market or by over-subscribing to higher cost firm contracts. Two notable examples to both signs of this coin include Seattle City Light and CDWR. Seattle City Light got caught short on generation in the recent drought due to its high dependence on hydro generation. CDWR, due to politics, inexperience, and a need to attempt to tame the California energy market, entered into high-cost contracts, the output of which when combined did not perfectly match the expected net short position of the California utilities.

[2] As defined here, capacity surplus exists if (nameplate capacity – load)/ load > 20%. This is not meant to imply that new projects could not still be economic.

The recent electric market events highlight the need for Integrated Resource Planning (IRP). IRP started as a regulatory-driven requirement in the late 1980s and early 1990s. It fell by the wayside as market restructuring was introduced in California in the mid-1990s. Now it is making a comeback as price volatility and over-exposure to risks has made everyone aware of the dangers of not having an integrated resource plan and a balanced portfolio. Some utility commissions are now re-emphasizing integrated resource planning. Even when there is no regulatory requirement to do an integrated resource plan, LSEs are doing it under their own volition. It simply makes good business sense to have an integrated resource plan.

Volatility and uncertainty place particular demands on load-serving entities. The experience of many utilities in the west has clearly demonstrated that reliance whether voluntary or forced — on spot markets carries very significant risks. Forward contracting, whether bilateral or through exchanges, is essential.

Risk, in the context of this report, means an uncertainty in the future state of a variable that can have a significant influence on the financial performance of an entity participating in the power markets. Risk can be segmented into long-term and short-term components.

Longer-term risks are those that could have a significant impact on the long-term—i.e., over several years—economic viability of a market participant. These longer-term determinants tend to be tied to the investment behavior of generation capacity developers and overall economic conditions, the value of which can be captured through measures such as gross domestic product (GDP). The relevant long-term risks are: demand uncertainty, supply risk, fuel price risk, market regulatory uncertainty, environmental regulatory uncertainty, and technological changes.

As the time horizon shortens into a perspective of a year or less, the determinants of wholesale electricity prices change. Changes in both demand and supply will affect short term electricity prices. The major source of demand fluctuation is weather, principally temperature, which influences variation in load from hour to hour and day to day. On the supply side, the three major causes of price fluctuations are seasonal hydroelectric potential (i.e., weather), fuel price, and generating equipment outages, although transmission equipment outages or transmission congestion can also significantly impact prices. These major short-term determinants—weather, fuel price and equipment outages—are mean reverting variables (i.e., their long term or equilibrium values are accurately represented by their mean or expected values).

For the purposes of this discussion, risks have been categorized into primary, secondary, and tertiary classes, reflecting a decreasing level of risk based on empirical evidence and expert opinion. The key determinants are listed below, along with their risk categorization:

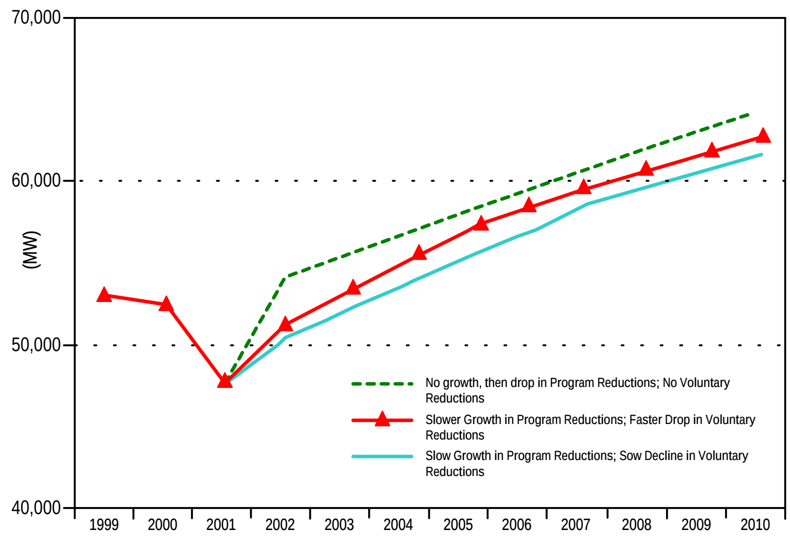
Table 2-1
Risk Characterization

	Short-Term	Long-Term
Primary Risks	Weather	Demand Uncertainty
	Outages	Supply
	Fuel Prices	Fuel Prices
Secondary Risks	Transmission	Market Regulation
Tertiary Risks		Technological Changes
		Environmental Regulation

Each of the risks outlined above are described in the following paragraphs.

Long-Term Demand Uncertainty. Uncertainty in long-term average demand, or consumption, is created by underlying uncertainty in both the growth rate of overall economic activity (GDP) and the average level of electricity consumption per unit of economic activity (kWh / $ of GDP). Electricity consumption is highly correlated with macro-economic growth over the long term, and annual changes in consumption are similarly correlated with changes in growth. Consumption per unit of GDP, in contrast, grew steadily until 1976, and has been declining ever since as the U.S. economy moves increasingly from industry to services. The use of air conditioning has become more widespread and as a result, annual "load factors" have been declining steadily, resulting in load profiles with higher peaks.[3] To capture these trends, demand forecasts created by individual Load Serving Entities (LSEs) and reported to the U.S. Department of Energy (and other similar sources) are used. These demand forecasts are used by regulators and utilities for regional planning purposes, and explicitly account for both consensus forecasts of regional growth and changes in electricity consumption per unit of GDP. Figure 2-6 shows the California Energy Commission's representation of uncertainty in load growth in California. The crisis of 2001 was resolved through dramatic decreases in loads in the region (both within California and the WECC as a whole). With lower prices and economic recovery, demand growth will return to normal levels.

[3] Load factor is equal to average annual demand [in MWh] / (peak demand [in MW] x 8,760).



Source: California Energy Commission

Figure 2-6: Uncertainty in Load Growth in California, 1999-2010

Long-Term Supply. Electricity prices are heavily influenced by the supply of electricity available from other generating units in a region. This supply, in turn, will change with the addition of new capacity, the refurbishment or enhancement of some existing capacity, and the retirement of other existing generation units. In theory, at equilibrium, the amount of capacity entering the market each year will be such that the last entrant is able to recover its costs and earn a reasonable return on capital invested. Such an equilibrium will produce a reserve margin sufficient to provide reliability without depressing prices to the point where new generation does not earn its anticipated return. In practice, the addition of new capacity is driven by the investment cycles typical of capital-intensive commodity industries, the timing, magnitude and duration of which are inherently uncertain. While an overbuild situation can result from such cycles, the discipline of capital markets that provide funding for new capacity provides a natural mitigant against sustained excess supply.

Long-Term Market Regulatory Risk. This risk manifests itself in the uncertainty surrounding the ultimate long-term regulatory structure of the WECC and California markets, as well as the "overhang" that occurs from the long-term purchases of power by CDWR. Although several initiatives are underway, there is currently no strong central independent authority for coordinating the WECC market. It is likely, however, that such an entity, in the form of an ISO or RTO[4] will eventually be created. Consistent with their purpose, these organizations would likely ensure equal market access, administer the transmission system on an equal and non-discriminatory basis, and help maintain competitive markets for energy and ancillary services.

California's dysfunctional electricity market coupled with the retail rate freeze placed two major IOUs in an untenable position, jeopardizing their financial health. CDWR

[4] Independent System Operators (ISOs) and Regional Transmission Authorities (RTOs) are two forms of regional market organizations proposed by the Federal Energy Regulatory Commission (FERC).

has been securing their net short position since January 2001. The same agency signed long-term contracts to buy power from generators in an attempt to stabilize retail prices and reduce the dependence of the volatile spot market.

Prices have calmed in the WECC and California market, and the IOUs appear to be on the road to slow recovery—although the process promises to be protracted and difficult. In the mean time:

- California is attempting to renegotiate its $42.8 billion obligations—having asked FERC to nullify the contracts. On April 22, 2002, California state officials announced that they had restructured eight of CDWR's long-term energy contracts. The renegotiated deals affected four contracts with Calpine, one with High Desert Power Plant LLC (Constellation Energy Corporation), and three contracts with renewable energy providers—Capitol Power, Cabazon, and Whitewater Hill. On May 2, 2002, CDWR announced that it had also restructured contracts with CalPeak Power. The new contracts call for the termination of one of seven peaking projects, shortening the term of another, and reducing the cost of the remaining projects;
- The state is also attempting to issue $11.1 billion worth of revenue bonds to be financed through rates collected by the IOUs;
- The California Public Utilities Commission (CPUC) has officially ended direct access, and has proposed a controversial exit fee for customers who have switched suppliers and do not wish to return to high, regulated tariffs;
- CPUC wants the IOUs to start procuring their power needs beginning January 2003; and
- Under pressure from FERC, California ISO is examining market design alternatives as well as the issue of whether it is independent enough to meet FERC criteria for an ISO.

Table 2-2
Largest Long-Term Contracts Signed by CDWR

Calpine	$11.7 billion
Sempra Energy	$6.6 billion
Williams	$4.6 billion
Allegheny Energy	$4.4 billion
Constellation Energy	$3.9 billion

Source: California Department of Water Resource, 2002

Oregon, Nevada, and Washington have experienced similar problems. How these difficult financial, regulatory, and legal issues are sorted over the coming years will have a significant bearing on the evolution of markets and prices in WECC.

Perhaps the most significant risk is with either activation of the SF Zone under the current zonal pricing scheme of the CAISO or more likely, the eventual movement to Locational Marginal Pricing (LMP).

Locational Marginal Pricing. In most markets in the US, electricity prices on the grid are determined on a "Market Clearing Price" basis; a common industry practice. Economists refer to this as an equilibrium price. Buyers are charged the price paid for the last block of power needed to satisfy demand. Dispatchers use the lowest priced generators first, bringing more expensive units on-line as needed so that the last used is also the most expensive.

This structure, which treats a market area as a single unit, does not address an important variable -- the location of supply and demand. Transmission grids suffer from traffic congestion as certain key transmission lines reach maximum capacity at times of high power demand. When lines become congested, using the lowest cost generator may not be possible. Many markets in the US are now moving toward an economic solution to this problem – Locational Marginal Pricing – or LMP. LMP is a flexible pricing system that reflects differences in electricity production costs, locations of generators and users, and total system demand. LMP is the marginal cost of supplying the next increment of electric energy at a specific location (node) on a network, taking into account both generation marginal cost and the physical aspects of the transmission system.

As will be discussed in Section 3, the City of San Francisco faces some critical risks related to transmission constraints. Those constraints as they exist today can cause Bay Area users to pay higher prices in the future than the rest of the PG&E territory, or suffer rotating outages, unless congestion is reduced through the addition of new transmission and/or new generation. Currently, PG&E spreads the costs of congestion among its rate classes. In the future, consumers of electricity in geographic areas that experience congestion – such as San Francisco – may be required to pay more directly the costs of that congestion via LMP. The cost of congestion could become a significant factor in the price of electricity in San Francisco. If the Jefferson-Martin 230 kV Transmission Project is constructed, the joint issues of transmission reliability and congestion will likely be adequately addressed through the study period. The issue of generation reliability and cost will continue to be an on-going issue until new generation resources that are more reliable, efficient and meet environmental standards are located within San Francisco, or more conservation programs are implemented, or a combination of both.

The FERC recently issued its "Working Paper on Standardized Transmission Service and Wholesale Electric Market Design."[5] This paper sets forth FERC's policy guidance to achieve "… robust, seamless competitive wholesale electric markets." San Francisco is vulnerable to loss of local generation and loss of transmission, which could increase its exposure to high LMPs. Although progress is apparently being made on the transmission side of the issue, much remains to be done on the supply- and demand-side of the issue through processes such as Integrated Resource Planning and portfolio management to mitigate this exposure

Regulatory Risk. The electric power industry is subject to numerous regulations. It is difficult to forecast what regulatory requirements will be in the future. While FERC is leaning toward competitively determined prices, it has the authority to cap prices

[5] See FERC Website, http://www.ferc.fed.us/Electric/RTO/Mrkt-Strct-comments/e-1finalSMD.PDF

and mandate other rules. Environmental requirements can change in ways that impact the economics of generation and wholesale power prices.

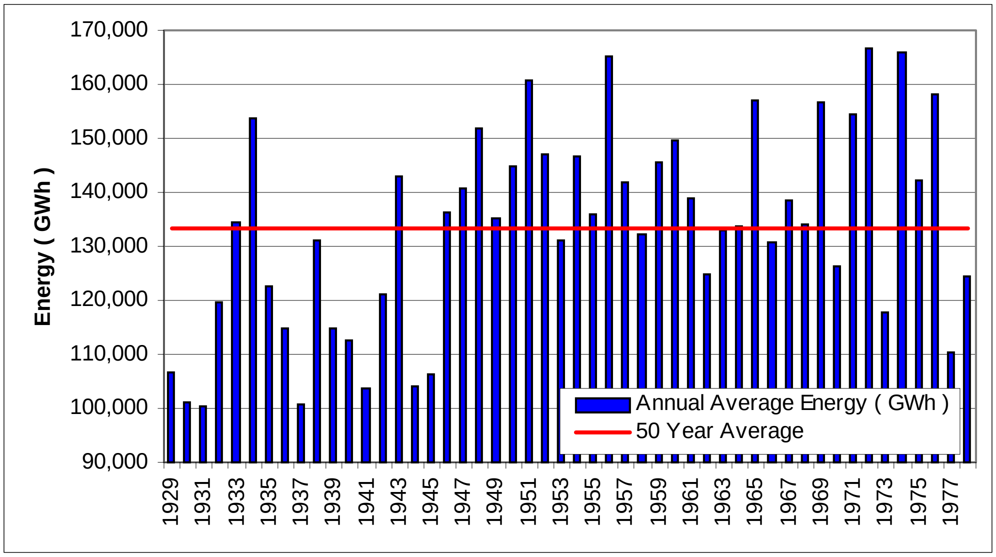
Technological Change. Technological change in the electric utility industry constitutes risk primarily in terms of new generation sources that could compete with or replace existing generation sources. The two likely potential sources of such new capacity are distributed generation and electricity storage. Entry of distributed generation into the electricity generation market can best be viewed as a "niche play" and the total market entry may well be limited. Energy storage technologies are best suited for "power quality" enhancing uses. These applications require lower power capacities, shorter service duration, and quicker response times than available from conventional electric generation technologies, and therefore compete in a different market niche.

For LSEs, technology can represent an opportunity for wholesale power purchases it makes in the spot market. Technology can also be viewed as an opportunity cost in that an LSE that locks in most of its portfolio into long-term contracts at the cost of a current technology may "leave money on the table" when new, lower cost technologies enter the market.

Short Term Demand Risk (Weather). The price of electricity on an hourly basis tends to vary dramatically in response to load demand. Weather conditions have an overriding impact on hourly load demand patterns. For example, the difference between an average summer day and a very hot summer day will be that the level of electricity usage will be markedly higher, as consumers run more air conditioning units. Weather also has a secondary impact on the availability of resources. Some types of generating technology, particularly combustion turbines, have lower maximum capacities in hot weather.

Short-Term Supply (Hydro). The WECC, more than other parts of the country, is heavily dependent on hydro generation. California, in particular, has traditionally relied on inexpensive hydro imports from the Pacific Northwest, notably during the hot summer months. This reliance, and the 2000-01 drought, was one of the chief contributors to high prices and price volatility during the California market crisis.

The relative significance of hydro gradually diminishes over time as more thermal units are added to the WECC system—but hydro will remain significant for years to come. Another prolonged drought, for example, can significantly reduce WECC's perceived high reserve levels and seriously affect prices in the region. The fact that hydrological conditions cannot be predicted with any degree of certainty makes this a major wild card in the WECC. Environmental and operational restrictions, notably for preservation of endangered salmon species, will add to these uncertainties. Figure 2-7 below illustrates the impact hydro conditions in the Northwest have on the availability of power. For example, the impact of a dry hydro year such as that which occurred in 1937 or 1977 is equivalent to the loss of about 4,500 MW of combined cycle power plants from the WECC system.



Source: BPA Whitebook, 1999

Figure 2-7: Annual Average Energy Available from Northwest Hydro Projects 1929-1978, GWh

The implications of the hydrology on the WECC are that there is a demand for weather-oriented derivatives—but such hedges remain expensive. Given that Hetch Hetchy's resource portfolio is hydro-based, hydro variability is a particularly important variable for San Francisco.

Short-Term Supply (Outages). The supply of electricity varies with time, both on an hourly basis, and on weekly and seasonal bases. The variation is a direct result of the nature of the resources that supply electricity—they are mechanical systems with the potential to break down (a "forced outage") and the need for periodic maintenance (a "maintenance outage"). Since electric storage is relatively expensive, most electricity is produced at the moment of consumption. These two factors, the occurrence of outages and minimal storage capability, lead to significant variation in the resources available to supply electricity, and corresponding variation in price. This price variation is explicitly captured in a structural simulation of electricity markets through an allowance for maintenance outages and a representation of forced outages.

Natural Gas Price. Natural gas prices are historically quite volatile. Increases in gas prices increase operating costs of gas-fired generation which, in turn, will normally result in higher prices for wholesale power. Reductions in natural gas prices will tend to lower prices for wholesale power. The market provides various methods for managing this gas risk in both the short-term and long-term.

Transmission. The risk associated with transmission systems is that trading parties are not always able to transmit the amount of energy that would be desired in the case of an unconstrained system. Such transmission congestion leads to price disparities among regions and contributes to electric price volatility. Congestion is caused because the transmission system has physical limits that restrict the amount of energy transported. These "path limits," and the risks they create, are captured in the analysis by incorporating the path limits explicitly in the deterministic model. San Francisco is located in an area that is subject to transmission constraints. However, with the increase in transmission capacity from the proposed Jefferson-Martin 230 kV Transmission Project, reliability issues from a transmission line perspective are likely addressed.

Growing Prominence of the Energy Marketplace

The embedded energy market risks described above have spawned new players in the electric industry in the last several years. Clear federal policy and many state regulatory initiatives are encouraging competitive market forces and a growing independent supply sector. Many states are also experimenting with or instituting retail competition as well.

Beginning with the Energy Policy Act of 1992, the federal government has pursued an initiative under which there would be robust competition in wholesale power markets. New players (Independent Power Producers) have been encouraged to build new generation facilities and provide the power to traditional utilities (now called load serving entities). Other new players, sometimes called "energy merchants," have developed business models that negotiate short- and long-term deals to buy and supply electricity and then use trading skills to maximize the value of those deals. The ability to originate agreements to buy and sell, to price risks appropriately, and to decide whether to keep or shed specific risks is a special skill that these companies have developed.

Energy merchants (such as Dynegy, Mirant and Reliant) pursue national and even global opportunities. They are open to owning power plants but equally open to controlling generation output through properly structured contracts. Many national or global merchants trade not only electricity but also gas and other related commodities. Indeed, the recent volatility of U.S. gas prices has highlighted the need for upstream players to be skilled in multi-commodity risk management. Many believe that electricity markets will move toward greater efficiency and liquidity, a development that will in turn place downward pressure on margins for even the most skilled competitors. Energy merchants offer a wide variety of products for meeting energy needs. A product could be a short-term or long-term firm "forward" or "future" purchase/sale.[6] A product could be an "option" where a premium is paid against a right to buy or sell at a specific price, or a derivative or other exotics. A product could be a right to "toll" gas through the merchant's gas-fired generator. A product could be a financial product that, for example, "swaps" a fixed power price for a volatile spot market price.[7] Under such an arrangement, the City could decide to buy

[6] Forwards are over the counter traded, with counter party risk. Forwards products are often custom negotiated to meet the needs of both parties. While forwards can be cash settled, they typically settle with physical delivery. Futures are traded in exchanges where parties do not know who the counter party is and there is no counter party risk. The Exchange itself takes on the credit risk and requires traders to be credit worthy. Future products necessarily need to be standardized. While futures can result in physical delivery, typically they "cash" settle based on change in value relative to the spot.
[7] All financial products involve some exchange of risk between fixed price and floating spot price.

its needs via the day ahead spot market but avoid the volatility in prices in such spot markets.[8]

In addition to encouraging new players to participate in wholesale power markets, the federal government has adopted the theory that competition will hold down wholesale power rates and that therefore wholesale power rates no longer are based on the cost of the power supplies. Similarly, prices for natural gas commodity and bulk natural gas transmission have been deregulated.

Focused Assessment of the City of San Francisco

The qualitative discussion of the WECC and California markets and associated risks must be accompanied by a specific assessment of the position of the City of San Francisco with respect to the forecast of load it will need to serve, the options for acquiring the generation to serve that load, and the costs of that generation.

This section will first briefly review the forecast of San Francisco's current and future position – a forecast of load requirements and how that compares to the available resources within the local area and the transmission capability to make up any shortfall with imports. Following the position report, estimates are made of the costs to a City Utility of wholesale power to serve that load. Three supply scenarios will be reviewed.

Load and Resource Report for San Francisco

San Francisco currently has an annual peak demand of approximately 900 MW. That peak is generally experienced some time during the months of September through November. Annual energy consumption in San Francisco is currently estimated at 5,500 GWh, or approximately seven percent of PG&E's total retail load.

Table 2-3 is a load and resource report for the City of San Francisco. The table shows the annual forecast of peak loads in the City, the expected energy requirements, the local area generation, and import capability for the period 2002 through 2012. As can be seen, the area relies extensively on imports and will in the near future come under risk of blackouts unless much discussed transmission and generation additions materialize.

Table 2-4 is a load and resource report on a monthly basis for the year 2003.

[8] There may be concern that while this kind of swap arrangement may provide price protection, it may not provide a reliable supply. It would be important to monitor WECC-wide reserve margins (existing and forecast) in order to ascertain if relying on such an arrangement might be a reliability risk or not.

Table 2-3
Annual Load and Resource Report – San Francisco
2002-2012

Annual Coincident Peak Hour

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Load											
Peak Load (MW)	**920**	**960**	**993**	**1,035**	**1,056**	**1,079**	**1,100**	**1,121**	**1,130**	**1,150**	**1,170**
Annual Energy (GWh)	**5,715**	**5,848**	**5,929**	**6,183**	**6,309**	**6,443**	**6,571**	**6,698**	**6,751**	**6,868**	**6,990**
Resource											
Thermal (MW)	**722**	**584**	**584**	**584**	**584**	**584**	**584**	**584**	**584**	**584**	**584**
Hunters Point 2	52	0	0	0	0	0	0	0	0	0	0
Hunters Point 3	86	0	0	0	0	0	0	0	0	0	0
Hunters Point 4	163	163	163	163	163	163	163	163	163	163	163
Hunters Point GT1	52	52	52	52	52	52	52	52	52	52	52
Potrero 3	207	207	207	207	207	207	207	207	207	207	207
Potrero GT 4	54	54	54	54	54	54	54	54	54	54	54
Potrero GT 5	55	55	55	55	55	55	55	55	55	55	55
Potrero GT 6	53	53	53	53	53	53	53	53	53	53	53
Firm Import (MW)											
BPA to BART	66	66	66	66	66	66	66	66	66	66	66
Total Resource (MW)	**788**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**
Reserves (MW)	**-132**	**-310**	**-343**	**-385**	**-406**	**-429**	**-450**	**-471**	**-480**	**-500**	**-520**
Reserve Margin (%)	**-14.3%**	**-32.3%**	**-34.5%**	**-37.2%**	**-38.4%**	**-39.8%**	**-40.9%**	**-42.0%**	**-42.5%**	**-43.5%**	**-44.4%**
Import Capacity (MW)	**730**	**730**	**730**	**730**	**1130**	**1130**	**1130**	**1130**	**1130**	**1130**	**1130**

Note: Hunters Point 2 and 3 are currently operating as synchronous condensers and do not contribute power to the grid

Table 2-4
Monthly Load and Resource Report – San Francisco
2003

Monthly Coincident Peak Hour

	January	February	March	April	May	June	July	August	September	October	November	December
Load												
Peak Load (MW)	**896**	**877**	**873**	**873**	**874**	**925**	**875**	**874**	**902**	**875**	**917**	**960**
Monthly Energy (GWh)	**507**	**458**	**495**	**468**	**479**	**467**	**477**	**488**	**481**	**495**	**499**	**534**
Resource												
Thermal (MW)	**584**	**584**	**584**	**584**	**584**	**584**	**584**	**584**	**584**	**584**	**584**	584
Hunters Point 2	0	0	0	0	0	0	0	0	0	0	0	0
Hunters Point 3	0	0	0	0	0	0	0	0	0	0	0	0
Hunters Point 4	163	163	163	163	163	163	163	163	163	163	163	163
Hunters Point GT1	52	52	52	52	52	52	52	52	52	52	52	52
Potrero 3	207	207	207	207	207	207	207	207	207	207	207	207
Potrero GT 4	54	54	54	54	54	54	54	54	54	54	54	54
Potrero GT 5	55	55	55	55	55	55	55	55	55	55	55	55
Potrero GT 6	53	53	53	53	53	53	53	53	53	53	53	53
Firm Import (MW)												
BPA to BART	66	66	66	66	66	66	66	66	66	66	66	66
Total Resource (MW)	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**
Reserves (MW)	**-246**	**-227**	**-223**	**-223**	**-224**	**-275**	**-225**	**-224**	**-252**	**-225**	**-267**	**-310**
Reserve Margin (%)	**-27.4%**	**-25.9%**	**-25.5%**	**-25.5%**	**-25.6%**	**-29.7%**	**-25.7%**	**-25.6%**	**-27.9%**	**-25.7%**	**-29.1%**	**-32.3%**
Import Capacity (MW)	**730**	**730**	**730**	**730**	**730**	**730**	**730**	**730**	**730**	**730**	**730**	**730**

In the early years of its analysis, the analysis only includes specific generation or transmission additions that are beyond the planning or development stage and actually in construction. For example, Mirant's proposed Potrero Unit 7 and other transmission improvement ideas have not been included. Small generating facilities that are primarily used to self-serve electric needs (with little left over for sale to the market) are not included in the load and resource balances in Tables 2-3 and 2-4.

Modeling Electricity Operations of San Francisco and the WECC

This modeling work followed its analysis of area capabilities and energy requirements with a simulation to forecast market clearing prices in the San Francisco area and to determine the level of imports required to be transported through transmission facilities into the San Francisco sub area.

The forecast of market clearing prices for individual markets within WECC was developed by conducting a simulation of the entire Western Interconnect system.[9] This requires a vast amount of data regarding power plants, fuel prices, transmission capability and constraints, and customer demands.

The analysis simulates the operation of the individual generators, utilities and control areas to meet the fluctuating loads within the region with hourly detail. The simulation takes into account various system and operational constraints, including a Monte Carlo methodology to incorporate individual unit planned and forced outages. Output from the simulation is generated in hourly, station-level detail and analyzed and these outputs were used within this study.

The price formation methodology combines information about the physical characteristics of the electric system in combination with reasonable assumptions about the behavior of various market participants to develop price forecasts. Two important non-physical market assumptions regard new generator entry behavior (that leads to long-term market equilibrium) and market participant bidding strategies.

The City of San Francisco was modeled in the topology as a separate liquid market so that the effects of transmission congestion on market clearing prices would be observed.

The load and resource balances shown in Tables 2-3 and 2-4 are interesting because they show a snapshot of area capability in the peak hour of the year. For example, the tables show that in the peak hour of 2003, San Francisco is expected to have a 960 MW peak load, with a total resource capability of 650 MW and a 730 MW total import capability. Just as instructive, however, is information on expected energy generation and imports by month and year to get a feel for the area's relative reliance on the two sources. Table 2-5 provides annual "in area" generation and energy

[9] Henwood utilizes its proprietary MARKETSYM data management system, in combination with its PROSYM production simulation model, to simulate the operation of the WECC.

imports for the years 2003-2012 for the Base Case. Table 2-6 provides the same data by month for the year 2003.

Table 2-5
Annual San Francisco Generation and Imports – 2003-2012 (GWh)

Year	Generation	Imports	Load
2003	2,059	3,789	5,848
2004	2,091	3,838	5,929
2005	2,189	3,994	6,183
2006	2,241	4,069	6,309
2007	2,296	4,148	6,443
2008	2,348	4,223	6,571
2009	2,395	4,303	6,698
2010	2,416	4,334	6,751
2011	2,460	4,408	6,868
2012	2,508	4,481	6,990

Table 2-6
Monthly San Francisco Generation and Imports – 2003 (GWh)

Month	Generation	Imports	Load
January	181	326	507
February	162	296	458
March	174	320	495
April	164	304	468
May	167	312	479
June	163	304	467
July	167	310	477
August	172	315	488
September	169	312	481
October	174	321	495
November	174	324	499
December	190	344	534
Total	2,059	3,789	5,848

San Francisco Wholesale Power Costs

This analysis has prepared estimates of wholesale power market costs for the City of San Francisco in the future based on three potential supply portfolio scenarios:

1. Rely on the Spot Market – where it is assumed the City will rely exclusively on the spot market to fulfill its demand requirements.
2. Contract and Spot Mix - envisions reliance on a combination of long-term bilateral purchases and the spot market.

3. PG&E Supply - is based on a scenario where the City purchases energy at the forecasted tariffed rates of PG&E.

Wholesale power costs are presented in 2002 dollars and only consist of the generation cost component of electricity service. Costs related to transmission, distribution, or public purpose are not included in the estimates. In each of the following supply portfolios, the costs of energy are based on the hourly load forecast for the City for the years 2003 through 2012. A five percent adder per year for required ancillary services was included in the generation cost estimates.

The five percent adder for ancillary services was developed based on careful examination of the available historical data for the California ancillary service market to statistically estimate the relationship between electricity and ancillary service prices. Data for the January 1999-January 2001 were used for the analysis. Due to market turbulence in the first six months of the unregulated California market, as well as in the period following January 2001, these time periods were excluded.

The wholesale power costs capture the impacts of transmission congestion which are not significant if the Jefferson-Martin 230 kV Transmission Project is constructed. Under the simulations performed, normal loads and outages were assumed in order to perform an economic, as opposed to a reliability-based transmission analysis. In a reliability-based transmission analysis for San Francisco, as reported by the California ISO, the focus is on *extreme* conditions.[10] Instead of using historical forced outage rates of the generating units in San Francisco, they assumed Potrero Unit 3 and one combustion turbine would not be operational. In addition, they assumed another combustion turbine in the greater Bay Area would not be operational. This was done for the *base case*. Then, on top of the base case, the California ISO applies the standard "L minus one, G minus one" criterion. Thus, for transmission reliability studies, extreme as opposed to normal conditions are used. Since extreme conditions are not expected to normally occur, and cannot be assigned a probability of occurrence (the criteria are deterministic), they are not used in an economic assessment such as that performed in this study.

Rely on the Spot Market

The City's wholesale generation component for this supply portfolio has been computed by assuming all power supplies are procured at the forecast of power market prices. Energy costs are calculated by multiplying the City's hourly load forecast by the hourly forecast of market clearing prices.

Scenarios provide a useful framework for thinking strategically about alternative views of the evolution of the markets and prices in the future. For purposes of the present study, three scenarios were created to estimate wholesale costs for the City, the Base Case, High Scenario, and Low Price Scenario.

[10] For more discussion of the basis for transmission reliability planning assumptions, see Section 3 of this report.

1. Base Case – The current view of the market which contains model assumptions that are consistent with the most up-to-date published WECC hourly pricing forecast (Henwood's Spring 2002 Update), including the most recent published forecast of gas prices.

2. High Price scenario – assumes that less generation will be built, gas prices will be higher, and there will be higher load growth in the WECC region. Henry Hub natural gas prices were increased by $0.50 per MMBtu. Load forecasts were increased by 2.5 percent over the Base Case for all transmission areas. Certain new generating plants not already under construction were delayed until market pricing dictated economic entry

3. Low Price Scenario – assumes the opposite conditions will prevail, *i.e.*, natural gas prices decrease by $0.50 per MMBtu, loads decrease by 2.5 percent due to slower economic growth, and certain generating plants online dates were advanced.

Table 2-7 presents the forecast of annual average market clearing prices for the San Francisco area for these three cases. The generation cost calculation for this case does not include an estimate of the exit fee that will be charged to all PG&E customers that leave the system.

Table 2-7
Market Clearing Price Forecast – San Francisco
(2002 $/MWh)

	Market Clearing Price		
Year	Base Case	High Scenario	Low Scenario
2003	38.02	43.84	30.16
2004	34.66	40.66	28.89
2005	33.94	39.96	28.07
2006	34.73	40.80	28.65
2007	35.32	41.65	29.11
2008	35.93	42.31	29.70
2009	35.95	42.41	29.81
2010	35.90	42.26	29.94
2011	36.11	42.42	30.31
2012	36.37	42.52	30.66

Figure 2-8 graphically illustrates the Base, High and Low market price forecasts.

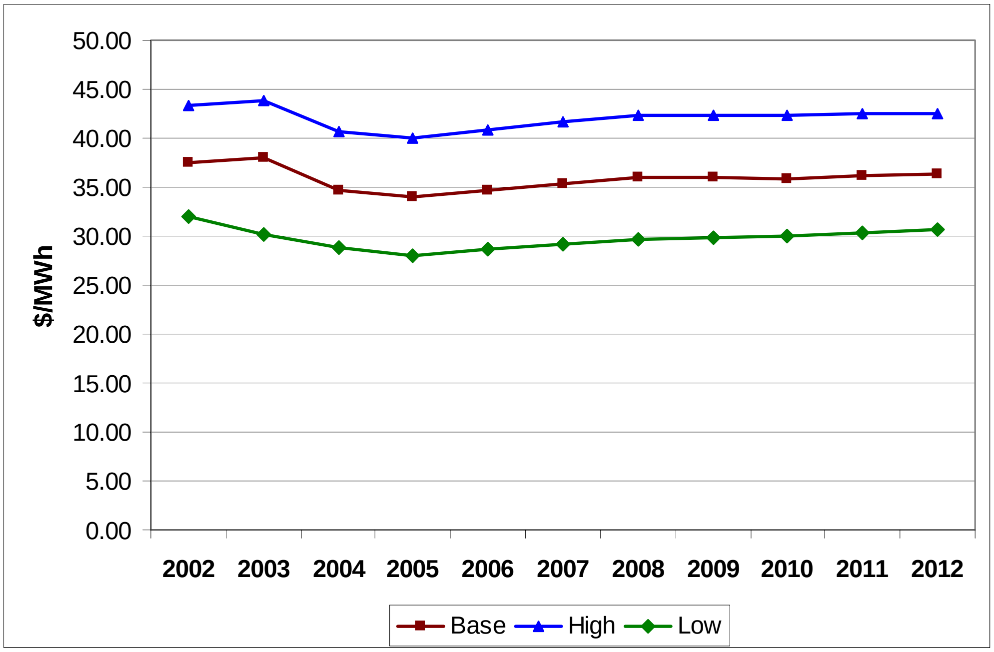


Figure 2-8: Market Clearing Price Forecast – San Francisco (2002 $/MWh)

Table 2-8 below summarizes the generation cost estimate for the City of San Francisco for the years 2003-2012 with total reliance on the spot market under the three price scenarios.

Table 2-8
Generation Cost Component Forecast – San Francisco
Rely on Spot Market Case
($ 000)

Year	Base Case	High Scenario	Low Scenario
2003	240,826	277,168	191,077
2004	222,925	261,433	185,729
2005	227,527	267,904	188,406
2006	237,664	279,114	196,331
2007	246,670	290,952	203,562
2008	255,730	301,336	211,852
2009	261,127	308,269	216,773
2010	262,707	309,200	219,317
2011	268,829	315,345	225,971
2012	275,598	321,524	232,789

Contract and Spot Mix

This analysis has computed the City's wholesale generation component for this supply portfolio by assuming a portion of the power supplies is procured through long-term contracts and the balance is procured at the forecast of power market prices. The amount of power procured through long-term contracts is defined, in this case, as the difference between annual peak demand and area generation. The price for this power is based on the estimate of the fixed and variable costs for a new, combined-cycle generator starting commercial operation in 2003. Over the period 2003 through 2012, the amount of power procured under fixed, long-term contracts ranges from about 51% to 68% of the total load. The balance of the load is assumed procured from the spot market.

Table 2-9 below summarizes the generation cost estimate (in 2002$) for the City of San Francisco for the years 2003-2012 with a combination of bilateral contract and spot market procurement under the base case scenario. . The generation cost calculation for this case does not include an estimate of the exit fee that will be charged to all PG&E customers that leave the system.

Table 2-9
Generation Cost Component Forecast – San Francisco
Contract and Spot Mix Case
($ 000)

Year	Base Case
2003	254,897
2004	241,634
2005	246,275
2006	254,606
2007	262,110
2008	269,628
2009	275,883
2010	278,188
2011	284,942
2012	291,788

The amount of power procured under a bilateral contract various over the years, as shown in Table 2-10 below.

Table 2-10
Bilateral Contract Capacity Forecast – San Francisco
Contract and Spot Mix Case

Year	Bilateral Contract Capacity (MW)	Percent of Load Served by Bilateral Contracts	Percent of Load Served by Spot Market
2003	339	51	49
2004	371	55	45
2005	412	58	42
2006	432	60	40
2007	454	62	38
2008	474	63	37
2009	495	65	35
2010	503	65	35
2011	522	67	33
2012	542	68	32

Figure 2-9 below is shows how this scenario would be represented in our modeling process for two, typical weekdays in August 2005.

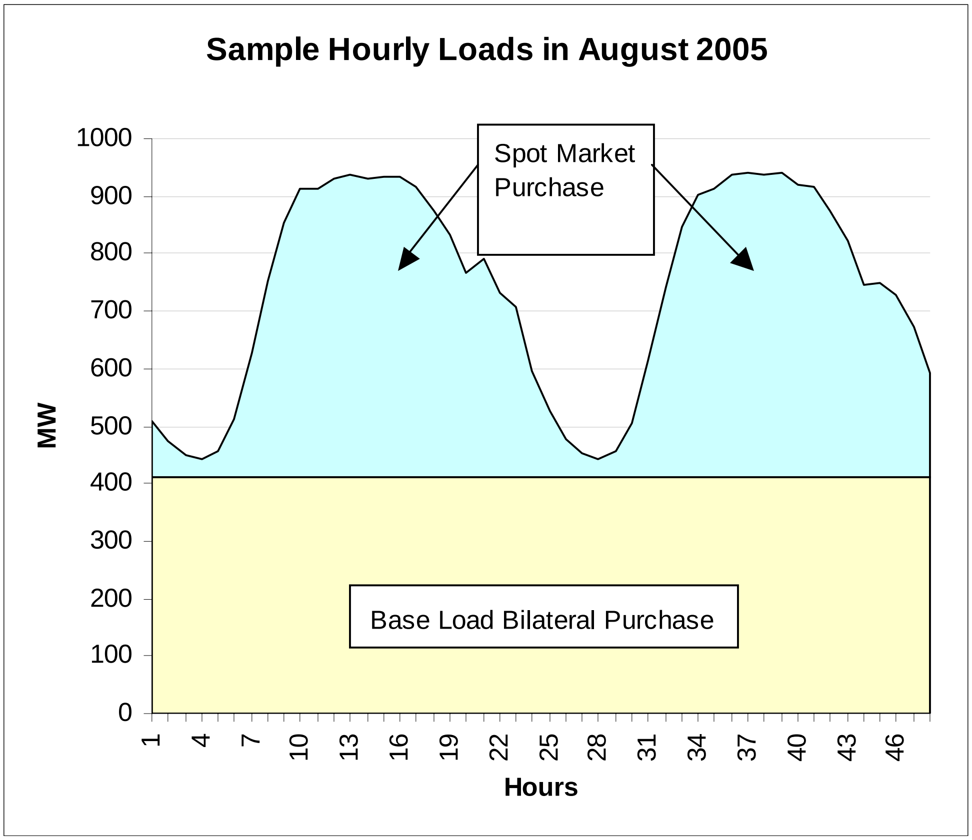


Figure 2-9: Typical Weekday Loads in August 2005 – San Francisco, Contract and Spot Mix Case

Combined cycle plants without any combustion turbines represent the most cost-effective bilateral purchase for this scenario, since the bilateral purchase can be base loaded (i.e., 7x24). If the magnitude of the bilateral purchase were to increase substantially, procurement of power from a peaking facility would become economic.

Although this scenario represents a simple approach to portfolio planning, it is nonetheless a start. For a comprehensive portfolio planning process, it would be appropriate to capture the inherent risks in the market due to load volatility, market clearing price volatility, generation and transmission outage volatility, and fuel price volatility. Taking a stochastic approach captures the risk and cost reduction that can be achieved from a combined portfolio of long-term, fixed price contracts, shorter-term contracts and spot market purchases. Thus, a portfolio that may appear more expensive than a 100% spot market purchase strategy may, in fact, be less expensive and reduce the volatility in the City's cost of power when viewed in a more realistic, stochastic assessment.

Remain as PG&E Customer

This analysis developed a final scenario to explore the costs to the City of continuing to rely on PG&E and the CAIOS for electricity service. This estimate of the electricity costs for San Francisco customers is based on a forecast of tariff rates for PG&E.

The California Energy Commission has published a retail electricity price forecast in its 2002-2012 Electricity Outlook Report, published in February 2002. A utility's retail rates include the costs for generation of electricity, transmission, distribution, public purpose programs, the competition transition charge, nuclear decommissioning, ancillary services, and other miscellaneous charges. The forecast published in the CEC Outlook Report was prepared largely in November of 2001. Since then, the CPUC and CDWR have taken actions and rendered decisions that directly affect the CEC's forecast. In addition, the CEC's forecast included a rough estimate of the effects of the CDWR long-term energy contracts. The CEC analysis was performed before CDWR renegotiated a portion of the contracts as well.

Figure 2-10 shows the CEC's estimate of PG&E rate components in nominal dollars. Note that the CEC anticipates that generation costs will make up approximately 60 percent of PG&E's average electricity rates over the next decade.

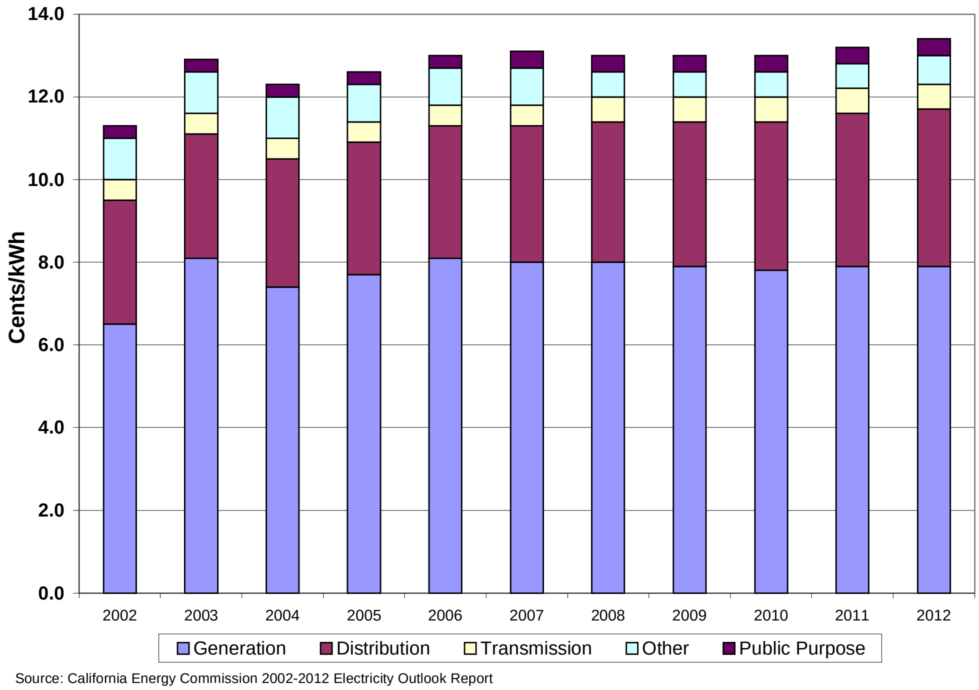
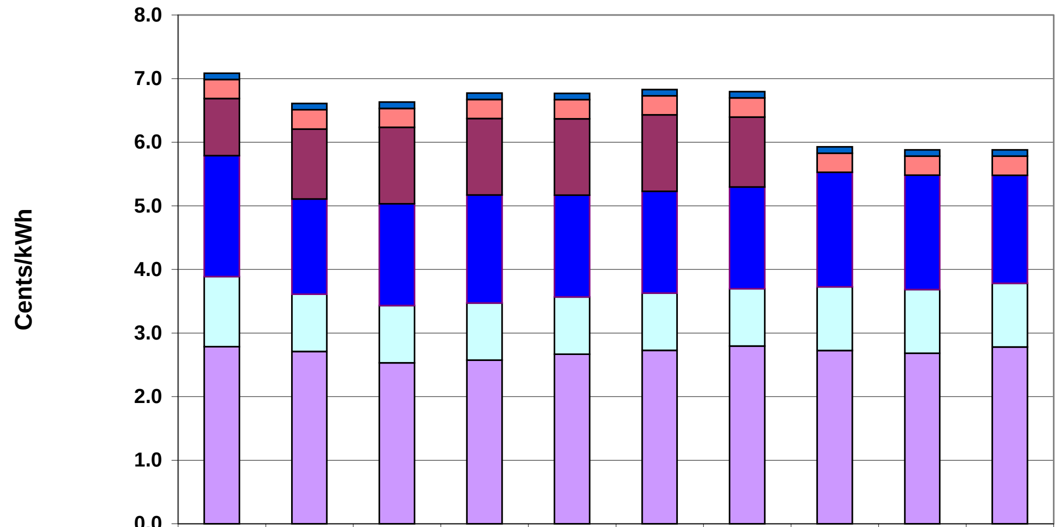


Figure 2-10: CEC Forecast of PG&E Electricity Rate Components ($Nominal)

This analysis used the CEC's forecast of retail rates as a base estimate of generation costs and supplemented it with estimates of generation costs related to the CDWR contracts, as recently amended.

To calculate the cost of CDWR contracts over the period 2003-2012, the analysis developed a coherent model of the California IOU system and CDWR's future purchases and costs pursuant to ABX1 1. Figure 2-11 shows the forecast of CDWR-related costs along with the CEC's forecast of the other generation cost components.



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Other Utility Contracts	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Utility Debt	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
DWR Financing	0.9	1.1	1.2	1.2	1.2	1.2	1.1	0.0	0.0	0.0
Utility QF Contracts	1.9	1.5	1.6	1.7	1.6	1.6	1.6	1.8	1.8	1.7
Utility Plants	1.1	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
DWR Contract	2.8	2.7	2.5	2.6	2.7	2.7	2.8	2.7	2.7	2.8

Source: California Energy Commission 2002-2012 Electricity Outlook Report

Figure 2-11: Forecast of PG&E Generation Cost Components ($Nominal)

Table 2-11 below summarizes the generation cost estimate (in 2002$) for the City of San Francisco for the years 2003-2012 if load were to continue to be served by PG&E.

Table 2-11
Generation Cost Component Forecast – San Francisco
Remain as PG&E Customer Case
($ 000)

Year	Base Case
2003	404,263
2004	372,883
2005	380,713
2006	387,018
2007	385,347
2008	386,872
2009	382,916
2010	328,381
2011	323,406
2012	321,063

Summary of Generation Cost Scenarios

Developing a portfolio of electricity supply sources for a load that fluctuates hourly, daily, monthly, and annually is a complicated undertaking. Only through a detailed Integrated Resource Planning process (which adequately addresses load and power supply risks) will it be possible to identify an appropriate portfolio of supplies and determine the cost of the commodity to consumers. While this report is primarily qualitative, an effort has been made to provide a rough estimate of generation costs that might be experienced in meeting loads in the San Francisco peninsula area. The three scenarios analyzed and rough costs are:

Table 2-12
Generation Cost Component Forecast – San Francisco
Summary
($ 000)

Electricity Supply Alternatives	Approximate Cents per kWh
1. 100% Purchases From Spot Markets	3.9¢ + Exit Fees
2. 50% Long-Term Contract, 50% Spot Market	4.1¢ + Exit Fees
3. PG&E Tariff (Utility Generation + CDWR)	5.7¢

The numbers presented above do not reflect "exit fee" ramifications and therefore, one should not infer from this table that the PG&E tariff costs[11] more than either Scenario 1 or Scenario 2. In theory, since the exit fees are calculated to make the utility and CDWR indifferent to customers going to direct access, then the exit fee that would be added to Scenarios 1 or 2 would increase the generation cost component of those scenarios to roughly that of Scenario 3. The CPUC is in the midst of the process of determining exit fees for direct access customers. The outcome of such proceeding can impact the cost under each of the three scenarios. In order for a SF Muni to evaluate any role in power generation or contracting, it would be necessary to add exit fees to Scenarios 1 and 2, and to update CDWR and other exit fees in Scenario 3.

The main discriminator among these Scenarios is the role that San Francisco would have in determining its desired risk tradeoff for a given portfolio. Although Scenario 1 would, on the surface, appear to be a lower cost scenario (ignoring exit fees), it would expose San Francisco to a high level of generation cost risk due to high price volatility in the spot market. Scenario 2 (again, ignoring exit fees) is only slightly more expensive, but has a much lower level of generation cost risk due to the large component of long-term contracts at a fixed price and less exposure to the spot market.

[11] PG&E Tariff Costs are based on data presented in the California Energy Commission's 2002-2012 Electricity Outlook Report modified to reflect an assessment of the CDWR contract costs. Many new proposals have and are being evaluated since the publication of the CEC report; hence, data in it may not accurately reflect current assumptions.

General Discussion of Transmission

The delivery of electric energy is a complex integrated process from production to utilization. The previous section discussed issues surrounding the production process – i.e., generation. This section discusses the process of delivering power from large generating stations to local areas – i.e., transmission.

Once the transmitted power reaches the local area and the delivery voltage is reduced, we typically say that the distribution system starts. It is important to note that although the distinction between generation, transmission and distribution can be very important from the standpoint of control and pricing of electric energy, the delineations are often imprecise. The distinction between production of electric energy (generation) versus the transportation of energy (transmission and distribution) is easier to delineate because of the distinct difference in physical process. The production process changes energy in one form to electricity. But the delineation between transmission and distribution does not have a clear-cut physical distinction. Very often, transmission is distinguished from distribution by the voltage level of the electrical equipment. Also, delivery on an interconnected network of lines is more characteristic of transmission; whereas delivery on radial lines is associated with distribution. There are, however, exceptions to these guidelines. For example, PG&E serves the downtown area of San Francisco on a highly meshed network that is considered to be distribution, whereas radial lines that are considered to be transmission serve much of PG&E's rural areas in other parts of the State. SCE's bulk delivery system below 230kv is termed distribution. Conversely, PG&E's extensive 115kv and 60kv delivery system is termed transmission. For the purpose of this Study we will use the terminology as it is commonly applied to the PG&E system that supplies San Francisco load, that is, 60 kV and above is typically transmission.

Prior to 1998, most transmission in California was operated by the three main investor-owned utilities: Pacific Gas and Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company. Beginning March 31, 1998, CAISO) took over operational control of the transmission facilities owned by the three investor-owned utilities. The CAISO is a public benefit corporation created as a result of AB1890 and is responsible for maintaining the reliability of the ISO-controlled grid, serving most California consumers. "The core functions of the California are to:

- provide open and nondiscriminatory transmission service
- ensure safe and reliable operation of the grid

- Operate energy and reliability markets in a responsive, flexible and transparent manner
- Foster reasonable energy costs for California consumers"[12]

Figure 3-1 shows the areas of California covered by the CAISO-controlled grid.

Figure 3-1: CAISO Control Area[13]

Transmission Constraints

There are three major constraints to the physical delivery of electric power from other areas of the State to San Francisco. The first constraint involves a restriction on the amount of power that can be imported into the Greater Bay Area (GBA), a second

[12] California ISO Website, www.caiso.com
[13] Ibid

constraint is a restriction on the amount of power that can be transmitted onto the Peninsula from the East Bay, and a third constraint is a restriction in the amount of power that can be imported to the northern Peninsula, including the City

Greater Bay Area Constraints

There is insufficient transmission into the Bay Area to serve its load, so reliable electric service depends on power produced by local generators. The GBA transmission system consists primarily of four major outlying 500/230kv substations (PG&E's Vaca-Dixon, Tesla and Metcalf substations, and WAPA's Tracy substation) and a network of 230kv "import" circuits across the boundary. Potential failures at these outlying 500/230kv transformers and other GBA facilities, limit the amount of power that can be imported to reliably serve the Greater Bay Area. Twenty-one transmission lines cross the "cut plane" representing the Bay Area transmission system in Figure 3-2 and the loading on these lines is important in serving the Greater Bay Area reliably.

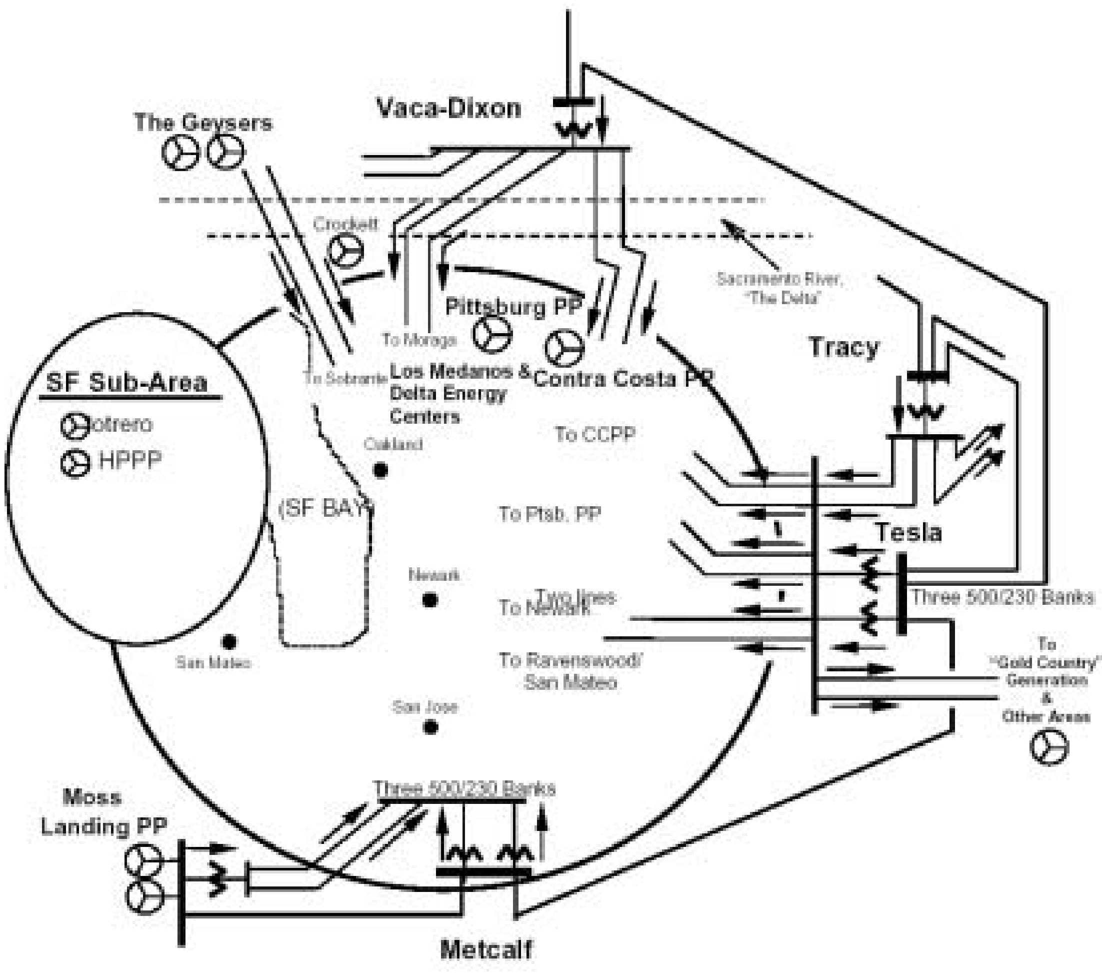


Figure 3-2: Greater Bay Area Transmission System[14]

[14] 2003 Reliability Must-Run Study Report, Appendix 5, May 2002

(Greater Bay Area is interior to the circle "cut plane")

From a transmission-planning standpoint, the GBA primarily consists of Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties. In 2000, the GBA exhibited a total simultaneous peak load of 8980 MW.[15] PG&E owns the majority of transmission and distribution facilities in the GBA. Three municipal electric utilities in the GBA own their own distribution systems: the Cities of Alameda, Palo Alto and Santa Clara. Additionally, some non-traditional municipal entities operate distribution systems to serve their own loads, including Hetch Hetchy, Stanford University and the University of California.

There are approximately 1,000 MW of regulatory Must-Take Qualifying Facility resources and self-generation in the Greater Bay Area that the CAISO assumes will be operating during the system peak. Table 3-1 is a listing of some generating plants in the Bay Area that must be operated to insure that the transmission lines into the Bay Area are not loaded above their rating. These units are considered by the CAISO to be "Effective Units" because their operation tends to relieve loadings on the critical transmission lines and/or transformer banks serving the Bay Area.

Table 3-1
2003 Greater Bay Area Generation Effective Units[16]

Name	MW
Alameda	50
Contra Costa PP	680
Delta Energy Center	975
Santa Clara	50
Hunters Point PP	222
IBM Cottle	38
Martinez Shell Refining Co.	100
Oakland CT's	165
LMEC	678
Pittsburg PP	2050
Potrero PP	366
Tosco Union Ch	25
J. Smurfit (Container Corp.)	25
Calpine Gilroy	135
Valero	100
Moss Landing PP	2560
Total Available	**8219**

[15] 2003 Reliability Must-Run study Report, Appendix 5, May 2002
[16] Ibid

The above table includes three new combined cycle generating plants: The Los Medanos Energy Center (LMEC) on-line July 2001; the Delta Energy Center (DEC) on-line June 2002; and the expansion at the Moss Landing Power Plant, Phase I, on-line July 2002 and Phase II is in the final stages of construction.

Peninsula Sub-Area Constraints

Besides the constraints of getting the needed power into the Bay Area, there are two additional constraints to serving the load in the City of San Francisco. One results from the lack of transmission capacity into San Mateo substation. There are only two sets of 230kv transmission lines linking the San Mateo substation to the East Bay, one crossing the bay parallel to the San Mateo Bridge and one crossing the bay parallel to the Dumbarton Bridge. At least some of the generation within the Upper Peninsula (chiefly Hunter's Point and Potrero Power Plants) must be operated to prevent overloading these lines during peak loading conditions and contingency conditions. Currently, a more limiting condition exists north of San Mateo substation; to prevent overloading of transmission serving the Upper Peninsula and San Francisco at certain levels of load, a minimum level of generation must be operating at Hunter's Point and Potrero Power Plants.

Figure 3-3 is a schematic of the transmission lines terminating at San Mateo Substation and the 5-115kv overhead lines which transmit power to San Francisco from San Mateo.

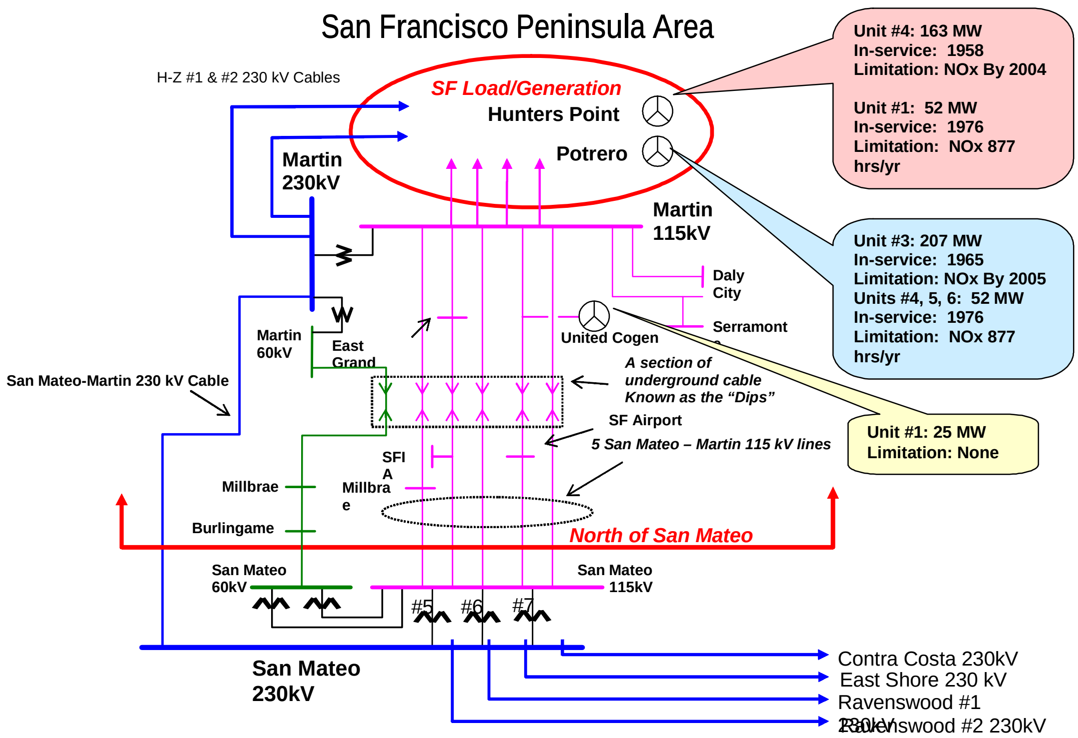


Figure 3-3: San Francisco Area Power System Diagram[17]

Transmission Service Reliability

Reliable service is very important to most electric customers. Although most customer outages are caused by deficiencies/outages of the distribution system, this section will focus on transmission system reliability. Though usually rarer than outages caused by a failure in the distribution system, outages caused by a failure in the transmission system tend to be of a larger scale and can lead to a complete shut down of a whole metropolitan area, such as occurred in San Francisco on December 12, 1998.

Transmission systems are designed so that for certain failures of components of the transmission system supplying an area that might occur at the same time as failures of the generation serving the same area, no interruption of service would be expected to occur. PG&E performs planning studies and develops a grid expansion plan to meet the CAISO Grid Planning Standards. These Planning Standards include separate guidelines for the Greater Bay Area and for the San Francisco Sub-area and include the WECC Reliability Criteria. The CAISO Grid Planning Standards are contained in **Appendix A**. At the present time, the contingency during the 5-year CAISO planning horizon that is most limiting (i.e., creates the greatest need for the construction of new transmission lines into the City) is the overlapping outage of the underground 230 kV

[17] Draft San Francisco Peninsula Long-Term Transmission Planning Study, Phase 2 Study Plan, Version 1.4, May 28, 2002.

circuit from the San Mateo Substation to the Martin Substation, with Potrero Unit 3 and a one Combustion Turbine at either Hunter's Point or Potrero off line.

Substantial upgrades have been and are being made to the transmission system into the Bay Area including a new 230kv line from Tesla to Newark and new 525/230kv transformer banks at Tesla, Tracy and Metcalf Substations. The Tesla and Tracy transformer upgrades should be completed in summer 2002, while the Metcalf Substation transformer upgrade should be completed by summer 2003. The combined affect of the above projects, along with other smaller projects, will be to increase the Bay Area import capability to 10,500 MW. The system still will be dependent on the operation of many older Bay Area generating units which often have been unavailable during peak times when they are needed the most. For example, a major contributing factor to the rolling blackouts in the Bay Area on June 14, 2000, was the inability of the existing Bay Area transmission and generation to provide adequate voltage support at Newark Substation.

PG&E is studying the potential for a series of new 525kv and 230kv lines and a new 525/230kv substation near Sunol to raise the load serving capability of the transmission system into the Bay Area. Assuming the existing generation is maintained and is supplemented with some new generation additions, the Bay Area transmission load serving capability could be increased by 2300 MW, from the current 10,500 MW to 12,800 MW. If the objective is only to meet the CAISO Planning Criteria, this plan likely would be implemented incrementally; it thus likely would require continued reliance on local generation .As an alternative to taking an incremental approach to meeting the CAISO Planning Criteria, PG&E is performing, with review by the Cities of San Francisco and Palo Alto, economic studies to determine if accelerating these contemplated additions would be economically justified. These studies will consider the economic benefits of reducing the "extra costs" incurred due to the need to operate more expensive Bay Area generation during times of transmission congestion and payments to local generators made under Reliability Must Run contracts. The studies potentially also will consider the economic benefits of reduced outage costs to customers resulting from transmission additions. In other words, outages are expected even when a system is designed to meet an established set of criteria. If additional transmission is built beyond that required to meet the minimum standards, the expected "outage costs" experienced by customers will be reduced.

The loss of the 115kv bus at San Mateo Substation on December 8, 1998, which resulted in the widespread outage of the City is an example of an outage risk that could be reduced if additional transmission were developed based on economic benefits. Following the outage, in April 1999 the CAISO formed a study group to evaluate the long-term power supply adequacy for serving San Francisco. The result of that study has been the decision to build a 230kv line from Jefferson Substation in Redwood City to Martin Substation near San Francisco by 2005. Figure 3-4 shows the existing and proposed transmission linking the Peninsula to the East Bay.

Figure 3-4: Peninsula Transmission Links[18]

Reliability Impacts of Generation Outages

An integral part of providing reliable service to the City's electric customers is the existing generation at Hunter's Point and Potrero Power Plants. Both Hunter's Point and Potrero are old, unreliable plants, and the City has been notified by the CAISO on numerous occasions to be ready to shed load because of conditions caused by the failure or repair of one or more of these generating units. Table 3-2 lists the age, capability and operating limitations of these plants.

Table 3-2[19]
Power Generation on the San Francisco Peninsula

Plant	Unit	Size	Fuel Type	In-Service Date	Operating Restrictions

[18] The Electricity Resource Plan, Choosing San Francisco's Future, March 2002
[19] Ibid

Potrero	3	207	Natural Gas	1965	NO_x restrictions
	4	52	Distillate	1976	877 hrs/yr
	5	52	Distillate	1976	877 hrs/yr
	6	52	Distillate	1976	877 hrs/yr
Hunter's Point	1	52	Distillate	1976	877 hrs/yr
	4	163	Natural Gas	1958	NO_x restrictions
United Cogen (at SFO)	1	20	Natural Gas	1986	None

Source: PG&E

An inherent limitation of the CAISO Planning Criteria is that they are deterministic. For example, they do not take into account the reliability of individual generating units, which is typically inversely related to the age of the units. A study by the California Energy Commission (Electricity Outlook for 2002-2012) used an internally developed model (the Supply Assessment Model) and historical plant outage data to estimate the likelihood of peak hour electric service demand reductions for various regions in the State. Table 3-3 shows that even though all of the areas within the State must meet the CAISO Planning Criteria, some areas are much more likely to experience load shedding at the time of an area's peak load. The three areas with the greatest risk of demand reductions (San Francisco, San Diego and Imperial Irrigation District) share the common characteristics that they depend on old and unreliable generation and on limited transmission to meet their needs. To bring the risk of outages in San Francisco in line with other areas in the State will require installation of newer, more reliable generation and increased transmission into San Francisco.

Table 3-3
Demand Reduction Uncertainties[20]

Demand Reduction Uncertainties
Shortage Risks and Maximum Deficits by Transmission Zone
Summer Peak Period 2003

Transmission Zones	Risks (Percent)		Maximum Deficit (MW)	
	Baseline Scenario	High Load Scenario	Baseline Scenario	High Load Scenario
South CA	1.3	4.3	1,730	5,210
North CA	0	0	0	0
San Diego	7	17	3,030	3,540
San Francisco	13.7	11	230	210
IID	7.3	18.3	280	310
LADWP	0	0	0	0
SMUD	0	0	0	0
CCENT	0	0	0	0

Reliability Impacts of Local Generation and the San Francisco Energy Plan

In July of 1998 San Francisco signed an agreement with PG&E to close Hunter's Point Power Plant when it is no longer needed to provide electric reliability in San Francisco. PG&E, with CAISO concurrence, has shut down the two oldest units at Hunter's Point (Units 2 and 3) and converted them to synchronous condensers. When the CAISO Board of Governors in May 2002 approved the Jefferson-Martin transmission project 2002, the City requested that the Board also approve the shut down of Hunter's Point Power Plant. The Board did not act on the City's request, but directed staff to "work with the City of San Francisco and interested stakeholder groups toward their goal of closing the Hunter's Point Power Plant." As part of implementing this directive, the CAISO is sponsoring Phase 2 of the San Francisco Peninsula Long Term Transmission Planning study to develop a long-term load-serving plan that is responsive to varying levels of load growth and generation development and retirement. The Draft Phase 2 Study Plan is included in **Appendix B**.

Mirant Corporation has proposed building a 540mw combined cycle power plant (Potrero Unit 7) next to their existing Potrero Power Plant. To improve the reliability of the proposed plant, the CAISO and CEC are considering requiring changes to the plant design to eliminate potential common mode failures that could trip the entire plant off line. The CEC staff, in February 2002, released its final staff assessment on

[20] 2002-2012 Electricity Outlook, California Energy Commission, February 2002

Potrero Unit 7, and recommending that the plant be licensed with certain mitigation measures. Two key mitigation measures are replacing the proposed once-through cooling system to reduce harmful impacts on the bay marine environment, and local mitigation of particulate emissions.

In March 2002, San Francisco's Department of the Environment and the Public Utilities Commission jointly published "The Electricity Resource Plan, Choosing San Francisco's Energy Future" ("Energy Plan"). The Energy Plan recommends that the City intervene in the CEC licensing process to ensure that the environmental impacts of the proposed Potrero Unit 7 are minimized. The Energy Plan also recommends the City oppose Potrero Unit 7 unless the plant is re-configured to ensure the prompt closure of both the Hunter's Point Power Plant and Potrero Unit 3. The Energy Plan also proposes that the City identify at least three locations to build City-owned cogeneration or small combined cycle power plants, and recommends identifying specific sites for various private sector sponsored distributed generation applications. A key recommendation of the Energy Plan is the aggressive pursuit of energy efficiency projects and identification of locations for the installation of solar and other small-scale renewable energy systems in the City.

Describing the relative reliability impacts of the various elements of the Energy Plan is beyond the scope of this Study. It is clear, however, that:

- Adding transmission will increase reliability even without new generation additions;
- Adding local generation will increase reliability
- Replacing existing local generation with new local generation can increase reliability due to the lower forced outage rate of new generation plants
- Reducing load through conservation increases reliability

Transmission Service Pricing

In the current electric market structure, electricity is delivered to both retail and wholesale customers over the PG&E transmission system. The Federal Energy Regulatory Commission approves the transmission rates for both sets of customers. These rates cover operations and maintenance costs, as well as recovery of the capital cost of the transmission system, including an authorized rate of return on investment. Transmission charges for retail customers are included in the bundled retail electric tariffs approved by the California Public Utilities Commission. Although PG&E's costs to provide transmission service vary by geographical location, PG&E's current method of recovering these costs (as authorized by the CPUC) does not take into account these geographical differences. For example, in general the capital, operations and maintenance costs related to providing transmission service to rural customers is greater than those for urban customers. Conversely, due to the transmission constraints into the Bay Area, the costs to deliver energy to the Bay Area customers tends to be higher than for customers in other parts of PG&E's service area. When it developed the northern California transmission system, PG&E was a vertically-integrated utility, with both generation and transmission assets. It therefore in some instances, such as the Bay Area, chose to substitute relatively inefficient local generation in lieu of expanding the transmission import capability. Now that PG&E has divested most of its generation assets, and the CAISO is proposing new transmission congestion cost allocation methods, the City could be exposed to higher total transmission costs as a result of PG&E's historical grid expansion policies.

At the wholesale level, the City's cost of using PG&E's transmission system to serve Municipal Loads, mostly to deliver power generated at Hetch Hetchy's hydroelectric facilities, is determined by rate schedules in its current Agreement with PG&E. Changes to these rates must be filed by PG&E and approved by the Federal Energy Regulatory Commission. To date, the City and other entities with existing transmission contracts with PG&E that are FERC jurisdictional have been successful in resisting major transmission rate increases. Upon termination of the Agreement, or if the City decides to use its own transmission facilities to serve retail customers, there are two main transmission service options: CAISO Transmission Service and Separate Control Area Service.

CAISO Transmission Service

In this section, we will describe the current structure and pricing of CAISO transmission service and proposed pricing changes associated with the ISO's Comprehensive Market Design proposal filed at FERC May 1, 2002.

The CAISO provides network, rather than point-to-point transmission service. This means that CAISO customers can use the CAISO grid to deliver energy from anywhere on the grid to their load, without having to link together a series of transmission paths. The costs of CAISO transmission service are grouped into three broad categories:

- Transmission Access Charges
- Grid Management Charges
- Transmission Congestion Charges

Transmission Access Charges predominately recover the capital and fixed operating costs of the grid. Grid Management Charges recover the ISO's administrative and overhead costs associated with providing various grid services. Transmission Congestion Charges are used to recover out of merit order generation costs and to allocate scarce transmission on constrained interfaces.

Transmission Access Charges

The ISO's access charge costs were "utility specific" at the start of the CAISO and are gradually changing to a common CAISO grid-wide charge. Beginning in 2001, when the City of Vernon joined the three main Investor-owned utilities as an CAISO Participating Transmission Owner (PTO), the utility specific access fees were changed into area-specific transmission access charges (TAC). The City of San Francisco is in the Northern California TAC area, which at the present time correlates to the PG&E

system. If other entities such as SMUD, Palo Alto, Santa Clara, Alameda or other NCPA cities should become Participating Transmission Owners, control of their transmission would be assumed by the ISO, and their transmission costs would be included in the Northern TAC area.

The Transmission Access Charge is broken into two components: a High Voltage access charge for use of the 230kv and above network, and an additional Low Voltage access charge for those customers that also use the lower voltage transmission facilities. The access charge methodology currently is under review by FERC, and the rates being charged today are subject to refund pending a FERC decision. The high voltage access charge is weighted 80% to pay for TAC area costs and 20% to pay for statewide costs. Assuming the filed tariff is approved by FERC and no future changes are made to its basic structure, the statewide portion of the High Voltage Charge will be increased each year by 10%, with a corresponding 10% decrease in the TAC area portion. Therefore, by 2010, everyone taking CAISO service would pay the same ("postage stamp") access fee for High Voltage service.

Most customers in Northern California take low voltage transmission service (below 230kV), the charges for which are recovered on a utility specific basis. For example, PG&E customers in San Francisco pay both the High and Low Voltage component of the access fee applicable for Northern California because San Francisco loads are served from PG&E's low voltage transmission system. FERC is expected to issue a Notice of Proposed Rule making this summer to develop an industry-wide Standard Market Design, which may change the methodology for recovering transmission access costs.

Table 3-4 below shows the current PG&E High Voltage and Low Voltage access charges.

Table 3-4[21]
Wheeling Access Charges

Wheeling Access Charge for PG&E Take Out Points Interconnecting Non-PTOs Within ISO Control Area to the ISO Controlled Grid

PTO	HV Wheeling Access Rate ($/MWh)	LV Wheeling Access Rate ($/MWh)	Effective Dates
PG&E	2.28	3.3678	1/1/2002 – 12/31/02

Grid Management Charges

The CAISO recovers its administrative, financing and overhead costs of providing various grid services using a Grid Management Charge (GMC). The GMC is unbundled into three charge types:

- Control Area Services

[21] Wheeling Access Charges 2002, California ISO

- Congestion Management
- Market Operations/Ancillary Services and Real Time Energy Operations

The Control Area Services charge recovers the ISO's cost of ensuring safe, reliable operation of the grid and dispatch of bulk power. This charge is applied to CAISO metered load and exports, and currently is $0.58/MWh.

The Congestion Management Charge recovers the ISO's costs of operating the congestion management process, firm transmission rights auction and monitoring. This charge is applied to net scheduled inter-zonal flow, and currently is $0.37/MWh.

The Market Operations Charge/Ancillary Services and Real Time Operations (ASREO) charge recovers the ISO's costs of market and settlement related services. This charge is applied based on total purchases and sales of ancillary services capacity, Supplemental Energy and Imbalance Energy, and currently is $0.96/MWh. It is applied to 50% of self-provided Ancillary Services capacity.

The ISO's grid management charges are significantly higher than charges for similar services provided by other independent system operators, and can be a significant cost for CAISO participants. The GMC costs are embedded in the PG&E retail tariffs for the City's residents and businesses served by PG&E. Under its Agreement with the City, PG&E could attempt to pass these costs on to the City's Municipal Loads, but to date has not done so. Should the City take CAISO service in the future for its Municipal Loads, or for direct sales to retail customers, it would be exposed to these GMC costs.

Transmission Congestion Charges

The CAISO has two types of Transmission Congestion Charges:

- Intra-zonal congestion charges
- Inter-zonal congestion charges

Intra-zonal congestion charges recover the cost of redispatching higher cost generation within a broader congestion zone during periods when the import capabilities of the lines into the zone would be exceeded. These intra-zonal costs currently are charged as an uplift to the customers within the zone in which they are incurred. If the amount of intra-zonal congestion reaches a significant level, a process exists for creating a new transmission zone.

Inter-zonal congestion charges are the means by which the CAISO allocates limited transmission capacity on lines between zones when the requests for usage exceeds the rated limits of the lines. Figure 3-5 depicts the ISO's Network Model and shows the linkages between each of the three active transmission zones (NP15, ZP26 and SP15) and other areas outside of the CAISO grid. Separate transmission zones have been defined for areas which are expected to experience a significant amount of inter-zonal congestion between the zones. Note that San Francisco and Humboldt are designated inactive zones by the CAISO Board of Governors on an interim basis, at least until such time that the CAISO determines the criteria for defining "workably competitive generation markets."

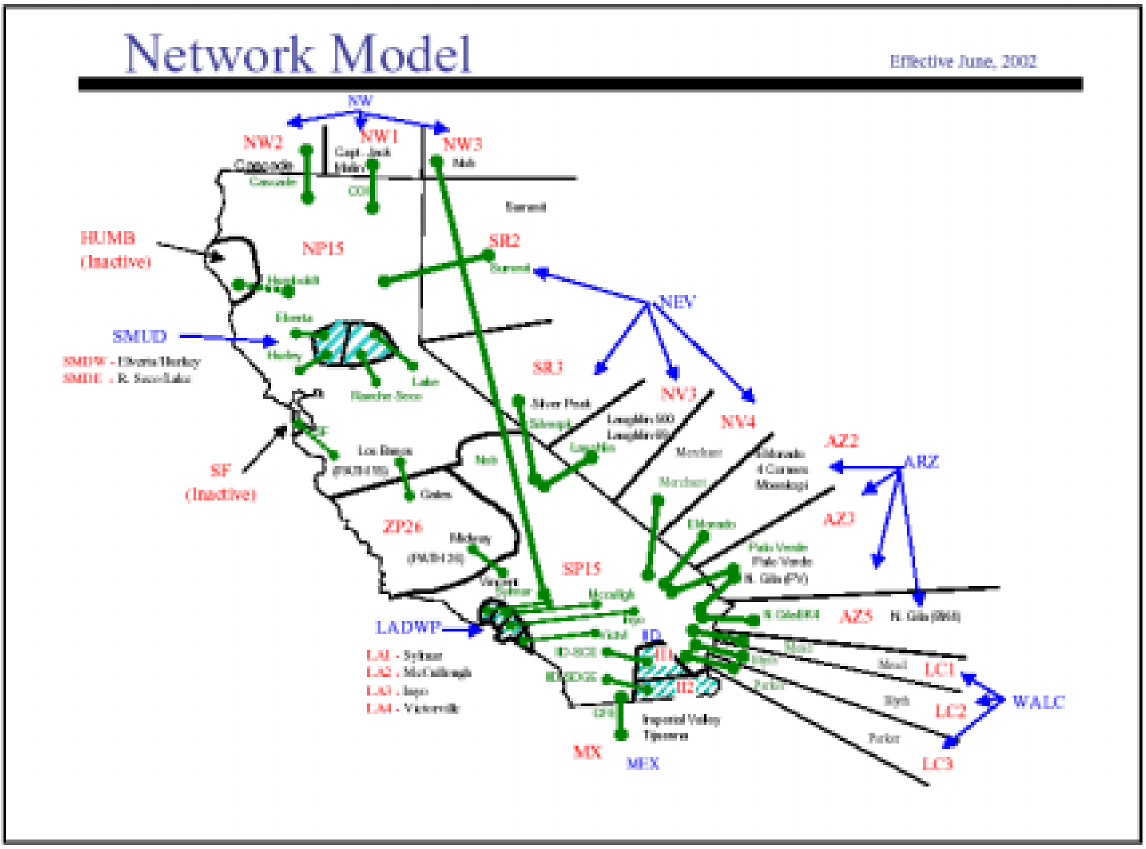


Figure 3-5: CAISO Network Model[22]

Under the current CAISO pricing system, Inter-zonal Congestion Charges are applied to deliveries using the CAISO grid into or out of each of the three active zones (NP15, ZP26, SP15) during periods when requests to schedule deliveries between the zones exceed the capability of the lines. The amount of Inter-zonal Congestion Charges is essentially the difference in market price of electricity between the zones. The imposition of these charges and the allocation of the revenues from them can have a large impact on the cost of power for all electric customers located in the City of San Francisco, and will be an important consideration in the exploration of alternative methods of City involvement in the provision of electric service to its consumers.

The Inter-zonal Congestion Charge revenues are allocated to the Transmission Owners, or to parties that have purchased Firm Transmission Rights (FTRs) for the constrained path from the Transmission Owner in an auction. The revenues from the FTR auction are used to reduce the Transmission Access Charges for all of each Transmission Owners' customers in future years. An undesirable result of this procedure is that during times of transmission constraints, consumers in constrained zones do not get the benefit of the lower cost electricity that is being imported on the lines. The City has been a vigilant critic of the inequities and perverse incentives inherent in this system. As a result of the City's efforts, San Francisco was declared

[22] California ISO

an "inactive" zone, and the adverse impacts of this system on electric consumers in the City have been avoided to date.

Unfortunately, San Francisco is exposed to changes in the above situation. The existing CAISO Tariff allows for the creation of new active zones and a proposal to create 15 local pricing areas (i.e., zones) was developed, but not adopted, in 2000. The latest threat, which appears likely to proceed because it has substantial stakeholder support and is consistent with proposed FERC policy, could create individual prices for all the approximately 3000 buses or "nodes" in the transmission network. This threat is one of the key elements of the ISO's Comprehensive Market Design filing with FERC on May 1, 2002.

Comprehensive Market Design Filing

On May 1, 2002, the CAISO submitted a major filing to FERC which could have a significant impact on the cost of delivered energy to the City. In its motion to intervene and protest the ISO's Comprehensive Market Design filing, the City notes that:

> "The ISO's MD02 Filing proposes to change the energy, capacity and transmission service pricing currently charged to San Francisco customers in ways that will shift significant costs currently shared by all users of the grid or all transmission customers in the former PG&E service territory directly to those customers located in San Francisco. The impact of the proposed Capacity Availability obligation ("ACAP"), the locational ACAP requirement, the transfer of current Reliability Must-Run ("RMR") procurement responsibility from all CAISO grid users to the local loads closest to the RMR unit, the exposure of load to locational pricing, the adequacy of Firm Transmission Rights ("FTRs") as a hedge against increased congestion costs due to Locational Marginal Pricing ("LMP") and other transmission and resource procurement issues affect San Francisco directly."23

Three elements of the CAISO filing that could influence the City's options for providing electric services are:

- Redesign of the ISO's congestion management, energy and ancillary services markets based on Locational Marginal Pricing (LMP)
- A locational capacity obligation on Load Serving Entities
- Increased CAISO commitment to transmission expansion to remove constraints.

Locational Marginal Pricing

The CAISO is proposing to move from the current three zone congestion management model to a model that produces locational marginal pricing at the nodal level, using an optimal power flow algorithm and full network model to adjust generation and load

[23] Motion to Intervene and Protest of the City and County of San Francisco (see **Appendix C**)

schedules. This means that for each scheduling period (i.e. 10-minute interval), there potentially could be approximately 3,000 different prices for energy within the CAISO grid. This approach would eliminate the distinction between intra-zonal and inter-zonal congestion. The CAISO believes this approach will lead to more efficient use of the grid and reduce operational problems created by infeasible schedules which currently are allowed in the zonal model.

To simplify scheduling and settlements, the CAISO is proposing to use Load Aggregations so customers served by some Load Serving Entities likely would see prices similar to the existing zonal prices. For example, Table 3-5 shows that San Francisco is included in the PGE3 Load Aggregation, which covers most of the load included in the current NP15 zone. This means that intra-zonal congestion costs that are spread as an uplift to all NP15 loads in the current zonal model would be spread to a slightly less broad aggregation of customers – those in PGE3. The proposal envisions disaggregating pricing to the Load Group level, but has not disclosed the criteria or timing for doing so. The City therefore could be at risk to being exposed both to higher Bay Area energy prices (if a Bay Area Load Aggregation is created), and to even higher prices at the San Francisco Load Group level.

Table 3-5[24]
Initial Definition of Standard Load Aggregations

Initial Definition of Standard Load Aggregations
(Work in Progress)

Trans-mission Area	Trading Hub	Load Aggregation		Name and Correspondence to Existing Load Groups[57]
PGAE	NP15	PGE3	*PGHB*	*Humboldt (PG&E Humboldt/ PGHB) (current PGE1 demand zone)*
			PGSF	*San Francisco (PG&E San Francisco/ PGSF and PG&E Peninsula North/ PGP1) (current PGE2 demand zone)*
			PGDI	*Diablo (PG&E Diablo/ PGDI)*
			PGEB	*East Bay (PG&E East Bay/ PGEB)*
			PGMS	*Mission (PG&E Mission/ PGMS)*
			PGSJ	*San Jose/ Peninsula (PG&E De Anza/ PGDA, PG&E Peninsula South/ PGP2, and PG&E San Jose/ PGSJ)*
			PGF1	*Fresno (PG&E Fresno North/ PGF1, and part of PG&E Yosemite/ PGYO)*
			PGNC	*North Coast (North Bay LPA portion of PG&E North Coast/ PGNC)*
			PGFG	*Fulton Geysers (Fulton Geysers LPA portion of PG&E North Coast/ PGNC)*
			PGBC	*Battle Creek LRA (RMR area in PG&E North Valley/ PGNV)*
			PGSI	*Sierra LRA (RMR area in PG&E Sierra/ PGSI and parts of PG&E Sacramento/ PGSA)*
			PGST	*Stockton LRA (RMR area in PG&E Stockton/ PGST and Stanislaus/ PGSN)*
			PGNB	North Bay (PG&E North Bay/ PGNB, and remaining portion of PG&E North Coast/ PGNC)
			PGNV	North Valley (remaining portion of PG&E North Valley/ PGNV)
			PGSA	Sacramento Valley (remaining portions of PG&E Sacramento/ PGSA and Sierra/ PGSI)
			PGSN	San Joaquin (remaining portions of PG&E Stockton/ PGST, PG&E Stanislaus/ PGST, and PG&E Yosemite/ PGYO)
			PGCC	Central Coast (PG&E Central Coast/ PGCC)
			CT1	California Oregon Transmission Project
			CSF1	City of San Francisco
		CWR1	CWR1	California Dept. Of Water Resources
			CWR4	California Dept. Of Water Resources
		LMD1	LMD1	Lassen Municipal Utility District
		MID1	MID1	Modesto Irrigation District
		NCP1	NCP1	Northern California Power Agency (includes City of Santa Clara)
		RED1	RED1	City of Redding
		SMD1	SMD1	Sacramento Municipal Utility District
		TID1	TID1	Turlock Irrigation District
		WAP1	WAP1	Western Area Power Administration
	ZP26	PGE4	PGLP	Los Padres (PG&E Fresno South/ PGF2, PG&E Kern/ PGKE, and PG&E Los Padres/ PGLP)
		CWR2	CWR2	California Dept. of Water Resources
			CWR5	California Dept. of Water Resources
		NCP2	NCP2	Northern California Power Agency
SCE	SP15	SCE1	SCSO	*LA/ Orange County (SCE South/ SCSO)*
			SCEA	Other SCE (SCE East/ SCEA, SCE High Desert/ SCHD, SCE North/ SCNO, SCE Sylmar/ SCDC, and SCE West/ SCWE)
		ANA1	ANA1	City of Anaheim
		CWR3	CWR3	California Dept. of Water Resources
			CWR6	California Dept. of Water Resources
		PAS1	PAS1	City of Pasadena
		RVD1	RVD1	City of Riverside
		VRN1	VRN1	City of Vernon
		Other ...	Other ...	Load Groups for other municipal utilities?
SDGE		SDG1	*SDG1*	*San Diego Gas and Electric*

In addition to concerns about exposure to higher Bay Area and Peninsula energy prices, the City is concerned that in a nodal model, the impact on consumers of potential market power abuse by generators will be very concentrated. The CAISO

[24] California ISO Comprehensive Market Design Proposal, May 1, 2002 FERC Filing

has proposed local market power mitigation measures, but these might be insufficient to fully address this exposure.

Finally, it is worth noting that most power is expected to be procured in bilateral, forward market transactions outside of the ISO's markets. Because PG&E is the Load Serving Entity currently serving most City consumers, the California Public Utilities Commission's approach for allocating PG&E's energy procurement costs will have a large impact on the electric costs for the City's consumers.

Locational Capacity Obligation on Load Serving Entities

The CAISO is proposing that Load Serving Entities would have an obligation to provide capacity in excess of their forecast needs to support the reliable operation of the grid. The LSE would have to use a combination of firm transmission rights and local generation to meet this obligation. The CAISO also is proposing to transition the current Reliability Must Run resource obligations to the local LSEs.

This proposal exposes all CAISO grid consumers to potentially higher costs due to the need to procure excess capacity. Further, consumers located in transmission constrained areas, such as San Francisco, would not be able to rely on transmission to import capacity to meet all of the capacity obligation. If the locational capacity obligation is imposed without allowing a transition period sufficient to develop new local generation, transmission, demand management and conservation projects, the City potentially would be in a difficult position in negotiating with only a handful of local generation owners. The CAISO is hoping to eliminate the need for "Condition 1" RMR units (the RMR units in San Francisco are "Condition 2" units) by 2006 by expanding the transmission grid in constrained areas. The CAISO also would like to develop a form of cost-based locational capacity contract to mitigate against the exercise of market power.

The locational capacity obligation should make local conservation programs, distributed generation and transmission projects more attractive.

PG&E's allocation of costs for a locational capacity obligation will be determined by the CPUC. The cost allocation actions of the CPUC will impact the transmission and retail services options available to the City.

Increased CAISO Commitment to Transmission Expansion

The CAISO recognizes the potential for severe cost impacts on consumers in congested areas due to constraints in a transmission system that was designed and built under an entirely different regulatory regime, one which did not anticipate competitive generation markets and locational pricing. The CAISO therefore has stated that it will attempt to address in a realistic manner the question of how to upgrade transmission into congested areas to enable consumers in these areas to enjoy the benefits of competitive energy markets.[25]

[25] Ibid

An important element of this renewed commitment is the ISO's efforts to develop a methodology for evaluating economically-driven transmission projects (as opposed to reliability-driven projects). This methodology could lead to the development of Bay Area transmission projects that might not be needed strictly to meet reliability criteria, but that could lower costs for consumers. It will be important for the City to participate in the development and implementation of this methodology, and in FERC proceedings regarding cost allocation.

The CAISO's stated commitment in the CMD filing to expanding the transmission grid to remove constraints is a step in the right direction, but needs further development. In particular,

- the CAISO does not have the authority to construct or finance facilities
- the CAISO has a limited ability to cause construction of facilities
- the CAISO has no ability to enforce construction "orders"
- PG&E's bankruptcy clouds the CAISO's ability to cause facilities to be built.

Nonetheless, if the CAISO can somehow accomplish the above, it could lead to construction of needed facilities in the Bay Area to improve reliability and reduce exposure to high-priced local generation.

Transmission Service Local Control

Historically, the City has had limited ability to control the development and operation of the transmission grid serving San Francisco. PG&E, as the Transmission Owner serving most of Northern California, is responsible for maintaining and developing the transmission system serving the Bay Area. The CAISO is responsible for operating the system. Prior to 1998, PG&E's transmission and generation were operated in an integrated fashion. Due to the high cost and difficulty of siting new transmission, PG&E chose to operate certain high-cost local generation facilities rather than to build more transmission facilities to allow import of lower-cost energy from more efficient resources. In the current zonal market structure, and in the proposed nodal market structure, it is more important than ever to ensure that sufficient transmission facilities are available to meet market needs. In its Comprehensive Market Design filing, the CAISO has proposed regulatory measures to give it greater control over the dispatch and pricing of generation facilities, both to ensure reliable operations and to reduce the risk of generators exercising market power. These regulatory measures cannot provide the same reliability and market power mitigation benefits that can be achieved by expanding the amount of transmission into and within the Bay Area.

Until recently, PG&E has been reluctant to invest in significant upgrades to its transmission system. For example, PG&E has resisted upgrading a major link between Northern and Southern California, Path 15, that often is fully loaded, particularly in the south-to-north direction during off-peak and winter hours. PG&E was ordered by the CPUC to submit an application for a Certificate of Public Convenience and Necessity (CPCN) at the height of the energy crisis last year. Subsequently, PG&E has unsuccessfully attempted to withdraw its application, and has reduced its participation in the project to building the substation facilities at each end of the line. Conversely, in the Bay Area, PG&E is supporting construction of the Jefferson-Martin line to improve reliability on the Peninsula. PG&E is expected to file a CPCN in September 2002. PG&E also has been meeting with representatives of San Francisco and Palo Alto to review Bay Area transmission needs at the order of CPUC Administrative Law Judge Gottstein.

The PG&E Bankruptcy creates a cloud over PG&E's ability to finance and build needed transmission facilities. PG&E has proposed to form a separate transmission utility, E-Trans, as part of its reorganization plan. It is possible that this entity might be more motivated to develop more transmission facilities, since doing so would increase its rate base. Even if this is true, however, PG&E is likely to request accelerated depreciation treatment, a higher equity/debt ratio, and a higher rate of return than on historical transmission projects. The effects of each of these actions would be to increase the cost to consumers to fund the transmission upgrades. The CPUC has submitted a rival reorganization plan that would not spin off the transmission activities of PG&E. The net effect of these rival plans is that there likely will continue to be uncertainty regarding PG&E's ability to develop the transmission infrastructure needed to improve the reliability of electric service to the City.

Alternatives to PG&E Transmission Service

As explained above, the fixed costs of transmission are recovered on a widespread basis – regionally in the past with more and more being spread Statewide in the future. The trend to recover the costs associated with congestion is just the opposite – i.e., the Comprehensive Market Design filing would recover those costs locally. These two factors, combined with the need to improve electric service reliability while enabling the shut down of power plants in the City, has led the City to place a high priority on having additional transmission facilities built by PG&E. PG&E, with CAISO approval, has made some additions to the transmission system serving the Greater Bay Area and San Francisco. The City has been very active in promoting those additions. Despite these successes, substantial limitations still exist. As the existing system is upgraded to better serve load reliably, it becomes less likely that additional transmission will be constructed to decrease the reliance on high-cost local generation. The result will be potential exposure to congestion charges.

The City has alternatives to PG&E transmission service, some of which could enable it to increase the capability and/or reduce the cost of the transmission system serving San Francisco and the Greater Bay Area.

Metered Subsystem

As part of its Comprehensive Market Design, the CAISO is refining the existing concept of a Metered Subsystem (MSS), to address concerns raised regarding the integration of Governmental Entities into CAISO operations. The fundamental characteristics of an MSS are that it:

- has its Load in a geographically contiguous Service Area, subsumed within the CAISO Control Area;

- has been operating for a number of years prior to the CAISO Operations Date as a vertically integrated utility with Load serving responsibility;
- has Generation, either owned or contracted;
- may own transmission or have an Entitlement to transmission; and
- is not subject to regulation by the California Public Utilities Commission ("CPUC") or FERC.

Potential benefits of participating in the CAISO as an MSS include:

- Reduced risk of curtailments during CAISO System Emergencies resulting from identifiable resource deficiencies of other Load Serving Entities.
  - Pro-rata curtailments only during System Emergencies not due to resource insufficiency.
- Greater control over own generation to meet local needs and resource optimization objectives.
  - Resources only available for CAISO dispatch during System Emergencies not due to resource insufficiency.
- Reduced exposure to some CAISO charges (applied to net load vs. gross load).

The CAISO has not yet filed tariff language describing the requirements, rights and obligations of a Metered Subsystem, and FERC will need to act on such a filing before it would be an alternative for the City. Assuming FERC acts favorably on the MSS portion of the ISO's Comprehensive Market Design filing, the City should evaluate the benefits and risks of becoming an MSS for additional load served using the CAISO grid, and upon termination of the City's existing agreement with PG&E. This evaluation would involve comparing the additional MSS costs, such as Scheduling Coordination services and potential imbalance charges with expected benefits, such as reduced CAISO service charges and greater control over City resources and reduced exposure to rotating outages due to the resource insufficiency of other Load Serving Entities.

Participating Transmission Owner (PTO)

The CAISO tariff provides for entities that own transmission facilities to apply to become Participating Transmission Owners (PTO). A PTO is a Transmission Owner that has turned operational control of its transmission facilities to the ISO. When the CAISO was formed, PG&E, Southern California Edison, and San Diego Gas & Electric were the original PTOs. On January 1, 2001, the City of Vernon became the first new PTO, and the City of Azusa submitted its application to the CAISO to become a PTO on June 3, 2002. One of the main advantages of becoming a PTO, especially for entities that have a large proportion of relatively new, high-cost transmission, is that each PTO's transmission revenue requirement is aggregated and included in each Transmission Access Charge Area's access charge. If an entity's average transmission access costs for its own facilities are greater than the TAC area average cost, becoming a PTO can provide economic benefits.

If the City should decide to serve electric customers directly from its transmission system within the City, and it becomes a Participating Transmission Owner (PTO), then the cost of that part of its transmission system that is at 230 kV will be recovered from all CAISO access fee customers regionally and statewide. The costs of its transmission system below 230 kV (probably 115 kV) would be recovered from its own customers. Since the City owns substantial transmission outside of the City (that presumably has a low cost basis, given its age), that is currently designated as a generation tie, any analysis of the consequences of becoming a PTO would need to include the possibility of any impacts on that system which delivers power to Hetch Hetchy's customers in the Central Valley (MID and TID) and to Warnerville and Newark Substations as part of existing contract service PG&E provides to Municipal Load.

Transmission Development and Funding

The City could become a project developer and/or a funding vehicle for additional transmission into the Bay Area and into San Francisco. The existing CAISO tariff envisions "market participants" funding new transmission and recovering congestion revenues associated with the new capacity. Since new transmission usually will eliminate or substantially reduce the amount of congestion charges, it is unrealistic to assume this will provide an adequate incentive for transmission investment. This is particularly true when only a subset of consumers in the constrained zone are exposed to the congestion charges, such as in the Bay Area, where most customers would pay the weighted average PGE3 price, but some municipal utilities could be exposed to potentially higher Bay Area prices. Because such "market participant" funded transmission investments are unlikely, other approaches will need to be explored, particularly ones in which the costs of transmission expansion are spread over a large number of customers.

Path 15 Expansion Example

The CAISO grid is composed of the transmission system of the three founding PTO's (PG&E, SCE and SDG&E) and one new PTO, the City of Vernon (on June 3, 2002, the City of Azusa submitted its application to the CAISO to become a PTO). The first stages of major new transmission projects which may provide a partial roadmap of how the City would participate as a developer and/or as a funder of transmission is contained in the proposal for an upgrade to Path 15, a major transmission link between Northern and Southern California. Since this proposal is in the early stages of development with respect to how the "Project Participants" will share the rights to the project and recover their respective investment, the example it provides is not a well defined one but it does provide some clues as to how new transmission that is owned by entities other than the existing PTO's will be added to the CAISO grid and how cost recovery may be provided.

The proposal to increase the south-to-north path rating of Path 15 from 3900 MW to 5400 MW was started by the Transmission Agency of Northern California (TANC), a group of municipal utilities in Northern California. The current proposal does not involve TANC but is funded by Trans-Elect, a new privately owned entity that has purchased other transmission systems and operated them on a cost of service basis subject to FERC jurisdiction. It is currently envisioned to be owned by the Federal Government, through the Western Area Power Administration (Western), Trans-Elect, and PG&E. PG&E would build the termination facilities for the new line. Western envisions turning over Operational Control of its capacity entitlements in the Path 15 expansion of the CAISO grid to the ISO, provided the CAISO makes the necessary changes to its tariff to allow Western to turn over control of that capacity without turning over control of all of its existing Central Valley Project (CVP) transmission system.

No new construction for the Path 15 upgrade would occur until all the issues for cost recovery were determined. It is not uncommon for a project of this magnitude to change its physical configuration and/or funding/ownership characteristics as it is developed.

Investment Cost Recovery Issues

Under the CAISO tariff, costs for new high voltage transmission are recovered from all CAISO customers if the project is needed for reliability, or if it can be justified by the cumulative benefits vs. the costs of the new facilities. The FERC's assessment of these issues will be strongly influenced by the ISO. Theoretically, PG&E is required to build new transmission facilities that are needed to meet the CAISO Reliability Standards. It is possible that the CAISO could have a different interpretation on the need for a reliability project and the City could, as project developer, assist in the construction of a project justified solely on reliability criteria violations. PG&E has not proposed any transmission project in advance of the need to meet minimum reliability standards. Therefore, it is likely that a City-sponsored transmission project would need to be justified based upon net economic benefits. If some of the existing Hetch Hetchy rights-of-way were utilized for the new transmission, it would create the opportunity for City ownership without the investment of new capital because of the value that could be attributed to the critical right-of-way by a team, which would provide for project development. It is likely that the City would not have to turn over its existing transmission to the CAISO if it did not want to, either based upon its designation as a generation tie or based upon a prior exemption granted for the Path 15 project.

Silicon Valley Power (the City of Santa Clara), the City of Palo Alto, and/or the City of Alameda are potential co-sponsors of a transmission project that increases the transmission capacity to the Bay Area. Two of these entities co-funded with Hetch Hetchy, a feasibility study of such a project in the early 1990s. Hetch Hetchy also had the Electric Power Research Institute (EPRI) study the cost and feasibility of utilizing some of the existing Hetch Hetchy rights-of-way and existing towers for a new transmission line.

Targeted Transmission Service

Hetch Hetchy is in the process of developing a new 115/12kv substation and 115kv underground transmission lines to connect the substation at Hunter's Point and/or Potrero switchyards. The purpose of the project is to serve Municipal Load, chiefly the new Muni Third Street project in a reliable and economic fashion. Since there are major economies of scale involved in transmission projects, it is likely the characteristics of this project would change if the goal of the City were to serve more than Municipal Load as defined in the City's contract with PG&E.

If the City chose to supply customers through Community Aggregation or from its own facilities it would experience the same TAC charges as are embedded in the PG&E retail rates. However, since PG&E currently spreads its total transmission costs across all its customers regardless of their location, the City could potentially have a cost advantage vs. PG&E. If the City delivered power to some customers through its own transmission and distribution system and it interconnected to the CAISO (PG&E) system at 230 kV, it would only experience the High Voltage Access charge (about 40% of the total). CPUC regulations regarding "exit fees" and allocation of Department of Water Resources/California Energy Resource Scheduler costs for long-term contracts will affect the viability of this opportunity. This opportunity likely will be most promising for new electric loads, since potential "exit fee" issues should be lower.

Separate Control Area

The Department of Water and Power of the City of Los Angeles is an example of a large municipally owned integrated utility in California that operates a separate control area from the one controlled by the ISO. Although the integrated municipal utilities in Northern California are partially served from CAISO facilities under existing contracts, their transmission is not part of the CAISO control area. SMUD became an independent control area on June 18, 2002.

Advantages of not being part of the CAISO control area include the potential to escape some of the substantial CAISO charges and increased control over generation and transmission resources to meet local reliability and pricing objectives. A disadvantage of an entity being its own control area is that the transmission costs cannot be spread to all TAC area customers.

Key Considerations of Alternatives to PG&E Transmission Service

Rates and Pricing

Transmission service rates and pricing will be driven by the tariffs and market designs approved by FERC. Within a given market construct, however, the ownership of the transmission facilities can affect the transmission pricing for consumers. Transmission service pricing and how it would relate to each ownership condition is discussed below.

PG&E Transmission Service

Pros

- Initially, under the Comprehensive Market Design proposal, City retail customers would be protected from increased energy prices due to transmission congestion.

Cons

- Transmission rates would be regulated by FERC and allocated to retail customers by the CPUC. The City's control over transmission service issues (costs and rates, maintenance, etc.) would be limited to interventions in PG&E and CAISO proceedings at FERC and the CPUC, and bi-lateral discussions with PG&E.
- CPUC procurement proceeding decisions could impact delivered energy cost, locational capacity obligation costs, and long-term resource costs
- Potential transition to separate, higher Bay Area or San Francisco nodal pricing depending on CAISO and PG&E decisions.
- PG&E's bankruptcy proceeding could significantly impact final retail rates.
- Financing costs associated with new transmission facilities developed by private companies would be higher than for those developed by a municipal entity.

City Utility Transmission Service

Pros

- The City Utility could construct new transmission into the Bay Area and potentially join a municipal control area; this would enable it to avoid potential transmission congestion charges and CAISO grid management charges.
- Transmission rates, though regulated by FERC, would be allocated to retail customers by the City Utility, giving the City greater control over transmission service issues (costs and rates, maintenance, etc.).
- Financing costs associated with new transmission facilities developed by the City Utility would be lower than for those developed by a private entity.
- Targeted transmission projects could result in an attractive revenue stream, providing benefits to all City consumers, as well as to the specific customers connected to the SFPUC and/or new municipal entity's transmission facilities.

Cons

- Costs to serve current PG&E retail customers under Community Aggregation potentially could be higher than existing PG&E retail service if those customers would no longer be included in the PGE3 Load Aggregation for settlements purposes.
- Similarly, if the City municipalizes, its customers might no longer be considered to be part of the PGE3 Load Aggregation and could be exposed to higher locational capacity obligation costs

- FERC is considering alternative transmission access charge cost allocation methodologies as part of its Standard Market Design proceedings that could result in the costs for new facilities being allocated to the beneficiaries, rather than on a broader scale.

Reliability

The reliability of the transmission system is largely driven by the actions of the ISO, but the City's ability to influence transmission facility decisions could increase if it expands its involvement in electricity services.

PG&E Transmission Service

Pros

- PG&E recently has taken steps to improve reliability to the City by making additions to the transmission system serving the City, and has proposed others for the near future, including the Jefferson-Martin 230 kV line.
- PG&E may get more aggressive in constructing new transmission facilities if they are allowed to "spin off" the transmission assets into a separately regulated company.

Cons

- PG&E has not shown a willingness to aggressively pursue all economically justified transmission.

City Utility Transmission Service

Pros

- If the City Utility were to become a metered subsystem or join a municipal control area, its exposure to curtailments due to potential resource insufficiency of PG&E would be lower.
- The City Utility could take a more active role in developing and/or funding new transmission and generation facilities on the Peninsula and into the Bay Area to improve reliability.

Cons

- The City Utility would be exposed to shortages caused by the lack of availability of its own resources.

Local Control

Local control refers to the perceived and actual ability of the customer to influence the policies and activities of the public agency and the ability of the governing body to more readily respond to local environmental and social needs. Local control allows self-regulation and the freedom to consider only constituent needs and sound business practices, not shareholders. The following are some considerations with respect to transmission in regard to local control.

PG&E Transmission Service

Pros

- None identified.

Cons

- The City's ability to influence Bay Area transmission planning and pricing is limited to participating in ISO, FERC and CPUC proceedings, and to bi-lateral discussions with PG&E.

City Utility Transmission Service

Pros

- City residential and business consumers would have a stronger voice in setting policies for electric transmission service, including the ability to set higher reliability standards, to build economically justified additions, and to allocate costs.

Cons

- The City Utility would need to coordinate its transmission planning, development and operations activities with the ISO, PG&E and other Northern California municipal utilities.
- If the City Utility pursues targeted transmission opportunities, it would need to address potential equity concerns from consumers in areas not served by those facilities.

Transmission Governance Issues

Appendix C on Governance Issues describes the existing authority of the SFPUC and the City to provide energy services, as well as the authority that could be obtained via formation of a municipal utility or municipal utility district. Given the authorities described in that section, the City likely could pursue the alternatives to PG&E transmission service described above either with the SFPUC as the vehicle or through formation of a municipal utility entity (municipal utility or municipal utility district). In either case, the most important characteristic for success would be the City's willingness to adopt a policy to pursue the alternatives and to allocate sufficient staff and budget resources.

The City's ability to quickly and easily raise funds for energy infrastructure projects will be important. Given that the SFPUC currently has some restrictions on its ability to use revenue bonds to raise funds, changes to the City's charter may be needed to increase the number of funding options. Although some of these opportunities could be developed without revenue bond financing, the existence of that option could increase the chance of success.

Some of the alternatives could benefit through prudent exercise of the power of condemnation, such as development of new transmission facilities and/or participation in a municipal control area. Conversely, targeted transmission service to new large retail customers by expanding the current transmission system probably would occur through minor extensions of that transmission system in the public streets and not require condemnation rights. California Code of Civil Procedure section 1240.125 authorizes a "local public entity" to acquire extraterritorial property by eminent domain for "electric supply purposes" if the public entity is otherwise authorized to acquire property by eminent domain for such purposes. Section 1240.125 states:

> "Except as otherwise expressly provided by statute and subject to any limitations imposed by statute, a local public entity may acquire property by eminent domain outside its territorial limits for water, gas, or electric supply purposes or for airports, drainage or sewer purposes if it is authorized to acquire property by eminent domain for the purposes for which the property is to be acquired."

The term "local public entity" is defined to include "any public entity other than the state." (Code of Civil Procedure section 1235.150)

Cities are authorized to "acquire by eminent domain any property necessary to carry out any of its powers or functions." (Government Code section 37350.5) Similarly, a municipal utility district formed under the Municipal Utility District Act, "may exercise the right of eminent domain to take any property necessary or convenient to the exercise of the powers granted" in the Act. (Public Utilities Code Section 12703). A municipal utility district may condemn property "within or without the district necessary to the full or convenient exercise of its powers." (Public Utilities Code Section 12771)

Given the broad condemnation powers noted above, the City appears to have adequate ability to pursue the alternatives to PG&E transmission service that might require condemnation using either the SFPUC or a new municipal entity as the vehicle. Condemnation proceedings, however, can be long, complicated and expensive. To avoid some of the issues associated with condemnation, the City could concentrate first on those opportunities that do not require condemnation.

Transmission Service Conclusions

- Even though the transmission system to the City is planned according to standards equal to or higher than those used elsewhere in California, electric consumers in the City continue to obtain less reliable transmission service than other parts of the State due to a dependence on old, unreliable, and emissions-limited generation at Hunter's Point and Potrero Power Plants
    - The City's consumers thus receive a lower quality of electric service than consumers in other parts of the State, while paying the same underlying costs.

  - If proposed regulatory changes are adopted, these costs could increase.
- New transmission built by PG&E into the Bay Area and within the Bay Area will tend to increase reliability and reduce costs to electric consumers in San Francisco.
  - Under current regulations the fixed costs of such facilities are spread widely, but transmission congestion charges are proposed to be recovered locally
- Although PG&E recently has completed, and has planned additional transmission to the Bay Area and within the Bay Area to San Francisco, it is unlikely that PG&E will build enough transmission to completely mitigate exposure to higher prices due to transmission congestion.
- Developing local, City-controlled generation can provide similar benefits to new transmission by increasing reliability and decreasing exposure to congestion charges.
  - Projects similar to those identified in the City's Energy Plan should be further explored.
- There are opportunities to provide greater influence on the addition of new transmission and generation resources that should be investigated further:
  - Developing new transmission and turning its control over to the CAISO may be the least-cost method for the City to more actively promote new transmission.
  - Developing a separate control area would provide the greatest level of local control, but its cost impacts need to be weighed against the benefits.
- The City Utility could provide an appropriate vehicle to pursue needed transmission projects.
- The City Utility should explore targeted transmission projects that could result in an attractive revenue stream, potentially lowering costs for all City consumers, as well as for specific customers connected to the City Utility’s transmission facilities.

Section 4
ELECTRIC ENERGY AND DISTRIBUTION SERVICE ISSUES AND OPTIONS

Introduction

This section discusses the opportunities available to the City for municipalizing either energy service or electric distribution service.

Energy service involves generating or purchasing electrical energy, scheduling that energy for delivery, and selling the energy to ultimate retail customers. ESPs who are selling the energy commodity may look at the diversified load characteristics of a pool of retail customers or they may structure terms that price power based on the load characteristics of a single retail customer. Under Direct Access, customers would have the option of contracting for energy service through bilateral contracts or aggregation service from either the City or another ESP. Bilateral contracts allow the customer to have terms of energy service tailored to their own unique needs and load characteristics, while aggregation service attempts to lower the cost of providing energy by aggregating customer loads into more sizable and less costly load shapes. The concept of energy service is that the wires are owned and maintained by a distribution company, which are used by an ESP to deliver energy. Energy service is not a monopoly service and would need to compete with PG&E, other aggregators and ESPs.

Distribution service would allow the City to provide delivery of energy to voltages less than 69 kV, whether or not the City combines distribution service with energy service. Distribution service would most likely be unbundled for billing purposes. Distribution service would require maintenance, operation, and development or purchase of a distribution system that could either compete with PG&E or replace PG&E as the monopoly distribution service provider for San Francisco.

There are a number of ways the City could provide either municipalized energy or distribution services which are described in more detail below.

Energy Service Comparison

Introduction and History

AB 1890 envisioned development of an active retail market for energy in which a customer, or groups of customers, would have control over the terms of their energy service from new ESPs. This market for retail energy service came to be known as Direct Access. However, at the outset of deregulation, few residential or small commercial customers made use of the new Direct Access market, since transition charges prevented them from achieving any real savings on their bills. Consequently, many new ESPs initially entered and eventually exited the market. This included even well-financed providers with substantial experience in energy markets. However, a number of industrial customers were able to use their buying power to reduce their energy bills through contracting with an ESP. With the onset of the energy crisis and the signing of long term contracts by the CDWR, the CPUC suspended Direct Access service retroactive to September 20, 2001. Those industrial customers who had contracts in place with an ESP as of that date are still being served by those ESPs today, while any new contracts are prohibited.

Although Direct Access has been suspended by the CPUC, a new California bill, AB 117, authored by Assembly Member Migden, would reinstate Direct Access service on a limited basis. AB 117 would allow cities or counties to aggregate electric loads within their boundaries, but require any resident participating in aggregation service to compensate the CDWR for both current costs of energy service and any unavoidable future CDWR energy costs incurred to serve the customer's future load. It would also allow the CPUC to set "exit fees" or levy other charges as appropriate, for unavoidable costs that are born by other "electrical corporations" (in this case, PG&E) due to a customer choosing to receive energy from an aggregator. Direct Access service, as envisioned by this bill or in some other capacity, would need to be reinstated either through legislative action or through the CPUC before the City could offer energy service. The Migden bill will need to be closely followed if the City plans to offer energy service through community aggregation.

There is still significant uncertainty in wholesale markets, as disclosed in Section 2. Many of the same factors that led to very high wholesale energy prices last year still exist today. A number of reliable agencies continue to forecast power shortages in California, suggesting prices for wholesale power would increase in absence of FERC price mitigation. Unsettled wholesale energy market conditions, along with reasonable volatility in energy prices, are likely going to continue.

San Francisco's Current Energy Service

Existing energy service in San Francisco is primarily provided by PG&E through its franchise granted by the CPUC. PG&E owns both hydroelectric and nuclear facilities to generate power for delivery to their retail customers and has long-term contracts to purchase electricity from other generators. Any electric demand that is greater than PG&E's generation resources is provided by the CDWR. The CPUC is currently investigating how and when PG&E will take back the purchasing obligation from the CDWR. Any transition will depend on restoration of PG&E's creditworthiness, which is being litigated and resolved in PG&E's bankruptcy case. These issues will need to be tracked and evaluated to determine what role PG&E will play in the energy future of San Francisco.

In addition to PG&E, the City, through the SFPUC, currently serves some wholesale electric loads from power produced by Hetch Hetchy project. In an average water year, Hetch Hetchy produces approximately 1.73 billion kWh, or about 28% of the

6.0 billion kWh consumed in San Francisco. Of this 1.73 billion kWh, about 0.63 billion kWh is used for municipal loads served by HHWP. It is estimated that another 0.27 billion kWh is committed to the Turlock and Modesto Irrigation Districts (Districts) under the Raker Act. Finally, 0.33 billion kWh is dedicated to Airport loads. Nearly all of the balance, or 0.50 billion kWh, is being sold under long-term contracts to the Districts. Were these long-term contracts renegotiated to make this surplus Hetch Hetchy power available to San Francisco retail customers, it would supply less than 10% of the potential retail load.

In terms of capacity, Hetch Hetchy is rated at approximately 400 MW, or about 42% of the estimated peak demand in San Francisco. Production varies dramatically from month to month and is highly dependent on annual precipitation. Additionally, because part of the capacity is dedicated to serving District loads, any capacity remaining for support of retail loads in San Francisco would have to be firmed up with thermal generation or other types of firming contracts. The Raker Act requires that Hetch Hetchy power be provided to serve all agricultural pumping and drainage loads in the Districts and all municipal loads in cities within the Districts. Therefore, under federal law, power available for retail sales in San Francisco has third priority after San Francisco municipal loads and sales at cost to the District loads defined in the Raker Act. Additional analysis would have to be conducted to determine how much power could be made available in different water years from Hetch Hetchy to other retail loads in the City. The SFPUC delivers Hetch Hetchy energy on transmission owned by the City. Most of the distribution for municipal loads is over PG&E facilities under a Wheeling Agreement with PG&E. The SFPUC regulates the terms of power sales to its retail customers, including price, term, quantity, and delivery points.

Alternatives to PG&E Energy Service

Assuming Direct Access is reinstated, the City as well as other ESPs could offer energy services to retail City loads, competing directly with PG&E's current energy service. There are four ways the City could offer energy service to retail customers:

- **Facilitate Aggregation Through an Existing ESP**. The City would solicit proposals from ESPs, select one and negotiate general terms of service arrangements. The ESP would contract and settle transactions directly with customers, thus the City would have no financial risk. The ESP, in conjunction with the City, would market its service to customers and aggregate targeted loads to minimize procurement costs. Currently there are few ESP available to contract with.
- **Become a Standard Aggregator**. The City would commit to one or more supply contracts to provide retail electric service. The City could market its energy service to (a) all loads in the City, (b) just loads near its primary service area or transmission and distribution facilities, or (c) to loads outside of the City. The City would determine which loads to aggregate in order to create a consistent and manageable load profile. The City could determine whether or not to pass market price risk on to customers and in what fashion. Depending on how market risks

were passed on, the City may be exposed to substantial price risk. Retail energy prices could be fixed long-term, indexed, or guaranteed to be a percentage below PG&E energy rates. The City would need to market to retail customers in order to provide them incentive to switch from default PG&E service.

- **Become an Aggregator Through Community Aggregation (Migden Bill)**. This option would be the same as the option of becoming a standard aggregator except that the City would not need to initially compete with other ESPs to capture the City's entire retail load. The Migden bill currently provides that all of the City's retail load would automatically be transferred to the City aggregation service unless a customer directly expressed the desire to opt out. Requiring retail load to opt out of the City's aggregation service should provide the City with a competitive advantage over other forms of aggregation service. Community aggregation service could only be provided within the boundaries of the community and not to customers outside those boundaries. Risks in providing this service are similar to standard aggregation risks, accept the City would not have to compete for initial customers.
- **Bilateral Contracting**. The City could sign bilateral energy contracts with strategically located large customers. The contracts could tailor price, length of service, delivery points, quantity, voltage level, and energy scheduling or service options directly to the customer's unique needs. Depending on how the City supplied and priced the power, the City may be exposed to significant risks.

Key Considerations of Alternatives to PG&E Energy Service

Rates and Pricing

PG&E Provides Energy Service

- PG&E has no financial incentive to continue buying and selling the energy commodity. Therefore, PG&E has no incentive to bear any risk associated with market energy price volatility. PG&E would like to pass all risk to customers as PG&E currently does with retail natural gas prices.
- PG&E does not have sufficient financial incentive to manage the risks associated with energy purchasing and volatile customer loads through the use of long term contracts or appropriate financial instruments that help limit price exposure.
- PG&E's proposal in its bankruptcy proceeding would transfer ownership of strategic generation resources to its less regulated affiliate (regulated only by FERC). If approved and upheld in court, these generation resources would transition to market prices. PG&E's plan would also provide an immediate increase in the retail price of retained generation.

SFPUC or a San Francisco Municipal Utility Provides Energy Service

Under this scenario, the costs and retail prices for energy would be managed and controlled by the governing body of the City's electric service provider, either the current SFPUC or a different form of San Francisco municipal utility.

Pros

- To the extent that the City Utility participates in generation ownership or long-term contracts, it can avoid market shortage premiums and price volatility.
- San Francisco's weather patterns create electric load patterns that are different from prevailing statewide patterns. This unique load pattern can be used to the City Utility's economic advantage when planning and acquiring power supply resources.
- Avoidance of market shortage premiums, use of tax-exempt financing, and effective employment of reserves can produce power cost savings in the long term, estimated at 10%.
- The governing board could enhance retail price stability by creating financial reserves that help the utility manage both volatility in energy market prices and retail customer's loads.
- The governing board could determine what approaches to use to manage volatile energy prices and risks, whether through financial instruments, long term contracts, or new generation.
- Energy-only service would avoid the expenses and risks associated with acquiring, owning and operating delivery facilities.
- The City could price energy to customers based on their unique load patterns. Customers would not need to be aggregated for pricing purposes and the City would have the flexibility to tailor energy pricing to local customer needs. As long as CPUC regulation of retail energy rates continues, PG&E will have no financial incentive to tailor retail energy rates to local needs.

Cons

- Direct access service would require new purchase agreements or generation sources to meet retail loads served by the City.
- Energy service would require managing volatile energy prices and customer loads as well as coordination with historically congested CAISO transmission markets. Poor management of these risks could result in higher retail prices.
- Numerous electric support services would be required, such as: customer care systems, pricing programs and cost recovery, billing, accounting, advertising, government affairs, human resources, safety, management, and regulatory support. Some of the initial expense of these services could be offset if the SFPUC offers aggregation service, as these services are already provided to water and wastewater customers, as well as municipal electric customers receiving Hetch Hetchy power.

Reliability

PG&E Provides Energy Service

- Based on financial conditions, PG&E may decide it can not fulfill its retail load obligations, potentially causing blackouts.
- Until 2000–2001, PG&E had always fulfilled its obligation to serve. PG&E has the energy traders, schedulers, dispatchers, and managers in place to reliably offer energy service.

SFPUC or a San Francisco Municipal Utility Provides Energy Service

Pros

- Serving retail energy loads would allow the City to ensure that all retail load is fully contracted for at prices negotiated by the City. Having enough resources under contract to meet these retail loads would help the City avoid blackouts caused by lack of payment.

Cons

- Even if the City's retail load was fully contracted for, customers could still be exposed to rolling blackouts because of Interconnection Agreements with PG&E or CAISO. For example, SMUD endured rolling blackouts during 2001 mainly because of its Interconnection Agreement with PG&E and not because it lacked generation or energy under contract to meet its own load.

Local Control

PG&E Provides Energy Service

- The local agency would continue to have no control over issues such as market vs. fixed energy pricing, financial reserves allocated to provide stability in energy prices, or the type and cost of new generation facilities or contracts. Energy services are about 70% of PG&E's bundled system average rates. Influence over energy service issues would be limited to CPUC, CEC, and FERC regulatory forums.
- Energy production costs, rate designs, and special pricing packages or contracts would not necessarily meet the needs of local customers.

SFPUC or a San Francisco Municipal Utility Provides Energy Service

Pros

- There are no service area restrictions for an ESP in California thus the City could offer energy service (but not community aggregation service) to compatible loads anywhere in the state.

- Constituents could influence decisions on capital expenditures, including types of generation and the resource portfolio mix (e.g., percent renewable), as well as policies on distributed generation and net metering.
- Public policy issues like low-income programs and services, environmental impacts, and energy efficiency could be managed through energy-only service although historically, the responsibility for public benefit programs has been assigned to and paid for by the distribution service company.
- Energy contracting, pricing, and portfolio characteristics could be available for public comment and debate and would be controlled by the utility's governing board.

Cons

- Political factions may prevent swift decisions from being made in volatile, rapidly-changing energy markets.

The Table 4-1 summarizes the options for providing aggregation service and how they relate to key components of energy service.

Table 4-1
Comparison of Governance Options for Energy Service

Characteristic of Service	PG&E Provides Energy Service	SFPUC or a San Francisco Municipal Utility Provides Energy Service
Pricing/Rates	■ PG&E has a financial incentive to transfer market price risk to customers. As long as bundled service is CPUC-regulated, PG&E is unable to effectively link wholesale costs and retail tariffs.	■ Governing Board would regulate the price and cost of energy as well as the retail pricing options available to customers.
Reliability	■ Financial emergency may affect reliability.	■ Utility could ensure all retail loads are met with contracted or generated energy.
Local Control	■ PG&E energy service continues to be regulated by FERC, CEC, or CPUC. Limited incentive to offer energy services that meet local needs.	■ Public would have opportunity to influence financial reserves, pricing options, and energy sources. Local residents could help define how the utility deals with market price risk.

Distribution Service Comparison

Introduction and History

Electric distribution service in California is provided by one of two types of entities: municipal (public) providers or investor-owned (private) utilities (IOUs). The following table details the major differences and similarities between the two options for electric distribution service.

Table 4-2
Comparison of Distribution Services Between Public Utilities and IOUs

Service	Public/Muni Service	PG&E Distribution Service
Electric Design, O&M	■ Similar design standards and construction practices. O&M can depend on budget allocations and be affected by distribution system conditions.	
Reliability	■ Similar standards, both measure SAIFI & SAIDI indexes and attempt to minimize outages.	
Safety	■ Both adhere to General Order 95 and 128 standards.	
Financing	■ Financing comes mainly from tax-exempt bonds.	■ Typically a higher cost of capital that is composed of bonds as well as common and preferred stock. ■ Has limited access to tax-exempt debt. ■ Financing cost and access can be volatile and unpredictable.
Rates/Pricing	■ Historical prices have averaged 20% below IOUs for similar customer segments.	■ Already have unbundled prices for all customer segments. Usually more pricing options than Muni.
Taxes	■ Publics are exempt from income taxes, some property taxes, and most franchise fees.	■ IOU's pay income taxes, property taxes, and franchise fees.
Regulation	■ Self-regulated by an elected governing body.	■ Regulated by at least the CPUC and FERC
Public Purpose Programs	■ Usually more emphasis on low-income programs, (with community involvement) in mix of public purpose programs.	■ Provides public purpose programs with CPUC oversight.
Resource Mix	■ Usually have more federal hydro power than IOUs.	■ IOU's have limited and declining access to federal hydro power.

The debate over whether public or private ownership of electric utilities is superior is decades old. Supporters of private industry argue that public ownership is less efficient, depends on tax subsidies, is too risk averse, is dependent on inexpensive federal power, and is too slow to react and market into changing technology and market price conditions. Public power advocates dispute the efficiency claim, point to average costs that are historically 20% lower, tout local control and lack of profit distributions, and note that the privately-owned utilities have more outstanding tax-exempt debt than do publicly-owned utilities. There are few significant differences between public and private when it comes to distribution design, reliability or safety.

San Francisco's Current Distribution Service

Existing electric distribution service in San Francisco is provided to non-municipal loads by PG&E through their franchise granted by the CPUC. PG&E provides bundled electric service to the majority of the electric load in the City. In other words, PG&E provides customers both energy and delivery (transmission and distribution) services as well as billing, metering, customer service, maintenance, upgrades, and new construction. There are very few viable and economic options for customers hoping to avoid PG&E's distribution service. The most obvious is acquisition of the distribution system by a public entity.

In exchange for an exclusive distribution franchise, PG&E is regulated by the CPUC and other local agencies and commissions for environmental and construction permitting. PG&E's distribution pricing, terms of service, connection fees, billing, maintenance, design standards, construction, environmental compliance, and project planning are all regulated. Customers or their representatives may intervene in PG&E rates cases before the CPUC to attempt to influence the characteristics of their distribution service. PG&E has little flexibility in tailoring distribution service to fit local needs and will only continue to have an incentive to develop and offer distribution service as long as the CPUC allows them a reasonable return on distribution infrastructure. Shareholder concerns and profit motives will continue to define the ultimate terms and conditions of PG&E distribution service in San Francisco.

Alternatives to PG&E Distribution Services

There are two primary ways the City could municipalize it's distribution service, either serve 100% of the City's residents and businesses or serve only small subsets of those customers (spot municipalization). In addition, there are two ways in which these services could be governed, either by a new municipal board or by the SFPUC. Issues of governance are dealt with in a later section and do not have a material impact on the characteristics of the distribution service options. Therefore, just the options for municipal distribution service are dealt with in this section.

Serve 100% of City Residents and Businesses

The first option for municipal distribution service is for the City to purchase PG&E's distribution lines and provide distribution service to all customers within San Francisco. A careful analysis of severing the acquired distribution system from the rest of PG&E's system would need to be performed as part of any feasibility study. The utility could be governed by a new utility board or by expanding the role of the SFPUC. The final retail distribution price paid by end-users would be regulated by the governing board and may include other non-bypassable fees collected on behalf of the CDWR or PG&E. The following are some key issues involved with offering this service.

Pros

- A City utility would have a lower cost of capital than PG&E and would avoid many of the taxes paid by PG&E. The Impact of lost taxes would need to be dealt with.
- A City utility would control the terms of service and prices for distribution service. Distribution service currently contributes about 15-20% of ultimate retail charges.

- Public policy issues with low-income programs and services, environmental issues, energy efficiency, and distributed generation could be managed effectively by offering distribution service, as Public Benefit Programs are funded through distribution charges. Local money contributed to these causes would be spent locally.

Cons

- Purchasing PG&E's existing distribution system would likely require substantial financing (especially given PG&E's downtown network) and can be expected to face vehement political and legal opposition by PG&E.
- Distribution service would require engineering, maintenance, planning, construction, operation, safety, and dispatch personnel and equipment. Many of the required staff may come from PG&E. The transition would require new Union negotiations and contracts.
- Numerous electric support services would be required, such as: customer care systems, pricing programs and cost recovery, billing, accounting, advertising, government affairs, human resources, safety, management, regulatory support, an outage notification and management system, and emergency repair crews and equipment. The SFPUC currently provides these services for water and wastewater customers and for transmission and distribution lines owned by the City.
- The City would lose the revenues paid by PG&E, an estimated $8 to $10 million annually. The revenue loss could be made up in distribution rates. A cost/benefit analysis of this option would quantify this impact.

Spot Municipalization

The second option for municipalizing San Francisco's distribution services is for a City utility to provide distribution services in re-development zones or new service areas in the City. The utility could begin this service by having developers transfer distribution assets from new development or re-development to the City rather than to PG&E. Developers and the City would avoid paying the up-front 34% gift tax to PG&E. The final retail distribution price of electricity would be regulated by the governing board and may include non-bypassable charges required by state law. Studies would need to be conducted to determine which areas would be best served by the City-owned distribution system and which should remain on the PG&E-owned system. The following are some key issues involved with offering this type of distribution service.

Pros

- A City utility would have a lower cost of capital than PG&E and would avoid many of the taxes paid by PG&E. The Impact of lost taxes would need to be assessed.

- A City utility would control the terms of service and prices for distribution service. Distribution service currently contributes about 15-20% of ultimate retail charges.
- Delivery service to only new customers through redevelopment work would have the lowest acquisition cost of either distribution service option, but would still require substantial investments in the support services listed above.

Cons

- For most customers, distribution prices, terms of service, construction practices, maintenance expenses, and outages would be managed by PG&E and regulated by the CPUC. The City utility would manage and regulate these aspects of distribution service for only those customers who were connected to the portion of the distribution system owned by the City.
- Spot municipalization could force the City utility to wheel over and through PG&E's distribution or primary electric system.
- Public benefit programs could not be standardized throughout San Francisco, as most City residents and businesses would remain on PG&E service.
- There would need to be active coordination between the City utility and PG&E for distribution service maintenance, operation, restoration of power, and repair as the City's distribution system would be imbedded within and surrounded by PG&E's distribution system.
- Maintaining, improving, and developing a fragmented distribution system would be more costly and difficult than if the system were an integrated whole. Also, because costs would be spread over a relatively small number of customers and usage, average costs may be somewhat higher than for other approaches.
- Issues of fairness may arise as some customers would receive electric distribution service controlled by the City utility, while others would continue receiving distribution service owned by PG&E and regulated by the CPUC.

Spot Municipalization Supplements

It may be possible to supplement Spot Municipalization in new developments by installing new distribution facilities in association with major sewer or water line replacements and competing for retail customers adjacent to such facilities. Considerations would have to include the following pros and cons:

Pros

- The use of joint trenches and construction coordination may reduce costs of new conduit and cable installation.
- It is reported that portions of the PG&E system are in need of replacement anyway.
- Facilities can remain idle until PG&E has to replace their facilities or until sufficient plant is in place to make interconnection feasible.

Cons

- The new lines may need to be connected to independent subtransmission to access power supply.
- An interconnection to PG&E facilities may be difficult as:
  - PG&E would want to maintain their part of the parallel system.
  - Obtaining agreement on cost sharing, loss responsibility and interconnection rules would be a challenge.
  - Customers would presumably have the option of acquiring distribution services from either PG&E or the City.
  - The current PG&E franchise is exclusive and would have to be modified.
- The City would have to invest in transformers, services, switches, capacitors, and meters that may or may not be utilized.
- PG&E would still control reliability if an interconnection approach is employed.
- To the extent that plant remains idle for a period of time, carrying costs will adversely affect the economics of this approach.
- Distribution costs are likely to be higher than for a conventional system.
- If customers are required to take service from the City, PG&E may attempt to recover the value of facilities idled under this plan.

As a second supplemental approach, when PG&E does an overhead-to-underground conversion, the City could determine whether they could legally require PG&E to deed the new system to the City. The City would lease it back to PG&E until such time as the sufficient interconnected underground facilities are in place to transfer to City power supply and subtransmission resources. Considerations would have to include the following pros and cons:

Pros

- One percent of PG&E's revenues are collected from customers for this purpose and the City has some influence on the location of underground conversion projects.

Cons

- The existing franchise may be violated due to exclusive service rights granted by the CPUC for the San Francisco service area.
- The inefficiencies already outlined for other forms of Spot Municipalization.

Other forms of Spot Municipalization include:

- Parallel construction of electric conduits and cables when replacing or installing new sewer and water pipelines.
- Acquiring facilities from PG&E at the time of overhead-to-underground conversions.

In both cases, detailed feasibility studies would be required to assure cost-effectiveness and practicality considering legal and reliability issues.

Key Considerations of Alternatives to PG&E Distribution Services

Rates and Pricing

Distribution service rates and pricing ultimately depends on who owns, manages, controls, and regulates the distribution system. Distribution system pricing and how it would relate to each ownership condition is discussed below.

PG&E Owns Distribution

- Distribution retail rates would be regulated by the CPUC. The City's control over distribution service issues (costs and rates, maintenance, hook-up fees, construction practices, etc.) would be limited to interventions in PG&E rate cases before the CPUC.
- The result of PG&E's bankruptcy proceeding could significantly impact final retail rates. Alternative plans by the CPUC and PG&E have been filed with the bankruptcy court for consideration by creditors. After a vote by creditors, the bankruptcy judge will hold confirmation hearings on the plans. If PG&E's plan is adopted and withstands legal challenges, PG&E's distribution service would continue to be regulated by the CPUC, while transmission and energy commodity prices would be regulated by FERC or set by market forces.
- Conservation, energy efficiency, and other public purpose programs would be regulated by the CPUC and not tailored to local needs. Local contributions to these causes through PG&E rates would not necessarily be spent locally.
- San Francisco residents would pay higher costs for financing and taxes than they would pay with a municipal provider.
- Rate options, customer segments, and special rate contracts would be managed by PG&E and regulated by the CPUC and would not necessarily meet local needs.
- Rate design priorities (cost equity, rate stability, and competitiveness) would be managed by PG&E and regulated by the CPUC.
- PG&E would determine, in conjunction with the CPUC and other parties, when and by how much to raise distribution rates.

A City Utility Offers 100% of Distribution Service

Pros

- The SFPUC or new municipal agency would determine ultimate distribution rates, customer segments, and distribution service options. The City would be free to design rates, set rate recovery priorities, offer rate stability mechanisms, and set competitive rates without oversight or management by PG&E or the CPUC.

- The City could control costs and rates, hook-up fees, and distribution construction practices and tailor these services to local needs.
- Public purpose program dollars would be collected and spent locally. Program priorities, funding levels, and options would be determined by the City.
- The City may be able to offer lower priced long run distribution service because of lower tax requirements and no profit motive. Profits and taxes have historically average about 30% of operating revenue for PG&E. The 30% is calculated from PG&E's 1995 – 1999 FERC Form 1s. During that five-year period, PG&E's average tax load (local, state, and federal) was 15.0% of operating revenues. During the same period, their average net income was 15.2% of operating revenue, resulting in a combined tax/profit load of 30%. These lower costs may be offset by the initial purchase price and whether or not it exceeds book value.
- Distribution rates for some customers might be able to be reduced. Any reduction would depend on the purchase price of the distribution system, how network costs are allocated, and average energy use per customer. The fact that the distribution service area in the city is highly concentrated would also support lower distribution system pricing.

Cons

- The City utility would have to determine how to severe their distribution system from that of PG&E. Studies would need to be completed to determine where the severance should take place, what customers would be affected, what new distribution facilities may need to be constructed in order for the severance to take place, and how the severance would affect reliability, revenues, transmission service, and local customer concerns. These studies and the actual costs of severing the system would likely affect distribution pricing over the long run. Because San Francisco is on a peninsula and because of the types of land uses along the boundary where severance would occur, it is likely that severance costs would be relatively low.
- PG&E would not likely be willing to sell the San Francisco distribution system. PG&E's resolve in maintaining ownership of the city's distribution system was recently tested when they were faced with City and County of San Francisco ballot measures both of which were defeated after a large media campaign by PG&E. PG&E has many legitimate business reasons for owning and operating electric distribution facilities.
- PG&E has a downtown San Francisco network system that is more expensive to own, operate and maintain than other portions of PG&E's system. PG&E's current distribution rates average the cost of this network to all of PG&E's customers. In absence of averaging the cost of this network to all of PG&E customers, distribution rates for just those customers using the downtown network or for all San Francisco ratepayers could rise if not offset by other savings.

- In owning the distribution system, the City utility would also take responsibility for distribution outage notification, emergency response, and emergency system dispatch and control. The expense of these reliability systems, as well as any new infrastructure costs, including needed system upgrades, and new distribution infrastructure could be financed and collected through rates. Although these services are currently provided by PG&E in their rates, PG&E is able to spread the cost of these systems over a large customer base. The new utility would have to develop new systems or improve systems already in place for other utility services, to serve only the San Francisco market, potentially increasing the average cost of this service element.
- Exit fees or non-bypassable charges may apply.
- Costs for customer care, settlement systems, and metering would have to be incurred and collected through rates.
- Tax implications for local government would also need to be considered.

A City Utility Offers Spot Municipalization

Pros

- The City utility would have the distribution facilities transferred to their ownership instead of to PG&E on new construction and re-development projects. Customers would save 34% on up front capital costs, due to avoiding the gift tax that PG&E must pay on non-revenue justified plant investment.
- Distribution system costs and rates would be regulated by the governing board for the portion of the distribution system that it controlled. This regulation would allow the City utility to control distribution cost equity between customer classes, segmentation of customers, and distribution pricing tailored to customer segments.
- Spot municipalization can be done with tax-free financing on new distribution service. However, purchasing PG&E's existing system cannot be done with tax exempt debt. See United States Tax Code Section 141.

Cons

- Distribution rates would continue to be controlled by PG&E and regulated by the CPUC for some customers, while others would receive distribution service from the City utility. Issues of fairness and equity may arise if PG&E's distribution pricing is significantly different from the new utilities' distribution pricing.
- Ongoing distribution O&M costs would likely be higher than PG&E, because administration, maintenance, meter reading, construction, and overhead costs would increase due the difficulty of performing these services on a fragmented utility distribution system embedded within and surrounded by PG&E owned lines. These costs would have to be born by a limited amount of customers, increasing the average cost of O&M.

- Costs for customer care, billing, credit, and payment settlements would have to be incurred and collected through rates. The average cost of these services would be high relative to offering 100% distribution service due to the limited number of customers with spot municipalization.
- Exit fees or non-bypassable charges may apply.
- Tax implications for local government would need to be considered.
- PG&E would not likely be willing to give up any of the San Francisco distribution system.
- This structure would likely discourage PG&E from assisting the new utility with project interconnection, project design and planning, and reliability issues which could increase the cost of these services for all customers.
- In owning a fragmented distribution system, the new utility would take responsibility for distribution outage notification, emergency response, and emergency system dispatch and control for at least the distribution system owned and controlled by the City utility. The expense of these reliability systems could be financed and collected through rates. Although the costs of these systems and services would be similar to the costs PG&E incurs to provide these services, spot municipalization would have less customers and usage to spread these costs to, leading to higher average costs of service.

Reliability

Regardless of who owns the distribution system, transmission service will be provided by CAISO. As long as transmission service is provided by CAISO, any shortages of energy experienced by CAISO would have to be partially born by the City. The reliability of electric distribution systems may vary more based on system design than ownership, as both municipally-owned and IOU-owned distribution systems are held to similar reliability standards in the CPUC's General Orders 95 and 128. Although distribution system reliability in the long run would likely be similar between an IOU and a municipality, the entity owning the distribution system could have some influence on reliability as noted below.

PG&E Owns Distribution

PG&E currently provides distribution reliability services to San Francisco through rates regulated by the CPUC. If PG&E continues to own and operate distribution facilities, the incentive to continue performing reliability services would not change and the status quo would likely prevail.

A City Utility Offers 100% of Distribution Service

Pros

- The City utility would have the flexibility to tailor distribution system reliability to local needs, respond to local distribution concerns, and provide distribution services local businesses or residents may value (power quality monitoring, back-up transformers, UPS systems, distributed generation, renewable power systems, etc.). These services enhance distribution reliability by providing redundancy, back-up generation, and power quality analysis to ensure proper power flow and voltages. PG&E offers these services, but does not necessarily have the incentive to tailor these services to local needs.

- The City may have more incentive to encourage distributed generation. This can have both a negative and positive effect on reliability, but in most instances reliability would be enhanced.

Cons

- If a City utility were to provide distribution services it would need to hire and develop the internal staff to support the critical distribution system reliability functions.
- The utility would also need to accept the liability for environmental issues, public and employee safety, and would have to invest in a system outage notification system and a system dispatch center.

A City Utility Offers Spot Municipalization

Pros

- Spot municipalization fragments the utility system into small islands or pockets of distribution facilities. Ordinarily, such a distribution structure could cause significant interconnection issues with the IOU, since that entity would have reduced incentive to support proper interconnection of the new utility's distribution service pockets and would not be responsible for service disruptions within the pockets. The City, however, has a long history of providing reliable service to pockets of municipal electric loads under its existing agreement with PG&E.
- If spot municipalization were to encourage cogeneration and distributed generation, planning would require that reliability be a key consideration. If properly balanced, reliability could be enhanced.

Cons

- Response times for local distribution system outages and problems would increase as restoration work would have to be well coordinated with PG&E and each distribution pocket would have to be dealt with independent of the others.
- A non-integrated distribution system would be more difficult to monitor, control, and maintain than an integrated whole and reliability would likely suffer.

Local Control

Local control refers to the perceived and actual ability of the customer to influence the policies and activities of the public agency and the ability of the governing body to more readily respond to local environmental and social needs. Local control allows self-regulation and the freedom to consider only constituent needs and sound business practices, not shareholders. The following are some considerations in regard to local control.

PG&E Owns Distribution

- The local agency would continue to have limited influence or control over issues such as distribution reliability, electric system aesthetics, siting and construction issues, line extension rules and fees, outage notification and repair, metering and meter reading, billing, customer care, and the total cost of electric utility service. Delivery and associated services typically comprise about 15% to 20% of the total cost of service. Distribution costs, rate designs, and special pricing packages or contracts would not necessarily meet the needs of local customers.
- Pursuant to CPUC policy, PG&E currently expends approximately 1% of its revenue derived from San Francisco on the undergrounding of its overhead electric facilities located in San Francisco. This expenditure is inadequate for meeting the undergrounding requirements of the City. Consequently, many neighborhoods will continue to have overhead electric lines for the indefinite future.
- Influence over conservation, energy efficiency, low-income benefits, and environmental concerns would be limited to CPUC and CEC regulatory forums. Customers would be paying for these services without a guarantee that funds are spent locally and without local input on how the funds are distributed.
- As in the past, future surcharges could be applied by the CPUC to distribution customers.

A City Utility Offers 100% of Distribution Service

Pros

- Residents would have a stronger voice in setting policies for their electric distribution service and would help shape the future of distribution service for San Francisco. One area of particular importance may be the undergrounding of overhead electric facilities that present aesthetic and safety concerns for San Francisco residential and commercial neighborhoods.
- Local control would extend to: distribution reliability, electric system aesthetics, siting and construction issues, line extension rules and fees, outage notification and repair, metering and meter reading, billing, customer care, economic development and the total cost of electric utility service. The City utility would also be able to control retail distribution rates and pricing packages and make sure they met local needs. Financial reserves and plans could be developed that would help stabilize distribution rates over the long run.
- The City utility would have substantial control over conservation, energy efficiency, low-income benefits, and environmental concerns and could determine appropriate funding levels and programs.

- Constituents could influence decisions on capital expenditures, including policies on distributed generation and net metering.
- Options for distribution service that meet local needs could be offered.

A City Utility Offers Spot Municipalization

Cons

- Local control would only extend to those areas served by spot municipalization and not to the entire City, potentially creating conflicts of distribution services offered and customer expectations.
- Local control over distribution system reliability would be limited because PG&E would control distribution interconnections with the new utility and any problem on PG&E's distribution system would affect the new utility's distribution system. Any policies or distribution operations that affect the PG&E portion of the distribution system would need to be coordinated with PG&E and potentially the CPUC, limiting local control.
- Public purpose programs would be funded by only a subset of the City's residents and businesses, but would likely benefit the entire City. Careful planning would need to be followed if it was determined that program revenues would be spent on those who made the contributions.

Governance

In conjunction with any of the services discussed above, governance of the new electric utility could be accomplished through one of two structures, a separate municipal agency with members that could be elected by the public or expanding the authority and responsibilities of the current SFPUC. Any public governance structure will have a tendency toward less agility caused by legal requirements for open meetings and hearings, lack of a profit motive, and risk aversity. However, public governance of electric utilities also allows greater local control, removes shareholders and profit concerns from decision making, and is directly responsible to the consumers of electric services. The options for governance of a new electric utility for San Francisco are discussed further below.

A New San Francisco Municipal Utility

A new municipal utility Board could be formed with Board members being elected by the voters of San Francisco and directly accountable to its constituency. Alternatively, the Board could also be appointed by local San Francisco elected officials and as such would be "one step" removed from the voters. In either event, the Board would be charged with managing the affairs of the new utility, whether it was structured to simply provide energy or whether its structure included distribution service. The Board would need to establish new operational policies, procedures, bylaws, hiring practices, legal counsel, financial administration, and union contracts.

Some pros and cons of creating a new agency to regulate electric services would be:

Pros

- Constituents would likely have slightly stronger influence on rate-setting and rate structures if the utility is governed by a new agency.
- The new utility would offer local control at least over energy supply costs and possibly over distribution service.
- Policies governing new generation supply and risk mitigation would need to be considered.

Cons

- A new Board would have to create all new systems for managing the utility. Regardless of whether the utility offered distribution service only or distribution and energy services, the utility would need to develop a customer care, billing, and settlement system, an energy trading and risk management operation, an account management team, pricing services and packages, and would have to deal with many legal, regulatory, and public policy issues.
- A new government bureaucracy would need to be created and a stakeholder process managed. Staff members would need to be hired that have very specific expertise.
- The new utility would have to gain the trust of citizens and voters that it could meet their electrical needs reliably, efficiently, safely, and in a least cost way.
- Projected long run costs would have to be less than those projected for PG&E. If the retail cost of electricity was higher than PG&E, the voting public would not understand the need for a new municipal utility.
- The service options would have to be chosen carefully in order to minimize acquisition and customer maintenance costs. Specifically if the new Board were to control both energy and distribution service, the costs of severance from PG&E's existing service could be significant. Non-bypassable surcharges could apply whether the utility offers energy service only or has distribution service options as well.

Expanding the Role of the SFPUC

Members of the current SFPUC are appointed by the Mayor and are therefore accountable to the people of San Francisco through the Mayor. A proposed City Charter amendment would change the appointment process and establish qualification requirements for each appointee. The SFPUC regulates retail water and wastewater services to the residents of San Francisco and regulates the production and sale of electric generation from the Hetch Hetchy hydroelectric project. Electricity produced by this project serves some municipal loads in the city. The SFPUC receives delivery services on transmission or distribution lines owned by PG&E through agreements with PG&E and CAISO. Additionally, the City owns transmission and distribution facilities, including 115-kV and 230-kV lines between its hydroelectric generation in the Sierras and Newark substation, numerous substations and transformers, and the distribution system serving SFO. The SFPUC regulates the structure of power sales to municipal customers, including price, term, quantity, and delivery points. The SFPUC manages a staff that performs the tasks of negotiating, contracting, pricing, marketing, accounting, billing, and settling current energy transactions. However, the main focus of the SFPUC today is water and wastewater services not electricity and the SFPUC would likely need to expand its staff and their capabilities in order to add a full range of electric services. The Board has established administrative rules and bylaws and existing agreements with organized labor. Some pros and cons of expanding the role of the SFPUC to regulate a broader range of retail electric services and customers are:

Pros

- Existing staff and administrative services could be leveraged to expand energy purchases and generation supply reasonable quickly.
- New staff would need to be added to provide distribution construction, repair, and maintenance if the SFPUC were to take on a distribution role. However, current staff that performs these services for existing electric transmission and distribution facilities could form a foundation and serve as the core group for expansion.
- Current water meter reading expenses, billing, settlement, customer care, legal, rate design, and other management functions could be reduced due to synergy with similar electric system requirements.
- SFPUC staff has some experience in managing energy contracts and volatility. As load expands, the role of energy trading and contracting would become more risky and could require more oversight.

Cons

- The SFPUC is not directly accountable to constituents, but rather to those who make the appointments to the SFPUC.
- The SFPUC staff has embedded policies, procedures, long-term contracts and work rules that would impose hurdles to agility and efficiency.
- The SFPUC would have to overcome a public image of being inefficient and bureaucratic.
- New generation supply would need to be purchased and appropriate risk mitigation measures would need to be considered.
- The SFPUC would need to quickly expand to integrate electricity service, particularly during any transition period. Even when a steady state is achieved, Board time spent on electricity is likely to be equal to, or require more time than currently spent on existing core businesses.

Table 4-3 summarizes the relationships between governance and service options.

Table 4-3
Summary of Governance and Service Options

Type of Service	Governance Type: New Utility Board	Governance Type: Expand SFPUC
Energy Only	■ Board, staff, and administrative systems would need to be developed from scratch. ■ Offering "aggregation only" service limits local control to just energy. ■ No familiarity with energy trading and contracting.	■ Existing systems, administration, and staff could be leveraged. ■ Offering "aggregation only" service limits local control to just energy. ■ Familiarity with energy trading and contracting. ■ May be difficult to manage energy trading with water and wastewater services.
Energy Service with Either Full Distribution Service or Spot Municipalization	■ Board, staff, and administrative systems would need to be developed from scratch. ■ Local control would cover energy and distribution service. ■ No experience with energy distribution. ■ Would need to gain the trust of constituents that it could operate the distribution system safely and reliably. ■ May be easier to offer distribution service options.	■ Existing systems, administration, and staff could be leveraged. ■ Local control would cover energy and distribution service. ■ More difficult to manage water and wastewater services with expanded energy role. ■ Perceived as more political and less likely to be responsive to constituents distribution needs.

Section 5
CONSERVATION, ENERGY EFFICIENCY, AND RENEWABLE RESOURCES

Background and Introduction

Conservation and energy efficiency refer to the ability of the utility to encourage passive and active conservation measures by their customers. Passive conservation usually requires a simple change in behavior, like turning off lights and managing thermostat settings. Active conservation requires investment in conservation, like purchasing a new refrigerator, installing compact fluorescent bulbs, and adding insulation to walls or ceilings. The net effect of these changes is to reduce demand for both generation and transmission resources. Renewable generation (primarily wind and solar) and clean self-generation (mainly natural gas microturbines) can also help customers avoid the need for traditional utility resources and reduce the strain on congested utility systems without significantly impacting the environment.

Throughout the decade of the 1990s, utilities on the West Coast of the United States scaled back energy efficiency and conservation investments while cogeneration or renewable energy projects became less economic. The driver of these changes was low market energy prices, which served as the substitute for energy efficiency investments and new customer-specific generation resources. However, in 1996 California's electric restructuring law, AB 1890, mandated minimum funding levels for renewable technology investments and energy efficiency measures. In addition, the energy crisis of 2000-2001 brought extreme price spikes and volatility to energy markets that increased customer, utility, and legislative interest in these programs. Presently, the State of California has appropriated millions of dollars to be spent on energy efficiency and has created both the Flex Your Power campaign and the Governor's 20/20 program to encourage people not to waste electricity. The state has also funded major utility programs that encourage the use of renewable generation technologies and clean self-generation. AB 970 allocated California General Fund revenues to provide project subsidies that encourage solar, wind, fuel cell, and natural gas micro-turbine projects. With funding from this bill, PG&E implemented programs that target new installations of renewable generation over 30 kW. Under the auspices of the same bill, the CEC has a similar incentive program that provides support for projects with less than 30 kW of capacity. In addition, legislation requiring renewable resources to be part of energy portfolios and more lenient net metering laws are continuing to encourage further investment in clean self-generation and renewable technologies. While these investments and changes have occurred mainly to avoid expensive short term energy markets, supporters of energy conservation and renewable or clean self-generation also point to the following reasons to invest in new energy saving technology.

- Improvements in energy efficiency and new renewable generation reduce the need for traditional generation and transmission resources.
- Passive conservation requires little investment and minor adjustments to customer lifestyles, and can cut electric demand and energy use significantly.
- All conservation reduces demand for electricity, which puts downward pressure on market prices.
- Efficient use of electricity saves natural resources and helps the environment.
- Active conservation reduces electric requirements now and in the future, while not reducing benefits to customers.
- Conservation programs in conjunction with other public purpose programs (low-income discounts) are symbiotic, and can be funded and administered jointly.
- New and improving technology along with increased production have made natural gas microturbines, fuel cells and photovoltaic arrays cheaper and more available.
- Distributed generation can support the local distribution grid and can significantly reduce customer demand on traditional electric systems.
- Issues of environmental justice are reduced when new generation and transmission can be avoided.

Energy efficiency and renewable energy funds are appropriated and collected as required by California law, Public Utilities Code Section 381-384, which provides funding through a surcharge on energy sales. The revenues collected through the surcharge are dispersed through IOUs, with regulation from the CPUC or through the CEC, which manages both its own programs and provides grants to both IOUs and municipal utilities. In addition to grants from the CEC, some municipal utilities also fund their own programs and self-regulate their own program design and effectiveness. Minimum funding levels and recovery mechanisms for energy efficiency and renewable generation investments were mandated by AB 1890 but were continued and enhanced through numerous new laws during 2001. Either the CEC or the CPUC provide oversight for the majority of new money dedicated to energy efficiency or renewable development. Program oversight by either of these regulatory authorities generally involves a project plan for spending the allocated dollars, a forecast of expected results and energy savings, and an evaluation of the program after it is implemented to ensure the program is achieving its goals. Both IOUs (regulated by the CPUC) and municipal utilities (self-regulated but may also report to the CEC) have developed rates and tariffs that provide rebates and other incentives for utility customers to conserve energy or to invest in renewable generation resources. Studies are usually performed to determine which programs are the most cost effective, given expected results. The following table demonstrates some of the programs that major Northern California utilities and the CEC have implemented.

Table 5-1
Programs Implemented by the CEC and Northern California Utilities

Program Manager	Program	Funding
SMUD	■ Residential – Air conditioners, whole house fans, heat pumps, lighting ■ Commercial – Cool Roof Program	■ $50–$500 ■ $0.20 per sq ft
PG&E	■ Residential – Programmable thermostats to heat pumps and furnaces ■ Commercial – Equipment rebates to self-generation projects	■ $20–$500 ■ Varies (> $50 million total funding)
Modesto Irrigation District	■ Residential – From window film to central air conditioners ■ Commercial – Lighting, windows, air conditioning	■ $50–$500 ■ Varies
CEC	■ Residential – Solar water heating, shade screens, renewable generation ■ Commercial – Peak load reduction programs, lighting, building insulation, HVAC, renewable generation	■ Water heating $750, screens $1 per sq ft, generation $4.50 per watt (up to 50% of cost) ■ Load reduction $20 million, Generation same as residential

San Francisco Energy Efficiency and Renewable Generation Programs

San Francisco has a reputation for promoting environmentally friendly technologies. Due to the recent energy crisis and rolling blackouts suffered by the City, residents have approved financing for renewable generation development and the City is considering even more aggressive energy efficiency programs. These initiatives will all serve to:

- Reduce the need for more investment in traditional transmission and generation infrastructure.
- Reduce congestion on key transmission pathways into the City, improving reliability.
- Reduce the use of inefficient and polluting Hunter’s Point and Potrero power plants.
- Improve air and water quality.
- Reduce demand for short term power, which helps lower market prices.
- Help to address environmental justice concerns without sacrificing quality electric service.

The following projects have recently been implemented by the City to support these goals.

- The Mayor's Energy Conservation Account (MECA) was established in 2001 to finance energy efficiency measures in city buildings and facilities. The fund was established through state grants and low interest loans, which will be paid back through energy savings from the investments. There are currently 15 energy efficiency projects that are being financed with the funds, which should save the City about 70 million kWh per year. The projects presently involve lighting retrofits, on-site electricity generation, HVAC work, and new energy efficient refrigerators.
- The San Francisco Department of Environment began administering a Resource Efficient Buildings (REB) program in 1999. This program helps ensure buildings are designed, constructed, renovated and demolished in an environmentally sustainable way. The program encourages this goal by providing Green Building Design Training for all city architects, engineers and project managers, demonstrating innovative green building design and construction practices through implementation of 10 city pilot projects, and by evaluating the performance of environmentally friendly construction practices at the pilot projects.
- On November 6, 2001, San Francisco passed two new propositions to support solar, wind, and energy efficiency projects through selling $100 million in revenue bonds, to be paid back through energy savings achieved by the programs. The propositions provide financing for about 10 to 12 megawatts of solar power and about 30 megawatts of wind generation. $50 million will be spent to install solar arrays on schools and other city-owned facilities and $30 million will be spent to place wind turbines on city and county-owned properties. The remainder will be spent on energy conservation and costs associated with the projects and issuing the bonds. Through these generation capacity additions, renewable resources are projected to meet 5% of San Francisco's peak electricity load, providing clean and reliable power for San Francisco's energy future.

Key Considerations of Conservation, Energy Efficiency, and Renewable Resources

Rates and Pricing

PG&E Status Quo

PG&E currently collects funds for conservation and renewable resources support through a usage fee added to distribution rates. The fee is currently $0.00432 per kWh for PG&E residential customers. Program revenue is allocated to four public benefit program categories and spent on projects on a case by case basis with regulation from the CPUC. In addition to the program funding from distribution rates, new laws passed in 2000 and 2001 have provided PG&E additional money (primarily from California's General Fund) to fund more rebate and incentive programs. These programs are also regulated by the CPUC and have fixed sunset dates as long as all the program money has been spent. PG&E has no incentive to ensure that local contributions to energy efficiency and renewable resource programs are spent locally.

A City Utility

Ultimate program funding and decisions on which programs to support would be governed by the City utility if it enters the distribution business. However, if it chooses to enter only the energy supply business, any new funding would be in addition to PG&E's $0.00432 per kWh. Therefore, if the funding mechanism were based on a percentage of total revenue and the City utility offered energy-only service and not distribution service, than total revenues would likely be low to avoid excessive ratepayer charges and there would be less money available for City-controlled energy efficiency and renewable generation programs. For spot market customers, the City utility could control the surcharge to either match the current surcharge paid by customers of PG&E or the revenue that is currently collected by PG&E.

Conservation and energy efficiency programs can also seem quite expensive, especially when market energy prices are low. A cost/benefit analysis and a life-cycle analysis should be performed to determine which programs should be implemented and which should be avoided.

Reliability

PG&E Status Quo

PG&E does not typically invest in energy efficiency, distributed generation or renewable technologies to improve distribution system reliability. As long as the CPUC continues to allow PG&E to earn reasonable returns on invested distribution plant and distribution revenue requirements are primarily recovered through usage based rates, PG&E will have an incentive to continue to expand its distribution system and maximize usage on that system.

A City Utility

Conservation and energy efficiency reduces the need for additional distribution, transmission, and generation resources. Short run conservation measures (more passive conservation) will reduce the stress on congested distribution and transmission lines and will reduce reliance on the purchase of short term market energy, which will help balance short run market supply and demand. Long run conservation measures (more active conservation) are more likely to reduce long run demand and energy, such that additional supply and delivery resources can be completely avoided. The effects of both short run and long run conservation should help improve delivery system reliability and the need for rolling blackouts as a system stability tool. The new utility could study the effect energy efficiency and renewable technology investments have on reliability and offer only those programs that provide the greatest value in terms of combined energy efficiency and enhanced distribution system reliability.

Local Control

PG&E Status Quo

PG&E is mandated by California law to provide energy efficiency funding. The revenues for the programs are based on how much energy consumers use, while the expenditures of program funds are based on individual project needs and requirements. There is no guarantee that funds contributed locally are spent on local energy efficiency projects. The City has very limited influence over the size of budgets for energy efficiency and renewable technologies and what programs ought to be offered to local businesses and residents. PG&E has little choice on how to spend allocated funds, as program funding is often dictated by legislation and regulated by the CPUC.

A City Utility

If a City utility offered electric service and created a conservation and energy efficiency funding mechanism, 100% of funds collected locally could be invested locally. A local regulatory authority, accountable to local constituents, would make final decisions regarding the level of conservation funding and the expenditures of the funds. The following are some other considerations regarding local control of energy efficiency and renewable funding.

Pros

- Current program funding is about 2.85% of gross revenues. The City utility would have control over the level of funding for these programs and could adjust the level according to local needs and interest.
- The City Utility could control which programs get support and which do not. Program choices could include low-income assistance, conservation and demand-side management, renewable technology, or research and development. The City utility would have the flexibility to decide which programs best meet local needs and fund only those programs.
- City-managed energy efficiency and renewable generation could significantly impact the feasibility of new generation and transmission projects, providing local control to new resource decisions.
- Environmental justice issues would be reduced without sacrificing legitimate electricity needs.

Cons

- If the City Utility only provides energy service and not distribution service, consumers may pay more than other PG&E customers are paying for energy efficiency and renewable programs.
- If the City Utility gets involved in spot municipalization, issues of fairness may arise as only certain City customers would be funding City-managed energy efficiency and renewable programs but program expenditures may benefit everyone.

Section 6
NEXT STEPS AND ISSUE RESPONSES

Introduction

A number of policy options have been outlined in this study. During and following the hearing on the initial Study draft, commentors requested that a discussion be added regarding next steps and costs associated with taking those steps. The following is in response to those requests. Additionally, issues have been raised regarding effects on labor and more detailed comparisons of public and private power. Those issues are also addressed.

Strategic Direction

Significant progress has already been made in terms of the development of a conceptual model for the City's energy future. That progress has been demonstrated by publication of the joint SFPUC/SFDOE Electricity Resource Plan in March 2002 and the submission of proposed charter amendments to restructure the SFPUC on June 17, 2002. The contents of these documents are consistent and when read in a combined context, produce a conceptual model of the SFPUC being an aggregator of retail electricity loads and an ESP. The foundation of the model includes integration of:

- Power supply development.
- Closure of polluting and inefficient power plants.
- A renewable (green) generation portfolio (25% renewable excluding hydro).
- Rates that are:
  - Cost-based
  - Financially prudent
  - Structured to encourage energy efficiency
- An option to add distribution if arrangements cannot be made with PG&E to facilitate the other model elements.

This conceptual model is consistent with the one described in this Study as SFPUC. It retains an appointed, although restructured, governing board and local control but has some limitations on integrated planning unless or until distribution is added.

This Study addresses **power supply** and **transmission** options, including:

- Investing in transmission and turning its control over the CAISO.
- Investing in transmission and creating a Control Area for San Francisco.
- Investing in generation to increase reliability, replace old plants, and to attain a 25% renewable portfolio.
- Contracting long term for generation to achieve the portfolio mix.
- Facilitating generation development by others.
- Facilitating cogeneration and distributed generation.
- Reliance on some share of short-term market purchases.

During strategic planning, none of these options should be evaluated independently. It is likely that a mix will evolve that reflects tradeoffs between transmission, central station, distributed generation, conservation, and energy efficiency investments.

The first step in developing or confirming a strategic direction is to adopt a conceptual model similar to that described or modified, as appropriate, to adjust to regulatory and legislative direction. The next step from an energy resource point of view is to develop an integrated Long-Term Resource Plan, including Financial and Competition Plans for support. It is estimated that this can be done within 6 months and a budget of between $80,000 and $120,000, depending in part on staffing capability and consultant support. This assumes that the SFPUC/SFDOE model is confirmed.

Confirmation of Energy Delivery Option

The Study also provides a number of **energy delivery options** that include:

- Facilitator of aggregation
- Aggregation as an ESP
- Community aggregation
- Bilateral contracting
- 100% distribution service
- Spot municipalization

The conceptual model is most closely aligned with Community Aggregation in that it includes accepting the role of default energy provider. This is important in that the SFPUC would give up the ability to select customers based on the size and characteristics of load. The utility would be at risk of losing customers when market prices are sustained for a few months at levels below the embedded cost of the SFPUC portfolio. When market prices are high, new customers will sign on, forcing the utility into short-term, high-cost energy markets to cover the increased load. The use of long-term contracts can help mitigate this risk.

The next step is to confirm or modify the preferred energy supplier role. This should include a risk assessment and an evaluation of benefits provided to customers, as compared to costs and services that are likely to be available from competing service providers.

The following step, assuming confirmation of a desire to be in the energy supply role, would be to monitor and support legislative and regulatory activities that provide for Direct Access and Community Aggregation (e.g., AB 117).

A Risk Management Plan should be developed for the selected energy service model and an Implementation Plan developed. It is estimated that a risk assessment and Risk Management Plan would take 3 months and require a budget of between $100,000 and $150,000.

Distribution services make up the third leg of the strategic planning process. Ownership of distribution would allow the SFPUC to become an integrated supplier of electricity. The utility would have the choice of whether or not customers could elect to purchase from another ESP. This would change the risk exposure substantially. The SFPUC would be in the position of controlling Public Benefits expenditures and be better able to structure rates to achieve efficiency and portfolio objectives.

Acquisition of the PG&E distribution system would allow 100% municipalization and would be a substantial undertaking compared to implementation of the other business options. The following steps should be taken if this option is to be considered:

- **Step 1**. Confirm that policy-makers understand the difficulty of the process as well as the cost and amount of time that it is likely to take.
- **Step 2**. Review the City's franchise with PG&E to determine its right under the franchise to acquire the facilities. Many franchises are indefinite and have to be challenged.
- **Step 3**. Perform a prefeasibility study that produces:
  - A determination of which, if any, transmission, subtransmission, or substation facilities are to be acquired.
  - Identification of severance problems along San Francisco's southern boundary.
  - General condition assessment of the facilities looking at age, condition, and state of technology (e.g., SCADA, metering, power quality enhancements).
  - A high-level estimate of book value and Reconstruction Cost New Less Depreciation (RCNLD) of the facilities to be acquired.
  - A business model that can be used to test the economics of ownership and operation for various assumptions as to acquisition costs, power supply costs, severance costs, or other key variables.
  - The above model will require high-level estimates of O&M costs, assumptions as to rates/rate structures, power supply sources and costs, and costs of acquisition and start-up.
- **Step 4**. Based on the business model evaluation, the SFPUC will need to decide whether its constituents are best served by the acquisition. They may want to

hold public hearings to test the level of public support before proceeding to the next step.

Several of the following steps are likely to proceed concurrently.

- **Step 5**. Assuming a decision to proceed based on the prefeasibility study, a more thorough system valuation will be required that is sufficient to support a condemnation, assuming acquisition. It is unlikely that PG&E will be willing to sell their facilities without condemnation. The more detailed valuation will also be needed to support bond financing that is likely to be required for the acquisition.
- **Step 6**. An application will be required and approval gained from SF LAFCo.
- **Step 7**. The need for a vote of the public will be determined by the potentially amended City Charter.
- **Step 8**. An offer to purchase would be made to PG&E. If turned down, a condemnation action would be initiated under the City's and County's rights of eminent domain.
- **Step 9**. Implementation would include:
  - Decisions of whether to operate or contract for operations.
  - Decisions on power supply development and acquisition.
  - Financing
  - Expansion, development, or contracting for business systems to handle customer service, billings, collections, etc.
  - Rate hearings and adoption of rates.
  - Consumer education and public relations necessary to counter strong opposition likely from PG&E.

The order of these steps may change somewhat based on the environment, cooperation from PG&E, and public interest in the issue. Power supply is likely to be a large factor in the considerations due to recent wholesale price levels and volatility, San Francisco generation and transmission limitations, and forecasts for new supply.

Implementation of Step 3 (a Prefeasibility Study) would take up to 4 months and require a budget in the range of $150,000 to $200,000.

Governance Options

In addition to the SFPUC model described herein, SF LAFCo could consider a model with an elected governing body or with a governing body appointed by the Mayor, the Supervisors, or a combination. The following are some considerations.

Municipal Electric Utility Model

An alternative model would be for the Board of Supervisors to create a separate municipal electric utility, with either the Board or an elected commission serving as the governing body. Arrangements could presumably be developed wherein HHWP would continue to provide electric service to municipal loads, to meet its Raker Act commitments to the Turlock and Modesto Irrigation Districts, and to sell all surplus Hetch Hetchy power at cost to the Municipal Electric Utility. This approach should produce approximately the same "Rates and Pricing" and "Reliability" outcomes as would be expected under the SFPUC model. A principal difference could be local control with governance by an elected body rather than an appointed body. Even then, it will be hard to assess or quantify the differences that might result. Reasons for different outcomes would be:

- Elected officials may be more responsive to public pressures than appointed officials. This is particularly noticeable in the setting of rates and service terms.
- If the Board of Supervisors governs, they have competing pressures for time and attention from many diverse community services and needs. They have less time to focus on electric utility matters.
- If a separate elected body governs, they can develop more in-depth knowledge of electric utility issues, trends, and practices, and better focus on balancing electric utility business and consumer needs.
- If an appointed body by multiple appointing services (e.g., Supervisors, Mayor, and Controller) is employed, governance will be one step removed from the voters.

The electric industry is evolving into a competitive environment. Whether public or private, a successful electric utility will have to be run like a business. It will need to be agile, able to compete for customers and employees, and be able to accommodate market-based pricing.

Ownership and Governance Considerations

Following the public hearing on the first draft of this Study, it was requested that an expanded discussion of the pros and cons of public versus private electric utility ownership be added. The following are some considerations that policy-makers may want to address.

Private or Investor-Owned Utility

Pros

- A combination of business (profit-driven) and highly regulated (consumer protection) elements is believed by many to produce more efficient operations, particularly in a regulatory mode of performance-based ratemaking.
- More flexibility in employee compensation and performance incentives.
- Access to capital is more flexible.

- Typically more agile and able to respond faster to changing market and regulatory conditions.
- Not restricted by open meeting laws and the Public Records Act. This can be important in developing and implementing confidential competitive strategies.
- Less restrictive purchasing and hiring practices.

Cons

- Economically forced to unbundled—removes opportunities and benefits of integrated planning and operations.
- Reduced opportunity for local involvement or input.
- No incentive to do more than required with regard to green portfolios, conservation, energy efficiency, facility aesthetics, environmental compliance, low-income assistance, environmental justice, and other social endeavors.
- Higher cost of capital.
- Income and property tax liability.
- Franchise fee liability.
- Low priority for federal Preference Power.
- Restricted access to tax-exempt financing.

Publicly-Owned Utility

Pros

- Can retain vertical-integration and benefits of integrated planning and operations.
- Access to tax-exempt debt. There is an exception for debt used to purchase facilities from an IOU.
- Able to avoid income taxes and most property taxes.
- No franchise fees.
- Local control allows attention to community needs, rates, environmental justice concerns, and low-income assistance.
- Historic access to federal Preference Power (new access is limited).
- Can adopt aggressive green portfolio, conservation, and energy efficiency programs.

Cons

- Typically not agile due to legal requirements and self-imposed policies and procedures.
- Social programs and concerns can override good business outcomes, raising product/service costs.

- Open meeting laws and the Public Records Act can frustrate strategic competitive decisions and implementation.
- Risk aversity can increase costs and in some cases exposure to risk (such as prohibition of effective hedging techniques.
- Civil service and personnel administration practices can reduce access to employees in competitive job categories.
- Purchasing practices and restrictions can add substantially to the cost of goods and services.
- The City would lose franchise fee revenues.
- The City and other local governments would lose property tax revenues unless in-lieu payments are arranged.

Figures 6-1 and 6-2 are provided below to add to the understanding of cost differences between public and private power. Figure 6-1 provides comparisons for a fully integrated public utility and unbundled private service providers during the period when costs of faulty deregulation are still being recovered. Differences are shown between the scenario where 30% of those costs are defended against a scenario where none of those costs can be avoided. Figure 6-2 shows differences after the period when all of these debts and costs have been worked out of the system. Both tables are based on an assumption of a reasonable cost of distribution acquisition. Previous studies have shown that very high costs of distribution system acquisition can eliminate the savings expected in O&M.

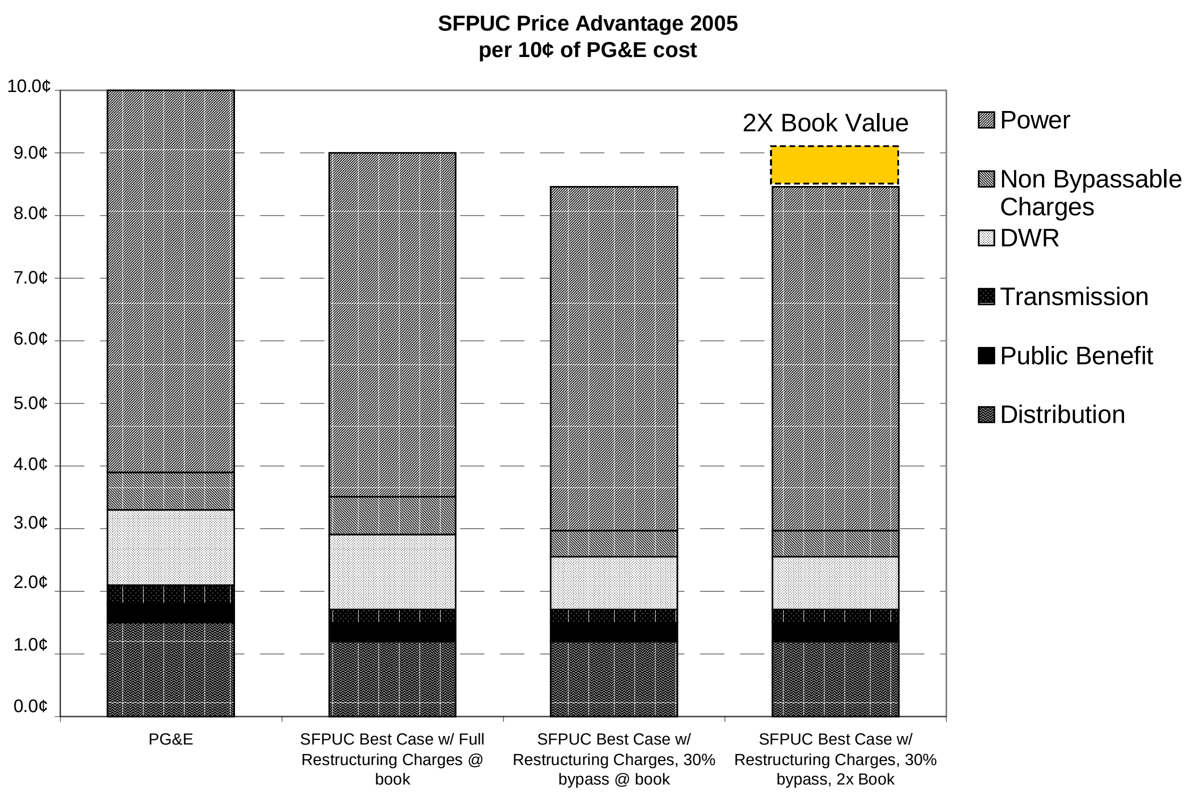


Figure 6-1: Price Comparisons for 2005

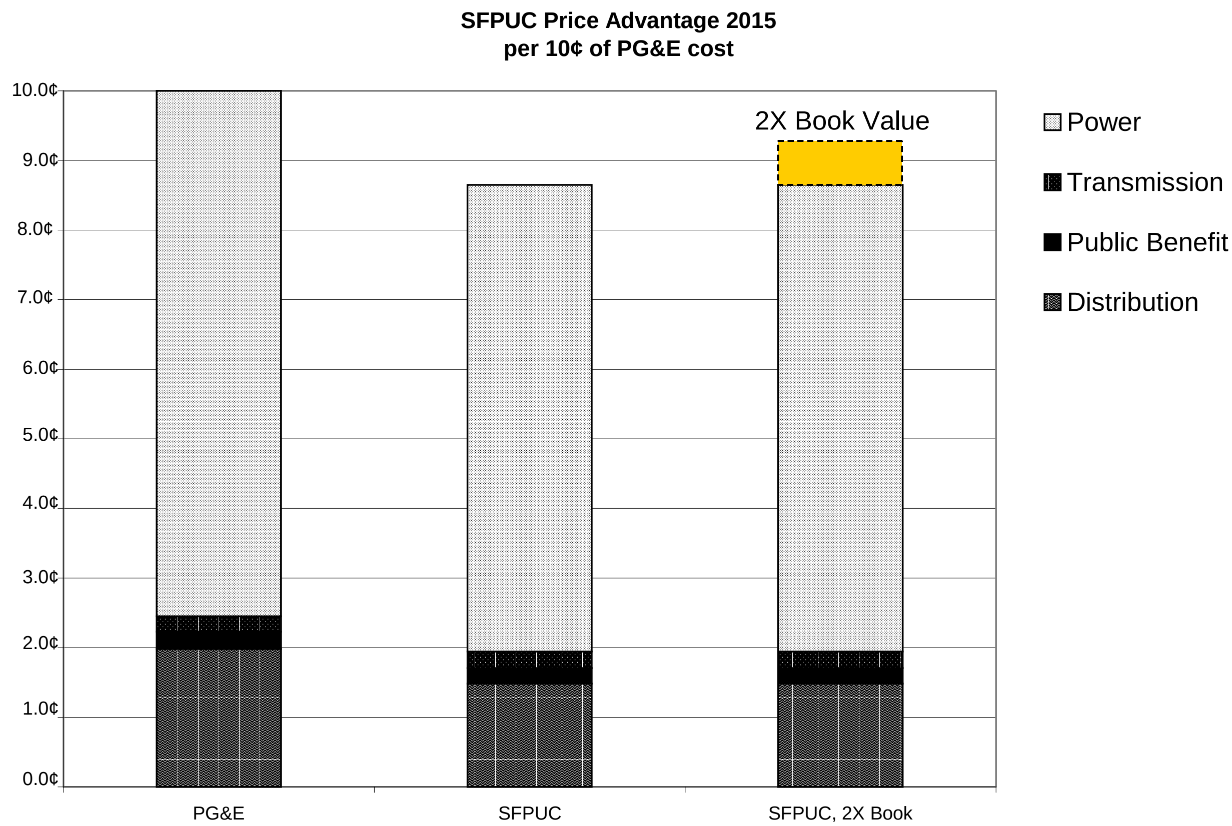


Figure 6-2: Price Comparisons for 2015

Responses to Written Public Comments

Written comments were received from two private parties. The following discussion is in response to those questions and concerns that could be addressed within the scope of this assignment.

1. Response to comments of Mr. Don Eichelberger:

   Mr. Eichelberger has provided several excellent observations, suggestions, and requests for more detailed evaluation. Unfortunately, it is not within the scope of this evaluation to provide much of the information requested.

   In general, Mr. Eichelberger should refer to the "Purpose" section in the Energy Services Study Summary. The second paragraph explains that the Study was to focus on business roles and methods of service delivery that could have a material effect on Rates and Pricing, Reliability, and Local Control. It is further noted that the Study is primarily qualitative rather than quantitative. Although many of the questions presented would be interesting to research, they are well beyond the scope of this Study.

In Section 1, Mr. Eichelberger would like to see analyses of the effects of in-state versus out-of-state power supply, effects on consumer patterns, effects of gas price fixing, and market manipulation, all as related to differences between effects on PG&E versus publicly-owned utilities. Additionally, he is interested in the impact of FERC jurisdictional differences on IOUs versus publicly-owned utilities. All of those questions would require major studies in themselves and are beyond the scope of this Study.

In Sections 2 and 3, Mr. Eichelberger expresses a number of opinions and raises questions about the past and future effects of distributed generation, renewable generation, conservation, limitations on market participation, and other factors that ultimately get to differences that local control can make in the outcome. These are addressed in Section 4 qualitatively. Again, quantitative analysis was not included in the scope of this Study, with the exception of Section 2. It should be noted that the Section 2 quantitative analysis was narrowly defined to estimate future wholesale market prices. These estimates include consideration of load forecasts (including the effects of conservation, distributed and renewable generation), supply additions and transmission constraints. Any additional evaluation of these factors would need to be included in future phases of energy service feasibility studies, if desired by SF LAFCo.

In Section 4, Mr. Eichelberger expresses some concerns about the balance of pros and cons in the Study and requests further analysis of tax losses and clarification of cost allocations and associated revenues to support the downtown network system and the urban distribution system. Some additional detail has been added to the final report on these last two issues. Any additional evaluation of cost allocations, effects on San Francisco rates, and the absorption of legal costs would need to be a part of a detailed feasibility analysis that would be done as part of a second phase if this effort continues.

2. Response to comments of Mr. Hunter Stern (IBEW):

- **Section 2**: Mr. Stern questions the conclusion that spot market prices will remain lower than contract pricing or IOU rates for the foreseeable future. There has been some clarification of the forecast prices in the final Study that address this issue. Additionally, there is a request for analysis and comparisons of San Francisco electricity prices in 2000 and 2001. This request is outside the scope of this Study.
- **Section 4**: Mr. Stern notes that publicly-owned utilities are not bound by General Orders relating to construction and safety standards. We agree. However, it is our experience that most adhere to GO 95 and 128, and it is our assumption that a San Francisco public utility would as well.

  Mr. Stern raises a number of issues relating to pricing advantages of publicly-owned utilities. We agree that low-cost federal preference power will not likely be available to San Francisco and have not assumed in our discussion that it would be. We provided additional information in the final report with regard to Hetch Hetchy power and have noted that any additional use of that power would depend on renegotiation of contracts with the Modesto and

Turlock Irrigation Districts for that portion of power sold to them that is not required under the Raker Act.

With regard to other power supply cost issues, it is believed that the ability to be an integrated utility, to engage in integrated resource planning, to use rates to influence conservation and demand management, to integrate some portion of Hetch Hetchy, to employ tax-exempt financing, and to avoid excessive profits to power marketers all lead to a potential to have lower power supply costs than PG&E. Advantages would be even greater if San Francisco could avoid the results of past PG&E power supply events, such as high-priced Independent Power Contracts, Diablo Canyon decommissioning, restructuring debt recovery, and obligations to CDWR (caused in part by PG&E's bankruptcy).

Mr. Stern's requests a discussion of distribution valuation methodologies. We have noted that different methodologies will lead to difference values and included some quantification of likely differences in the Study. We do not believe that, for purposes of developing policy options, it is useful to get into technical evaluation discussions. We have included an estimate of PG&E payments to San Francisco in the final report, per Mr. Stern's request.

There was no intent to imply in the Study that governing bodies of publicly-owned utilities had to be elected. That has been clarified in the Final Study Report.

Finally, Mr. Stern provides a view and several arguments as to why municipalization (particularly of the distribution system) would not reduce electric rates. We believe that any conclusions regarding electric rate savings can only be made following a comprehensive analysis that considers the specifics for San Francisco.

CALIFORNIA ISO

PLANNING STANDARDS

February 7, 2002

Table of Contents

I. Introduction

The purpose of this document is to specify the Planning Standards that will be used in the planning of ISO Grid transmission facilities. The primary principle guiding the development of the ISO Grid Planning Standards is to develop a consistent reliability standards for the ISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-ISO planning standards.

The ISO Tariff specifies:

> "After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs, will work to develop a consistent set of reliability criteria for the ISO Controlled Grid which the TOs will use in their transmission planning and expansion studies or decisions."[1]

The ISO Tariff specifies in several places that the facilities that are to be added to the ISO Grid are to meet the Applicable Reliability Standard, which is defined as follows:

> "The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC."[2]

These ISO Grid Planning Standards fill the role of the "consistent set of reliability criteria" in the above tariff language. To facilitate the development of these Standards, the ISO formed the ISO Grid Planning Standards Committee (PSC), which includes representation from all interested market participants. One of the primary roles of the PSC is to periodically review the ISO Grid Planning Standards and recommend changes as necessary. In recognition of the need to closely coordinate the development of the ISO Grid with neighboring electric systems both inside and outside of California, the approach taken by the PSC is to utilize regional (WSCC) and continental (NERC) standards to the maximum extent possible. These ISO Grid Planning Standards build off of, rather than duplicate, Standards that were developed by WSCC and NERC. The PSC has determined that the ISO Grid Planning Standards should:

- Address specifics not covered in the NERC/WSCC Planning Standards.
- Provide interpretations of the NERC/WSCC Planning Standards specific to the ISO Grid.
- Identify whether specific criteria should be adopted that are more stringent than the NERC/WSCC Planning Standards.

The following Section details the ISO Grid Planning Standards. Also attached are interpretations of the terms used by NERC and background information behind the development of these standards.

[1] ISO Tariff, October 13, 2000, Section 3.2.1.2, Original Sheet No. 144.
[2] ISO Tariff, October 13, 2000, Appendix A, Original Sheet No. 303.

II. ISO Grid Planning Standards

The ISO Grid Planning Standards include the following:

1. **NERC/WSCC Planning Standards -** The standards specified in the NERC/WSCC Planning Standards unless WSCC or NERC formally grants an exemption or deference to the ISO.

2. **Specific Nuclear Unit Standards -** The criteria pertaining to the Diablo Canyon and San Onofre Nuclear Power Plants, as specified in Appendix E of the Transmission Control Agreement.

3. **Combined Line and Generator Outage Standard -** A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.

4. **New Transmission versus Involuntary Load Interruption Standard**

   A. Involuntary load interruptions are not an acceptable consequence in planning for ISO Planning Standard Category B disturbances (either single contingencies or the combined contingency of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly not cost effective (after considering all the costs and benefits). In any case, planned load interruptions for Category B disturbances are to be limited to radial and local network customers as specified in the NERC Planning Standards.

   B. Involuntary load interruptions are an acceptable consequence in planning for ISO Planning Standard Category C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly cost effective (after considering all the costs and benefits).

   C. In cases where the application of Standards 4A and 4B would result in the elimination of a project or relaxation of standards that would have been built under past planning practices, these cases will be presented to the ISO Board for a determination as to whether or not the projects should be constructed.

5. **San Francisco Greater Bay Area Generation Outage Standard -** Before conducting Grid Planning studies for the San Francisco Greater Bay Area, the following three units should be removed from service in the base case:

   - One 50 MW CT in the Greater Bay Area but not on the San Francisco Peninsula.
   - The largest single unit on the San Francisco Peninsula.
   - One 50 MW CT on the San Francisco Peninsula.

   The case with the above three units out of service should be treated as the “system normal” or starting base case (NERC Category A) when planning the system. Traditional contingency analysis, based on the standards specified in the NERC, WSCC (including voltage stability), and ISO standards (such as single line outage, single generator outage etc), would be conducted on top of this base condition. The one exception is that when screening for the most critical single generation outage, only units that are not on the San Francisco peninsula should be considered. Similarly, when examining multiple unit outages, at least one of the units considered should not be on the San Francisco Peninsula.

This standard is intended to apply to system planning studies and not system operating studies. In addition, this standard has not been designed to be used to determine Reliability Must-Run generation requirements. The RMR standards are intentionally developed separately from the Planning Standards.

It is recognized that it may require several years to add the facilities to the system that are necessary to allow the system to meet this standard. The amount of time required will depend on the specific facility additions this standard generates.

III. ISO Grid Planning Guides for New Generator Special Protection Systems

As stated in the NERC/WSCC Planning Standards, the function of a Special Protection System (SPS) is to: “detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance.” In the context of new generation projects, the primary action of a SPS would be to detect a transmission outage (either a single or credible multiple contingency) or an overloaded transmission facility and then trip or run back generation output to avoid potential overloaded facilities or other criteria violations. The alternatives to a SPS are pre-contingency generation curtailment or new transmission facilities.

The primary reasons why a SPS might be selected over new transmission facilities are that a SPS can normally be implemented much more quickly and for a much lower cost. In addition, a SPS can increase the utilization of the existing transmission facilities and make better use of scarce transmission resources. Due to these advantages, a SPS is an alternative commonly proposed as a cost-effective method of integrating new generation into the grid while maintaining system reliability. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of a SPS, there can be increased exposure to potential criteria violations, transmission outages can become more difficult to schedule, and the system can become more difficult to operate. If there are a large number of SPSs, it may become difficult to assess the interdependency of these SPSs on system reliability. It is these reliability concerns that have led to the development of the additional guides in this document concerning the application of SPS. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of the existing transmission facilities while maintaining system reliability and operability. The need for these guides has become more critical as a result of the large number of new generators that are currently planning to connect to the ISO Grid.

It needs to be emphasized that these are guides rather than standards. This is to emphasize that judgement will need to be used by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of a SPS in all potential applications.

<u>California ISO New Generator SPS Guides</u>

ISO G1. The overall reliability of the system should not be degraded after the combined addition of the SPS and the generator.

ISO G2. The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. To meet this requirement, the SPS may need to be fully redundant.

ISO G3. The SPS must be fully automatic, including arming, as much as practical.

ISO G4. The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO’s largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the maximum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and may increase or decrease. In addition, the actual amount of generation that can be tripped is project specific and may depend on the reliability criteria violations to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts shown in this guide. The net amount of generation is the gross plant output less the load (plant and other) tripped by the same SPS.

ISO G5. For SPSs designed to protect against single contingency outages, the following consequences are normally unacceptable should the SPS fail to operate correctly (even for a fully redundant SPS):

A) **C**ascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the line the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) Voltage instability, transient instability, or small signal instability: While these are rarely concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

These restrictions apply to single contingency outages and not double contingency outages due to the much higher probability of occurrence of single contingency outages.

ISO G6. Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno etc) and grid-wide need to be evaluated as a whole and studied as such.

ISO G7. The SPS must be simple and manageable. Generally, there should be no more than 4 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS and the SPS should not be monitoring the loading on more than 4 system elements. The exception is that if the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements, then the new generation cannot materially increase the complexity of the existing SPS scheme. Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided, if possible.

ISO G8. The SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO G9. Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment or to the loading levels that would exist on the system prior to the addition of the new generator. For example, the operation of a SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back generation to bring the line loading to be within the line’s 4 hour or longer rating.

ISO G10. The SPS should not run-back or trip existing Reliability Must-Run generators unless there is no plausible expectation that the ISO would call upon such generators for reliability purposes during the periods where the SPS would be armed.

ISO G11. The SPS needs to be approved by the ISO and may need to be approved by the WSCC Remedial Action Scheme Reliability Task Force.

ISO G12. The CA-ISO, in coordination with affected parties, may relax SPS requirements as a temporary bridge to system reinforcements. Normally this bridging period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of a SPS requirement would be to allow 6 initiating events rather than limiting the SPS to 4 initiating events.

ISO G13. The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO G14. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies).

ISO G15. The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO G16. All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation. To facilitate transmission system studies, documentation will be made available to others upon request to the ISO.

ISO G17. Normally, the transmission owner, in coordination with affected parties, will be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO G18. Generally, the generating units tripped by the SPS should be highly effective in reducing the loadings on the facilities of concerns.

ISO G19. Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO will normally be required. Specific telemetry requirements will be determined on a project specific basis.

IV. Interpretations of NERC/WSCC Planning Standard Terms

Listed below are several of the terms that are used in the NERC Planning Standards which members of the PSC have determined require clarification. Also provided below are ISO interpretations of these terms:

Bulk Electric System: The ISO Bulk Electric System refers to all of the facilities placed under ISO control.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTOs and the ISO subject to appropriate coordination and review with the relevant state, local, and federal regulatory authorities and WSCC. The PTOs develop annual transmission plans, which the ISO reviews. Both the ISO and PTOs have the ability to identify transmission upgrades needed for reliability.

Entity Required to Develop load models: The TOs, in coordination with the UDCs and others, develop load models.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. The PSC decided that for studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a higher standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified in the ISO Grid Coordinated Planning Process and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

IV. Background behind the New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under some contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of specific single contingencies. Historically, there has been a wide variation in approaches exists among the California ISO PTOs. One PTO may allow involuntary loss of load following a specific type of contingency while another PTO would build a project to prevent loss of load for the same type of contingency. This standard is intended to lead to the elimination of these inconsistencies and also to provide the information needed to help ensure that the ISO is making cost effective transmission system additions.

This standard is also a change in the approach the ISO uses in planning from primarily deterministic planning standards[3] toward probabilistic planning standards. It is the general belief of the PSC that this trend will be an improvement in that it will provide additional information for the ISO and others to use when making decisions associated with making improvements to the grid. It is the intent of the PSC that the implementation of these principles should not result in lower levels of reliability to end-use customers than existed prior to restructuring.

To implement this standard, the following process will be used:

1) Identification of Reliability Concerns: As part of the PTO's annual transmission expansion plans, each PTO will identify those ISO Category B outages that would require the involuntary interruption of load either as a result of the system configuration (i.e., such as for a radial system) or because interrupting load was necessary to meet the ISO Grid Planning Standards.

2) Information Gathering: For each of the ISO Category B outages that required involuntary interruption of load, the PTOs will estimate the following:

- The maximum amount of load that would need to be interrupted
- The duration of the interruption
- The annual energy that would not be served or delivered
- The number of interruptions per year
- The time of occurrence of the interruption (e.g., weekday summer afternoon)
- The number of customers that would be interrupted
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural)
- Value of Service or Performance Based Ratemaking assumptions concerning the dollar impact of a load interruption

[3] An example of a purely deterministic standard is the following: There should be no more than 200 MW of load loss for a double contingency.

The above information will be documented in the PTO's Transmission Expansion Plans. Using this information, the PTOs and other interested stakeholders can estimate the benefit to the end-use customers of reducing the likelihood of interruption.

3) PTO Recommendations: As part of the evaluation of alternatives in the PTO's Five-Year Transmission Expansion Plans, the PTOs will propose either projects or operating procedures[4] to be the appropriate solution to address identified reliability criteria violations. The PTOs shall also provide their rationale for selecting either an operating procedure or a project.

4) Cost-Benefit Estimates: The PTO will estimate the costs[5] and benefits of projects to remedy the reliability concerns identified in 1) above. In addition to developing new projects, the PTOs will review currently approved projects to determine if they would still propose to construct those projects or propose an alternative solution.

For cases where the PTO has proposed an operating procedure that involves the interruption of load to be the appropriate solution, the PTOs will estimate the following:

- The future frequency and duration of outages for impacted substations
- The historical frequency and duration of outages for impacted substations
- The communities served by these substations

5) Notification: All of the above information will be provided to the stakeholders as part of the Transmission Expansion Plan prior to an ISO decision to accept or reject PTO-proposed involuntary load dropping in lieu of transmission reinforcement. The information will be made available in a timely manner so that customers can intervene before the ISO Board if they desire.

One way the information could be provided would be to develop a table such as the following:

<u>Projected and Historical Reliability Data for Single Contingencies that can Result in Load Interruptions</u>

Case	Area Affected		Possible Future Outage Without Project		Possible Future Outage With Project	
	Substations, Feeders, And Peak MW	Communities	Frequency	Duration	Frequency	Duration

[4] The proposed operating procedures shall be in sufficient detail in concept and application so as to allow review and approval in principle in lieu of upgrade projects.
[5] Project costs may need to be handled as confidential information.

6) ISO Review and Approval: The ISO, with input from the PTOs and other stakeholders, will review the PTO's five-year plans and determine whether to adopt the PTO's proposed projects or operating procedures[6]. The final ISO approved plan will be distributed to the stakeholders.

7) Periodic Reevaluation: Cases where it has been decided by the ISO Board to plan for involuntary load interruptions rather than a project (transmission, generation, or load reduction) will be re-evaluated every three years or more frequently if merited by load growth or system changes or if the reliability in that area has significantly deteriorated.

[6] Proposed operating procedures will be reviewed by the ISO to determine whether they can be reasonably implemented.

V. Background behind the San Francisco Greater Bay Area Generation Outage Standard

On June 14, 2000, rolling blackouts were initiated in the San Francisco Bay area to protect against the potential for voltage collapse. The major reason behind the need to implement rolling blackouts was the large number of generating units that were forced out of service on that day. The problem had not been uncovered in the planning studies for the area because the current ISO Grid Planning Standards only require that a single generating unit be assumed out of service in combination with the most critical transmission line. As a result of the June 14, 2000 rolling blackouts, the ISO Grid Planning Standards Committee was tasked with reviewing the ISO Grid Planning Standards to determine whether they need to be revised.

As a result of this review, the ISO Grid Planning Standards Committee determined that, while the normal standard of planning for one generating unit in combination with one transmission line out is adequate for most of the ISO Grid, it is inadequate for the greater San Francisco Bay area. In the Bay area, there is an unusually large concentration of generating units (more than 30) which increases the likelihood that more than one unit could be forced out of service at a given time. In addition, the historical forced outage rates for the units in the Bay area are significantly higher than the industry averages for similar units resulting in a higher probability of such multiple outage occurrences. The higher forced outage rates are at least partially due to the age of the units. Based on this information, and discussion at six stakeholder meetings where a variety of approaches to potential new standards were considered, the San Francisco Greater Bay Area Generation Outage Standard was developed.

While this proposed standard only applies to the San Francisco Bay Area, the ISO Grid Planning Standards Committee will periodically review various areas of the ISO Grid to determine if additional specific standards are warranted to address issues unique to those areas.

The ISO Grid Planning Standards Committee will review this standard periodically. This review will require forced and scheduled outage data for all generating units in the area.

The following tables provide the statistical basis for the work that has been completed by the ISO Grid Planning Standards Committee. This data was provided by PG&E and is based on outage data available to PG&E during their ownership of the units prior to the formation of the CAISO. It is assumed for this analysis that outage data will be similar under the present ownership of the units. For a description of how the data was compiled or computed, please refer to the original report that was prepared by Anatoliy Meklin of PG&E. The report is entitled “STATISTICAL ANALYSIS OF SIMULTANEOUS FORCED OUTAGES IN BAY AREA” and dated October 31, 2000.

Table 1. Forced Outage Data for Bay Area Generators

Name	MW	T2 - hours between forced outages		T1 - hours of forced outages	
		Mean	Standard deviation	Mean	Standard deviation
OAKLND 1	55	2130	1978	521	1150
OAKLND 2	55	4804	6612	306	649
OAKLND 3	55	4352	4399	29	17
ChevGen1	54	1475	1032	25	18
ChevGen2	54	1475	1032	25	18
PDEFCT2	199	1475	1032	25	18
PDEFCT1	199	1475	1032	25	18
PDEFST1	280	1475	1032	25	18
PTSB 1	170	1720	2078	79	75
PTSB 2	170	2448	1986	622	1925
PTSB 3	170	1520	1549	570	873
PTSB 4	170	2307	2048	153	138
PTSB 5	325	1798	2389	262	373
PTSB 6	325	4596	3773	67	48
PTSB 7	710	3252	6196	147	131
MOSS 5	750	2735	1416	64	35
MOSS 6	750	1626	1970	94	94
C.COS 6	340	1930	1522	429	1365
C.COS 7	340	1158	843	41	57
POTRERO3	210	3090	3156	212	186
POTRERO4	52	4705	6151	253	242
POTRERO5	52	13090	6869	75	35
POTRERO6	52	5596	9842	47	41
HNTRS P2	108	2047	1961	129	160
HNTRS P3	108	3207	4253	76	51
HNTRS P4	170	3165	4511	130	146
HNTRS P1	52	7856	7498	55	31
GLRY COG	130	1445	1010	55	38
FMC CT	52	1445	1010	55	38

Table 2. NERC Forced Outage Data for Selected Types of Units

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	FOF (%)	Assuming 6 outages per year	
					T2 - hours between forced outages	T1 – hours of forced outages
FOSSIL	All Sizes	1,532	7,126	3.82	1408	56
All Fuel Types	1-99	351	1,486	3.18	1417	47
	100-199	426	2,016	3.45	1413	51
	200-299	171	825	3.68	1410	54
	300-399	147	717	5.07	1390	74
	400-599	262	1,250	4.29	1401	63
	600-799	127	602	4.22	1402	62
	800-999	34	165	3.48	1413	51
	1000 Plus	14	65	5.78	1379	85
Gas Primary	All Sizes	466	1,965	3.58	1412	52
	1-99	145	554	3.53	1412	52
	100-199	147	624	3.61	1411	53
	200-299	47	211	2.31	1430	34
	300-399	41	188	4.33	1401	63
	400-599	63	296	3.92	1407	57
	600-799	20	81	4.27	1401	63
	800-999	3	11	1.50	1442	22
Gas Turbine	All Sizes	768	3,475	3.84	1408	56
	20-49	251	1,161	5.60	1382	82
	50 Plus	318	1,386	2.12	1433	31
Comb. Cycle	All Sizes	58	242	1.50	1442	22

Table 3. Probabilities of Simultaneous Forced Outages of Generators
(Actual Greater Bay Area Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	91	8.1
>=2	68	6.2
>=3	40	3.7
>=4	17	1.6
>=5	6	0.6

Observations:

- One out of 30 generators is unavailable 91 % of time
- The probability of simultaneous forced unit outages is very high and two units are unavailable 68% of the time
- The coincident forced outage of 5 generators could occur for 520 hours/year or 52 peak-hours/year.
- The probability of having 5 generators forced out of service in the Greater Bay Area is 20 times higher using actual historical data than it would be if the units had typical NERC forced outage rates as shown in Table 4.

Table 4. Probabilities of Simultaneous Forced Outages of Generators
(NERC Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	67	5.8
>=2	28	2.4
>=3	8.3	0.72
>=4	1.59	0.15
>=5	0.22	0.03

Observations:

- The lower generator forced outage rates in the NERC data result in a much lower probability for multiple unit outages.

Table 5. Probabilities of Simultaneous Forced Outages of Megawatts (Using Actual Data).

Unavailable MW in forced outage	% of year	% of year if in peak	occurrences/year (as result of a forced outage event with loss of >100 MW)	occurrences/year if in peak (as result of a forced outage event with loss of >100 MW)
>=100	88.2	7.7	60.44	5.55
>=200	74.9	6.4	54.31	4.8
>=300	66.2	5.65	49.93	4.48
>=400	48.3	4.07	40.30	3.71
>=500	42.6	3.56	35.92	3.30
>=600	28.8	2.4	26.28	2.53
>=700	20.7	1.69	20.15	2.07
>=800	15.2	1.21	20.15	1.59
>=900	10.8	0.92	12.26	1.31
>=1000	8.0	0.69	9.64	1.05
>=1100	5.5	0.46	7.01	0.61
>=1200	4.0	0.34	5.26	0.44
>=1300	2.7	0.21	3.50	0.32
>=1400	1.8	0.12	2.63	0.22
>=1500	0.9	0.07	1.75	0.16
>=1600	0.6	0.04	0.88	0.11

Note: Peak hours make up about 8.8% of the year.

San Francisco Peninsula Long-Term Transmission Planning Study Phase 2 Study Plan

Version 1.4
May 28, 2002

Draft

Cal-ISO Stakeholder Project Joint Study
California Independent System Operator
Pacific Gas & Electric Company
City and County of San Francisco
Interested Stakeholders/Public Participants

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Introduction

Transmission lines and local power plants supply electric demand in San Francisco and northern San Mateo County (estimated to be 1,328 MW by 2005). Hunters Point and Potrero Power Plants are the two major local power plants with a total combined generating capacity of 570 megawatt[1] (MW). There is also a small 30 MW co-generation power plant, United Airlines Cogen, near the airport. The remaining electric supply is delivered by transmission from generation resources outside the area.

Before the recent energy crisis and current economic downturn, this area had been experiencing rapid economic expansion. Between the years 1998 and 2000, peak electric demand grew from 1,130 MW to 1,245[2] MW, or an average of about 57 MW per year. Electric demand, while lower in 2001, is expected to grow at or near the previous pace in the longer term with the recovery of the California economy. Peak demand is expected to reach 2000 levels again in 2002.

In April 1999, the ISO formed a study group to evaluate long-term power supply adequacy to San Francisco, and to identify the best alternatives to meet future demand. This effort was initiated following the December 1998 disturbance that interrupted electric service to a significant portion of San Francisco. Participants included the ISO, PG&E, the City and County of San Francisco (CCSF), CPUC, California Energy Commission and others. The study group submitted a final report entitled "San Francisco Peninsula Long-Term Electric Transmission Planning Technical Study" ("San Francisco Long-Term Study") to the ISO Board of Governors in October 2000.

[1] In 2001, Hunters Point Units 2 and 3 were converted to synchronous condensers for reactive support. Hunters Point Units 1 (54 MW) and 4 (163 MW) are in-service today. Potrero Power Plant consists of steam Unit 3 with a capability of 207 MW and three gas turbines with a total capability of about 52 MW each. Potrero Unit 3 began commercial operation in December 1965. Hunters Point Unit 4 began commercial operation in November 1958.

[2] San Francisco load alone accounts for 950 MW of the total with about 400 MW of demand in the Financial District.

One key finding in the study group report is that, unless new generation resources are built in San Francisco, new 230 kV transmission facilities will be needed to meet customer demand by Summer 2006. Such new transmission facilities could originate at Jefferson Substation, San Mateo Substation, or come across the San Francisco Bay from Moraga Substation (east of Oakland). The study group selected the Jefferson-Martin alternative as the preferred electrical solution and found that this alternative would increase transmission capacity by about 400 MW. The ISO and the stakeholder group also recommended the initiation of permitting for the Jefferson-Martin 230 kV line so that the transmission project could be in place when needed.

In October 2000 ISO Management recommended to the ISO Board of Governors that they approve the Jefferson – Martin 230kV Transmission Project as the preferred long-term transmission alternative to address the identified reliability concerns in the San Francisco Peninsula Area. Due to the long lead-time that is required to complete the project, the ISO Board of Governors also directed PG&E to initiate permitting activities for the Project. Prior to committing to construction, the Project was to be brought before the ISO Board of Governors once again for final approval.

Since the initial action of the ISO Board of Governors in October 2000, ISO Management has continued to assess the need and timing of the Jefferson – Martin 230kV Transmission Project. The need of the Project is based on the inability of PG&E’s existing transmission system to serve the projected load in the San Francisco Peninsula Area beyond 2005, even with reinforcements to the 115kV system north of San Mateo substation.

Consideration of the existing generation at Hunters Point Power Plant and Potrero Power Plant Unit 3 is also warranted. While these generation facilities provide the most efficient load serving benefit to the San Francisco Peninsula Area, their continued operation beyond 2005 cannot be considered without addressing the necessary upgrades that would be required for either of these plants, each at least 35 years old, to meet NOx limitations. Thus, the long-term cost-effectiveness of investing additional dollars towards upgrading these plants over the development of alternative facilities will need to be considered. To ensure that there are adequate facilities to meet load in the San Francisco Bay Area by 2005, decisions must be made within the near future about the combination of new transmission, new generation, emissions reduction equipment, and/or conservation or load management resources that will be pursued.

Based on this information, ISO Management believes that the Jefferson – Martin 230kV Transmission Project is needed no later than 2005. The ISO Board of Governors gave their final approval of this project through the following ISO Board motion:

Moved that the Board of Governors,

1. Grants its approval of the Jefferson-Martin 230 kV Transmission Project as the preferred long-term transmission alternative (without regard for routing) to address the identified reliability concerns in the San Francisco Area beginning in 2005 and directs PG&E to proceed expeditiously with design and licensing activities for the proposed project and to include the ISO's analysis of the alternatives in its application to the CPUC.

2. Approves ISO support of PG&E recovery of reasonably incurred costs associated with the permitting and construction of the Jefferson-Martin 230 kV Transmission project in relevant FERC rate cases.

3. Instructs ISO staff to work with the City of San Francisco and interested stakeholder groups toward their goal of closing the Hunters Point Power Plant.

The development of the Jefferson – Martin 230kV Transmission Project represents a first step resulting from a commitment on the part of the ISO and stakeholders to develop a long-term plan for the San Francisco Area. However, significant additional work is required to assure reliability in the San Francisco Peninsula Area in light of load, generation, and emission variables. The purpose of this study plan is to provide a technical study approach for a Phase 2 study effort to address these variables and to complete development of a long-term load serving plan for the San Francisco Peninsula Area.

Objectives

The study objectives of the Phase 2 study effort are listed below.

> ***Working in a collaborative and pro-active manner, the SFSSG will complete the following objectives:***
>
> 1. ***With Jefferson – Martin in-service and Hunters Point Power Plant retired, develop a long-term load-serving plan that is responsive to varying levels of load growth and generation development and retirement, that will meet established reliability standards in serving the electric needs of the San Francisco Peninsula Area.***
> 2. ***Support the Cal-ISO and PG&E in the preparation of a detailed report that documents all technical analysis and stakeholder input necessary to assess the long-term load serving needs of the San Francisco Peninsula Area.***

Responsibilities

In order to complete the objectives of the Phase 2 study effort, participation is required by all SFSSG members. It is expected that the Cal-ISO and PG&E will undertake the majority of the study responsibility, however, all Stakeholder members will derive the fundamental success expected of a stakeholder forum through their proactive and constructive participation in the process. For this study, the responsibilities for each of the key member groups are:

The SFSSG will:

1. Support the Cal-ISO and PG&E in completing the study in a timely manner;
2. Develop the Phase 2 study objectives and technical study assumptions;

3. Develop applicable alternatives to be assessed against the identified study objectives;
4. Review and comment on technical study results and provide guidance and suggestions on how the results meet the intent of the study objectives;
5. Prepare conclusions and recommendations that are representative of the technical study results;
6. Support the Cal-ISO and PG&E in the preparation of a written report that documents the efforts of the SFSSG;
7. As necessary, support the Cal-ISO in achieving approval from the Cal-ISO Board of Governors on SFSSG recommendations that may require Cal-ISO Board of Governor action.

The PG&E will:

1. Be a proactive member of the SFSSG;
2. Assume a leadership role in the coordination and preparation of all the power flow base cases and associated dynamic data that is required to perform the technical studies for this Phase 2 study effort;
3. Assume a leadership role in the performance of technical studies required to fulfill the objectives of the SFSSG.

The Cal-ISO will:

1. Be a proactive member of the SFSSG;
2. Assume the leadership role of the SFSSG;
3. Support PG&E in the coordination and preparation of all the power flow base cases and associated dynamic data that is required to perform the technical studies for this Phase 2 study effort;
4. Support PG&E in the performance of technical studies required to fulfill the objectives of the SFSSG;
5. Coordinate the development of the SFSSG study conclusions and recommendation;

6. Assume the leadership role in preparing all documentation for the Phase 2 study effort;
7. Assume responsibility for preparing and presenting all materials necessary for presenting SFSSG recommendations to the Cal-ISO Board of Governors that may require their action.

Reliability Criteria

As with all studies that are performed as part of the ISO controlled grid, study results must meet the intent of the ISO Grid Planning Standards before they can be considered acceptable. The application of these standards provides for the application of a consistent reliability criteria that is intended to maintain or improve the level of transmission system reliability that currently exists within the ISO controlled grid. The ISO Grid Planning Standards were developed through a stakeholder process and have been approved by the ISO Board of Governors. In general, the ISO Grid Planning Standards include:

- Planning Criteria for the San Francisco Area
- Western Electricity Coordinating Council (WECC) Reliability Criteria
- North American Electric Reliability Council (NERC) Planning Standards

A copy of the ISO Grid Planning Standards is included as Attachment III of this study plan.

Methodology

The performance of technical studies is a required undertaking to develop an understanding of how an electrical system works and responds to expected system perturbations given certain assumptions about the electrical system itself. System analysis requires a detailed mathematical model, or power flow base case, of the electrical system that is being studied as well as computer simulation models that can translate the power flow base case model representation into recognizable electrical components that define how the electrical system works. Electrical components such as voltage, current, and power are typically used to determine, for example, how power will flow through the electrical system or whether or not electrical system equipment capabilities are being exceeded. Variations of these components are also used to assess the ability of the system to withstand failure of some system components (lines, transformers, generators, etc.) and continue to operate in a manner that does not result in the remaining components being overloaded or lead to some catastrophic failure of the system such as dynamic instability or voltage collapse. As expected, the modeling and assessment of power systems using the mathematical data and computer models is extremely complex and requires the review and manipulation of great deals of technical data.

Traditionally, technical studies are performed using computer models that assess system power flows or system dynamic stability. A base case is usually developed to represent a specific, real life system condition to be studied and is generally related to load levels, line flows, or voltage levels. The base cases may be modified by changing how the base case represents the electrical system (loads, lines, generators, etc.) to see how this system would respond to these changes.

The studies initially performed by the SFSSG were done in this manner. Base cases were developed to represent a specific system load level that was tied to a specific year in which that load level was expected to occur. This approach works well as long as there is acceptance of the relationship of the load level to the year it represents. Considering that the San Francisco Peninsula Area load (Area Load) is the issue of concern, it is recommended that this Area Load be considered a “variable” in the Phase 2 study effort. As such, a different approach to assessing the long-term needs of the San Francisco Peninsula Area is proposed.

For the Phase2 study effort, a base case will be developed which represents the San Francisco Peninsula Area for the 2006 time frame. Area Load will be adjusted up or down depending on whether or not a system limit has been reached. For example, a base case could be developed with zero generation on-line in the San Francisco Peninsula Area. If all planning standards are met for all applicable contingencies, then the Area Load could be increased until a planning standard is violated. At that point, the Area Load level represented would be characterized as the “Load Serving Capability” of the San Francisco Peninsula Area. Adding new transmission or generation alternatives are assessed in the same manner, by adjusting the Area Load until a planning standard is violated. This methodology will result in Load Serving Capability quantities being associated with the different alternatives being assessed in the study. The value of this approach is that it will allow the assessment of the relationship of the Area Load to a specific year to be addressed in a separate forum from the technical analysis.

Based on this discussion, the Phase 2 study effort will be performed in the following manner.

1. The study area will be defined by the system within the Peninsular and CCSF areas. This area is generally delineated by San Mateo substation defining the most southern system through the CCSF as the most northern system.
2. Within the overall study area, two load sub-areas will be identified:
    a. Peninsular load area
    b. CCSF load area
3. Develop base cases based on intermediate load growth scenario (December 2000 load forecast) and will be developed from the most recent PG&E transmission expansion study base cases representing the 2006 summer time (the Jefferson-Martin 230 kV Transmission Project is scheduled to be in operation in late 2005). Other seasons may be studied if the SFSG believes it is necessary.
4. The cases should reflect the most up to date WECC data and, as a minimum, must have gone through detailed review by PG&E and the CAISO. These cases should include all planned transmission facilities identified in the PG&E 2001 Transmission Expansion Plan. This includes the Jefferson - Martin project. This

case will represent the study “benchmark” base case and all study base cases will be developed from this case.

5. The use of reactive support in appropriate places can increase the Load Serving Capability of the San Francisco Peninsular Area, therefore, its impact on the Load Serving Capability in the San Francisco Peninsular Area will need to be assessed. To accomplish this, the benchmark base cases will only include reactive currently included in PG&E’s 2001 transmission expansion plan. Some reactive adjustments in the benchmark base case may be needed and will be allowed to assure that the benchmark case meets all applicable CAISO Grid Planning Standards.

6. Additional post-benchmark cases will be developed to represent the following transmission/generation scenarios. The performance of these scenarios will be measured by their ability to serve Area Load. The Load Serving Capability of a scenario will be determined by adding that scenario to the benchmark case and increasing the Area Load in proportional amounts until an ISO Grid Planning Standard is violated for the appropriate single or multiple contingency being taken. The contingency taken will be based on the level of performance that is being tested.

    a. Assess the San Francisco Peninsular Area load serving capability with zero generation on in the CCSF load area. Do not adjust the reactive capability in the study area beyond what is currently identified in the 2001 PG&E Transmission Expansion Plan. This will provide insight into the capability of the existing transmission system to serve load in the San Francisco Peninsular Area.

    b. It is likely that the ability to develop the load serving capability in the San Francisco Peninsula Area with zero generation will be dependent on reactive constraints. These constraints are worthy of mention, especially in helping the SFSSG understand the difficulties of serving load in the area based on transmission alone. Therefore, if the zero generation study results are reactive limited, reactive will be added at realistic locations and the load serving capability will be re-assessed until a thermal limit is achieved.

c. Assess the impact of adding generation in the San Francisco Peninsula Area on the load serving capability for the area. This will be done without adding any new transmission beyond Jefferson - Martin. The application of generation at Hunters Point, Potrero, and the SF Airport are three suggested sites. SFSSG members may suggest others. Only sites where generation can be realistically located will be considered. The need to assess load serving capability with generation on at more than one of the identified sites will be addressed by the SFSSG.

d. Assess the impact of adding new transmission into the San Francisco Peninsula Area on the load serving capability. The transmission alternatives considered will include but not be limited to:

    i. San Mateo – Martin 230kV underground cable

    ii. Moraga – Potrero 230kV line

    iii. Others?

Assumptions

The San Francisco Peninsula Area load consists of the electric load of the City of San Francisco and the northern portion of San Mateo County. San Francisco area load varies based on the seasons and temperature. San Francisco Area peak load is projected to be 1073 MW in 2006 with 1401 MW north of San Mateo Substation and 328 MW in the Peninsula corridor. Historically, the San Francisco peak load for the year usually occurs in summer during hot days in September or October.

San Francisco and Northern Peninsula loads are primarily supplied from a single transmission corridor along the Peninsula past the San Francisco International Airport and from local generation located in San Francisco. San Mateo Substation is the primary source for energy flowing towards San Francisco and the Peninsula. San Mateo Substation is located near the San Francisco Bay, and has transmission lines entering and exiting at the 60 kV, 115 kV, and 230 kV voltage levels. Five 230 kV lines that can import power to San Mateo Substation and are listed below:

- Contra Costa – San Mateo 230 kV line
- East Shore – San Mateo 230 kV line
- Newark – San Mateo 230 kV line
- Ravenswood – San Mateo 230 kV line
- Jefferson-Martin 230 kV

The Jefferson-Martin 230 kV Transmission Project was granted final approval by the Cal-ISO on April 25, 2002. PG&E will be filing for a CPCN from the California Public Utilities Commission in late 2002. This project is scheduled to be in service in late 2005. Additional reactive power support may be required to fully utilize the import capability of this project.

A diagram of the San Francisco Area is provided in Attachment I.

The performance of the existing system with the Jefferson-Martin Project in service will serve as a benchmark for the study results of subsequent years. This will also identify any current reliability problems associated with the San Francisco Peninsula Area based on existing, reliability criteria.

The 2006 GE-format base case, developed for the PG&E 2002 Electric Transmission System Assessment, will be used to develop the Benchmark base case for the Phase 2 study effort. This Benchmark base case will represent the most up-to-date power flow and dynamic data for the San Francisco Peninsula Area.

The following assumptions are proposed in developing the power flow base case(s) and performing power flow and dynamic stability analysis:

Power Flow Base Case Assumptions

The following assumptions will be used to develop the power flow benchmark cases for the Phase 2 study effort.

- The power flow base case(s) and stability data will be developed using General Electric PSLF Version 11.0.

- Base case representation (system representation, generation, etc.) will be reviewed and accepted by the SFSSG.

- PG&E and the Cal-ISO will be responsible for preparing the computer models that accurately represent the base case representations that have been accepted by the SFSSG.

- PG&E will coordinate the development of all power flow base cases that will be used to perform the Phase 2 technical study.

- The benchmark base case will represent 2006 Heavy Summer conditions. This case will be developed from PG&E's 2006 HS (heavy summer) transmission assessment case and include a detailed representation inside the Cal-ISO control area.

- For all areas outside California, the network topology and loads will reflect information that has been provided to WECC through the coordinating council's base case development process.

A summary of base case assumptions is tabulated in Attachment IV.

Load-Related Assumptions

The following assumptions will be used to develop the load levels modeled in benchmark cases for the Phase 2 study effort.

- **PG&E Load Level.** Loads modeled in power flow cases representing peak load conditions will represent a maximum anticipated coincident[3] peak load for the San Francisco Bay Area[4], based upon a one-in-ten-year ("90/10") forecast. In other words, for the given year of interest there exists a 90% probability that the peak load will not exceed the forecast value. Likewise, there exists a 10% chance that the actual peak load will exceed the forecast amount. The remainder of the Cal-ISO Grid shall be modeled at a coincident one-in-five-year load level.

  The mechanics of how the load modeling will be achieved is as follows:

  1. The San Francisco and Peninsula Planning Areas (represented as red in Figure 1) will be modeled to represent their maximum anticipated coincident peak load, based on a one-in-ten year forecast.

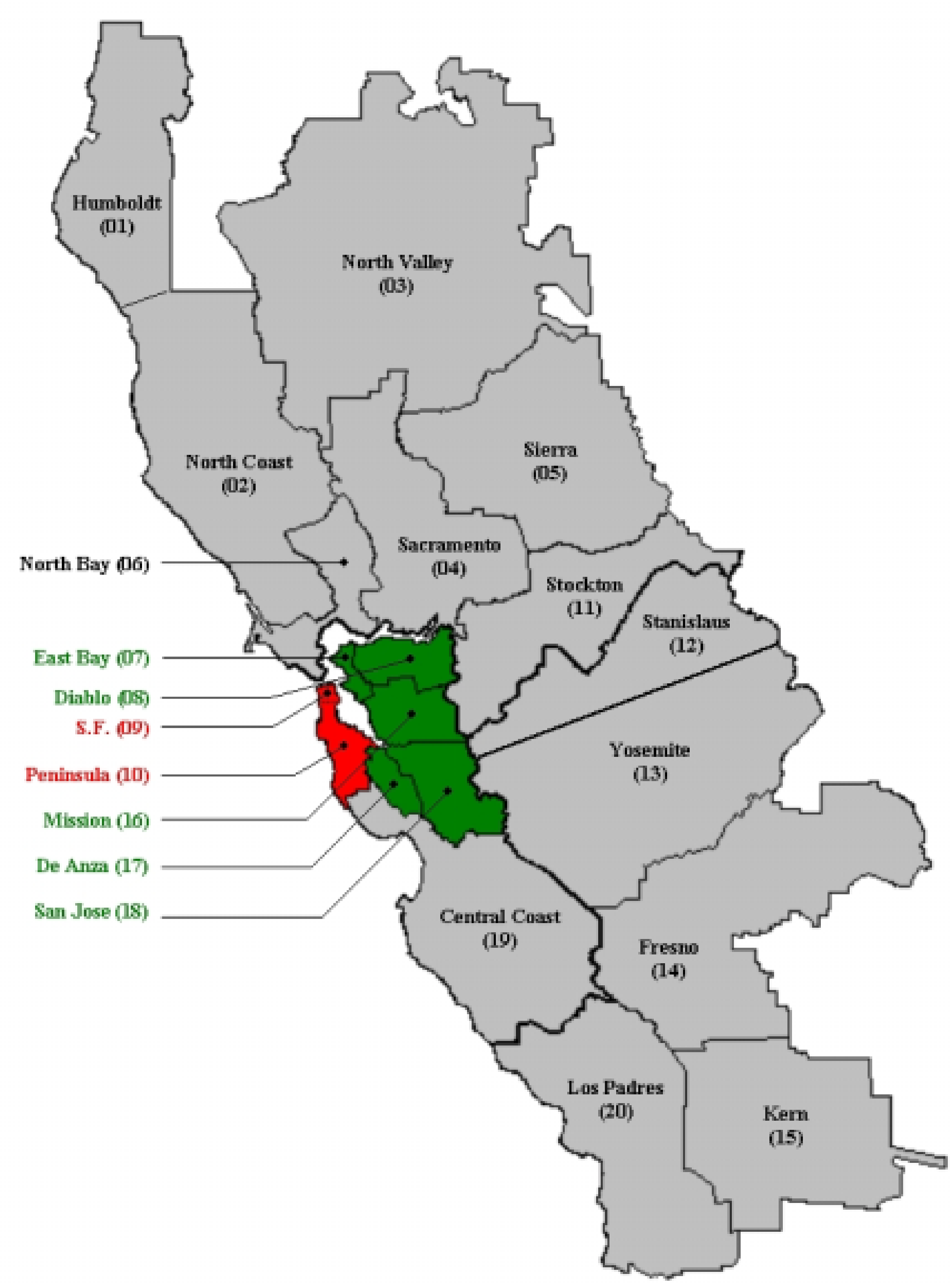
  2. The remaining planning areas that constitute the "Greater Bay Area" (represented as green) will be modeled at their expected one-in-ten load at the time of the San Francisco / Peninsula coincident peak.

  3. The planning areas, outside of the "Greater Bay Area" (represented as gray), will be modeled at their anticipated one-in-five peak load.

  To account for uncertainty in forecasted load and present reduced load forecasts, additional studies may be required to determine at what load level additional import transmission facilities are required.

[3] Planning Areas do not necessarily peak simultaneously. Similarly, substations within planning areas do not peak at the same time. Coincident peak forecasts are developed in order to assess a planning area as a function of their overall expected system peak. Summation of individual substation (and/or planning area) peak loads is typically greater than the overall projected area (and/or system) peak load.
[4] PG&E (with input from the Study Group) shall define this "local area" of influence, based on past load pattern experience.

Figure 1. Illustration of PG&E Planning Areas



- **Power Factor.** Reactive load Watt/VAR ratios represented in the base cases will reflect reasonable adverse values for the operating conditions being studied. For 2006 Heavy Summer, PG&E's overall power factor will be (*0.XXXX*) leading / lagging.

- **"Municipality" Loads.** Loads of a Non-Participating Transmission Owners that are within PG&E's service area and directly interconnected to their host utility's transmission or distribution facilities, will be modeled based on the most recent forecast available from those entities.

- **Neighboring Area Loads.** Loads located outside the PG&E area (including SCE, SDG&E, LADWP, IID, CFE and other WECC member systems) will be modeled based on information provided to WECC.

Generation-Related Assumptions

- **High / Low Generation.** In addition to evaluating the SF-Peninsula with all existing generation facilities in service, the study will include thermal analysis on a high and low generation scenario within San Francisco. Scenarios to be considered in the study will include variations in generating levels that are determined by the study group. Levels of +590 MW and -422 MW from existing generation in San Francisco will be studied. To clarify:

  1. 590 MW of new generation in San Francisco represents the proposed Potrero #7 Project and a new peaking unit near the San Francisco Airport. and

  2. 422 MW of existing generation that could be shut down included the Hunters Point Power Plant and the Potrero Unit #3. The assumption to shut down the Hunters Point Power Plant includes the shut down of units #2 & #3 which have been converted to synchronous Condensers.

- **Reliability Must-Run Generation.** The most recent and appropriate levels of RMR Generation within the Greater Bay Area will be incorporated into these studies.

- **Qualifying Facilities.** QF generation located within PG&E's service area will be modeled at an output which reflects their historic dependable operating capacity. In the absence of such information, maximum contract value will be used. For steady-state power flow analysis, all explicitly-modeled QF generation will have their reactive power capabilities represented according to contractual requirements; otherwise historical operating data will be used. For dynamic stability analysis, actual reactive power capabilities (manufacturer data or field test data) will be modeled as available. Those QFs who are expected to either reach the end of their contract or be bought out by the study period will be regarded in the same fashion as other "merchant" or market-driven units.

- **Hydro and Public Power Utilities Sources.** Hydroelectric generation will be modeled to reflect the season of the base case and will be based on both historical records and expected seasonal output.

- **Distribution-Sited Generation.** All generation directly interconnected to PG&E's distribution systems (i.e. not directly interconnected to the Cal-ISO Controlled Grid) will be netted with the load represented at the nearest Cal-ISO Grid Take-Out Point. For accounting purposes, distributed generation will be discretely modeled from existing load as "negative load" and identified with a load ID "DG". This will include the sensitivity of distributed generation described within the

- **New Generation.** The study group will include the impact of proposed new generation. If necessary, the initial studies will assume those plants on-line that have signed interconnection agreements with PG&E as of June 1, 2002. The study group will evaluate planned generating resources, and determine what new generation outside of the SF-Peninsula should be assumed.

Generation & Load-Related Assumptions

- **Air Quality.** A sensitivity study will assess Greater Bay Area air quality impacts related to NOX limits on existing generation and SCR retrofitting.

Scope

The scope of the technical analysis shall include the following power system analysis techniques:

Transmission Network Analysis

Thermal Analysis

Power flow studies will be performed to determine the extent to which thermal overloading may occur on facilities in the San Francisco Bay Area. Base case (all lines in service) analysis, as well as the appropriate contingency analysis will be performed in accordance with the set of assumptions developed by the study group.

During the course of the thermal analysis discussed above, facility loading will be monitored to ensure that overloads do not occur. Power flows must be at or below the continuous ratings for “All Lines in Service” analysis, and must be at or below the emergency rating for all contingency cases. Summer "normal" and "emergency" equipment ratings will be used to assess the thermal performance of the SF-Peninsula under both summer and autumn (Fall) conditions. To the extent that unacceptable power flows are seen, upgrades or other remedial measures will be investigated, including load shedding proposals.

Voltage Analysis

During the course of the thermal analysis discussed above, voltages will be monitored to ensure that they each fall within the acceptable voltage range. To the extent that unacceptable (low) steady-state voltages are seen (pre- or post-contingency), upgrades or other remedial measures will be studied.

Reactive Margin Analysis

Detailed technical analysis will be required to assess reactive pwer support margin requirements. Such requirements affect the ability of the system to withstand the phenomenon known as “voltage collapse”, and are studied using post-transient analysis and Q-V curves known as “nose curves”. The most recent WECC methodology will be used that, for the most part involves evaluating a load level 5% above the load level being used in this study (5% above the 1 in 10 yr load in the Greater Bay Area and 5 % above the 1 in 5 yr load modeled outside of the Greater Bay Area. Details of reactive margin analysis are provided in that WECC document. (Also see Appendix V.)

Transient Stability Analysis

Transient stability will be performed to ensure that stability is maintained within the San Francisco Bay Area. (See Appendix V for a sample of Transient Stability.)

Loss Analysis (Optional)

Transmission system losses (net positive or negative) associated with various transmission system reinforcement proposals will be measured against the base case.

Potential Transmission / Generation Projects for Consideration

The SFSSG will develop alternative system reinforcements. It is expected they will include:

External[5] Transmission Reinforcements

San Mateo - Martin Corridor

- A second San Mateo - Martin 230 kV underground cable
- Rebuild overhead 115 kV line(s)
- Reactive support

East Bay Corridor

- Transmission alternatives via Bay Bridge or submarine cable(s) from various East Bay locations.[6]

Internal[7] Transmission System Reinforcements

- Second Hunters Point - Potrero 115 kV underground cable
- Martin – Hunters Point?

Generation Alternatives Internal to SF-Peninsula

- No Generation at Hunters Point

[5] As it pertains to transmission, "external" is used to describe system reinforcements that allow for power to be transmitted into the SF-Peninsula.
[6] These transmission alternatives will likely require some reinforcements between the major 230 kV stations east of Oakland and the interconnection point of the new line(s) in Oakland.
[7] As it pertains to transmission, "internal" is used to describe system reinforcements that allow for power to be transmitted the SF-Peninsula.

- Sensitivity of no Potrero unit #3
- Expansion of Generation at Potrero (Potrero unit #7)
- Vicinity SF Airport Peaking Generation ?
- Distributed Generation
- QF Capacity Shift
- Other?

Load Management / Conservation Alternatives

Based on the methodology that is being used to perform the Phase 2 study effort, an analysis of specific load management/conservation alternatives is not applicable since these alternatives are aimed at reducing the San Francisco Peninsula Area load which is considered a variable in this study.

Project Cost Estimates

Estimated project costs (including the impact of losses), and permitting/construction timelines will be developed for each of the alternatives considered.

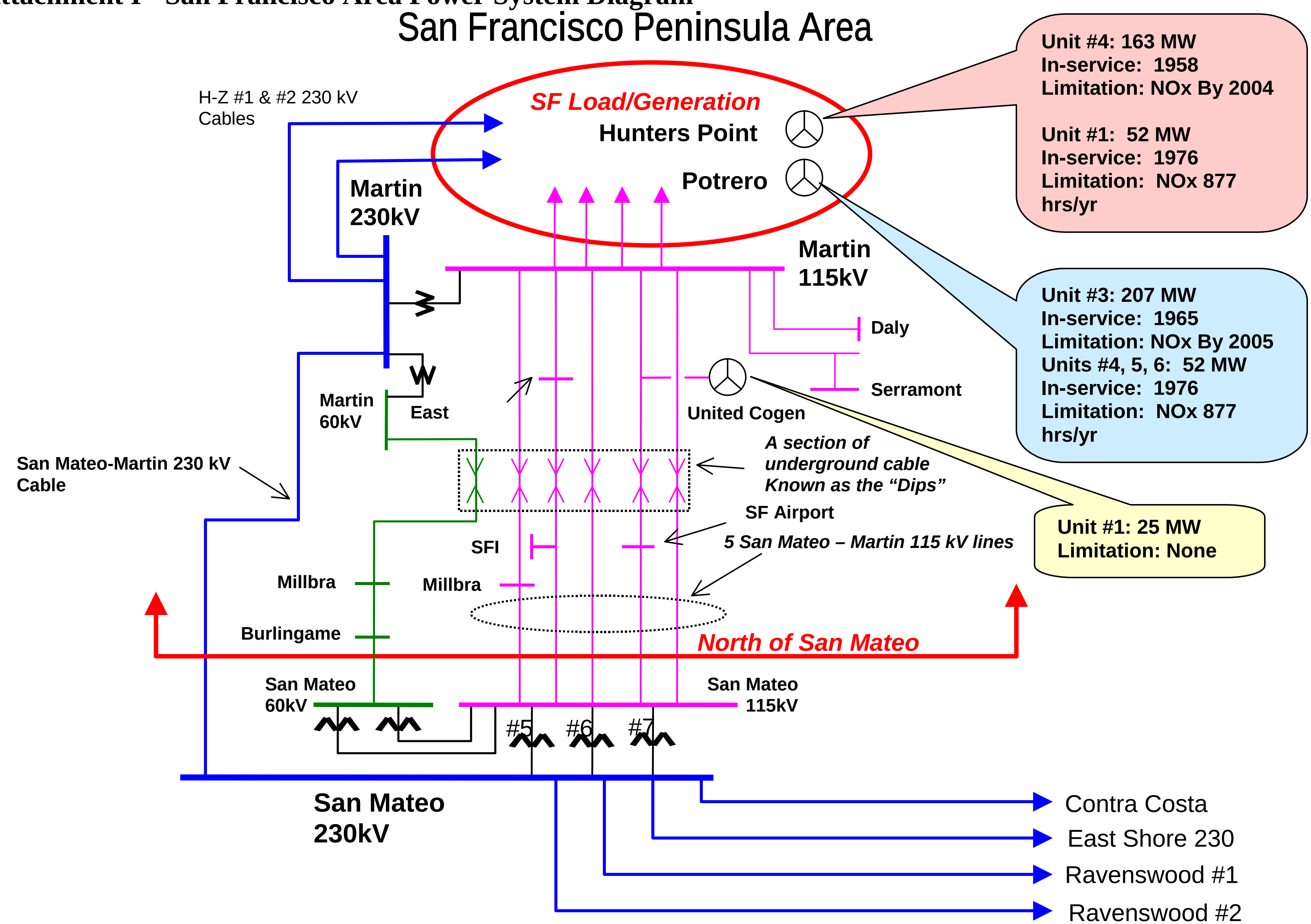
Schedule

Milestone	Date
Initial Study Group Meeting (#1) to discuss study objectives	2/21/02
Study Group Meeting (#2) to discuss Study Plan / objectives	5/28/02
Study Group Meeting #3 to discuss study power flow base cases	07/01/02
ISO Issues Public Notice regarding Study Group goals & objectives	07/15/02
Conduct technical studies / prepare Preliminary Report	7/15/02 - 10/15/02
Study Group Meeting #4 to discuss Preliminary Study	10/15/02

Results	
ISO Issues Public Notice regarding Preliminary Study Results	11/01/02
Additional Analysis if Required & Issue Draft Final Report	12/02/02 - 02/01/03
Public Comments to ISO Study Group on Draft Report	03/03/03
Study Group Meeting to Review and Approve Report	04/01/03
ISO Board of Governors Adopts Final Report	05/01/03
Distribution of Final Report	06/02/03

Attachment I
San Francisco Area
Power System
Diagram

Attachment I - San Francisco Area Power System Diagram



Attachment II
SF / Peninsula Planning Study Group Members

Attachment II - SF / Peninsula Planning Study Group Members

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Attachment III
Reliability Criteria

Supplementary Guide for Application of the Criteria for San Francisco
Cal-ISO Grid Planning Criteria
WECC Reliability Criteria (*excerpt*)
NERC Planning Standards (*excerpt*)

Attachment III - Supplementary Guide for Application of the Criteria for San Francisco

Power is supplied to the city of San Francisco from a combination of local generation and transfers into the city through transmission. The city is located at the end of a peninsula, and all of the major overhead transmission lines are forced into a common corridor adjacent to the San Francisco Airport. This corridor extends between Martin Substation, just south of San Francisco, and San Mateo Substation, located 13 miles to the south.

Given the location of the City, the nature of its supply, and the lack of significant seasonal diversity, special planning criteria that consider simultaneous outage of multiple system elements for San Francisco have been in place since 1978. Historically there have been five important multi-element outages to be considered in planning San Francisco's supply. These may be viewed as an application of the NERC Planning Standards – Table I with explicit consideration for planned generator maintenance outages.

At all times, the resources available to serve the city of San Francisco shall be sufficient to serve all loads within the city limits for NERC Category A and B as well as the following Category C contingencies:

A. Loss of the largest available generation unit plus the loss of one overhead transmission circuit from San Mateo to Martin in addition to any generation unavailable due to regular overhaul schedules. (ISO Grid Criteria Level B)

B. Loss of one underground circuit from San Mateo to Martin plus the loss of the largest available generation unit in addition to any generation unavailable due to regular overhaul schedules. (ISO Grid Criteria Level B)

C. Loss of one underground transmission circuit plus the loss of one overhead transmission circuit from San Mateo to Martin in addition to any generation unavailable due to regular overhaul schedules.

D. Overlapping loss of the two largest available generation units in addition to any generation unavailable due to regular overhaul schedules.

The controlled interruption of customer demand, excluding downtown network loads and critical public services, is permitted to prevent facilities from overloading for the following Category D disturbance.

E. Loss of all overhead transmission from San Mateo Substation to Martin Substation in addition to any generation unavailable due to regular overhaul schedules.

Attachment III - Cal-ISO Grid Planning Criteria

I. Background

The purpose of this document is to specify the Planning Criteria that will be used in the planning of ISO Grid transmission facilities.

The ISO Tariff specifies:

> "After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs, will work to develop a consistent set of reliability criteria for the ISO Controlled Grid which the TOs will use in their transmission planning and expansion studies or decisions."[8]

The ISO Tariff specifies in several places that the facilities that are to be added to the ISO Grid are to meet the Applicable Reliability Criteria, which is defined as follows:

> "The reliability standards established by NERC, WECC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC."[9]

These ISO Grid Planning Criteria will fill the role of the "local reliability criteria" in the above definition. To facilitate the development of these criteria, the ISO formed the ISO Grid Planning Criteria Subcommittee (PCS), which includes representation from all interested market participants. In recognition of the need to closely coordinate the development of the ISO Grid with neighboring electric systems both inside and outside of California, the approach taken by the PCS is to utilize regional (WECC) or continental (NERC) standards to the maximum extent possible. These ISO Grid Planning Criteria build off of, rather than duplicate, criteria that were developed by WECC and NERC. The PCS has determined that the ISO Grid Planning Criteria should:

- Address specifics not covered in the NERC Standards and WECC Criteria.
- Provide interpretations of the NERC Standards and WECC Criteria specific to the ISO Grid.
- Identify whether specific criteria should be adopted that are more stringent than the NERC Standards or WECC Criteria.

The following paragraphs describe the general philosophy behind the ISO Planning Criteria and how the NERC Standards and WECC Criteria will affect the planning of the ISO grid.

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[8] ISO Tariff, April 7, 1998, Section 3.2.1.2, Page 129.
[9] ISO Tariff, April 7, 1998, Appendix A, Page 297.

II. ISO Grid Planning Criteria Principles

The primary principle guiding the development of the ISO Grid Planning Criteria is to develop a consistent reliability criteria for the ISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-ISO planning criteria.

III. ISO Grid Planning Standards (excerpt)

I. Introduction

The purpose of this document is to specify the Planning Standards that will be used in the planning of ISO Grid transmission facilities. The primary principle guiding the development of the ISO Grid Planning Standards is to develop a consistent reliability standards for the ISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-ISO planning standards.

The ISO Tariff specifies:

"After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs, will work to develop a consistent set of reliability criteria for the ISO Controlled Grid which the TOs will use in their transmission planning and expansion studies or decisions."1

The ISO Tariff specifies in several places that the facilities that are to be added to the ISO Grid are to meet the Applicable Reliability Standard, which is defined as follows:

"The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC."2

These ISO Grid Planning Standards fill the role of the "consistent set of reliability criteria" in the above tariff language. To facilitate the development of these Standards, the ISO formed the ISO Grid Planning Standards Committee (PSC), which includes representation from all interested market participants. One of the primary roles of the PSC is to periodically review the ISO Grid Planning Standards and recommend changes as necessary. In recognition of the need to closely coordinate the development of the ISO Grid with neighboring electric systems both inside and outside of California, the approach taken by the PSC is to utilize regional (WSCC) and continental (NERC) standards to the maximum extent possible. These ISO Grid Planning Standards build off of, rather than duplicate, Standards that were developed by WSCC and NERC. The PSC has determined that the ISO Grid Planning Standards should:

- Address specifics not covered in the NERC/WSCC Planning Standards.
- Provide interpretations of the NERC/WSCC Planning Standards specific to the ISO Grid.
- Identify whether specific criteria should be adopted that are more stringent than the NERC/WSCC Planning Standards.

The following Section details the ISO Grid Planning Standards. Also attached are interpretations of the terms used by NERC and background information behind the development of these standards.

4. **San Francisco Greater Bay Area Generation Outage Standard -** Before conducting Grid Planning studies for the San Francisco Greater Bay Area, the following three units should be removed from service in the base case:
5.
   - One 50 MW CT in the Greater Bay Area but not on the San Francisco Peninsula.
   - The largest single unit on the San Francisco Peninsula.
   - One 50 MW CT on the San Francisco Peninsula.

The case with the above three units out of service should be treated as the "system normal" or starting base case (NERC Category A) when planning the system. Traditional contingency analysis, based on the standards specified in the NERC, WSCC (including voltage stability), and ISO standards (such as single line outage, single generator outage etc), would be conducted on top of this base condition. The one exception is that when screening for the most critical single generation outage, only units that are not on the San Francisco peninsula should be considered. Similarly, when examining multiple unit outages, at least one of the units considered should not be on the San Francisco Peninsula.

IV. WECC Transmission System Planning Criteria

The WECC Criteria for Transmission System Planning was originally developed to insure that disturbances in one system do not spread to other systems and produce widespread transmission system outages. Recently the WECC Criteria have been amended to provide specific requirements for internal system design. The WECC criteria are currently primarily deterministic criteria but WECC is working towards transitioning to probabilistic criteria. The ISO has also expressed strong interest in developing probabilistic criteria. The ISO and its members should be proactive in guiding NERC and WECC in this direction. Until probabilistic criteria are adopted by WECC, the current criteria will apply. In areas where the PCS believes that it would be uneconomic to comply with specific standards, the ISO can apply for deference with NERC and WECC.

V. NERC Planning Standards

In September of 1997, the NERC Board of Trustees approved the NERC Planning Standards. The approval of these standards marked a significant change for NERC and significantly affects the development of the ISO Grid Planning Criteria. Prior to the Planning Standards, NERC only provided "Planning Principles and Guides" which were very general. In contrast, the NERC Planning Standards provide specific planning requirements. In addition the NERC Planning Standards apply uniformly across bulk electric systems and do not distinguish between internal and external systems. The NERC Planning Standards appear to provide the majority of what is needed for an ISO Grid Planning Criteria. However, there is still a major question concerning the cost impact of implementing a stringent interpretation of the NERC Planning Standards. In addition, in past PCS meetings, a variety of entities expressed concern over a lack of clarity on some points in the NERC Planning Standards. The PCS decided that clarifications to the NERC Standards should be developed and that it would be preferable for the PCS to develop the interpretations rather than request that NERC provide clarifications. The adoption of specific interpretations may directly impact the costs associated with compliance with the NERC Planning Standards. If NERC or WECC provides clarifications that are different than the ones adopted by the PCS, then those clarifications will apply unless the ISO has been granted deference.

V. Interpretations of NERC Planning Standard Terms

Listed below are several of the terms that are used in the NERC Planning Standards which members of the PCS have determined require clarification. Also provided below are ISO interpretations of these terms:

Bulk Electric System: The ISO Bulk Electric System refers to all of the facilities placed under ISO control.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTOs and the ISO subject to appropriate coordination and review with the relevant state, local, and federal regulatory authorities and WECC. The PTOs develop annual transmission plans, which the ISO reviews. Both the ISO and PTOs have the ability to identify transmission upgrades needed for reliability.

Entity Required to Develop load models: The TOs, in coordination with the UDCs and others, develop load models.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. The PCS decided that for studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a higher standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified in the ISO Grid Coordinated Planning Process and corresponding operating procedures are in place when required. The PCS is developing guidelines for the use of load dropping to meet planning criteria.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

Appropriate Level of Reactive Reserves: As determined by the WECC *"Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology"* except where a specific area of the system warrants more stringent criteria.

VI. ISO Grid Planning Criteria

The ISO Grid Planning Criteria consists of the following:

1) The criteria specified in the WECC Criteria for Transmission System Planning unless WECC formally grants an exemption or deference to the ISO.
2) The standards specified in the NERC Planning Standards, and the interpretations discussed in Section V of this document, unless NERC formally grants an exemption or deference to WECC or the ISO.
3) The criteria pertaining to the Diablo Canyon and San Onofre Nuclear Power Plants, as specified in Appendix E of the Transmission Control Agreement.
4) A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.

In addition to these criteria, the PCS will be developing planning guidelines to provide guidance on a variety of issues such as the use of load dropping to meet applicable WECC and/or NERC criteria. These Planning Guidelines may evolve to be specific enough to be incorporated into this document as planning criteria.

JCM/GrdPlng

Attachment III - WECC Reliability Criteria (*excerpt*)

WECC Disturbance-Performance Table of Allowable Effect on Other Systems (1)

Performance Level	Disturbance (2) Initiated By: No Fault 3 Ø Fault - Normal Clearing SLG Fault - Delayed Clearing DC Disturbance (3)	Transient Voltage Dip Criteria (4) (5) (6)	Minimum Transient Frequency (4) (5)	Post Transient Voltage Deviation (4) (5) (6) (7)	Loading Within Emergency Ratings	Damping
A	Generator One Circuit One Transformer DC Monopole (8)	Max V Dip - 25% Max Duration of V Dip Exceeding 20% - 20 cycles	59.6 Hz Duration of Frequency Below 59.6 Hz - 6 cycles	5%	Yes	>0
B	Bus Section	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 20 cycles	59.4 Hz Duration of Frequency Below 59.4 Hz - 6 cycles	5%	Yes	>0
C	Two Generators Two Circuits DC Bipole (8)	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 40 cycles	59.0 Hz Duration of Frequency Below 59.0 Hz - 6 cycles	10%	Yes	>0
D	Three or More circuits on ROW Entire Substation Entire Plant Including Switchyard	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 60 cycles	58.1 Hz Duration of Frequency Below 58.1 Hz - 6 cycles	10%	No	≥0

(1) This table applies equally to the system with all elements in service and the system with one element removed and the system adjusted.
(2) The examples of disturbances in this table provide a basis for estimating a performance level to which a disturbance not listed in this table would apply.
(3) Includes Disturbances which can initiate a permanent single or double pole DC outage.
(4) Maximum transient voltage dips and duration, minimum transient frequency and duration, and post transient voltage deviations in excess of the values in this table can be considered acceptable if they are acceptable to the affected system or fall within the affected system's internal design criteria. The transient frequency must remain below the indicated frequency for more than six cycles to be considered a violation.
(5) Transient voltage and frequency performance parameters are measured at load buses (including generating unit auxiliary loads), however, the transient voltage dip should not exceed 30% for any bus. Allowable post transient voltage deviations apply to all buses.
(6) Refer to Figure 1.
(7) If it can be demonstrated that post transient voltage deviations that are less than these will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem. Simulation of post transient conditions will limit actions to automatic devices only and no manual action is to be assumed.
(8) Refer to section 8.0 - Application to DC Lines, paragraph 8.2.

Attachment III - NERC Planning Standards (*excerpt*)

Transmission System Standards - Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Component(s)	Components Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A – No Contingencies	All Facilities in Service	None	Normal	Normal	Yes	No	No
B – Event resulting in the loss of a single component.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of a Component without a Fault.	 Single Single Single Single	Applicable Rating [a] (A/R) A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing: 4. Single Pole (dc) Line	 Single	 A/R	 A/R	 Yes	 No[b]	 No
C – Event(s) resulting in the loss of two or more (multiple) components.	SLG Fault, with Normal Clearing: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned[d] Planned[d]	 No No
	SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned[d]	No
	Bipolar Block, with Normal Clearing: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing: 5. Double Circuit Towerline	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned[d] Planned[d]	 No No
	SLG Fault, with Delayed Clearing: 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Multiple Multiple Multiple Multiple	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 Planned[d] Planned[d] Planned[d] Planned[d]	 No No No No

D [e] – Extreme event resulting in two or more (multiple) components removed or cascading out of service	3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of a all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) for an event or condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. • May involve substantial loss of customer demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems. • Document measures or procedures to mitigate the extent and effects of such events. • Mitigation or elimination of the risks and consequences of these events shall be at the discretion of the entities responsible for the reliability of the interconnected transmission systems.

(a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner.

(b) Planned or controlled interruption of generators or electric supply to radial customers or some local network customers, connected to or supplied by the faulted component or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

(c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

(d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

(e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

Attachment IV
Base Case Summaries

(To Be Provided)

Attachment VI
List of Contingencies

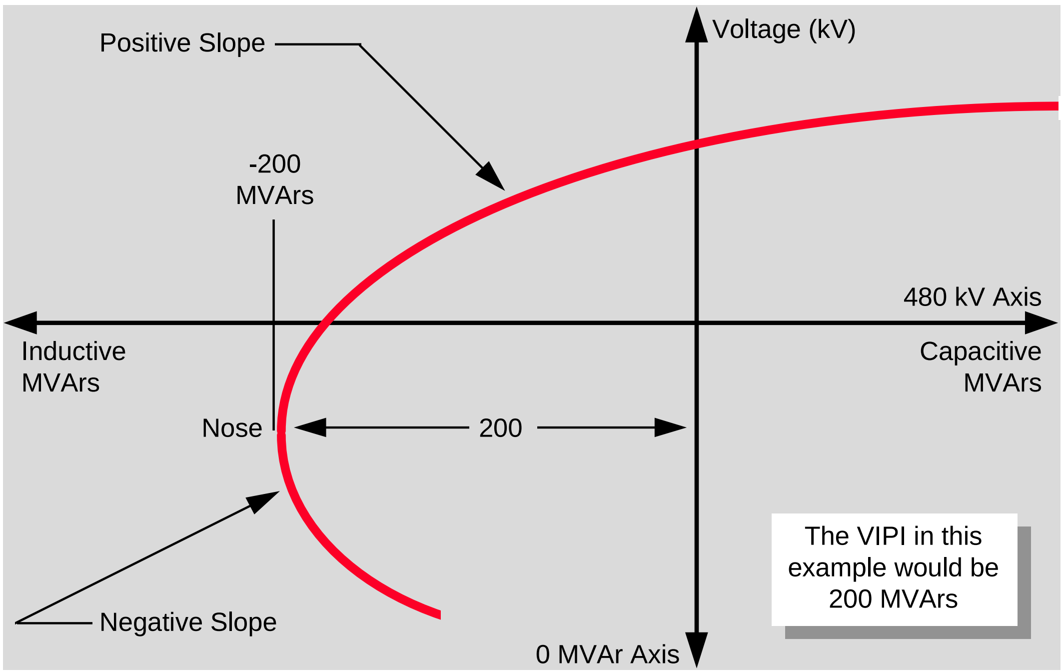
(To Provided Once Base Cases are Developed)

Attachment VII
Reactive Margin
&
Transient Stability
Example

Attachment VII - Reactive Margin Example

The method used in analyzing voltage instability in Cal-ISO study reports is to model a fictitious synchronous condenser at a specific bus, and record the reactive requirements for variations in bus voltage. Q-V curves, voltage versus reactive requirement, are developed from these data.

Figure 1. Example of a Q-V Curve



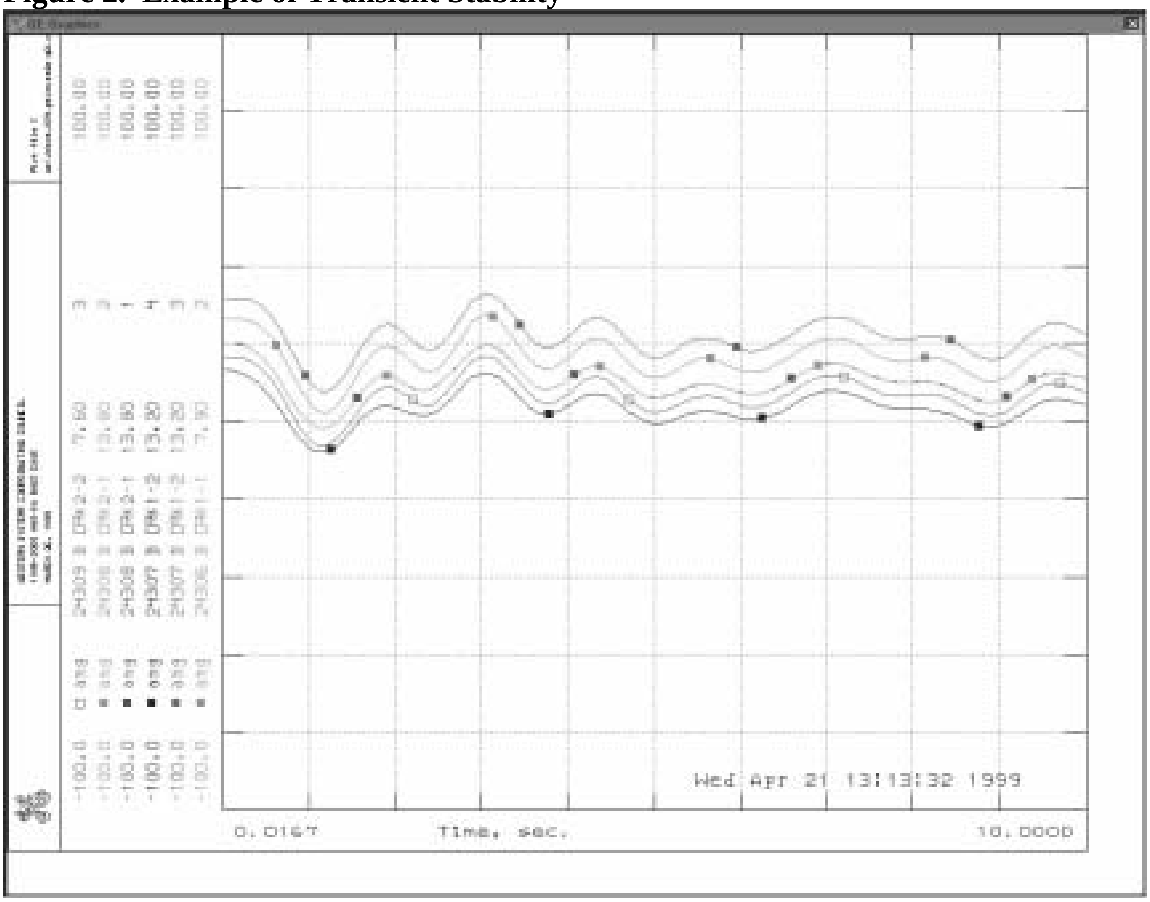
Proximity to the point of certain voltage instability is measured by the amount of additional reactive load at a bus necessary to change the slope of the voltage vs. reactive requirement nose curve (dV/dQ) from positive to negative. A positive slope implies that voltage rises as capacitive support is added - as is usually the case under normal operating conditions. A negative slope implies that voltage decreases as capacitive support is added. The Voltage Proximity Indicator (VIPI) is illustrated in Figure 1. It should be noted that the point at which the slope changes from positive to negative, or the nose of the voltage vs. reactive curve, is the point of certain voltage instability.

Attachment VII - Example of Transient Stability

Transient stability analysis is a time-based simulation, which illustrates the response of the entire WECC power system during a contingency. Transient stability simulations are typically run for a time-period of ten seconds. Occasionally, it is necessary to extend the simulation runtime to 20 seconds to accurately assess system performance. Unless otherwise noted, the contingencies assessed in the San Francisco / Peninsula Planning studies assume three-phase, four-cycle faults with normal fault-clearing times. Voltage, frequency and system damping were evaluated.

An example of transient stability is illustrated in Figure 2.

Figure 2. Example of Transient Stability



The example above shows the rotor angle response of several of SCE's Big Creek hydroelectric generation units. This plot exhibits transiently stable performance and positive damping - system oscillations decrease over time. With regard to transient stability analysis, this would be considered an acceptable case.

Attachment VIII
Definition of Terms

Attachment VIII - Definition of Terms

Ancillary Services Market	The market for services other than scheduled energy which are required to maintain system reliability and meet WECC/NERC operating criteria. Such services include spinning, non-spinning, replacement reserves, regulation (AGC), voltage control and black start capability.
Breaker	Circuit breaker - An automatic switch that stops the flow of electric current in a suddenly overloaded or otherwise abnormally stressed electric circuit.
Bus	Conductors that serve as a common connection for multiple transmission lines.
Cal-ISO	California Independent System Operator - The Cal-ISO is the FERC regulated control area operator of the ISO transmission grid. Its responsibilities include providing non-discriminatory access to the grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The Cal-ISO has no affiliation with any market participant.
Cogeneration	The consecutive generation of thermal and electric or mechanical energy.
Congestion	The condition that exists when market participants seek to dispatch in a pattern which would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules.
Contingency	Disconnection or separation, planned or forced, of one or more components from the electric system.
Day-Ahead Market	The forward market for the supply of electrical power at least 24 hours before delivery to Buyers and End-Use Customers.
Fault Duty	The maximum amount of short-circuit current which must be interrupted by a given circuit breaker.

FERC	Federal Energy Regulatory Commission
General Order 95	California Public Utilities Commission (CPUC) General Order which specifies transmission line clearance requirements.
Generation Outlet Line	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation to the main grid.
Generation Tie	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation to the main grid.
Generator	A machine capable of converting mechanical energy into electrical energy.
Hour-Ahead Market	The electric power futures market that is established 1-hour before delivery to End-Use Customers.
Imbalance Energy	Energy not scheduled in advance that is required to meet energy imbalances in real-time. This energy is supplied by Generators under the ISO's control, providing spinning and non-spinning reserves, replacement reserved, and regulation, and other generators able to respond to the ISO's request for more or less energy.
ISO Tariff	Document filed with the appropriate regulatory authority (FERC) specifying lawful rates, charges, rules, and conditions under which the utility provides services to parties. A tariff typically includes rates schedules, list of contracts, rules and sample forms.
ISO-controlled Grid	The combined transmission assets of Transmission Owners that are collectively under the control of the Cal-ISO.
KV	Kilovolt - A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground.
L.L.C.	Limited Liability Company
Load	Demand - The rate expressed in kilowatts, or megawatts, at which electric energy is delivered to or by a system, or part of a system at a given instant or

	averaged over an designated interval of time.
MVAR	Megavar - One megavolt ampere reactive.
MW	Megawatt - A unit of power equivalent to 1,341 horsepower.
NERC	North American Electric Reliability Council
Operational Transfer Capability	The maximum amount of power which can be reliably transmitted over an electrical path in conjunction with the simultaneous reliable operation of all other paths. This is limit is typically defined by seasonal operating studies, and should not be confused with path rating. Also referred to as OTC.
Outlet	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation to the main grid.
Path 15	The Los-Banos - Gates - Midway and Los Banos - Midway 500 kV transmission lines.
Path 26	The Midway - Vincent 500 kV transmission lines 1,2, and 3.
Path Rating	The maximum amount of power which can be reliably transmitted over an electrical path under the best set of conditions. Path ratings are defined and specified in the WECC Path Rating Catalog.
PG&E	Pacific Gas & Electric Company
PG&E Interconnection Handbook	Detailed instructions to new customers (either load or generation) on how to interconnect to the PG&E electric system.
Post-Transient Voltage Deviation	The change in voltage from pre-contingency to post-contingency conditions once the system has had time to readjust.
Power Flow	A generic term used to describe the type, direction, and magnitude of actual or simulated electrical power flows on electrical systems.
PTO	Participating Transmission Owner (i.e., PG&E, SCE, SDG&E)

Pump	A hydro-electric generator which acts as a motor and pumps water stored in a reservoir to a higher elevation.
RAS	Remedial Action Scheme - An automatic control provision (i.e., trip a generation unit to mitigate a circuit overload).
Reactive Power	Reactive Power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system. An adequate supply of reactive power is required to maintain voltage levels in the system.
Real-Time Market	The competitive generation market controlled and coordinated by the Cal-ISO for arranging real-time imbalance power.
Reliability	The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. May be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.
Reliability Criteria	Principals used to design, plan, operate, and assess the actual or projected reliability of an electric system.
Reliability Must-Run	The minimum generation (number of units or MW output) required by the Cal-ISO to be on line to maintain system reliability.
SCE	Southern California Edison Company
Series Capacitor	A static electrical device which is connected in-line with a transmission circuit that allows for higher power transfer capability by reducing the circuit's overall impedance.
Substation	An assemblage of equipment that switches, changes, or regulates voltage in the electric transmission and distribution system.
Switching Station	Similar to a substation, but there is only one voltage

	level.
System Reliability	See "Reliability".
Thermal Loading Capability	The current-carrying capacity (in Amperes) of a conductor at specified ambient conditions, at which damage to the conductor is non-existent or deemed acceptable based on economic, safety, and reliability considerations.
Transformer	A device that changes the voltage of alternating current electricity.
Voltage	Electromotive force or potential difference.
WECC	Western Electric Coordinating Council

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I. <u>Role of San Francisco Local Agency Formation Commission</u>:

The San Francisco LAFCo was formed in August of 2000 as a result of an initiative petition to create a municipal utility district for the City and County of San Francisco and the City of Brisbane. Although this measure was narrowly defeated at the polls, the Commission determined that public hearings should be held to gather information from energy experts regarding the current utility service needs of San Francisco and the various options that may be available to increase service reliability, efficiency and cost effectiveness. These hearings are consistent with LAFCo's primary purpose which is to review public service needs, including utility service, and to determine whether new government entities should be created or changes in existing governments should be made to address the needs of its citizens.

From February 2002 until April 2002, the San Francisco LAFCo conducted a series of public hearings and representatives from the following public entities and private organizations provided presentations:

- San Francisco Public Utilities Commission (SFPUC)
- State of California Consumer Power and Conservation Authority (California Power Authority)
- California Public Utilities Commission (CPUC)
- P G & E
- Sacramento Municipal Utility District (SMUD)
- Representative who managed utility department for the Cities of Anaheim, Palo Alto, Austin, Texas and Pasadena

- City of Roseville
- City of San Jose
- Onsite Energy Group specializing in cogeneration development and operation
- The Utilities Reform Network (T.U.R.N.)
- Northern California Power Agency

The information provided through the hearings is available through the LAFCo Executive Officer. At the conclusion of the hearings, the Commission determined that a study should be prepared to provide the public with information regarding the utility needs of San Francisco. A critical part of this analysis is an understanding of the various ways in which government can provide utility services to its citizens.

II. San Francisco Public Utilities Commission (SFPUC):

A. Authority to Provide Electric Utilities:

Currently, SFPUC is responsible for overseeing "the construction, management, supervision, maintenance, extension, operation, use and control" of all the City's energy supplies and utilities. (1996 San Francisco City and County Charter (San Francisco Charter) § 4.112) SFPUC is authorized to contract for the provision of "heat, light and power for municipal purposes." (San Francisco Administrative Code § 2A.130)

B. Governance:

Created under the San Francisco Charter, SFPUC is a department of the executive branch of San Francisco. (San Francisco Charter § 4.112) SFPUC is governed by five (5) Commissioners, appointed for four-year terms by the Mayor subject to the veto power of the Board of Supervisors. (San Francisco Charter §§ 3.100, 4.112) The Mayor is responsible for generally administering and overseeing each department or unit of the executive branch, including SFPUC, and has the power to sit but not vote on all matters. (Charter § 3.100(1)(9)) A General Manager, appointed by the Commission, monitors daily operations as the chief administrative officer of SFPUC.

C. Operations:

SFPUC is operationally divided into the General Manager's Office, Hetch Hetchy Water and Power ("HHWP") and the Utilities Engineering Bureau. HHWP, a support bureau of SFPUC, operates and maintains three hydroelectric powerhouses in the vicinity of Yosemite National Park. HHWP's transmission lines deliver the electricity generated in the mountains to Turlock and Modesto Irrigation Districts and to PG&E in the Bay Area for distribution.

HHWP provides electricity for all of San Francisco's municipal functions, including San Francisco Municipal Railway and San Francisco International Airport and sells excess electricity at cost to Modesto and Turlock Irrigation Districts.[1] Any additional power is sold to public entities and private business, but not to the general public.

D. Acquisition of Utilities:

San Francisco has the authority to acquire and own public utilities "when public interest and necessity demand." (San Francisco Charter § 16.101) The Board of Supervisors must obtain a report from the SFPUC whenever the Board determines that

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[1] The Raker Act of 1913 granted rights-of-way through Yosemite National Park and Stanislaus National Forest to San Francisco for the production of hydroelectric power through the Hetch Hetchy system. Under the Raker Act , San Francisco is required to sell electricity it produces in excess of its own municipal needs to Modesto and Turlock Irrigation Districts at cost.

"public interest or necessity demands the acquisition, construction or completion of any public utility" by San Francisco or the public petitions the Board to acquire any public utility. (San Francisco Charter § 16.101) SFPUC is responsible for valuing the acquisition of a public utility. (San Francisco Administrative Code § 2A.130)

E. Use of Operational Revenue:

HHWP's operational revenue is allocated for expenses related to operating, repairing and replacing existing facilities, bond payment, "extensions and improvements," and a surplus fund for each utility. Surplus funds are transferred to the General Fund of the City and County by the Board of Supervisors. (Charter § 16.103)

F. Restrictions on Bonding:

The Board of Supervisors may fund construction and acquisition projects by providing for the issuance of revenue bonds or general obligation bonds in compliance with state and local law. (San Francisco Charter §§ 9.106, 16.101) General obligation bond indebtedness may not exceed "three percent of the assessed value of all taxable real and personal property, located within the City and County." (Charter § 9.106) Revenue bonds require majority voter approval unless they are issued for the purpose of reconstructing or replacing current energy facilities and are authorized by resolution of the Board of Supervisors adopted by a three-fourths vote; or to finance certain projects for conservation and renewable energy facilities or equipment. (Charter § 9.107)

III. <u>Forms of Municipal Utility Service</u>:

A. Municipal Utilities:

(i) Authority:

A city is legally authorized to furnish electric power to its inhabitants. Under Section 9 of Article 11 of the California Constitution, a municipal corporation may "establish, purchase and operate public works to furnish its inhabitants with . . . power." The authority to provide municipal utility service is broad. The municipality may determine that it will provide a complete utility service or only certain portions of service. Although a municipality may grant a utility franchise to an investor utility such as P G & E, the municipality still retains the power to acquire back the utility franchise by purchase or condemnation. The power to operate a municipal utility is flexible. According to Public Utilities Code section 10004:

> "[A] municipal corporation may acquire, own, control, sell, or exchange lands, easements, licenses, and rights of every nature within or without its corporate limits, and may operate a public utility within or without the corporate limits when necessary to supply the municipality, or its inhabitants or any portion thereof, with the service desired."

A municipal corporation may also "sell, lease, or distribute" surplus power outside of its territory. (Public Utilities Code section 10005)

(ii) Formation:

Cities have the power to provide electric utilities by creating new departments within themselves. A city may create its own utilities department by amending its charter or its municipal code through adoption of an ordinance.

(iii) Governance:

The City's legislative body or an independent board may govern the utilities department. An independent board may be appointed by the City's legislative body or mayor and may be representative of the general public or a class such as industry, consumer groups or financial experts. The independent board may also be elected by general or district vote. Mayoral appointment is typically subject to the legislative body's approval.[2] Although legislative bodies govern most public utilities, independent boards govern the majority of those that serve over 50,000 customers.[3]

For example, the City of Roseville's utility department is governed by the City Council. A five (5) member advisory commission appointed by the Council provides recommendations to the City Council. Utility funds are kept separate from the general fund of the City.

The City of Los Angeles created the Los Angeles Department of Water and Power ("LADWP") under the City Charter as a Proprietary Department of the City of Los Angeles. (Charter of the City of Los Angeles § 600) LADWP is the largest municipal utility in the world. It is governed by a five (5) member Board of Water and Power Commissioners, appointed by the Mayor, subject to City Council approval. (Charter of the City of Los Angeles §§ 502, 670, 675)

The City of Pasadena created Pasadena Water and Power ("PWP") by ordinance under the Pasadena Charter as a department of the City. (Charter of the City of Pasadena Title 2, Chapter 2.305.010) PWP provides electricity to 57,000 customers within the City. PWP is directed by a General Manager appointed by the City Manager. Pasadena's City Manager is charged with general administration of the utilities department subject to City Council oversight. (Charter of the City of Pasadena Title 2, Chapters 2.255.020, 2.305.010)

The American Public Power Association asked publicly owned electric utilities to identify the governing body or individual within their system that controls key decisions such as rate-setting, budget and bonding issues, condemnation and personnel matters.

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[2] American Public Power Association, *2001 Governance Survey*, July 2001.
[3] *Id.*

For utilities governed by legislative bodies, the study found that the legislative body usually controls most of the actions that were surveyed. In some cases, individual officials such as a city treasurer, utility general manager or city manager decide investment and personnel decisions. On the other hand, independently governed utilities reported that their boards typically make most of the surveyed decisions such as determining salaries, approving budgets, investing and purchasing power. However, boards are less likely to have final approval over issuing bonds and exercising eminent domain powers.[4]

B. Joint Power Authority:

A municipality may enter into a point powers agreement with another public entity to provide certain municipal utility services and exercise certain powers. Joint powers agreements are authorized under state law and merely require the consent of the public agencies involved.

(i) Formation:

A joint powers authority may be created by agreement between two or more public agencies. The joint powers authority created is a separate legal entity from the creating public agencies. It has the powers designated in the agreement, which must be a power common to the creating agencies.

(ii) Governance:

A joint powers authority is governed by an appointed body. The terms and nature of the appointment is set forth in the joint powers agreement

[4] *Id.*

IV. Municipal Utility Districts:

A. Authority:

Municipal utility districts have broad power to provide electricity. A municipal utility district may "acquire, construct, own, operate, control, or use, within or without . . . the district, works . . . for supplying the inhabitants of the district and public agencies therein" with "power" and "may do all things necessary or convenient to the full exercise of" such powers. (Public Utilities Code section 12801)

B. Formation:

Municipal utility districts are formed by two or more “public agencies,” or a public agency and unincorporated territory, acting together. (Public Utilities Code section 11561) The term “public agency” includes a “city, county water district, county sanitation district, or sanitary district.” (Public Utilities Code section 11504) The City and County of San Francisco may not form a municipal utility district under current law without joining with another public agency outside the City/County boundaries.

The formation process is initiated by resolutions of at least half of the public agencies involved or by petition. (Public Utilities Code §§ 11581, 11611) The board of supervisors of the county with the most voters inside the proposed boundary of the district receives the resolutions or petition. (Public Utilities Code §§ 11583, 11611) In order to form a municipal utility district, the resolution or petition must be presented to the local agency formation commission of the county and proceedings conducted in accordance with the Cortese Knox Hertzberg Local Government Reorganization Act of 2000. In addition, a report of the California Public Utilities Commission may be required. Finally, the creation of a municipal utility district would be subject to the

California Environmental Quality Act. Due to these requirements, the process to establish a municipal utility district can be lengthy.

C. Governance:

An independently elected board of directors governs a municipal utility district. The voters, divided into five wards within the proposed district boundary, decide the issue of formation and select one director from each ward to sit on the board of directors. (Public Utilities Code §§ 11641, 11642, 11646) The board of directors is a legislative body that regulates the utilities within the district. (Public Utilities Code §§ 11883, 11885)

V. <u>City Energy Efficiency and Conservation Programs Provided in Addition to Private Investor Utility Service</u>:

Instead of forming a municipal utility or a municipal utility district, some cities have elected to retain utility service from existing investor-owned utilities such as P G & E and complement these services with City programs or policies that promote energy efficiency and conservation. The City adopts programs that encourage and facilitate new building construction and rehabilitation with energy efficient code and zoning requirements. The programs promote the use of renewable energy and typically involve the adoption of building design and construction features that reduce energy operation and maintenance costs. An example of this type of City commitment is the City of San Jose's Green Building policy. The City has adopted the "Leadership in Energy and Environmental Design" (LEED) rating system and requires that new construction and retrofit of buildings meet specific criteria. The City of Santa Monica has developed its own rating system. The City of Portland has a "Green Building Action Plan" and "green building staff" are allocated throughout the various City departments, including the public works, planning, utility, and building departments.

(i) Authority:

The City and County of San Francisco currently has the authority through its building code and zoning powers to implement energy efficient programs.

(ii) Formation:

The City and County of San Francisco already has a building department and public works department that typically administers such programs. No additional governmental structure is required.

(iii) Governance:

The legislative body of the permitting public entity governs these programs, which would be the City and County of San Francisco. In addition most public entities have created an advisory group appointed by the legislative body to make recommendations to the legislative body regarding policies and new programs.

VI. Findings:

Based upon the information provided through the hearing process and reviewing the different governance structures, the following findings can be made:

1. The City and County of San Francisco has an existing utility department in the SF PUC with experienced staff and established programs.
2. The SF PUC has proposed an energy plan which sets forth short term and long-term utility policies and programs. A copy of the plan is attached to this report.

3. Current language in the San Francisco charter limits the SF PUC ability to respond to a changing energy market. The Commission should consider charter amendments to remove restrictions on the SF PUC to allow greater flexibility and local control for energy needs.
4. Surplus funds generated by the SF PUC are currently transferred to the City general fund pursuant to the charter terms. The Commission should consider recommending a charter amendment to limit the transfer of surplus funds to the general fund to allow greater flexibility for utility financing and programs.
5. San Francisco has the necessary authority and charter provisions for the operation of a municipal utility. The Commission should consider whether the current appointment structure of the governing body of the SF PUC is adequate in the event additional powers are recommended. The issue of accountability, local control and governance should be addressed in terms of the specific powers granted to the governing body.
6. The City and County of San Francisco cannot currently form a municipal utility district within its boundaries. State law would have to be amended to allow such a district to be formed. Without such a state law amendment, the City and County would have to join with another public entity outside of the City and County of San Francisco in order to form such a district. Given the unique nature of the energy needs of the City and County of San Francisco (including supply, transmission and generation) it is not certain whether such a district is advisable. This is particularly true given the fact that the City and County of San Francisco

has an established utility department and has the necessary powers to provide utility service if advisable.

7. The Commission should that recommend that the City and County of San Francisco review and adopt energy efficiency programs, building codes and zoning ordinances that promote energy conservation and energy efficiency.

[Note: The following information regarding condemnation may be inserted in a different section of the report.]

<u>Extraterritorial Condemnation</u>:

California Code of Civil Procedure section 1240.125 authorizes a "local public entity" to acquire extraterritorial property by eminent domain for "electric supply purposes" if the public entity is otherwise authorized to acquire property by eminent domain for such purposes. Section 1240.125 states:

> “Except as otherwise expressly provided by statute and subject to any limitations imposed by statute, a local public entity may acquire property by eminent domain outside its territorial limits for water, gas, or electric supply purposes or for airports, drainage or sewer purposes if it is authorized to acquire property by eminent domain for the purposes for which the property is to be acquired."

The term “local public entity” is defined to include “any public entity other than the state.” (Code of Civil Procedure section 1235.150)

Cities are authorized to "acquire by eminent domain any property necessary to carry out any of its powers or functions." (Government Code section 37350.5) Similarly, a municipal utility district formed under the Municipal Utility District Act, "may exercise the right of eminent domain to take any property necessary or convenient to the exercise of the powers granted" in the Act. (Public Utilities Code section 12703) A municipal utility district may condemn property "within or without the district necessary to the full or convenient exercise of its powers." (Public Utilities Code section 12771)

Appendix D
GLOSSARY OF TERMS

- **Aggregator.** An entity that puts customers into a buying group for the purchase of a commodity service. Vertically integrated IOUs, municipal utilities, and rural electric cooperatives perform this function in today's power market. Other entities, such as buyer cooperatives or brokers, could perform this function in a restructured power market.
- **Ancillary Services**. Services that CAISO may develop in cooperation with market participants to ensure reliability and to support the transmission of energy from generation sites to customer loads. Such services may include regulation, spinning reserves, non-spinning reserves, replacement reserves, voltage support, and black start.
- **Bilateral Contract**. A two-party agreement for the purchase and sale of energy products or services.
- **Blackout**. A power loss affecting many electricity consumers over a large geographical area for a significant period of time.
- **California Energy Commission or CEC**. The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act of 1974 (Public Resources Code, Section 25000, et seq.) responsible for:
  - Forecasting future statewide energy needs
  - Licensing power plants
  - Promoting energy conservation and efficiency measures
  - Developing renewable and alternative energy resources
- **California Independent System Operator or CAISO**. CAISO is the FERC-regulated control area operator of most of the transmission assets in California. Its responsibilities include providing non-discriminatory access to the grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. CAISO has no affiliation with any market participant.
- **California Public Utilities Commission or CPUC**. A state agency created by constitutional amendment in 1911 to regulate the rates and services of more than 1,500 privately-owned utilities and 20,000 transportation companies. The CPUC is an administrative agency that exercises both legislative and judicial powers; its decisions and orders may be appealed only to the California Supreme Court. The major duties of the CPUC are to:
  - Regulate privately-owned utilities from customer service to construction activities.

- Ensure adequate utility service at rates that are just and reasonable to both customers and shareholders.
- Evaluate infrastructure developments and issue Certificates of Public Convenience and Necessity (CPCN).
- Forecast electric and natural gas resource needs.
- Analyze and plan energy supply and resources.

- **Capacity**. The maximum amount of electricity that a generating unit, power plant, or transmission or distribution line can deliver under specified conditions. Capacity is measured in megawatts.
- **Cogenerator**. Cogenerators use the waste heat created by one process (for example, during manufacturing) to produce steam that is used, in turn, to spin a turbine and generate electricity. Cogenerators may also be Qualifying Facilities (QFs).
- **Competition Transition Charge or CTC**. A "non-bypassable" charge generally placed on distribution services to recover utility costs incurred as a result of restructuring (stranded costs usually associated with generation facilities and services) and not recoverable in other ways.
- **Congestion**. A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules simultaneously.
- **Congestion Management**. Alleviation of congestion by CAISO.
- **Conservation**. Activities that reduce the amount of energy being consumed while accomplishing the same amount of work. This may involve installing new equipment, modifying equipment, or simply changing behavior patterns.
- **Control Area**. An electrical region that regulates its generation in order to balance load and maintain planned interchange schedules with other control areas and assists in controlling the frequency of the interconnected system in accordance with the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) criteria.
- **Demand**. The rate expressed in kilowatts or megawatts at which electric energy is delivered by a system at a given instant or averaged over a designated interval of time.
- **Direct Access**. The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility.
- **Distribution**. The delivery of electricity to the retail customer's home or business through low voltage electric lines.
- **Distributed Generation**. Small capacity electric generators meant to offset a portion of, or all of, the electrical requirements of a single customer or group of customers. Distributed generation can reduce the need for additional or upgraded distribution, transmission, or large scale, centrally located generation facilities.
- **Energy Efficiency**. Using less energy/electricity to perform the same function.

- **Energy**. This is broadly defined as the capability of doing work. In the electric power industry, energy is more narrowly defined as electricity supplied over time, expressed in kilowatt-hours.
- **Energy Service Providers or ESPs.** ESPs are sellers of energy and coordinators (as well as possibly providers) of other essential elements of energy service necessary for customers to use energy. They are made up of power aggregators, generators, utilities, municipalities, power marketers, and brokers, who match buyers and sellers, tailor both physical and financial instruments to suit the needs of particular customers, and aggregate small customer loads to form buying groups or cooperatives that give them additional bargaining power.
- **Federal Energy Regulatory Commission or FERC**. An independent regulatory commission within the U.S. Department of Energy that has authority to:
  - Regulate energy producers that sell or transport fuels for resale in interstate commerce.
  - Set oil and gas pipeline transportation rates and to set the value of oil and gas pipelines for ratemaking purposes.
  - Regulate wholesale electric rates and hydroelectric plant licenses.
- **Grid Management Charge or GMC**. An approved FERC tariff that recovers CAISO's ongoing operating and management costs.
- **Investor-Owned Utility or IOU**. A private company that provides a utility such as water, natural gas, or electricity to a specific service area. The IOU is regulated by the CPUC. In California, the IOUs supplying energy are:
  - Canadian Pacific National Corp.
  - Pacific Gas and Electric Co.
  - Pacific Power and Light Co.
  - San Diego Gas and Electric Co.
  - Sierra Pacific Power Co.
  - Southern California Edison Co.
  - Southern California Gas Co. (The Gas Co.)
  - Southwest Gas Corp.
- **Locational Marginal Price or LMP**. The price at which supply equals demand at a specified location on the transmission system. All demand that is prepared to pay at least this price at the specified location has been satisfied and all supply which is prepared to operate at or below this price in the specified location has been purchased.
- **Municipalization**. The process by which a municipal entity assumes responsibility for supplying utility service to its constituents. In supplying electricity, the municipality may generate and distribute the power or purchase wholesale power from other generators and distribute it.
- **Municipal Utility**. A provider of utility services owned and operated by a municipal government.

- **Obligation to Serve.** The obligation of a utility to provide electric service to any customer who seeks that service and is willing to pay the rates set for that service. Traditionally, utilities have assumed the obligation to serve in return for an exclusive monopoly franchise.
- **Participating Transmission Owner or PTO**. An entity that owns transmission facilities and has turned over the operation control of those facilities to CAISO.
- **Regional Transmission Organization or RTO**. An organization that would coordinate the operation and dispatch of the transmission system over most likely a multi-state jurisdiction. The RTO would ensure open, non-discriminatory access to transmission, organize ancillary service markets, provide market surveillance, and manage congestion.
- **Reliability**. Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities.
- **Renewable Resources.** Renewable energy resources are naturally replenishable resources that can be used for electric generation. Renewable energy resources include biomass, hydroelectric, geothermal, solar, and wind. In the future, they may also include the use of ocean thermal, wave, and tidal action technologies.
- **Tariff**. A document approved by the responsible regulatory agency listing the terms and conditions, including a schedule of prices, under which utility services will be provided.
- **Transmission Access Charge or TAC**. A charge paid by all market participants withdrawing energy from the CAISO-controlled grid. The access charge supports recovery of a utility's transmission revenue requirement.
- **Transmission Owner**. An entity that owns transmission facilities or has firm contractual right to use transmission facilities.
- **Unbundling**. Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission, and distribution could be unbundled and offered as discrete services.
- **Wheeling.** Using a utility's lines to transport power from one neighboring system to another.
- **Western Electricity Coordinating Council or WECC**. A voluntary industry association created to enhance reliability among western utilities.
- **Wholesale Power Market.** The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.