San Francisco Peninsula
Phase 2
Long - Term Electric Transmission Planning Technical Study

Final Report

Cal-ISO Stakeholder Process Joint Study

California Independent System Operator
City & County of San Francisco
Pacific Gas & Electric Company
San Francisco Interested Stakeholders/Public Participants

November 14, 2005

EXECUTIVE SUMMARY

INTRODUCTION

At approximately 08:15:24 on the morning of December 8, 1998, the Pacific Gas and Electric Company (PG&E) experienced a severe disturbance initiated at San Mateo Substation that resulted in a blackout of most of the City of San Francisco and nearby communities on the San Francisco Peninsula. A recommendation from the California Independent System Operator (CAISO) December 8th Disturbance Report was to develop a long-term plan (five and ten-year) to reliably serve the future electric needs of the San Francisco Area. As a result, the San Francisco Stakeholder Study Group (SFSSG) was formed. This stakeholder group includes a variety of entities such as: the City and County of San Francisco (CCSF), the Pacific Gas & Electric Company (PG&E), the California Public Utility Commission (CPUC), the California Energy Commission (CEC), various generation developers, representatives of local San Francisco community groups and others. This group recommended the Jefferson-Martin 230 kV Line Project as the preferred alternative for increasing power imported to San Francisco and improving the state of reliable load serving capability. This project was approved by the CAISO and California Public Utilities Commission (CPUC) and is scheduled for operation in early 2006.

With the requirement to replace old generator units within San Francisco with new and lower emission power resources within and outside of San Francisco, there became a need to identify additional transmission system reinforcements and/or established load management or distributed/renewable generation programs to fulfill the requirement of establishing a long-term (10 year) reliable load-serving plan beyond 2006. The CAISO developed an Action Plan (Revised Action Plan for San Francisco (Attachment 1)) that will allow for the release from Reliability Must-Run Contracts all generator units at the Hunters Point and Potrero Power Plants by early 2006 and 2007 respectively. That Action Plan provides for reliable load serving capability within San Francisco and the Peninsula in the near term; however technical studies show that a major project is needed to reliably serve this area's load beginning 2012.

THE SITUATION

Recognizing the need to establish a longer-term transmission plan once the Action Plan was implemented, the ISO, together with the SFSSG, initiated the Long Term (Phase 2) Study to determine the transmission facilities necessary to reliably serve the load in this area through at least 2018. The results of this stud
5y indicated that once the Revised Action Plan for San Francisco is fully implemented, it would provide sufficient load serving capability for the San Francisco Peninsula Area through 2011; however, beginning 2012 reliability planning standard violations would exist in northern San Mateo County and San Francisco. While the Action Plan does achieve the retirement of old generation in San Francisco, it also contributes to increased flows on the transmission facilities that serve electric load in San Francisco and the Peninsula. The San Francisco Peninsula Area presently receives all of its imported power

from the south from points as far away as Pittsburg, Contra Costa, Tesla, and Metcalf. Once the Action Plan is fully implemented, this same transmission infrastructure must support an additional 378 MW[1] of San Francisco Peninsula Area load as well as anticipated load growth of approximately 15 to 20 MW per year that is expected to occur in this area.

While the increased reliance on this transmission infrastructure was addressed in the Action Plan through various transmission additions, upgrades, and re-rates, the impact on the area's future load serving capability was not assessed beyond 2007 until the Phase 2 study effort was initiated. Due to the long lead times required for building new transmission infrastructure, ISO Staff believes that action to mitigate these limitations must be taken now to assure that the necessary transmission infrastructure is in place by the time the limitations are expected to occur. Not withstanding the identified reliability planning standard violations that are projected to occur in 2012, there are several operational constraints and locational capacity issues that this area will face once the Action Plan is fully implemented and the existing generation at Hunters Point and Potrero is retired. These issues are discussed below.

Operation of the existing San Francisco Peninsula area's electrical system relies on the use of Special Protection Schemes (SPS) that arm over 540 MW of firm load to trip for critical double contingencies to meet the minimum operating reliability criteria required by the Western Electricity Coordinating Council (WECC). While the Jefferson – Martin 230 kV Project would decrease the amount of load shedding required to meet expected WECC operating practices in 2006, a significant reduction in generation in this area after implementation of the ISO Action Plan will offset this and significant load shedding will remain as implemented through an existing SPS and will continue to increase as the load in the area increases.

The California Public Utilities Commission (CPUC) and California Energy Commission (CEC) have taken the leadership role in ensuring resource adequacy for the State. The CPUC's Resource Adequacy requirements are designed to ensure that load serving entities have procured sufficient resources to meet their load and that these resources are deliverable to their load. A key requirement for ensuring the deliverability of Load Serving Entity resource portfolios is to ensure that there are sufficient generation resources in transmission constrained local load pockets such as the San Francisco Bay Area, the Los Angeles Basin, and San Diego to reliably serve customer demand.

At the request of the CPUC, the ISO performed a technical analysis to determine the local generation capacity requirements within the transmission constrained local areas of the grid. These studies show that after the San Francisco Action Plan is implemented, the San Francisco Peninsula Area's Locational Capacity requirements will exceed the amount of

[1] Existing generation at Hunters Point Units 1 and 4 (52 MW and 163 MW, respectively) and Potrero Units 3, 4, 5, and 6 (207 MW, 52 MW, 52 MW, 52 MW, respectively) total 578 MW. The proposed four CCSF Peakers will total 195 MW. The ISO Action Plan will allow for the retirement of all generation at Hunters Point and Potrero and the installation of the CCSF Peakers. As a result, there will be a net increase in transmission import requirements of 383 MW.

generation expected to be available in this area by approximately 100 MW. Because it is likely that no new generation can be sited in San Francisco, the only alternatives available to meet this additional locational capacity requirement is to either install a new SPS to trip about 100 MW of firm load when required or build new transmission into the San Francisco load area to replace the area's generation deficit.

The study results indicated that without transmission system reinforcement, a new major transmission line into San Francisco, new generation facilities in San Francisco, or establishment of substantial new load management and/or distributed/renewable generation, load-serving capability beyond 2011 cannot be maintained while meeting CAISO Grid Planning Standards. The system would be subjected to thermal overloads under various single and multiple facility outages.

DIFFERENT APPROACHES TO A LONG-TERM SOLUTION

The San Francisco Long Term (Phase 2) study was initiated to recommend a long-term solution for maintaining reliable electric load-serving capability within the San Francisco Peninsula. Several options were considered to potentially meet this objective. Power flow studies were conducted by PG&E to assess the technical performance of pursuing one of the following options:

1. Do nothing beyond utilizing the transmission facilities planned to exist by 2007 summer. Rely upon new load management and or distributed/renewable generation programs to maintain reliable load-serving capability beyond 2007.

2. PG&E would continue to replace, reconductor, and/or rerate existing transmission infrastructure and implement operating solutions as needed to mitigate overloads and increase load serving capability for facilities serving the Greater Bay Area.

3. An independent developer (Babcock & Brown) would permit and build a new ±400 kV, 400 MW High Voltage Direct Current (HVDC) submarine DC cable between Pittsburg Substation in the East Bay area and Potrero Substation in San Francisco.

4. PG&E would permit and build a new 230 kV AC line from Moraga Substation in the East Bay area to Potrero Substation in San Francisco. This new line would be a combination of overhead and underground conductors running from Moraga to the San Francisco Bay and then run beneath San Francisco Bay to Potrero. This new line would partially run beneath San Francisco Bay.

5. PG&E would permit and build a new 230 kV AC line from Tesla Substation to Potrero Substation. This option will either utilize or convert existing transmission facilities leading into and through the Peninsula and San Francisco areas from Tesla to Potrero. This option also includes a new line across San Francisco Bay.

RECOMMENDED SOLUTION

Due to the magnitude of load reduction required to take the place of importing more power into San Francisco and the Peninsula, existing load management programs will not be sufficient. Because there is no certainty that new and substantial load management programs will be established, pursuing this as a long-term solution for San Francisco was deemed not sufficiently effective at this time to rely upon. This consensus was also reached when assessing the effectiveness of established distributed/renewable generation programs. As these programs are established, they are incorporated into PG&E's annual revision of projected load. This projected load is modeled in power flow studies when determining if sufficient load serving capability exists. It was agreed that these options are valuable programs in deferring the need for a new transmission or generation project. As additional load management, distributed and renewable generation programs are established; future transmission and generation projects may be able to be deferred.

The SFSSG determined that the preferred long-term reliable load serving capability option for the San Francisco area is Option 3 (a new DC Line between Pittsburg and Potrero Substations and is referred to as the Trans Bay Cable Project (The Project)). The Project is needed for reliability and is being recommended to mitigate violation of reliability planning standards beginning in 2012, but is being recommended for early operation. The Project, as currently structured, is planned to be in-service by 2009. The ISO staff performed technical and economic analyses to assess the reliability benefits and the cost to the ISO ratepayers for advancing the in-service date by three years to 2009. ISO's technical analysis concluded that installation of this project in 2009 would significantly improve reliability of the San Francisco Peninsula electrical system. Existing generation within San Francisco is expected to reduce significantly after implementation of the ISO's Revised Action Plan for San Francisco in late 2007. Although the Action Plan will allow for the termination of Reliability Must-Run contracts for all existing generator units at the Hunters Point and Potrero power Plants, it will also lead to increasing San Francisco Peninsula's Operational Constraints and Locational Capacity Requirements. This Project, with a 2009 in-service date, will significantly reduce expected Locational Capacity Requirements and the need for Special Protection Schemes that are currently in place to shed firm load for critical double contingency disturbances for San Francisco Peninsula. Further, ISO's economic analysis concluded that while the Project does have identified benefits, the present value of the revenue requirements of the benefits and costs over the three-year advancement results in a net cost to the ISO ratepayers of $26 million. This "net cost" is viewed as an assurance cost against intangible benefits such as immediate increased reliability to the San Francisco Peninsula Area, unforeseen load forecast errors and consideration of unknowns such as project siting, schedule, cost risks, and economic benefits. Overall, ISO Management considers this assurance cost acceptable in return for the certainty that the Project will be there when it is needed.

Fulfilling a much broader vision, the Project will also establish a long-term transmission solution for load serving needs within the San Francisco Peninsula Area. Overall, the Project will increase the import capability into the San Francisco Peninsula Area by 400

MW via a route independent and separate of transmission line routes through which San Francisco load is served from the south. Commensurate with increasing import capability, this project will decrease overall transmission system losses. The Project has been in development for over 18 months and due to the long lead-time required to build new transmission, is the only alternative evaluated by the San Francisco Stakeholder Study Group (SFSSG) that builds new transmission infrastructure into the ISO Controlled grid that can be in-service in time to address the identified reliability planning standard violations. The Project was initially presented to the SFSSG in February 2004.

Because the Trans Bay Cable Project is proposing an early in-service date (early 2009), the ISO also undertook an analysis of the cost impact to the ISO ratepayers of advancing the in-service date ahead of the reliability need date by three years (2012 to 2009). Once the preferred long-term solution has been identified, the remaining question is whether the online date of the Trans Bay Cable Project should be planned for 2012 or brought online earlier. The primary criteria for this decision for a reliability project are likely to be based on reduced risk of loss of load and other considerations by bringing the project on-line earlier than needed. However, there is also an economic impact of an earlier on-line date that should be considered.

Capital projects are often compared on the basis of the present value of revenue requirements (PVRR). As shown in Table 1, the PVRR increases $63 million if the Trans Bay Cable Project is brought online in 2009 versus 2012. However, the earlier online date provides some distinct benefits including increased reliability to San Francisco, reduction of project schedule and cost risk, and economic benefits. The economic benefits are estimated to be about $14 million per year. The present value of 3 years of economic benefits is approximately $37 million. Thus, the net cost of bring the project online by 2009 as compared to 2012 is $26 million.

This net cost can be viewed as a 6.2 percent Assurance Cost against intangible benefits such as reductions in SPS requirements, unforeseen load forecast errors, Reliability Must-Run/Locational Capacity requirements, reduced project siting costs, schedule, and cost risks (as well as increased San Francisco reliability for the three years. From ISO Management's perspective, this 6% Assurance Cost is considered a prudent investment given the intangible benefits mentioned above and the certainty that the Project will be there when it is needed. Based on these considerations, ISO staff believes the Trans Cable Project's early in-service date is warranted.

The majority consensus of the stakeholder group is that the proposed DC Line will provide for long-term reliable load serving capability while improving the security of importing more power into the San Francisco Area as opposed to generating power within the area. Please see Attachment 5 for positions of stakeholders.

ISO Management supports the Trans-Bay Cable Project proposal as the preferred alternative, because it not only provides long-term reliable load serving capability to the San Francisco Peninsula Area, it increases the diversity and security of the power supply to this area with implementation risks that are considered lower than the Moraga – Potrero alternative. Further, the project's early availability will reduce this area's operational constraints and expected locational capacity requirements immediately upon becoming operational.

ISO Management requested and obtained ISO board approval of the Trans Bay Cable Project at their Sep 8, 2005 board meeting. The ISO Board approved the Trans Bay Cable Project (the "Project") as the preferred long-term transmission alternative (without regard for routing) to address the identified reliability concerns in Northern San Mateo County and San Francisco beginning in 2012 and supported the early implementation of the project for operation by 2009 provided, however, that this approval shall be subject to change or withdrawal by the ISO so that other projects may be considered as alternative preferred options to address the identified reliability concerns, in the event that all necessary permits and state easements have not been received for construction of the Project by April 2007.

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INTRODUCTION

The San Francisco Stakeholder Study Group (SFSSG) is comprised of various entities such as: the City and County of San Francisco (CCSF), the Pacific Gas & Electric Company (PG&E), the California Public Utility Commission (CPUC), the California Energy Commission (CEC), various generation developers, representatives of local San Francisco community groups and others. This group was tasked with developing a long-term reliable electric power supply plan for the San Francisco Peninsula Area. This plan would build on having PG&E's Jefferson-Martin 230 kV Line Project in operation and successful completion of the CAISO Revised Action Plan for San Francisco (Attachment 1). The action plan was developed to facilitate the release from Reliability Must-Run Contracts all generator units at the Hunters Point and Potrero Power Plants by early 2006 and 2007 respectively. That Action Plan provides for reliable load serving capability within San Francisco and the Peninsula in the near term; however a major project is needed to reliably serve this area's load beginning 2012.

Upon completion of the Action Plan, there will still be operating constraints within the San Francisco area as well as developing Locational Capacity Requirements in addition to the need for a long-term power supply plan. Operation of the existing San Francisco Peninsula area's electrical system relies on the use of Special Protection Schemes (SPS) that arm over 540 MW of firm load to trip for critical double contingencies to meet the minimum operating reliability criteria required by the Western Electricity Coordinating Council (WECC). While the Jefferson – Martin 230 kV Project would decrease the amount of load shedding required to meet expected WECC operating practices in 2006, a significant reduction in generation in this area after implementation of the ISO Action Plan will offset this and significant load shedding will remain as implemented through an existing SPS and will continue to increase as the load in the area increases.

The California Public Utilities Commission (CPUC) and California Energy Commission (CEC) have taken the leadership role in ensuring resource adequacy for the State. The CPUC's Resource Adequacy requirements are designed to ensure that load serving entities have procured sufficient resources to meet their load and that these resources are deliverable to their load. A key requirement for ensuring the deliverability of Load Serving Entity resource portfolios is to ensure that there are sufficient generation resources in transmission constrained local load pockets such as the San Francisco Bay Area, the Los Angeles Basin, and San Diego to reliably serve customer demand.

At the request of the CPUC, the ISO performed a technical analysis to determine the local generation capacity requirements within the transmission constrained local areas of the grid. These studies show that after the San Francisco Action Plan is implemented, the San Francisco Peninsula Area's Locational Capacity requirements will exceed the amount of generation expected to be available in this area by approximately 100 MW. Because it is likely that no new generation can be sited in San Francisco, the only alternatives available to meet this additional locational capacity requirement is to either install a new SPS to trip about 100 MW of firm load when required or build new transmission into the San Francisco load area to replace the area's generation deficit.

OBJECTIVES

Working in a collaborative and pro-active manner, the SFSSG will complete the following objectives:

With the Jefferson-Martin Project in operation and Hunters Point Power Plant retired, develop a long-term load-serving plan for the City & County of San Francisco and San Francisco Peninsula Areas that takes into account the following:

1. Builds on the Revised Action Plan for San Francisco, developed to account for the release from Reliability Must-Run Contracts all generator units at the Hunters Point and Potrero Power Plants by early 2006 and 2007 respectively.

2. Considers varying levels of load growth, new generation development, generation retirement, and electric transmission system reinforcement.

3. Considers San Francisco Greater Bay Area power import capability, ability to transfer power to the San Francisco Peninsula, and diversity of supplying power to the San Francisco Peninsula.

4. That alternatives will meet established CAISO Grid Planning Standards and other applicable NERC/WECC standards.

5. That recommends a preferred transmission system reinforcement considering existing and new established generation resources (including distributed and renewable), and load management programs within the City & County of San Francisco and Peninsula Areas.

STUDY RESPONSIBILITIES

Study responsibilities are outlined within the study plan developed for this SF Phase 2 activity (Attachment 2). Assumptions and reliability criteria were developed utilizing both the Cal-ISO Grid Planning Criteria and the Supplementary Guide for Application of the Criteria for San Francisco. PG&E's Electric Transmission Planning staff conducted the technical analyses. The San Francisco Stakeholder Study Group the technical analysis and related documentation. Stakeholder Group members authored a final report, documenting the technical study findings and recommendations.

RELIABILITY CRITERIA

As with all studies that are performed as part of the CA ISO controlled grid, study results must meet the intent of the CA 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 CA ISO controlled grid.

The CA ISO Grid Planning Standards were developed through a stakeholder process and have been approved by the CA ISO Board of Governors. In general, the CA ISO Grid Planning Standards include:

A. CA ISO Grid Planning Criteria
B. Specific Nuclear Unit Standards
C. Combined Line and Generator Outage Standard
D. New Transmission versus Involuntary Load Interruption Standard
E. San Francisco Greater Bay Area Generation Outage Standard
F. Western Electricity Coordinating Council (WECC) Reliability Criteria
G. North American Electric Reliability Council (NERC) Planning Standards

The CA ISO also considers PG&E's "Supplementary Guide for Application of the Criteria for San Francisco" when analyzing the transmission system between San Mateo and Martin Substations.

A summary of these criteria is included within the Study Plan (Attachment 2).

STUDY ASSUMPTIONS

For the Phase 2 study effort, a base case was developed to represent the San Francisco Greater Bay Area for the 2011 time frame because past history has shown that it could take 7 years lead-time to determine, design, permit, and construct a new 230 kV line into the San Francisco Area. The San Francisco Peninsula Area and GBA loads were adjusted up or down depending on whether or not a system limit has been reached. Due to the complexity of the transmission system within the GBA and that local areas within the GBA are projected to grow at different rates, the GBA area load was not scaled up or down with one scaling factor nor in the small increments possible when scaling loads just within the San Francisco Peninsula.

The 2009 GE-format base case, developed within PG&E's 2004 annual electric assessment and expansion planning, served as the starting point in the development of the 2011 power flow base case. The San Francisco Peninsula Area load corresponds to load within the CCSF and Peninsula areas. CCSF and Peninsula loads are presently 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. Four existing 230 kV lines that can import power to San Mateo Substation are listed below:

?? Pittsburg – San Mateo 230 kV line
?? East Shore – San Mateo 230 kV line
?? Ravenswood – San Mateo #1 & #2 230 kV lines

A new 230 kV line (The Jefferson-Martin 230 kV Transmission Project) was approved by the CAISO and California Public Utilities Commission for operation in early 2006.

Power Flow Base Case Assumptions

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

1. The power flow base case(s) and stability data were developed using General Electric PSLF.

2. Base case representation (system representation, generation, etc.) was coordinated and prepared by PG&E with the support of the Cal-ISO and was reviewed and accepted by the SFSSG.

3. The benchmark base case represented 2011 Heavy Summer conditions. This case was developed from a recently created 2009 PG&E base case. The primary base case included representation of only Northern California.

PG&E's proposed Jefferson-Martin 230 kV Project and related transmission reinforcement required to utilize this line were modeled in the base case. In addition, all transmission projects approved by the CA ISO and scheduled for operation prior to 2011 were also modeled.

Load-Related Assumptions

1. **PG&E Load Level.** As a starting point, PG&E load was represented in the benchmark case at the peak level projected for the 2011 time period. Load adjustments were made to the Area Load to represent .

   The mechanics of how the load modeling was achieved starting with PG&E's 2009 base case as follows:

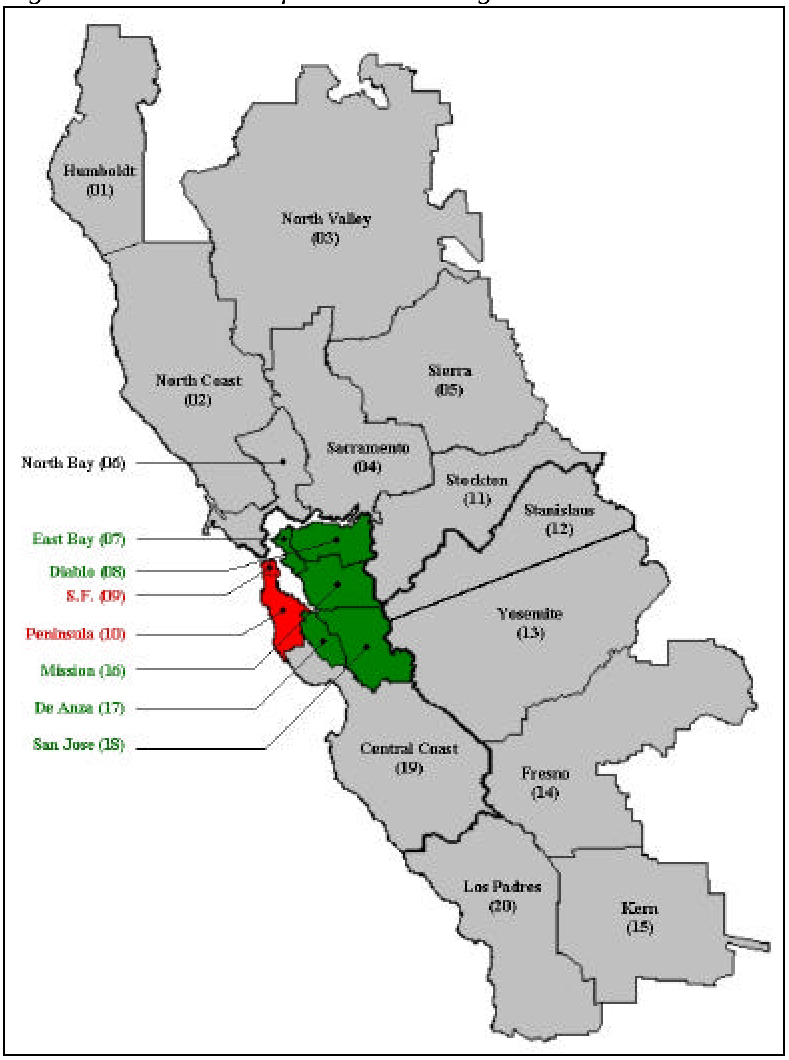
   a. The San Francisco and Peninsula Planning Areas (Figure 4) were modeled to represent their maximum anticipated 2011 coincident peak load, based on a one-in-ten year high temperature forecast.

   b. The remaining planning areas that constitute the "Greater Bay Area" were modeled at their expected 2011 one-in-ten load at the time of the San Francisco- Peninsula coincident peak.

   The primary base caseload within the GBA was scaled up to define the load serving capability in 2011. From that load level, the load was scaled up and down to analyze what reliability problems may occur prior to or later than 2011.

1. **Power Factor.** Reactive load Watt/VAR ratios represented in the base cases reflected reasonable values for the operating conditions being studied.
2. **"Municipality" Loads.** Loads of Non-Participating Transmission Owners within PG&E's service area were modeled based on the most recent forecast available.
3. **Neighboring Area Loads.** Loads located outside the PG&E area (including SCE, SDG&E, LADWP, IID, CFE and other WECC member systems) were modeled based on information provided to WECC.

Figure 1. Illustration of PG&E Planning Areas



Generation-Related Assumptions

1. **Generation Retirements.** This study assumed the existing generation at Hunters Point and Potrero Power Plants to be offline. Further, generating units Contra Costa 6 and Pittsburg 7 were also assumed to be offline.

2. **Reliability Must-Run Generation.** The most recent and appropriate levels of RMR Generation within the Greater Bay Area were incorporated into the study.

3. **Qualifying Facilities.** QF generation located within PG&E's service area was modeled at an output that reflects their historic dependable operating capacity.

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

5. **Distribution-Sited Generation.** All generation directly interconnected to PG&E's distribution systems (i.e. not directly interconnected to the CA ISO Controlled Grid) was netted with the load represented at the nearest CA ISO Grid Take-Out Point.

6. **New Generation.** Consistent with the CA ISO Guidelines for modeling new generation, this Phase 2 study will include the impact of proposed new generation within the CA ISO Controlled Grid Area and Greater Bay Area. Per the CAISO revised Action Plan for San Francisco, four new City & County of San Francisco (CCSF) peakers (48.7 MW each) were assumed to be in service for the study. It is expected that three of these new peakers will be connected to the Potrero substation in San Francisco and fourth will be connected to the San Francisco Airport.

7. **Air Quality.** The impact of Greater Bay Area air quality restrictions as described by reduced future NOX limits on existing generation and related SCR retrofitting will be considered within the study.

Modeling of Transmission Projects

The analysis included modeling transmission projects approved by CAISO and PG&E that are scheduled to be in service by 2011 as well as those projects outlined in the CAISO's Revised Action Plan for San Francisco.

STUDY SCOPE

The scope of the study includes the following:

- ?? Evaluation of the transmission capacity adequacy in serving the San Francisco Peninsula Area for the Years 2008 thru 2018.

The scope of the technical analysis will utilize the power system analysis techniques described below.

1. 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. 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 the seasonal conditions studied. To the extent that unacceptable power flows are seen, transmission system reinforcement, new generation resources, load management or other mitigation measures will be investigated.

2. Voltage Analysis

Voltages levels will be monitored to ensure that they are within the acceptable voltage range per the reliability criteria in Attachment III. To the extent that unacceptable (low) steady-state voltages are seen (pre- or post-contingency), upgrades or other remedial measures will be studied.

3. Economic Analysis

The following attributes of the various long-term options were evaluated to assess their economic impacts on the estimated cost to ratepayers.

1. Transmission system losses.
2. Other transmission system reinforcements directly associated with each long-term option through 2018.
3. Increased economic dispatch of generation.

ISO ECONOMIC ANALYSIS OF THE PREFERRED ALTERNATIVE

The transmission alternatives are designed to satisfy an important San Francisco planning need that is forecasted to start in 2012. The long-term alternatives considered were therefore primarily evaluated from a reliability perspective (i.e. the least-cost alternative that satisfies the reliability need, subject to other considerations such as project risk). The least-cost alternative is determined by considering the projected capital and operating costs, as well as any difference in economic benefits provided by the individual alternatives. Evaluation of the least-cost alternative is the approach used in this economic analysis. ISO staff recognizes that the least-cost analysis is only one of many critical decision criteria that are considered when recommending a transmission project.

ISO staff views the determination of the long-term preferred alternative, and the recommended timing of this preferred alternative, as two separate considerations for supporting the selection of the preferred transmission alternative. ISO staff developed economic data and analyses to assist in assessing these considerations. The economic results are summarized in this section.

Three long-term alternatives were evaluated from an economic perspective. These alternatives include the Trans-Bay Cable Project, the Moraga-Potrero line, and the Tesla-Potrero line.

The economic benefits of the Tesla-Potrero alternative were less than the other two alternatives evaluated. Also, the Tesla-Potrero capital costs were almost 50 percent higher than the other two alternatives. Given this significant cost differential and the other issues associated with this alternative and stated within this memorandum, no further economic evaluation was made for this alternative.

The remaining two long-term alternatives (Trans-Bay Cable and Moraga-Potrero) considered are more closely related in economic benefits and capital costs. Both options can provide up to 400 MW of new capacity to the San Francisco Peninsula from East Bay generation. The Trans-Bay Cable, however, is projected to result in lower system losses than the Moraga-Potrero option, since the DC line itself is expected to have lower losses than an AC alternative. The capital costs of the two alternatives are within 2 percent of each other and based on the accuracy of their estimated cost, are deemed to be equivalent for purposes of this analysis. As a result of the projected lower system losses and other issues identified in this memorandum, the Trans-Bay Cable Project was preferred over the other alternatives.

Because the Trans Bay Cable Project is proposing an early in-service date (early 2009), the ISO also undertook an analysis of the cost impact to the ISO ratepayers of advancing the in-service date ahead of the reliability need date by three years (2012 to 2009). Once the preferred long-term solution has been identified, the remaining question is whether the online date of the Trans Bay Cable Project should be planned for 2012 or brought online earlier. The primary criteria for this decision for a reliability project are likely to be based on reduced risk of loss of load and other considerations by bringing the project on-line earlier than needed. However, there is also an economic impact of an earlier on-line date that should be considered.

Capital projects are often compared on the basis of the present value of revenue requirements (PVRR). As shown in Table 1, the PVRR increases $63 million if the Trans Bay Cable Project is brought online in 2009 versus 2012. However, the earlier online date provides some distinct benefits including increased reliability to San Francisco, reduction of project schedule and cost risk, and economic benefits. The economic benefits are estimated to be about $14 million per year. The present value of 3 years of economic benefits is approximately $37 million. Thus, the net cost of bring the project online by 2009 as compared to 2012 is $26 million.

This net cost can be viewed as a 6.2 percent Assurance Cost against intangible benefits such as reductions in SPS requirements, unforeseen load forecast errors, Reliability Must-Run/Locational Capacity requirements, reduced project siting costs, schedule, and cost risks (as well as increased San Francisco reliability for the three years. From ISO Management's perspective, this 6% Assurance Cost is considered a prudent investment given the intangible benefits mentioned above and the certainty that the Project will be there when it is needed. Based on these considerations, ISO staff believes the Trans Cable Project's early in-service date is warranted.

Table 1
Economic Comparison of a 2009 or 2012 Trans Bay Cable Online Date

PV of revenue requirements	$483	$420	$63
PV of 2009-2011 economic benefits	$37	$0	$37
NPV of revenue requirements	$446	$420	$26
Revenue requirement risk premium			**6.2%**

SAN FRANCISCO PENINSULA AREA LOAD

This study primary focus was on reliably serving load within the San Francisco load area upon successful completion of the CAISO's Revised Action Plan for San Francisco (Attachment 1). This load area consists of electric load in the City of San Francisco and the northern portion of San Mateo County (the Peninsula). San Francisco area load varies based on the seasons and temperature. Historically, the San Francisco peak load for the year usually occurs in late summer during September or October.

SAN FRANCISCO PENINSULA CORRIDOR TRANSMISSION NETWORK

San Francisco and Northern Peninsula loads are supplied through a single transmission corridor along the Peninsula past the San Francisco International Airport and from local generation located within San Francisco. San Mateo Substation has been the primary source for energy flowing towards San Francisco and the Peninsula. Starting in early 2006, about 350 MW will also be able to be imported through the Peninsula via a new

230 kV line between Jefferson and Martin Substations. San Mateo Substation is located near the San Francisco Bay and the western terminus of the San Mateo Bridge, and has transmission lines entering and exiting at the 60 kV, 115 kV, and 230 kV voltage levels. Four existing 230 kV lines that import power to San Mateo Substation 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 Substation is located west of the western terminus of the Dumbarton Bridge with power supplied via Monta Vista over two 230 kV lines and then via Metcalf Substation over four 230 kV lines.

A geographical diagram with the primary transmission lines for serving load in the San Francisco Area is provided in Figure 1. Figure 2 is a diagram of Greater Bay Area transmission most directly associated with serving load within the San Francisco Peninsula and as related to the CAISO Revised Action Plan for San Francisco. Figure 3 is a single-line diagram of the transmission system within San Francisco.

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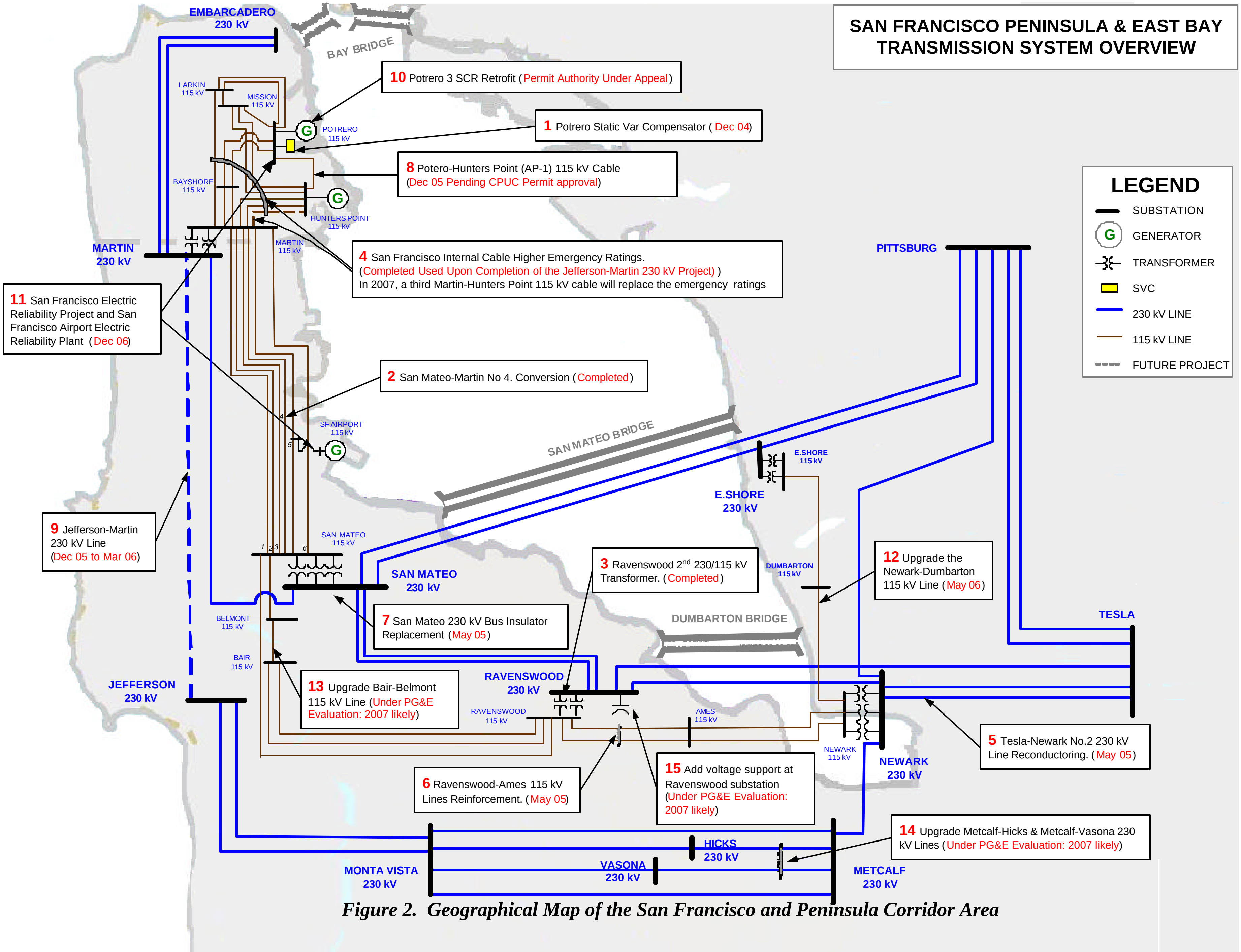
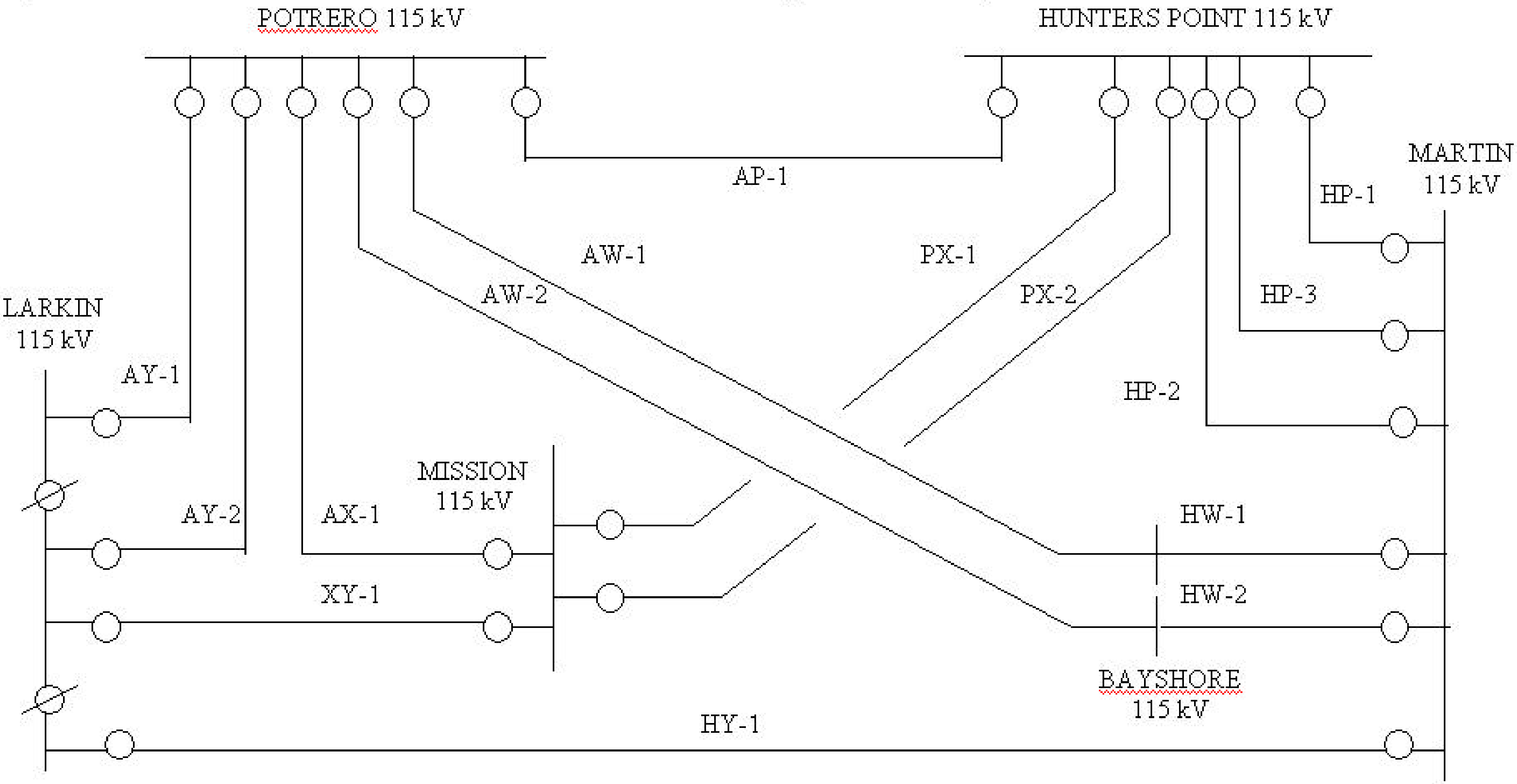


Figure 2. Geographical Map of the San Francisco and Peninsula Corridor Area

Figure 3
San Francisco 115 kV Underground Cable System



As illustrated in Figure 3 above, the transmission system in San Francisco is primarily an underground cable system energized at 115 kV. The system presently consists of thirteen 115 kV and two 230 kV cables. Rating of the 115 kV cables ranges from 130 to 160 MVA. In addition, there are two 230 kV cables between Martin and Embarcadero Substations. Embarcadero is not directly connected to the 115 kV system and is used to primarily serve load in the downtown high-rise buildings. The two 230 kV cables are rated at approximately 420 MVA each. The 115 kV cables are of gas filled pipe type and the 230 kV cables are of oil filled pipe type.

CONSIDERED TRANSMISSION ALTERNATIVES

Building upon the CAISO Revised Action Plan for San Francisco (Attachment 1), the study results indicate that without transmission system reinforcement, a new major transmission line into San Francisco, new generation facilities in San Francisco, or establishment of substantial new load management and/or distributed/renewable generation, load-serving capability beyond 2011 cannot be maintained while meeting CAISO Grid Planning Standards. The system would be subjected to thermal overloads under various single and multiple facility outages.

Power flow studies were conducted by PG&E to assess the technical performance of pursuing one of the following alternative options. The next several pages provide more detailed descriptions of these alternatives.

<u>Option 1</u> – Do nothing beyond utilizing the transmission facilities planned to exist by 2007 summer.

<u>Option 2</u> – PG&E would continue to more fully utilize the transmission system as it is planned to exist by 2007 summer through continued addition of voltage support and reconductoring of transmission lines.

<u>Option 3</u> – An independent developer (Babcock & Brown) would permit and build a new 400 MW High Voltage Direct Current (HVDC) submarine cable between Pittsburg Substation in the East Bay area and Potrero Substation in San Francisco.

<u>Option 4</u> – PG&E would permit and build a new 230 kV AC line from Moraga Substation in the East Bay area to Potrero Substation in San Francisco. This new line would partially run beneath San Francisco Bay.

Option 5 – PG&E would permit and build a new 230 kV AC line from Tesla Substation in the East Bay area to Potrero Substation in San Francisco. This new line would include a new line across San Francisco Bay.

Long-tem power supply options were compared using the following attributes.

Long-Term Reliable Load Serving Capability – Does the option allow the ISO to reliably serve load for at least 10 years without building another major new line into the San Francisco Area?
Capital Cost – How much would this option cost and is there a risk of significant cost escalation?
Economic Benefits - Does this option decrease or increase power losses and does it promote more economic generation dispatch?
Import Security – Will the option improve the overall security of power imports into the San Francisco Area?
Ability to permit and construct – Are there significant uncertainties associated with the ability to permit and construct the project when needed?

The following options were considered in arriving at a preferred long-term power supply solution.

<u>Option 1</u> – **Do nothing beyond utilizing the transmission facilities planned to exist by 2007 summer.**

This option does not meet the objective of establishing long-term reliable load serving capability. It is not expected that this option will provide reliable load serving capability in a timely manner and, in fact, will most likely result inability to serve all load during daily peak load periods. It relies upon significant new load management and or distributed/renewable generation programs to maintain reliable load-serving capability beyond 2007. There is no certainty that sufficient programs will be established when needed. Although the cost of this option is not known, existing programs, while having greater environmental benefits, have been more costly than building bulk transmission system improvements.

<u>Option 2</u> – **PG&E will utilize existing transmission infrastructure to support existing and anticipated load growth in the area. When needed, PG&E will employ replacing, reconductoring, re-rating and operating alternatives to mitigate transmission system overloads and low voltages.**

This option does not meet the objective of establishing long-term reliable load serving capability. It provides enough load-serving capability to serve the San Francisco Peninsula load only up to 2018, beyond which a major new transmission project will be needed in this area. Permitting and building this new transmission in 2018 will be extremely difficult, if not impossible. All other new transmission alternatives improve this area's load serving capability for a longer duration. This alternative does not improve diversity in supply of power serving the San Francisco load. It relies on increasing the import of power into the San Francisco Peninsula by upgrading existing transmission facilities. San Francisco Peninsula area's Locational Capacity Requirements and its reliance on Special Protection Schemes are expected to increase after full implementation of ISO Action Plan takes place by the end of 2007. This alternative will not reduce this area's operational constraints and will not offset this area's growing locational capacity requirements until 2017, when PG&E's proposed new San Francisco Internal Capacity Project goes in service. To implement this alternative, few key existing transmission facilities need to be removed from service for construction. This coupled with significant reduction in the amount of generation in San Francisco per the ISO Action Plan, can potentially deteriorate the reliability of this area. It is expected that pre-contingency dropping of load in the San Francisco Peninsula area would be necessary to take the clearances that are necessary to perform the construction and that would be a violation of the ISO Planning Standards. The potential capital cost of this alternative through 2018 is estimated at $114 million.

<u>Option 3</u> – **An independent developer (Babcock & Brown) would permit and build a new 400 MW High Voltage Direct Current (HVDC) submarine cable between Pittsburg Substation in the East Bay area and Potrero Substation in San Francisco for operation by 2009.**

This option fully meets the objective of establishing long-term reliable load serving capability by adding 400 MW of load serving capability upon its initial operation. This option will increase the diversity of transmission routes to San Francisco through installation of controllable transmission capacity from PG&E's Pittsburg Substation in the East Bay to Potrero Substation in San Francisco. It will unload the existing transmission system that serves load in San Francisco and therefore greatly improve the ability to allow transmission facility clearances that are a part of normal day-to-day system operation. This alternative provides for significant savings by reducing power losses within the parallel AC transmission system, deferral of new 115 kV cables within San Francisco as well as facilitates a more economic generation dispatch pattern within the Greater Bay Area. This project is estimated to cost $300 million including Interconnection costs of up to $15 million. In addition, there are economic savings associated with the Trans-Bay Cable resulting from transmission system loss savings (capacity and energy) and improved economic dispatch of generation. The ability to permit and build this project in a timely manner requires about half the lead-time (three years) as either the Moraga to Potrero or Tesla to Potrero 230 kV Projects. In addition, development of an Environmental Impact Report is well underway as is filing with the Federal Energy Regulatory Agency for rate recovery.

<u>Option 4</u> – PG&E would permit and build a new 230 kV AC line from Moraga Substation in the East Bay area to Potrero Substation in San Francisco. This new line would partially run beneath San Francisco Bay.

While this option will provide long-term reliable load serving capability, the ability to successfully permit and construct this project by 2012 is very uncertain. As such, this alternative is not preferred due to its high implementation uncertainty, risks, and costs associated with successful routing and timely permitting. The potential capital cost of this alternative is estimated at $274 million but could be much higher due to its implementation uncertainties as related to the ability to obtain and permit a route through the congested Oakland area.

<u>Option 5</u> – PG&E would permit and build a new 230 kV AC line from Tesla Substation in the East Bay area to Potrero Substation in San Francisco. This new line would include a new line across San Francisco Bay.

Similar to the Moraga-Potrero alternative, the ability to permit and construct the Tesla-Potrero alternative is highly uncertain. This alternative parallels existing transmission infrastructure through the San Francisco peninsula corridor that already accommodates numerous 115 kV and 230 kV lines, including the Jefferson – Martin 230 kV Transmission Project. This alternative does not provide the diversity and increased security of power supply that is attainable with the Trans-Bay Cable project. Siting another transmission project through this area would be extremely difficult considering the recent siting of the Jefferson – Martin line in this same area. This alternative will also require the construction of a new transmission facility across and above the San Francisco Bay as well as through the eastern boundary of the Bay Area. This alternative is not preferred due to its high implementation uncertainty and risks associated with new construction through the San Francisco peninsula corridor and across the San Francisco Bay. In addition, the potential capital cost of this alternative is estimated at $457 million, which is significantly more than the Trans-Bay Cable Project or Moraga to Potrero 230 kV Project. Due to the significant increase in capital cost of this alternative over the other alternatives considered, an economic assessment was not performed.

POWER FLOW ANALYSIS OF THE CONSIDERED ALTERNATIVES

Study Methodology & Assumptions

The following methodology and assumptions were utilized for all Options during the power flow study. The power flow study assumed that the existing generating units in Potrero and Hunters Point power plants are retired and the proposed four City and County of San Francisco (CCSF) combustion turbine generating units are operational. The study range was from year 2011 to year 2018. The power flow analysis was performed on three base cases representing Years 2011, 2016 and 2018 Heavy Summer conditions.

The San Francisco Greater Bay Area Generation Outage Standard was applied for this study. For analysis of the transmission lines in the San Francisco Peninsula Corridor, the Supplementary Guide for Application of the Criteria for San Francisco was also applied. For analysis of the transmission system within San Francisco, the CAISO Grid Planning Criteria Category B was used.

Each CCSF generating unit has an assumed net output of 48.7 MW. The starting 2011 power flow base case has a San Francisco and Peninsula load of 983 MW and 1059 MW respectively.

In developing the future year base cases up to 2018, the San Francisco load was increased at 10 MW per year. Greater Bay Area division loads were increased proportionately representative of their projected yearly load growth.

The starting 2011 base case also assumed that the transmission projects identified by the CAISO to facilitate the retirement of Hunters Point Power Plant are operational. The starting base case also includes projects identified in the CAISO's Revised Action Plan related to the release of the Potrero Power Plant from RMR. These projects are the:

Metcalf-Hicks and Metcalf-Vasona 230 kV Reconductoring,
Bair-Belmont 115 kV Line Reconductoring,
Dumbarton-Newark 115 kV Line Reconductoring, and
Ravenswood Switched Capacitors.

Option 1 – Status Quo

This option does not meet the study objectives. It was concluded that the San Francisco Peninsula transmission system would experience reliability criteria violations beginning 2012, if this option is pursued.

Option 2 - Reconductoring

The power flow analysis for this option assumed that instead of building a new line into San Francisco, reconductoring, rerates and operating solutions will be utilized to eliminate overloads and increase the load serving capability for the San Francisco Peninsula Area. For this reason, this alternative is referred to as the "Reconductoring Alternative".

Key Findings:

In summary, the following are some of the key findings reached in this thermal analysis study:

This alternative would require 8 projects to increase the Greater Bay Area transmission load serving capability through 2018. These projects exclude the 4 projects identified in the CAISO Revised Action Plan, which are assumed to be operational prior to 2011.
The San Francisco Internal System would reach its load serving capability limit in 2012. Installation of series reactors could extend its load serving capability through 2016. To serve the load beyond 2016, an additional capacity upgrade project would be required. No overloads were identified through 2018 (the last study year) to the transmission lines along the San Francisco Peninsula Corridor.

Year 2011 Analysis:
Table 1 below summarizes the power flow results for 2011 assuming that the four CCSF combustion turbines are operational and no new transmission line is built into San Francisco. For the Greater Bay Area transmission facilities, a 3% overload was identified in the Lambie-USWind-Contra Costa 230 kV line due to the Vaca Dixon-Peabody 230 kV line outage with Contra Costa Unit 7 out. Rerating this line would eliminate the overload and makes Peabody-HiWind-Contra Costa 230 kV the next highest loaded line at 98 % loading. Power flow studies of a line outage and DEC out (instead of Contra Costa Unit 7) resulted in Newark-Ravenswood 230 kV line as the highest loaded line at 99 % loading[2]. Reconductoring the Newark-Ravenswood 230 kV line (this line is already rerated) would make Lambie-USWind-Contra Costa 230 kV line the next highest loaded line at 94 % loading and provide the Greater Bay Area additional capacity to support load growth beyond 2012.

For the San Francisco Internal System, the power flow studies show that the highest loaded facility is the Martin-Bayshore 115 kV #2 line at 99 % loading. Installing series reactors to the Martin-Bayshore 115 kV lines would reduce the loading to these lines and give the San Francisco Internal System additional capability to serve additional load beyond 2012.

No overloads were identified along the San Francisco Peninsula Corridor.

Table 1 – 2011 Results: Reconductoring Alternative with CCSF Generation Operational

Year: 2011 SF Load: 983 MW Peninsula Load: 1059 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Lambie–USWind-Contra Costa 230 kV *with Contra Costa Unit 7 as G-1.*	103 %	1

[2] High Wind output in base case is 162 MW.

	Peabody-HiWind-Contra Costa 230 kV *after Lambie-USWind-Contra Costa 230 kV rerate; Contra Costa Unit 7 as G-1.*	98 %	1
	Newark-Ravenswood 230 kV *with DEC as G-1.*	99 %	2
	Lambie-USWind-Contra Costa 230 kV *with Newark-Ravenswood 230 kV reconductored; DEC as G-1.*	94 %	2
SF Internal System[3]	Martin-Bayshore-Potrero 115 kV #2	99 %	3
	Martin-Hunters Point 115 kV #1 *with series reactors installed in the Martin-Bayshore-Potrero 115 kV lines.*	91 %	3
SF Peninsula Corridor	None Loaded Above 90 %.	< 90 %	4

Year 2016 Analysis:

Table 2 below summarizes the power flow results for 2016. These results assumed that potential capacity upgrade projects discussed in the 2011 study are operational. These projects include the rerate of Lambie-USWind-Contra Costa 230 kV and the reconductoring of Newark-Ravenswood 230 kV. For the Greater Bay Area facilities, a 4 % overload to the Peabody-HiWind-Contra Costa 230 kV line was identified due to the Lambie-USWind-Contra Costa 230 kV line outage with Contra Costa Unit 7 out (L-1/G-1). A 3 % overload[4] was also identified in the Lambie-USWind-Contra Costa 230 kV line with just Contra Costa Unit 7 out (G-1 only). These overloads can be eliminated by rerating the Peabody-HiWind-Contra Costa 230 kV line to 4 fps and reconductoring the Lambie-USWind-Contra Costa 230 kV line. Completion of these projects would make Vaca Dixon-Peabody 230 kV the new highest loaded facility at 96 % loading. Power flow studies of a line outage and DEC out (as the G-1) instead of Contra Costa Unit 7 resulted to Monta Vista-SLAC Tap #2 230 kV to be the highest loaded facility at 98 % loading.

For the San Francisco Internal System, the highest loaded facility is the Hunters Point-Martin 115 kV #1 at 100 % loading. This assumed that series reactors are installed in the Martin-Bayshore 115 kV lines as discussed in the 2011 study. For the San Francisco Internal System to serve additional load beyond 2016, an additional capacity upgrade project would be required. Additional studies would be needed to determine the best capacity upgrade for the San Francisco Internal System for this scenario. This project could be a new circuit in San Francisco or, depending on the development of the underground cable technology such as the super conducting cables, replacing existing underground cables. Sensitivity studies show that a new Martin-Potrero 115 kV circuit would provide additional load serving capacity to the San Francisco Internal System. Installation of this new circuit would make the Larkin-Martin 115 kV circuit the highest loaded facility at 95 % loading.

No overloads were identified along the San Francisco Peninsula Corridor.

Table 2 – 2016 Results: Reconductoring Alternative with CCSF Generation Operational

Year: 2016

[3] These results do not assume interim long-term emergency ratings for the San Francisco 115 kV cables.
[4] This overload was based on the normal rating of the line during a G-1.

SF Load: 1033 MW Peninsula Load: 1122 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Peabody-HiWind-Contra Costa 230 kV *with Lambie-USWind-Contra Costa 230 kV line rerated; Contra Costa Unit 7 as G-1.*	104 %	5
	Lambie-USWind-Contra Costa 230 kV *with G-1 only; Contra Costa Unit 7 as G-1.*	103 % [5]	5
	Vaca Dixon-Peabody 230 kV *with Peabody-HiWind-Contra Costa 230 kV lines rerated and Lambie-USWind-Contra Costa 230 kV reconductored; Contra Costa Unit 7 as G-1.*	96 %	6
	Monta Vista-SLAC Tap #2 230 kV *with Peabody-HiWind-Contra Costa 230 kV lines rerated and Lambie-USWind-Contra Costa 230 kV reconductored; DEC as G-1*	98 %	7
SF Internal System	Hunters Point-Martin 115 kV #1 *with series reactors installed in the Martin-Bayshore-Potrero 115 kV lines.*	100 %	8
	Larkin-Martin 115 kV *with new Martin-Potrero 115 kV line.*	95 %	9
SF Peninsula Corridor	None Loaded Above 90 %	< 90 %	10

<u>Year 2018 Analysis</u>:

Table 3 below summarizes the power flow results for 2018. The study assumed that the potential capability upgrade projects identified in the 2016 study are operational. These projects include the rerating of the Peabody-HiWind-Contra Costa 230 kV line and reconductoring the Lambie-USWind-Contra Costa 230 kV line. For the Greater Bay Area facilities, the Vaca Dixon-Peabody 230 kV is the highest loaded facility at 98 % loading due to Lambie-USWind-Contra Costa 230 kV line outage with Contra Costa Unit 7 out. For L-1/G-1 outages with DEC as G-1, Monta Vista-SLAC Tap #2 is the highest loaded line at 100 % loading. A capability upgrade project would be needed for the Greater Bay Area facilities to serve loads beyond 2018. This project could potentially be the reconductoring of the Monta-Vista SLAC Taps # 1 and #2 in 2019 (beyond the scope of this study).

For the San Francisco Internal System, the Larkin-Martin 115 kV has the highest loading at 97 % loading. The study assumed that a new 115 kV circuit between Martin and Potrero is operational. Without this new circuit, the Martin-Bayshore-Potrero 115 kV #2 circuit would have overloaded at 120 % loading. As mentioned previously, additional studies would be needed to determine the best capability upgrade work for the San Francisco Internal System.

No overloads were identified along the San Francisco Peninsula Corridor.

Table 3 – 2018 Results: Reconductoring Alternative with CCSF Generation Operational

Year: 2018 SF Load: 1053 MW Peninsula Load: 1133 MW			
Study Area	Highest Loaded Facilities	Loading	Case #

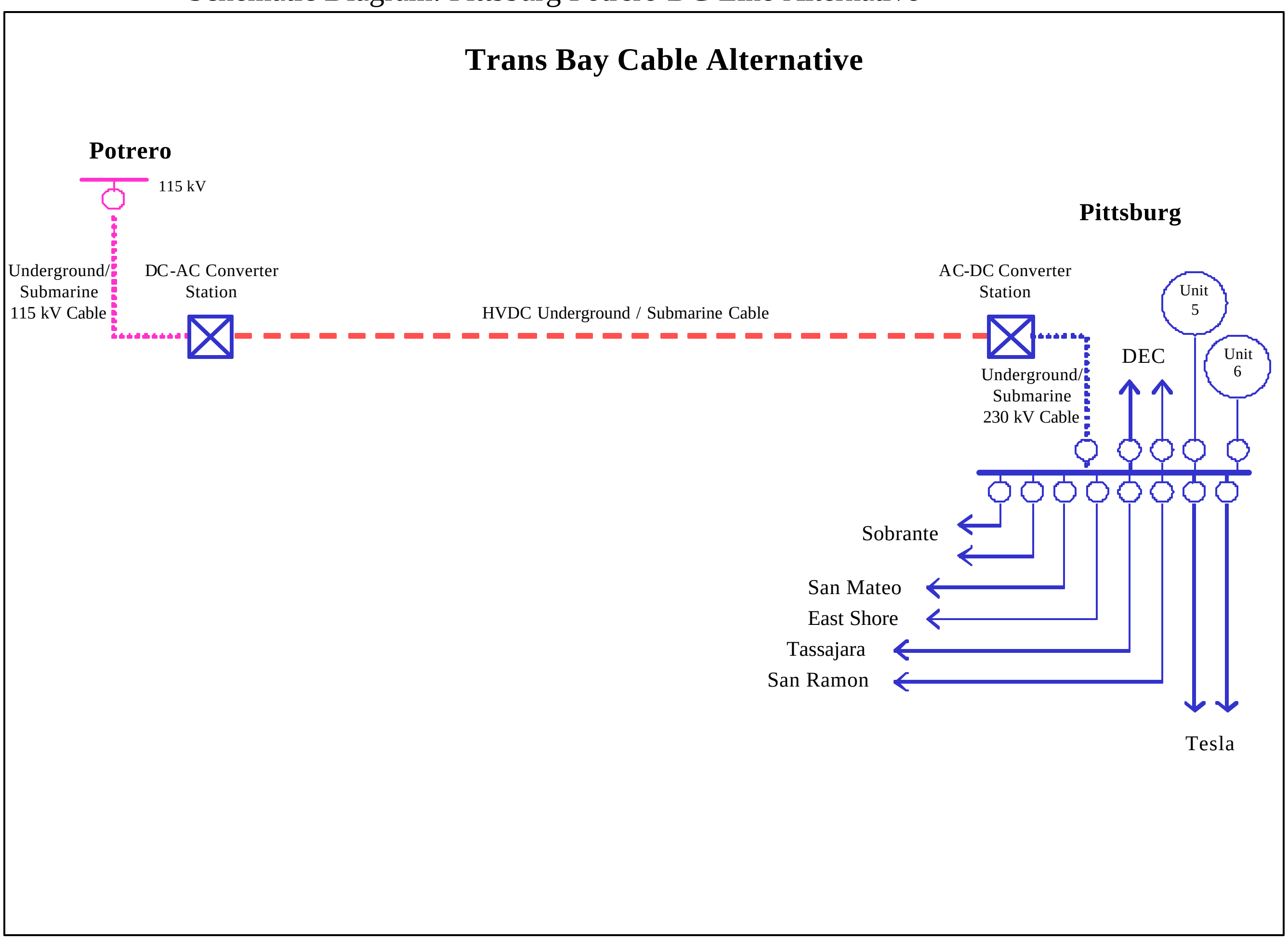
[5] This overload was based on the normal rating of the line during a G-1.

Greater Bay Area	Vaca Dixon-Peabody 230 kV *with Lambie-USWind-Contra Costa 230 kV reconductored and Peabody-HiWind-Contra Costa 230 kV rerated; Contra Costa Unit 7 as G-1.*	98 %	11
	Monta Vista-SLAC Tap #2 230 kV *with Lambie-USWind-Contra Costa 230 kV reconductored and Peabody-HiWind-Contra Costa 230 kV rerated; DEC as G-1.*	100 %	12
SF Internal System	Larkin-Martin 115 kV *with installation of a new Martin-Potrero 115 kV line.*	97 %	14
	Martin-Bayshore-Potrero 115 kV #2 *for comparison: without proposed Martin-Potrero 115 kV line.*	120 %	13
SF Peninsula Corridor	Jefferson-Martin 230 kV	92 %	15

Option 3 – Trans Bay Cable Project

The power flow analysis for this option assumed that the new Pittsburg-Potrero 400 kV DC Transbay Cable Alternative is installed by 2011. The Pittsburg-Potrero DC line Alternative consists of installing a new 50-mile long transbay DC circuit from Pittsburg Switchyard to Potrero Switchyard.

Schematic Diagram: Pittsburg-Potrero DC Line Alternative



Key Findings:

In summary, the following are some of the key findings reached in this thermal analysis study:

?? In addition to installing the proposed Pittsburg-Potrero DC Alternative, this alternative requires six projects to increase the Greater Bay Area transmission load serving capability through 2018 (see Appendix 1, Items 5 to 8). These projects exclude the four projects identified in the CAISO Revised Action Plan, which are assumed to be installed prior to 2011.

?? The ISO Grid Planning Category B overlapping contingency of a line out (L-1) and Contra Costa Unit 7 out (G-1) has a greater limiting impact on the Greater Bay Area load serving capability than a line out and Delta Energy Center (DEC) out.

?? For the San Francisco Internal System, thermal loadings are higher during a line outage by itself (L-1) than a line outage with one of the CCSF units out (L-1/G-1).

?? The San Francisco Internal System would reach its load serving capability limit in 2011. Implementation of a DC runback scheme for the Transbay cable would be needed to mitigate thermal loadings and extend the Internal System's load serving capability beyond 2018. If a DC runback scheme were not a solution, then a potential project would be to install series reactors in the Potrero-Mission cable.

?? No overloads were identified along the San Francisco Peninsula Corridor.

Base Case Assumptions:

The study assumed that the Pittsburg-Potrero DC Line Alternative is operational by 2011. This Alternative consists of installing about 50 miles of new DC line from Pittsburg to Potrero PP Switchyard. See Attachment 1 for a schematic of this Alternative.
In addition to the generating units assumed retired in the CAISO Scenario 2[6], this study assumes the following generation scenario in San Francisco:

?? The proposed four CCSF combustion turbine-generating units in operation with three units in Potrero and one unit near the San Francisco International Airport.

?? Potrero Power Plant retired.

?? Hunters Point Power Plant retired.

Each CCSF generating unit has an assumed net output of 48.7 MW. The starting 2011 power flow base case has a San Francisco and Peninsula load of 983 MW and 1059 MW respectively.

[6] In CAISO Generation Scenario 2, the retirement of Potrero Unit 3, Pittsburg Unit 7 and Contra Costa Unit 6 are assumed. This generation scenario was presented in the July 22, 2004 stakeholders meeting.

The starting 2011 base case also assumed that the transmission projects identified by the CAISO to facilitate the retirement of Hunters Point Power Plant are operational. The starting base case also includes projects identified in the CAISO's Revised Action Plan related to the release of the Potrero Power Plant from RMR. These projects are the:

- Metcalf-Hicks and Metcalf-Vasona 230 kV Reconductoring,
- Bair-Belmont 115 kV Line Reconductoring,
- Dumbarton-Newark 115 kV Line Reconductoring, and
- Ravenswood Switched Capacitors.

In developing the future year base cases up to 2018, the San Francisco load was increased at 10 MW per year. Greater Bay Area division loads were increased proportionately representative of their projected yearly load growth.

Study Results Summary:

Year 2011 Analysis:

Table 1, below, list the power flow results for 2011 assuming the Pittsburg-Potrero DC line Alternative is installed and that the proposed four CCSF combustion turbines are operational. For the Greater Bay Area transmission facilities, the highest loading was on the Lambie-USWP-Contra Costa 230 kV line at 102% loading due to a Vaca Dixon-Peabody 230 kV line outage with Contra Costa Unit 7 out. For the Greater Bay Area facilities to carry additional load much beyond the forecasted 2011 loads, a line capability increase project would be needed to eliminate thermal loading constraint. One potential solution could be a rerate of the Lambie-USWP-Contra Costa 230 kV line to 4 fps wind speed assumption. With this line rerated, the highest loaded facility would be the Peabody-HiWind-Contra Costa 230 kV line at 98% loading. Power flow studies with a line outage (L-1) and DEC out (G-1) (instead of Contra Costa Unit 7) showed the highest loaded facility to be the Contra Costa-Moraga 230 kV #1 line with a loading of 94%.

One thermal overload was identified in the San Francisco Internal System, which relates to outlet capability constraint with DC line power import to San Francisco. Power flow studies showed the highest loaded facility in the SF internal system to be the Potrero-Mission 115 kV cable. This cable will experience 112% overload during an outage of the Potrero-Larkin #2 cable (L-1). The loading on this cable will be 108% if CCSF unit 1 is out (G-1) during an outage of the Potrero-Larkin #2 cable (L-1). One potential solution to alleviate this overload could be a DC runback solution which will require the transbay cable loading to be reduced to 260 MW using a Special Protection Scheme (SPS) during Potrero-Larkin #2 cable outage. If DC runback were not a solution, then a potential project to mitigate the thermal overloads would be to install series reactors in the Potrero-Mission 115 kV cable.

No thermal overloads were identified along the San Francisco Peninsula Corridor.

Table 1 – 2011 Results: Pittsburg-Potrero DC Line with CCSF Generating Units Operational

Year: 2011 SF Load: 983 MW Peninsula Load: 1059 MW

Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Lambie-USWP-Contra Costa 230 kV *with Contra Costa Unit 7 as G-1.*	102%	1
	Peabody-HiWind-Contra Costa 230 kV *after rerate of Lambie-USWP-Contra Costa 230 kV line; with Contra Costa Unit 7 as G-1.*	98%	1
	Contra Costa-Moraga 230 kV #1 *with DEC as G-1.*	94%	2
SF Internal System[7]	Potrero-Mission 115 kV *with all CCSF units online; DC line runback required*	112%	3
SF Internal System	Potrero-Mission 115 kV *Sensitivity - with one CCSF unit taken offline; DC line runback required*	108%	4
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	5

<u>Year 2016 Analysis:</u>

Table 2 below summarizes the power flow results for 2016. This study assumes that the proposed 4 fps rerate for Lambie-USWP-Contra Costa 230 kV line was implemented during 2011. For the Greater Bay Area transmission facilities, the Peabody-HiWind-Contra Costa 230 kV line was identified to have the highest loading at 104% due to a Lambie-USWP-Contra Costa 230 kV line outage (L-1) with Contra Costa Unit 7 out (G-1). The power flow study also identified a loading of 103%[8] on the Lambie-USWP-Contra Costa 230 kV line during Contra Costa Unit 7 outage (G-1). For the Greater Bay Area facilities to carry additional load beyond forecasted loads for 2016, additional capacity upgrade projects would be needed. Potential capacity upgrade projects could be the reconductoring of the Lambie-USWP-Contra Costa 230 kV line using 954 ACSS conductor and re-rate of the Peabody-Contra Costa 230 kV line to 4 fps wind speed assumption during 2014. Assuming these two potential projects are implemented, the highest loaded Greater Bay Area facility would be the Vaca Dixon-Peabody 230 kV line at 95% loading. Power flow studies with a line outage (L-1) and DEC out (G-1) (instead of Contra Costa Unit 7) showed the highest loaded facility to be Tesla-Pittsburg 230 kV #2 circuit. This line will experience 102% emergency overload during an outage of Tesla-Pittsburg 230 kV #1 circuit. Similarly, the Tesla-Pittsburg #1 line loads to 101% due to outage of the Tesla-Pittsburg #2 circuit. One potential solution to alleviate these overloads could be a DC runback option which will require the transbay cable loading to be reduced to 375 MW using a Special Protection Scheme (SPS) during Tesla-Pittsburg #2 or Tesla-Pittsburg #1 line outage. If DC runback were not a solution, then a potential project to mitigate these thermal overloads would be to reconductor the Tesla-Pittsburg Lines #1 and #2.

One thermal overload was identified in the San Francisco Internal System, which relates to outlet capability constraint with DC line power import to San Francisco. Power flow studies showed the highest loaded facility in the SF internal system to be the Potrero-Mission 115 kV cable. This cable will experience 116% overload during an outage of the Potrero-Larkin #2 cable (L-1). The loading on this cable will be 112% if CCSF unit 1 is out (G-1) during an outage of the Potrero-Larkin #2 cable (L-1). One potential solution to alleviate this overload could be a DC runback

[7] These results do not assume interim long-term emergency ratings for the San Francisco 115 kV cables.
[8] This overload was based on the normal rating of the line during a G-1.

solution which will require the transbay cable loading to be reduced to 210 MW using a Special Protection Scheme (SPS) during Potrero-Larkin #2 cable outage. If DC runback were not a solution, then a potential project to mitigate the overloading would be to install series reactors in the Potrero-Mission 115 kV cable.

No thermal overloads were identified along the San Francisco Peninsula Corridor.

Table 2 – 2016 Results: Pittsburg-Potrero DC Line with CCSF Generating Units Operational

Year: 2016 SF Load: 1033 MW Peninsula Load: 1122 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Peabody-HiWind-Contra Costa 230 kV *after rerate of Lambie-USWP-Contra Costa 230 kV line; with Contra Costa Unit 7 as G-1.*	104%	6
	Lambie-USWP-Contra Costa 230 kV *Sensitivity – with Contra Costa Unit 7 as G-1.*	103% [9]	6
	Vaca Dixon-Peabody 230 kV *Contra Costa Unit 7 as G-1.* *After Lambie-USWind-Contra Costa 230 kV line reconductoring and Peabody-HiWind-Contra Costa 230 kV line rerate;*	95%	7
	Tesla-Pittsburg 230 kV #2 line *Sensitivity – with DEC as G-1.* *DC line runback required*	102%	8
	Contra Costa-Moraga 230 kV lines *Sensitivity – with DEC as G-1.* *After Lambie-USWP-Contra Costa 230 kV line reconductoring, Peabody-HiWind-Contra Costa 230 kV line rerate;*	100%	8
SF Internal System	Potrero-Mission 115 kV *with all CCSF units online;* *DC line runback required*	116%	9
	Potrero-Mission 115 kV *Sensitivity - with one CCSF unit taken offline;* *DC line runback required*	112%	10
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	11

<u>Year 2018 Analysis:</u>

Table 3 below summarizes the power flow results for 2018. This 2018 study assumes that the capacity upgrade projects proposed in the 2016 study were implemented. These are re-rating the Peabody-Contra Costa and Contra Costa-Moraga 230 kV lines and reconductoring of the Lambie-USWP-Contra Costa 230 kV line. Power flow studies with a line outage (L-1) and DEC out (G-1) showed the highest loaded facility to be Tesla-Pittsburg 230 kV #2 circuit. This line will experience 106% emergency overload during an outage of Tesla-Pittsburg 230 kV #1 circuit. One potential solution to alleviate these overloads could be a DC runback option which will require the transbay cable loading to be reduced to 255 MW using a Special Protection

[9] This overload was based on the normal rating of the line during a G-1.

Scheme (SPS) during Tesla-Pittsburg #2 or Tesla-Pittsburg #1 line outage. If DC runback were not a solution, then a potential project to mitigate these thermal overloads would be to reconductor the Tesla-Pittsburg Lines #1 and #2. For the Greater Bay Area transmission facilities, the Vaca Dixon-Peabody 230 kV line was identified as having the loading at 97% due to a Lambie-USWP-Contra Costa 230 kV line outage with Contra Costa Unit 7 out. Power flow studies showed no overloads with a line outage with DEC out instead of Contra Costa Unit 7 out.

One thermal overload was identified in the San Francisco Internal System, which relates to outlet capability constraint with DC line power import to San Francisco. Power flow studies showed the highest loaded facility in the SF internal system to be the Potrero-Mission 115 kV cable. This cable will experience 118% overload during an outage of the Potrero-Larkin #2 cable (L-1). The loading on this cable will be 114% if CCSF unit 1 is out (G-1) during an outage of the Potrero-Larkin #2 cable (L-1). One potential solution to alleviate this overload could be a DC runback option which will require the transbay cable loading to be reduced to 185 MW using a Special Protection Scheme (SPS) during Potrero-Larkin #2 cable outage. If DC runback were not a solution, then a potential project to mitigate the overloading would be to install series reactors in the Potrero-Mission 115 kV cable.

No thermal overloads were identified along the San Francisco Peninsula Corridor.

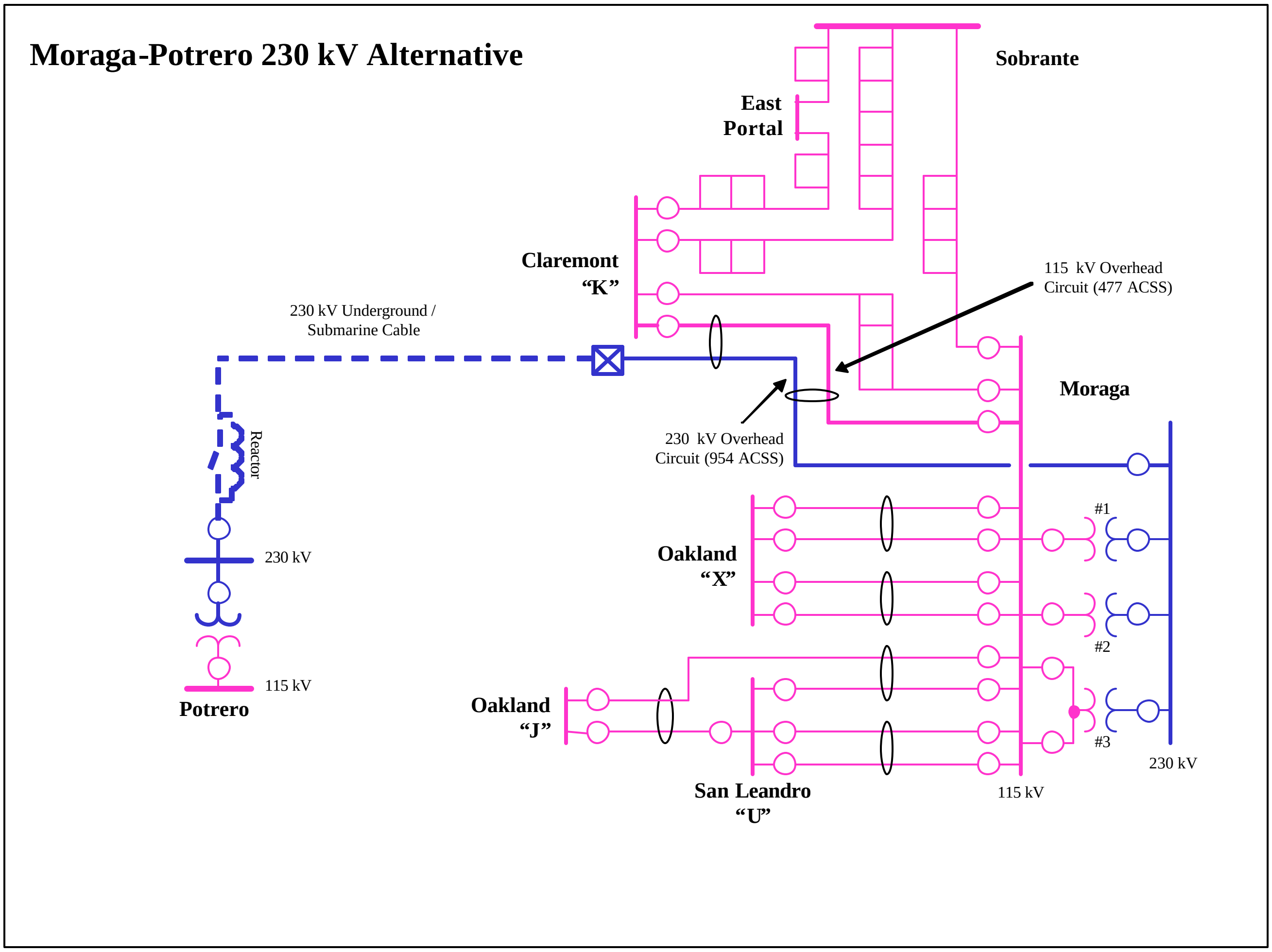
Table 3 – 2018 Results: Pittsburg-Potrero DC Line with CCSF Generating Units Operational

Year: 2018 SF Load: 1053 MW Peninsula Load: 1133 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Vaca Dixon-Peabody 230 kV *with Contra Costa Unit 7 out, Lambie-USWP-Contra Costa 230 kV reconductored, and Peabody-HiWind-Contra Costa 230 kV rerated.*	97%	12
	Tesla-Pittsburg 230 kV #2 line *Sensitivity – with DEC as G-1.* *DC line runback required.*	106%	13
	Saratoga-Vasona 230 kV *DEC as G-1; Lambie-USWP-Contra Costa 230 kV reconductored, Peabody-HiWind-Contra Costa and Contra-Costa –Moraga 230 kV lines rerated.*	93%	13
SF Internal System	Potrero-Mission 115 kV *with all CCSF units online*	118%	14
	Potrero-Mission 115 kV *Sensitivity - with one CCSF unit taken offline*	114%	15
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	16

Option 4 – Moraga Potrero Project

The power flow analysis for this option study assumes a new 230 kV AC line between Moraga Substation (East Bay) and Potrero Substation (San Francisco) is installed by 2011.

Schematic Diagram: Moraga-Potrero 230 kV Alternative



Key Findings:

In summary, the following are some of the key findings reached in this thermal analysis study:

- ?? In addition to the new Moraga-Potrero 230 kV line, this alternative requires 6 projects to increase the Greater Bay Area transmission load serving capability through 2018 (see Attachment 2, Items 6 to 10). These projects exclude the 4 projects identified in the CAISO Revised Action Plan, which are assumed to be operational prior to 2011.
- ?? The ISO Grid Planning Category B overlapping contingency of a line out (L-1) and Contra Costa Unit 7 out (G-1) has a greater limiting impact on the Greater Bay Area load serving capability than a line out and Delta Energy Center (DEC) out.
- ?? For the San Francisco Internal System, line loadings are higher with a line outage by itself (L-1) than a line outage with one of the CCSF units out (L-1/G-1).

- ?? The San Francisco Internal System would reach its load serving capability limit in about 2012. Installation of series reactors could extend its load serving capability through 2018.
- ?? No overloads were identified along the San Francisco Peninsula Corridor.

Base case Assumptions:

The study assumed a new 230 kV line is operational in 2011 between Moraga and Potrero substations and would consist of about 5 miles of overhead line and about 14 miles of underground and submarine cable. See Attachment 1 for a schematic of this proposed line.

Study Results Summary:

Year 2011 Analysis:

Table 1 below lists the power flow results for 2011 assuming a new 230 kV AC line between Moraga and Potrero substations is installed and the proposed four CCSF combustion turbines are operational. For the Greater Bay Area transmission facilities, the highest overload was on the Lambie-USWP-Contra Costa 230 kV line at 105 % loading due to a Vaca Dixon-Peabody 230 kV line outage with Contra Costa Unit 7 out. Power flow studies of a line outage and DEC out (instead of Contra Costa Unit 7) resulted to Contra Costa-Rossmoor Tap 230 kV #1 to be the highest loaded facility at 101% loading. These overloads can be eliminated by rerating the Lambie-Contra Costa Sub, the Peabody-Contra Costa PP and the Contra Costa-Moraga 230 kV lines to 4 fps. The Lambie-USWind(USWP)-Contra Costa 230 kV line would eventually need to be reconductored in about year 2012 to eliminate the projected normal overload to this line.

For the San Francisco Internal System, the highest loaded facility is the Potrero-Mission 115 kV line at 99% loading due to the Potrero-Larkin 115 kV #1 line outage with all the CCSF generating units in operation. Installing a series reactor on the Potrero-Mission 115 kV line can reduce this loading. Turning off one or more CCSF generating units connected to the Potrero Substation would also reduce this loading.

No overloads were identified along the San Francisco Peninsula Corridor.

Table 1 2011 Results: Moraga-Potrero 230 kV Alternative with CCSF Generation Operational.

Year: 2011 SF Load: 983 MW Peninsula Load: 1059 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Lambie-USWind-Contra Costa 230 kV *with Contra Costa Unit 7 as G-1.*	105 %	1a
	Lambie-USWind-Contra Costa 230 kV	99% *(Normal)*	1a
	Vaca Dixon-Peabody 230 kV *after rerate of Lambie-Contra Costa and Peabody-Contra Costa 230 kV lines with Contra Costa Unit 7 as G-1.*	92 %	1a

	Contra Costa-Rossmoor Tap 230 kV #1 *with DEC as G-1.*	101 %	1b
	Contra Costa-Rossmoor Tap 230 kV #1 *after rerate of Contra Costa-Rossmoore Tap, Peabody-Contra Costa Sub and Lambie-Contra Costa PP 230 kV lines with; DEC as G-1.*	<90 %	1b
SF Internal System[10]	Potrero-Mission 115 kV *with all CCSF units online.*	99 %	2a
	None Loaded Above 90% *with series reactor installed in Potrero-Mission 115 kV line.*	< 90%	2a
	Potrero-Mission 115 kV *Sensitivity - with one CCSF units taken offline.*	96 %	2b
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	3

Year 2016 Analysis:

Table 2 below summarizes the power flow results for 2016. These results assume that the Contra Costa-Moraga and Peabody-Contra Costa PP 230 kV lines were rerated and the Lambie-USWP-Contra Costa 230 kV line was reconductored as part of 2011 and 2012 upgrades. For the Greater Bay Area transmission facilities, the Vaca Dixon-Peabody 230 kV was identified to have the highest loading at 97% due to a Lambie-USWP-Contra Costa 230 kV line outage with Contra Costa Unit 7 out. Power flow studies of a line outage and DEC out (as the G-1) instead of Contra Costa Unit 7 resulted to Contra Costa-Rossmoor Tap 230 kV #1 to be the highest loaded facility at 92% loading.

For the San Francisco Internal System, no overloads were identified once the series reactors were installed in the Potrero-Mission 115 kV line. No overloads were found along the San Francisco Peninsula Corridor.

Table 2 – 2016 Results: Moraga-Potrero 230 kV Alternative with CCSF Generation Operational

Year: 2016 SF Load: 1033 MW Peninsula Load: 1122 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area[11]	Vaca Dixon-Peabody 230 kV *with Contra Costa Unit 7 as G-1.*	97%	4a
	Contra Costa-Rossmoor Tap 230 kV #1 *With DEC as G-1.*	92 %	4b
SF Internal System	Larkin-Martin 115 kV *with all CCSF units online and series reactor installed in Potrero-Mission 115 kV line.*	93%	5a
	Potrero-Mission 115 kV *Sensitivity-with all CCSF units online; no other work done.*	104%	5a

[10] These results do not assume interim long-term emergency ratings for the San Francisco 115 kV cables.
[11] Lines rerated to 4 fps were implemented to Contra Costa-Moraga and Peabody-Contra Costa 230 kV lines. Lambie-Contra Costa 230 kV line assumed reconductored.

	Potrero-Mission 115 kV *Sensitivity - with one CCSF unit taken offline and no other work done.*	101 %	5b
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	6

Year 2018 Analysis:

Table 3 below summarizes the power flow results for 2018. This study also assumed that all potential upgrade projects identified in the 2016 study for the Greater Bay Area were implemented. For the Greater Bay Area transmission facilities, the Vaca Dixon-Peabody 230 kV was identified to have the highest loading at 100 % due to a Lambie-USWP-Contra Costa 230 kV line outage with Contra Costa Unit 7 out. A normal overload was also identified in the Peabody-Contra Costa 230 kV line at 101% loading. Reconductoring the Peabody-Contra Costa 230 kV line would eliminate this normal overload. Additional capacity upgrade project would also be needed for the Greater Bay Area transmission system to serve additional load beyond 2018. This project could be rerating the Vaca Dixon-Peabody 230 kV in 2019 (beyond this study's scope). No overloads were identified for power flow studies with a line outage (L-1) and DEC out (G-1) instead of Contra Costa Unit.

For the San Francisco Internal System, no overloads were identified with series reactors installed in the Potrero-Mission 115 kV line. No overloads were also found along the San Francisco Peninsula Corridor.

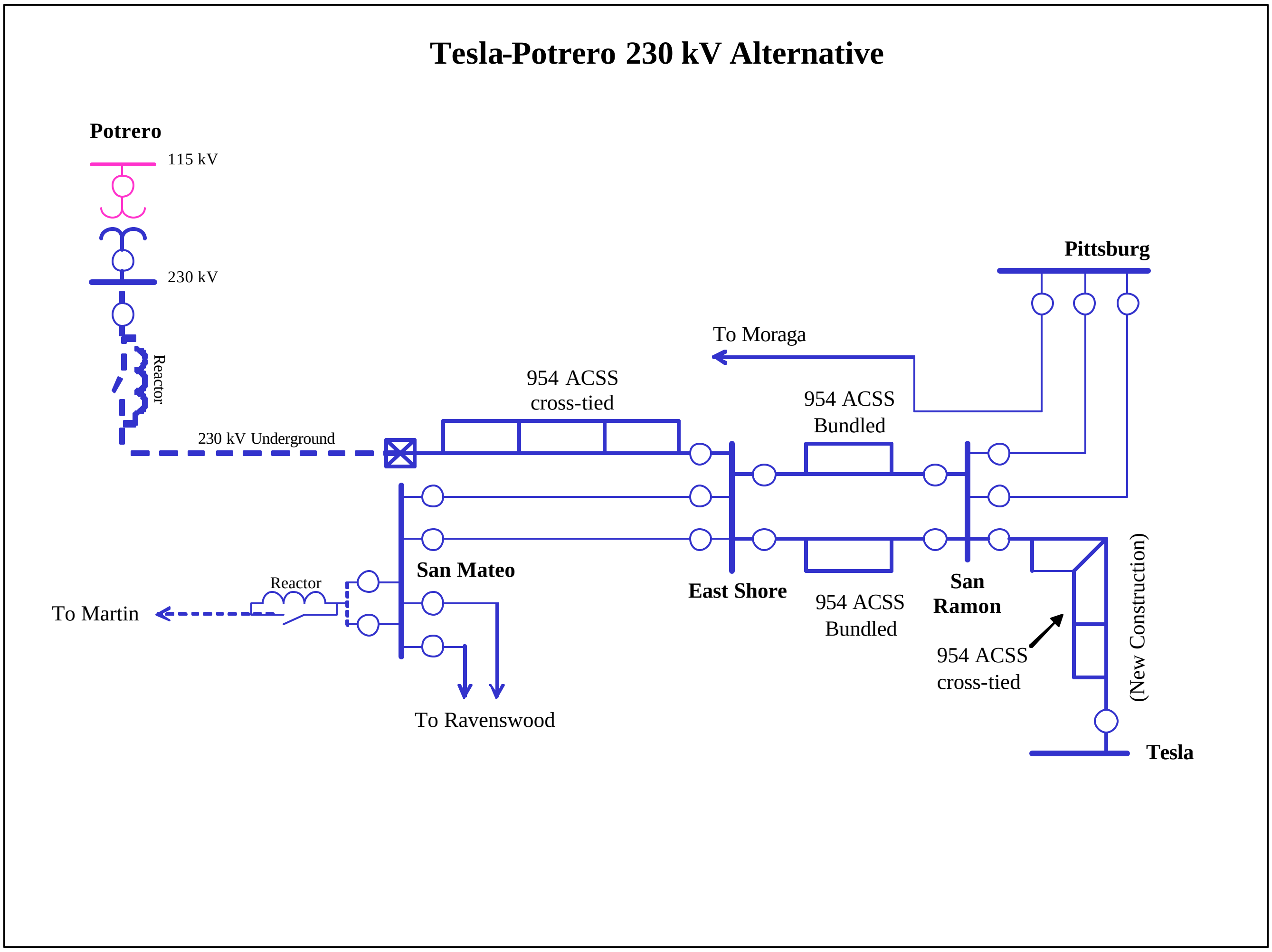
Table 3 – 2018 Results: Moraga-Potrero 230 kV Alternative with CCSF Generation Operational

Year: 2018 SF Load: 1053 MW Peninsula Load: 1133 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Vaca Dixon-Peabody 230 kV *with Contra Costa Unit 7 as G-1.*	100%	7a
	Peabody-Contra Costa 230 kV	101% *(Normal)*	7a
	Contra Costa-Rossmoor Tap 230 kV #1 *with DEC as G-1.*	95%	7b
SF Internal System	Larkin-Martin 115 kV *with series reactor installed in Potrero-Martin 115 kV line.*	95 %	8a
	Potrero-Mission 115 kV *Sensitivity - with all CCSF units online and no other work done.*	108%	8a
	Potrero-Mission 115 kV *Sensitivity - with one CCSF unit taken offline and no other work done.*	105%	8b
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	9

Option 5 – Tesla Potrero Project

The power flow analysis for this option assumed that the Tesla-Potrero 230 kV Alternative is installed by 2011. The Tesla-Potrero 230 kV Alternative consists of installing a new 230 kV circuit from Tesla Substation to San Ramon Substation, reconnecting San Ramon Substation to be on the same 230 kV circuits as East Shore Substation, reconductoring the 230 kV circuits connecting San Ramon and East Shore substations, and installing a new 230 kV circuit from East Shore to Potrero substations.

Schematic Diagram: Tesla-Potrero 230 kV Alternative



Key Findings:

In summary, the following are some of the key findings reached in this thermal analysis study:

?? In addition to installing the proposed Tesla-Potrero 230 kV Alternative, this alternative requires 4 projects to increase the Greater Bay Area transmission load serving capability through 2018(see Appendix 2, Items 5 to 8). These projects exclude the 4 projects identified in the CAISO Revised Action Plan, which are assumed to be installed prior to 2011.

?? The ISO Grid Planning Category B overlapping contingency of a line out (L-1) and Contra Costa Unit 7 out (G-1) has a greater limiting impact on the Greater Bay Area load serving capability than a line out and Delta Energy Center (DEC) out.

?? For the San Francisco Internal System, line loadings are higher with a line outage by itself (L-1) than a line outage with one of the CCSF units out (L-1/G-1).

?? The San Francisco Internal System would reach its load serving capability limit in 2017. Installation of series reactors would extend the Internal System's load serving capability beyond 2018.

?? No overloads were identified along the San Francisco Peninsula Corridor.

<u>Base case Assumptions:</u>

The study assumed that the Tesla-Potrero 230 kV Alternative is operational by 2011. This Alternative consists of installing about 21 miles of new 230 kV line from Tesla to San Ramon substations, reconnecting lines so that there are two 230 kV lines connecting San Ramon and East Shore substations, reconductoring the two lines from San Ramon to East Shore substations (about 14 miles), and installing a new 230 kV overhead and underground line about 31 miles from East Shore Substation to Potrero PP Switchyard. See Attachment 1 for a schematic of this Alternative.

<u>Study Results Summary:</u>

<u>Year 2011 Analysis:</u>

Table 1 below lists the power flow results for 2011 assuming the Tesla-Potrero Alternative is installed and that the proposed four CCSF combustion turbines are operational. For the Greater Bay Area transmission facilities, the highest loading was on the Lambie-USWP-Contra Costa 230 kV line at 99 % loading due to a Vaca Dixon-Peabody 230 kV line outage with Contra Costa Unit 7 out. For the Greater Bay Area facilities to carry additional load much beyond the forecast 2011 loads, a capability increase project would be needed. This could be a rerate to the Lambie-USWind-Contra Costa 230 kV line to 4 fps. With this line rerated, the highest loaded facility would be the Peabody-Contra Costa 230 kV line at 95 % loading. Power flow studies with a line outage (L-1) and DEC out (G-1) (instead of Contra Costa Unit 7) showed the highest loaded facility to be the Lambie-USWP-Contra Costa 230 kV line with a loading of 90%.

No overloads were identified in the San Francisco Internal System and along the San Francisco Peninsula Corridor.

Table 1 – 2011 Results: Tesla-Potrero 230 kV Line with CCSF Generating Units Operational

<table>
<tr><td colspan="4">Year: 2011
SF Load: 983 MW
Peninsula Load: 1059 MW</td></tr>
<tr><th>Study Area</th><th>Highest Loaded Facilities</th><th>Loading</th><th>Case #</th></tr>
<tr><td rowspan="3">Greater Bay Area</td><td>Lambie-USWind-Contra Costa 230 kV
with Contra Costa Unit 7 as G-1.</td><td>99 %</td><td>1</td></tr>
<tr><td>Peabody-Contra Costa 230 kV
after rerate of Lambie-Contra Costa 230 kV line;
with Contra Costa Unit 7 as G-1.</td><td>95 %</td><td>1</td></tr>
<tr><td>Lambie-USWind-Contra Costa 230 kV
with DEC as G-1.</td><td>90 %</td><td>2</td></tr>
</table>

SF Internal System[12]	Potrero-Mission 115 kV *with all CCSF units online.*	94 %	3
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	4

Year 2016 Analysis:

Table 2 below summarizes the power flow results for 2016. This study assumes that the proposed 4 fps rerate for Lambie-USWP-Contra Costa 230 kV line was implemented. For the Greater Bay Area transmission facilities, the Peabody-Contra Costa 230 kV line was identified to have the highest loading at 100% due to a Lambie-USWP-Contra Costa 230 kV line outage with Contra Costa Unit 7 out. The power flow study also identified a high normal loading of 99% on the Lambie-USWP-Contra Costa 230 kV line. For the Greater Bay Area facilities to carry additional load much beyond forecast loads for 2016, additional capacity upgrade projects would be needed. Potential capacity upgrade projects could be the reconductoring of the Lambie-Contra Costa 230 kV line and rerating of the Peabody-Contra Costa 230 kV line to 4 fps. Assuming these two potential projects are implemented, the highest loaded Greater Bay Area facility would be the Vaca Dixon-Peabody 230 kV line at 92 % loading. Power flow studies of a line outage with DEC out (instead of Contra Costa Unit 7) showed no overloads.

No overloads were also identified in the San Francisco Internal System and along the San Francisco Peninsula Corridor.

Table 2 – 2016 Results: Tesla-Potrero 230 kV Line with CCSF Generating Units Operational

Year: 2016 SF Load: 1033 MW Peninsula Load: 1122 MW			
Study Area	Highest Loaded Facilities	Loading	Case #
Greater Bay Area	Peabody-Contra Costa 230 kV *after rerate of Lambie-USWind-Contra Costa 230 kV line; with Contra Costa Unit 7 as G-1.*	100%	5
	Lambie-USWind-Contra Costa 230 kV *Sensitivity – with Contra Costa Unit 7 as G-1 and no capability upgrade work done*	105%	5
	Lambie-USWind-Contra Costa 230 kV	99% (Normal)	5
	Vaca Dixon-Peabody 230 kV *After Lambie-USWind-Contra Costa 230 kV line reconductoring and Peabody-Contra Costa 230 kV line rerate; Contra Costa Unit 7 as G-1.*	92%	6
	Lambie-USWind-Contra Costa 230 kV *DEC as G-1; no capability work done.*	97%	7
SF Internal System	Potrero-Mission 115 kV *with all CCSF units online; no capability upgrade work in SF.*	98%	8
	Potrero-Mission 115 kV *Sensitivity - with one CCSF unit taken offline; no capability upgrade work in SF.*	95%	9
SF Peninsula Corridor	None Loaded Above 90 %.	< 90%	10

[12] These results do not assume interim long term emergency ratings for the San Francisco 115 kV cables.

Year 2018 Analysis:

Table 3 below summarizes the power flow results for 2018. This 2018 study assumes that the capacity upgrade projects proposed in the 2016 study were implemented. These are rerating of the Peabody-Contra Costa 230 line and reconductoring of the Lambie-USWind-Contra Costa 230 kV line. For the Greater Bay Area transmission facilities, the Vaca Dixon-Peabody 230 kV line was identified as having the highest loading at 94 % due to a Lambie-USWP-Contra Costa 230 kV line outage with Contra Costa Unit 7 out. Power flow studies also showed no overloads with a line outage with DEC out instead of Contra Costa Unit 7 out.

For the San Francisco Internal System, a 1% overload to the Potrero-Mission 115 kV line was identified. Installation of a series reactor to the Potrero-Mission 115 kV would eliminate this overload and allow the San Francisco Internal System to carry additional load. Turning off one or more CCSF units in San Francisco would also eliminate this overload.

No overloads were identified along the San Francisco Peninsula Corridor.

Table 3 – 2018 Results: Tesla-Potrero 230 kV Line with CCSF Generating Units Operational

<table>
<tr><td colspan="4">Year: 2018
SF Load: 1053 MW
Peninsula Load: 1133 MW</td></tr>
<tr><th>Study Area</th><th>Highest Loaded Facilities</th><th>Loading</th><th>Case #</th></tr>
<tr><td rowspan="3">Greater Bay Area</td><td>Vaca Dixon-Peabody 230 kV
with Contra Costa Unit 7 out, Lambie-Contra Costa 230 kV reconductored, and Peabody-Contra Costa 230 kV rerated.</td><td>94%</td><td>11</td></tr>
<tr><td>Lambie-USWind-Contra Costa 230 kV
DEC as G-1; no capability work done.</td><td>100%</td><td>12</td></tr>
<tr><td>Saratoga-Vasona 230 kV
DEC as G-1; Lambie-Contra Costa 230 kV reconductored and Peabody-Contra Costa 230 kV rerated.</td><td>93%</td><td>12</td></tr>
<tr><td rowspan="3">SF Internal System</td><td>Potrero-Mission 115 kV
with all CCSF units online; no capability upgrade in SF.</td><td>101%</td><td>13</td></tr>
<tr><td>Larkin-Martin 115 kV
with series reactor installed in Potrero-Mission 115 kV line.</td><td>96%</td><td>13</td></tr>
<tr><td>Potrero-Mission 115 kV
Sensitivity - with one CCSF unit taken offline; no capability upgrade in SF.</td><td>98%</td><td>14</td></tr>
<tr><td>SF Peninsula Corridor</td><td>None Loaded Above 90 %.</td><td>< 90%</td><td>15</td></tr>
</table>

ISO ECONOMIC ANALYSIS

As discussed in the previous section, the transmission alternatives are designed to satisfy an important San Francisco planning need that is forecasted to start in 2012. The long-term alternatives considered were therefore primarily evaluated from a reliability perspective (i.e. the least-cost alternative that satisfies the reliability need, subject to other considerations such as project risk). The least-cost alternative is determined by considering the projected capital and operating costs, as well as any difference in economic benefits provided by the individual alternatives. Evaluation of the least-cost alternative is the approach used in this economic analysis. ISO staff recognizes that the least-cost analysis is only one of many critical decision criteria that are considered when recommending a transmission project.

ISO staff views the determination of the long-term preferred alternative, and the recommended timing of this preferred alternative, as two separate considerations for supporting the selection of the preferred transmission alternative. ISO staff developed economic data and analyses to assist in assessing these considerations. The economic results are summarized in this section.

As part of the San Francisco Phase 2 Long Term Activity, the ISO staff conducted an economic analysis of all the reinforcement options considered.

The economic evaluation utilized the Transmission Evaluation Assessment Methodology (TEAM) developed by the CAISO, which is used to evaluate projects requiring regulatory approval. The goal of TEAM is to improve the overall accuracy of the evaluation and to add greater predictability to the assessment of economic transmission need. TEAM methodology is a result of a public stakeholder process.

Overview of the Methodology and Benefits

The studies were performed using the ABB Grid View computer program. This program simulates operation of a competitive electric energy market under realistic transmission system constraints. The program can be used to analyze utilization of transmission and generation, identify transmission system bottlenecks and evaluate economic impacts of new transmission projects or impacts of addition or retirement of power plants and changes in fuel prices.

The Grid View simulates operation of the market in hourly intervals for any duration. In the studies, one-year simulation was performed. The year 2008 was chosen to determine if there would be economic benefits in early implementation of the Trans Bay Cable project. The Grid View model incorporates detailed supply model, demand model and transmission system model. It performs transmission and security constrained optimization of the system resources and produces realistic simulation of power flow patterns. The constraints that can be modeled include thermal limits under normal conditions, contingency-based security constraints, interface limits and simultaneous transfer limits.

The following input data is used for the simulations:

- Supply Model – generators' locations, types, heat rates, fuel costs, operation constraints, bidding information.
- Demand Model- load magnitudes and load duration curves.
- Transmission System Model- detailed load flow model and security constraints

The output information includes:

- Transmission line utilization levels – line flow throughout the study period
- Generation – dispatch hours, production cost, revenues
- Location market clearing prices for energy and ancillary services
- Transmission bottlenecks- locations, hours and cost of congestion
- Total cost of generation, load and generation revenue

For every hour of the simulation period, the program calculates and records market clearing price for every bus, power flow for each transmission facility, congestion cost, shadow price, output and production cost of each generator. The Grid View output may be represented as tables or as plots.

In this report, the focus is on identifying the economic benefits that can be quantified and attributed to the proposed upgrades. Benefits such as fuel diversity, insurance value (e.g. risk premium), and long-term reliability advantages are not easily quantified and are, therefore, beyond the scope of this economic analysis. For this economic evaluation, we quantified the following economic benefits attributable to the proposed upgrades:

- Energy cost savings
- Operational benefits
- Capacity benefits
- System-loss reduction benefits
- Emission reduction benefits

Methodology for Calculating Benefits

Transmission economic benefits are calculated by comparing system models "without" and a "with" transmission expansion and determining the difference in costs for the two simulations. Transmission benefits can be calculated from various perspectives including:

- Societal (generally WECC but can be defined as a smaller geographical area)
- California (CAISO and non-CAISO participants)
- CAISO Ratepayer
- CAISO Participant (includes ratepayers, generators, and transmission owners in the CAISO area)
- CAISO Organization (includes impact on CAISO rates only)

There are many other perspectives that can be defined (e.g. Northern California industrial ratepayers, individual municipal utilities), but for purposes of this report, the above list represents the primary perspectives that will be considered.

There are two important economic identities that should hold true for all market simulations, no matter how simple or how complex:

1. CTL – GR = TR, where
    - ?? CTL = Cost To Load
    - ?? GR = Generator Revenue
    - ?? TR = Transmission Revenue

2. TB = ? PC = CS + GS + TS, where
    - ?? TB = Total Benefits
    - ?? PC = Total Production Costs
    - ?? CS = Consumer Surplus (or benefit)
    - ?? GS = Generator Surplus
    - ?? TS = Transmission Owner Surplus

The first identity refers to each individual market simulation. This identity is true irrespective of the market design (contract path, LMP, postage-stamp or pancaked wheeling rates, or losses). The difference between what consumers pay for the energy portion of their rates, and the amount the generators get paid, is always equal to the transmission revenue.

The second identity refers to two market simulations, or one "case" (e.g. base case, high-gas case). The benefits to all segments of society are always equal to the difference in production costs between the cases "without" and "with" the transmission expansion. (This identity may not be true when losses are incorporated in the analysis; when the impact of losses is included, there is an additional, "cost of loss", component).

If one wants to understand the overall economics of a proposed transmission line, the easiest way to do this is by studying the production costs in a cost-based environment. Market prices are interesting, and are critical to develop in order to understand the benefits at any level other than societal, but if the initial analysis is at the societal level, market prices are not necessary.

This is the approach used for the Economic Analysis. The study did not include developing and benchmarking market prices. To understand the overall economics of the proposed alternatives, a cost-based societal approach was used. Since reduction in production costs due to the project identified in the studies was significantly lower than the leveraged annual revenue requirements for all alternatives, the more detailed analysis was not performed. This more complete analysis would have developed both sensitivity cases and market-based cases (i.e. including the impact of strategic bidding). However, from the study results it appeared that such detailed analysis was not necessary.

System Model and Assumptions

The latest available database (updated in 2005) developed by the technical support group of the Seams Steering Group-Western Interconnection (SSG-WI) was used in the production cost simulation studies. The SSG-WI database includes full WECC system model for the year 2008. The model consists of three major components: Generation, Load and Transmission Network.

The generation component includes all the generators specified by their capacity, costs and availability. Generators are identified either as dispatchable, thermal units, or as non-dispatchable units such as hydro, wind, and solar. Hydro - pump storage generators are specified separately, the program optimizes its use, the timing and magnitude of their generating or pumping. All the data regarding thermal generators' heat rates, type and cost of the fuel used, minimum up- and down time, startup and shutdown costs, ramp rates, cost of operation and maintenance and other data is also included in this component. Generation of the non-dispatchable units (hydro, wind, solar and some pumping loads) was modeled as hourly curves. The data for these curves was obtained from the actual real time data for an average hydro year (2002).The load component includes load distribution by control area, which incorporates annual energy, monthly maximum demand and hourly demand profiles. The transmission network component includes a complete WECC system - busses, lines, transformers (including phase shifters) and generators. It is the same network model that is used in the WECC power flow cases. In addition to the AC components of the network, the model also includes DC components: DC lines, inverters and rectifiers.
Another part of the database is modeling transmission constraints. For the purpose of this analysis, several nomograms were developed to model the limitations caused by transmission outages. The purpose of developing these nomograms was to ensure that for the most critical outage, the limiting element should not exceed its emergency rating. A computer program was used to identify the critical outages and flow limits (or nomograms) for the limiting facilities.

While calculating power flow of each hour of the year, the Grid View program verifies the nomogram constraints. If during a certain hour, the value of the nomogram is higher than the specified emergency rating, the program considers this condition as congestion and re-dispatches the system generation to satisfy the nomogram's constraint.

The Grid View model used for this analysis did not include the whole WECC system, but just the PG&E's part of it. Imports and exports to PG&E (California-Oregon Intertie and the Midway-Vincent (Path 26)) were modeled as fictitious generators with an hourly output (or consumption) according to the latest actual real time data. Such modeling allowed substantial reduction of computer time and also allowed to avoid impact of any inaccurate or inconsistent modeling in the areas outside PG&E. The PG&E model was verified and updated by the CAISO for the purpose of this study. The updated model included all approved transmission projects, updated load shapes which were modeled separately for categorized under (1) San Francisco and Peninsula area(2) rest of the Bay Area and (3) rest of the PG&E system.
The production cost simulation study also modeled the most critical maintenance of transmission lines. Taking lines out for maintenance was modeled for both circuits of the San Mateo-Ravenswood 230 kV line and for the Newark-Ravenswood and Tesla-Ravenswood 230 kV lines. It was assumed that each one of these circuits would be out for maintenance three times a year

for four days each time: in January, April and October. During the time when one transmission circuit is cleared for maintenance, load shedding is not allowed in case of an outage of the parallel circuit. The study results were obtained both for the cases with and without transmission line maintenance.

Study Results

Three long-term alternatives were evaluated from an economic perspective. These alternatives include the Trans-Bay Cable Project, the Moraga-Potrero line, and the Tesla-Potrero line. Production cost simulation study was performed for these alternatives.
For each production cost simulation run, Location Marginal Prices (LMP) including their loss and congestion components, total generation, load and losses, generation revenue, production cost and load payments were recorded. In Attachment II, this data is shown for each area and summarized for the total PG&E system. The specified areas are San Francisco and Peninsula (SAN FRANCISCO), the rest of the Bay Area (PG&E_BAY) and the rest of the PG&E system, excluding the San Francisco Bay Area (PG&E_VLY
The Trans-Bay HVDC line alternative was studied with two approaches: 1) 'Flexible'- Pittsburg-Potrero HVDC line is dispatched economically, and 2) 'Fixed' - Pittsburg-Potrero HVDC line is dispatched to transmit 400 MW from Pittsburg to Potrero all year round.

The results both for the 'Flexible' and 'Fixed' HVDC simulations are provided in the Attachment II

The economic benefits of the Tesla-Potrero alternative were less than the other two alternatives evaluated. Also, the Tesla-Potrero capital costs were almost 50 percent higher than the other two alternatives. Given this significant cost differential and the other issues associated with this alternative and stated within this memorandum, no further economic evaluation was made for this alternative.

The remaining two long-term alternatives (Trans-Bay Cable and Moraga-Potrero) considered are more closely related in economic benefits and capital costs. Both options can provide up to 400 MW of new capacity to the San Francisco Peninsula from East Bay generation. The Trans-Bay Cable, however, is projected to result in lower system losses than the Moraga-Potrero option, since the DC line itself is expected to have lower losses than an AC alternative. The capital costs of the two alternatives are within 2 percent of each other and based on the accuracy of their estimated cost, are deemed to be equivalent for purposes of this analysis. As a result of the projected lower system losses and other issues identified in this memorandum, the Trans-Bay Cable Project was preferred over the other alternatives.

Recommended Timing of Preferred Alternative

Because the Trans Bay Cable Project is proposing an early in-service date (early 2009), the ISO also undertook an analysis of the cost impact to the ISO ratepayers of advancing the in-service date ahead of the reliability need date by three years (2012 to 2009). Once the preferred long-term solution has been identified, the remaining question is whether the online date of the Trans Bay Cable Project should be planned for 2012 or brought online earlier. The primary criteria for this decision for a reliability project are likely to be based on reduced risk of loss of load and other considerations by bringing the project on-line earlier than needed. However, there is also an economic impact of an earlier on-line date that should be considered.

Capital projects are often compared on the basis of the present value of revenue requirements (PVRR). As shown in Table 1, the PVRR increases $63 million if the Trans Bay Cable Project is brought online in 2009 versus 2012. However, the earlier online date provides some distinct benefits including increased reliability to San Francisco, reduction of project schedule and cost risk, and economic benefits. The economic benefits are estimated to be about $14 million per year. The present value of 3 years of economic benefits is approximately $37 million. Thus, the net cost of bring the project online by 2009 as compared to 2012 is $26 million.

This net cost can be viewed as a 6.2 percent Assurance Cost against intangible benefits such as reductions in SPS requirements, unforeseen load forecast errors, Reliability Must-Run/Locational Capacity requirements, reduced project siting costs, schedule, and cost risks (as well as increased San Francisco reliability for the three years. From ISO Management's perspective, this 6% Assurance Cost is considered a prudent investment given the intangible benefits mentioned above and the certainty that the Project will be there when it is needed. Based on these considerations, ISO staff believes the Trans Cable Project's early in-service date is warranted.

Table 1
Economic Comparison of a 2009 or 2012 Trans Bay Cable Online Date

PV of revenue requirements	$483	$420	$63
PV of 2009-2011 economic benefits	$37	$0	$37
NPV of revenue requirements	$446	$420	$26
Revenue requirement risk premium			**6.2%**

SELECTION OF THE PREFERRED TRANSMISSION ALTERNATIVE

ATTRIBUTES FOR COMPARING OPTIONS

The following are the major attributes for comparing the pros and cons of each option:

Long-Term Reliable Load Serving Capability – Does the option allow the ISO to reliably serve load at least until 2018?

Capital Cost – How much will this option cost? How does it compare with the cost of other alternatives and is there a risk of significant cost escalation?

Economic Benefits - Does this option decrease or increase power losses and does it promote more economic generation dispatch? What related savings to ratepayers are projected?

Import Security – Will the option improve the overall security of the transmission system through which power is imported into San Francisco and the Peninsula?

Ability to permit and construct – Are there significant uncertainties associated with the ability to permit and construct the project when needed?

PROPOSED LONG-TERM OPTION DESCRIPTIONS

Option 1 – Do nothing beyond utilizing the transmission facilities planned to exist by 2007 summer.

Option 2 – PG&E would continue to more fully utilize the transmission system as it is planned to exist by 2007 summer through continued addition of voltage support and reconductoring of transmission lines.

Option 3 – An independent developer (Babcock & Brown) would permit and build a new 400 MW High Voltage Direct Current (HVDC) submarine cable between Pittsburg Substation in the East Bay area and Potrero Substation in San Francisco.

Option 4 – PG&E would permit and build a new 230 kV AC line from Moraga Substation in the East Bay area to Potrero Substation in San Francisco. This new line would partially run beneath San Francisco Bay.

Option 5 – PG&E would permit and build a new 230 kV AC line from Tesla Substation in the East Bay area to Potrero Substation in San Francisco. This new line would include a new line across San Francisco Bay.

The preferred long-term option should meet the principal objective of the 'San Francisco Peninsula Phase 2 Long-Term Electric Transmission Planning Study' by providing reliable long-term load-serving capability in the most economic and environmentally sensitive manner while also being deemed ‘constructible’ by factoring into account the option-specific right-of-way, permitting, regulatory and other development requirements.

‘Reliable long-term load-serving capability’ measures should include: (i) whether or not the amount of incremental load-serving capability attributed to the option is good through at least Year 2018; (ii) whether or not all applicable NERC, WECC, Cal-ISO and PG&E reliability standards are achieved; and (iii) positive impacts on PG&E system performance by minimizing reliance on the peninsula transmission corridor.

‘Economic’ measures should include the ‘benefits’ of improved generation dispatch, system loss reduction and other deferred transmission system or resource investment weighed against capital and operating ‘costs’, including required system upgrades, as quantified on a Net Present Value or annualized basis.

Environmental’ measures should include the option-specific CEQA requirements for rights-of-way, visual aesthetics, electric and magnetic filed effects, construction and other impacts.

‘Constructability’ measures should include an assessment on whether an option is deemed to be able to acquire the necessary land and right-of-way and be successful in securing the necessary permits and regulatory approvals.

Through SFSSG stakeholder input, CAISO listed several advantages/disadvantages of all the options. Below is a table that compares these:

Alternative	**Advantages**	**Disadvantages**
<u>Option 1</u> – Do Nothing	?? Deferred transmission investment ?? Option value of future load serving technologies/projects ?? No adverse environmental impacts	?? Does not meet the goal of establishing a Long-Term (10 Year) Reliable Load Serving Capability. ?? Continues reliance on importing power on transmission lines only through the SF Peninsula corridor. Therefore, would expose load to unreliable load serving conditions as load exceeds the capability of the transmission system through which power is imported. ?? Will increase system losses as compared to Options 2, 3, 4, and 5, as existing lines load more heavily in serving increased load. ?? Installing future transmission projects may be more difficult with time.

Alternative	Advantages	Disadvantages
Alternative	**Advantages**	**Disadvantages**
<u>Option 2</u> – Upgrade & Replace Existing Facilities. **Cost: $114 million** **LSC improvement: until 2018**	?? Least capital cost option. ?? For most part, implementation of this option will need less lead-time as compared to that for Options 4, 5, & 6.	?? This option is dependent on the timely identification, permitting and construction of many transmission system upgrades, including building up to two new 115 kV cables within San Francisco and therefore incur related routing and permitting uncertainty. ?? Increased reliance on importing power across the SF Peninsula corridor and Martin substation. This option doesn't improve supply diversity, as done so by Options 3, 4, and somewhat by 5. ?? As the load grows, existing facilities will experience loadings closer to their operating capabilities. This could potentially have an adverse impact on life of facilities, and will lead to higher system losses as compared to Options 3, 4, and 5. ?? The improved load serving capability provided by this option will be good until Year 2018. Additional project(s) in San Francisco will be needed by 2019. ?? Environmental permitting and regulatory approval process not yet initiated. ?? This option reduces real-time operational flexibility, because of the added need of taking clearances of several existing facilities to implement the projects outlined for this option. ?? Installing future projects may be more difficult with time.
Alternative	**Advantages**	**Disadvantages**

<u>Option 3</u> – Trans-Bay Cable Project Cost: $295 million LSC improvement: at least until 2018	?? Provides fully controllable bi-directional power delivery up to 400 MW, thus brings in the flexibility of supplying a “desired” amount of power into San Francisco as needed in real time, with flexibility of having a Runback scheme ?? This option improves supply diversity by providing a new route of delivering power to San Francisco. ?? The ability to permit and build this project in a timely manner requires about three years lead-time as compared to six years for Options 4 and 5. ?? EIR has been started with no adverse comments received to date. ?? DC connection inherently improves angular stability ?? Doesn’t require increased risk of load dropping due to clearance requirements ?? Increases System Stability and Security (i.e. support of weak AC system in case of contingencies)	?? Potential for extended repair time for forced outages compared with overhead line options. ?? New largest contingency loss of source to the San Francisco Peninsula (i.e. loss of 400 MW HVDC line) ?? A DC Cable and converter stations increases the complexity of operating the transmission system within the SF Greater Bay Area.
Alternative	**Advantages**	**Disadvantages**
<u>Option 4</u> – Moraga-Potrero 230 kV Line Cost: $274 million LSC improvement: at least until 2018	?? For a portion of the line, existing rights of ways and corridors will be utilized. ?? This option improves supply diversity by providing a new route of delivering power to San Francisco. ?? This option can be enhanced to provide 230 kV service to Oakland area. However, other	?? Environmental permitting and regulatory approval process not yet initiated. ?? May require up to six years lead-time as compared to three years for Option 3. ?? Requires series reactors to assist in control of power delivery.

	alternatives for Oakland are concurrently being pursued.	
Alternative	**Advantages**	**Disadvantages**
<u>Option 5</u> – Tesla-Potrero 230 kV Line **Cost: $457 million** **LSC improvement: at least until 2018**	?? For a portion of the line, existing rights of ways and corridors will be utilized. ?? This option improves supply diversity by providing a new route of delivering power to San Francisco.	?? While this option involves importing power across San Francisco Bay as compared to all imported power now being routed through the San Francisco Peninsula, this option would include the significant difficulty of building a major new transmission line and new supporting towers above San Francisco Bay. ?? May require up to six years lead-time as compared to three years for Option 3. ?? Requires series reactors to assist in control of power delivery. ?? A portion of this line would be within the existing SF Peninsula corridor between San Mateo and Potrero Substations. ?? Environmental permitting and regulatory approval process not yet initiated.

The SFSSG determined there is a Reliability need for supplying load in the San Francisco and Peninsula areas beginning in 2012 following the completion of the ISO's Action Plan for San Francisco components.

✍ What is the objective?

- o Assuming the successful completion of the ISO's Revised Action Plan, assess and identify the preferred transmission alternative to provide reliable, long-term (through 2018) load serving capability for the San Francisco Peninsula Area

✍ How was this to be accomplished?

- o As appropriate, evaluate practical alternatives through technical analysis and certain economic assessment to determine their viability in meeting the SFSSG's Phase 2 objectives.

✍ Alternatives assessed?

- o The alternatives assessed are discussed in detail in above.

✍ Two key issues to help resolve some differences:

- o Should the next transmission line into the San Francisco Peninsula Area come from the south (Tesla – Potrero) or from across the San Francisco Bay (Moraga – Potrero/Trans-Bay Cable)?
- o Electrically, is there a preference between connecting to Moraga or Pittsburg?

✍ Economic Analysis? The ISO's economic analysis is included within this report.

✍ Stakeholder positions on the alternatives

- o Comments received at the June 2005 SFSSG meeting are included in Attachment 5

✍ <u>Reconductoring of Existing Facilities</u> – this alternative is not recommended for the following reasons:

- o Difficult to implement and provides less operational flexibility and could place PG&E customer load at unnecessary risk (ISO concern: clearance for Newark-Ravenswood & Ravenswood-Shrdr Jct Reconductoring)
- o Two new cable projects in San Francisco are needed for this option (one before 2018 & another shortly after 2018) – Cost of second cable is not included in $114 million estimate for this option. Routing & permitting uncertainty associated with new cable implementation.
- o Increased reliance on power across SF Peninsula & Martin substation.
- o Existing facilities will be loaded more heavily – adverse impact on life span of the existing facilities.
- o Use of series reactors also possible to control flow, but this is not considered an acceptable long-term solution.

✍ <u>Trans-Bay Cable Project</u> – this is the preferred alternative for the following reasons:

- o Ability to permit & construct this option is far more certain than the competing 230 kV alternatives

- It provides supply diversity – feeds San Francisco from the north
- DC technology provides operational flexibility
- It is the only new transmission option that can be implemented prior to the Reliability need in 2012.
- Capital cost is $300 million and includes up to $15 million for interconnection facilities cost.
- It can be operational by January 2009, which will help offset some of the SF Locational Capacity as soon as the project is placed in-service in 2009

✍ Moraga – Potrero Transmission Line – this alternative meets the long-term load serving capability objective and also improves supply diversity. However, it is not recommended for the following reasons:

- Ability to permit and construct this option in a timely manner is uncertain
- Capital cost is $274 million but could be much higher due to permitting uncertainty

✍ Tesla – Potrero Transmission Line – this alternative is not recommended for the following reasons:

- Includes the notable difficulty of building a major new transmission line and new supporting towers above San Francisco Bay
- Includes construction of new transmission infrastructure that parallels existing transmission through the San Francisco peninsula corridor that already accommodates numerous 115 kV and 230 kV lines, including the Jefferson – Martin Project. Siting another transmission project through this area would be extremely difficult considering the recent siting of the Jefferson – Martin 230 kV line in this same area.
- Ability to permit and construct this option in a timely manner is uncertain
- Capital cost is $457 million. This cost could be much higher due to permitting uncertainty
- Doesn't provide supply diversity – feeds San Francisco from the south

ISO conclusion is that the Trans-Bay Project is preferred:

This alternative is the preferred option and fully meets the objective of establishing long-term reliable load serving capability by adding 400 MW of load serving capability upon its initial operation. This option will increase the diversity of power import route through controllable transmission capacity from PG&E's Pittsburg Substation in the East Bay to its Potrero Substation in San Francisco. This option provides for significant savings by reducing power losses within the parallel AC transmission system, deferral of new 115 kV cables within San Francisco as well as facilitates a more economic generation dispatch pattern within the Greater Bay Area. This project is estimated to cost $300 million including interconnection costs.

Economic savings associated with the Trans-Bay Cable are estimated to be as much as $10 million per year as attributed to transmission system loss savings, improved economic dispatch of generation and reduction in Reliability Must-Run costs. The ability to permit and build this project in a timely manner requires about half the lead-time (three years) as either the Moraga to Potrero or Tesla to Potrero 230 kV Projects. In addition, development of an Environmental Impact Report is well underway as has preliminary approval with the Federal Energy Regulatory Agency for rate recovery.

<u>Attachment 1</u>

CAISO Revised Action Plan for San Francisco

Revised Action Plan

PG&E Transmission Projects and City Peaking Power Plants Necessary
To Meet NERC/WECC/CAISO Planning Requirements

AS OF SEPTEMBER 2, 2005

	Project	Estimated Completion Date/Status	Issue	Resolution of Issue
Release Hunters Point Units 2 & 3 From Their RMR Agreements				
1	Potrero Static VAR Compensator	December 2004, Completed	NERC/WECC/CAISO Planning Standards	This project allowed ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 2 and 3 released from their RMR Agreement
Release Hunters Point Units 1 & 4 From Their RMR Agreements				
2	San Mateo-Martin No. 4 Line Voltage Conversion	Completed	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
3	Ravenswood 2nd 230/115 kV Transformer Project	Completed	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
4	San Francisco Internal Cable Higher Emergency Ratings	Completed: To Be Used Upon Completion of the Jefferson-Martin 230 kV Project	NERC/WECC/CAISO Planning Standards	These ratings are an interim solution that in combination with the other listed projects allows PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreements. In 2007, a third Martin-Hunters Point 115 kV cable will replace the emergency ratings.
5	Tesla-Newark No. 2 230 kV Line Reconductoring	February 2005, Completed	RMR Criteria	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
6	Ravenswood-Ames 115 kV Lines Reinforcement	April 2005, Completed	RMR Criteria	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
7	San Mateo 230 kV Bus Insulator Replacement	May 2005, Completed	Operations Requirement During San Mateo Bus Wash	Eliminate bus wash at San Mateo 230 kV bus will reduce the 400 MW generation operational requirement down to less than 200 MW

8	Potrero-Hunters Point (AP-1) 115 kV Cable	December 2005 CPUC Permit Approval Granted	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement. Scheduled for Dec. 2005 operation.
9	Jefferson-Martin 230 kV Line	March '06 to June '06 Under construction	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
10	Potrero 3 SCR retrofit	June 2005 Completed	NERC/WECC/CAISO Planning Standards	This project ensures the availability of Potrero 3 at full capacity thereby reducing overall Greater Bay Area RMR requirements. This project or the reduced capacity available without the retrofit in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreements
Release Potrero Unit 3 From Its RMR Agreement				
11	San Francisco Electric Reliability Project and San Francisco Airport Electric Reliability Plant	June 2007	NERC/WECC/CAISO Planning Standards	These projects will allow ISO/PG&E to meet planning requirements with Potrero 3 released from its RMR Agreement. CEC permit suspended due to a change in where to site near Potrero.
Release Potrero Units 4, 5, & 6 From Their RMR Agreements (assumes previous completion of Peaking Power Plants by the City)				
12	Upgrade the Newark-Dumbarton 115 kV line	December 2006 Engineering in Progress	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement
13	Upgrade the Bair-Belmont 115 kV Line	Scheduled for May 2007	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement
14	Upgrade the Metcalf-Hicks & Metcalf-Vasona 230 kV lines	Scheduled for May 2007	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement
15	Add voltage support at Ravenswood substation	Scheduled for May 2007	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement

Attachment 2

San Francisco Stakeholder Study Group

Phase 2 Study Plan

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

Revised Version 3.0
April 1, 2004

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

Gary DeShazo / Larry Tobias
Grid Planning
California ISO

Manho Yeung / Stan K. Nishioka
Transmission Planning
Pacific Gas & Electric Company

I. Introduction

This San Francisco Peninsula Long-Term Phase 2 Study is being conducted to determine what future mix of transmission system reinforcement, existing and new generation resources (including distributed and renewable), and load management programs are required to maintain the ability to serve load within the City & County of San Francisco (CCSF) and along the San Francisco Peninsula (Peninsula) (See Figure 1 on page 3) after the Jefferson-Martin 230 kV line is in operation and the Hunters Point Power Plant is retired. A long-term plan is defined as a 10-year plan. Because the ability to serve load within the San Francisco Peninsula is impacted by the ability to import power into and through the San Francisco Greater Bay Area (GBA – see Figure 2), load-serving capability within the GBA will be analyzed as necessary.

Presently, transmission lines and local power plants supply electric demand in the CCSF and the Peninsula. Hunters Point Power Plant[13] (HPPP) and Potrero Power Plant (PPP) are the major local power plants presently in operation within the San Francisco area. Their total combined generating capacity is 570 megawatt[14] (MW). There is also a 28 MW co-generation power plant, United Airlines Cogen, near the airport that is normally modeled on-line to serve United Airlines load. Also, the CCSF is in the process of siting up to four combustion-turbine (CT) generator units (45 MW each) within the CCSF.

In April 1999, the California Independent System Operator (CA ISO) formed a study group (the San Francisco Stakeholder Study Group (SFSSG) to evaluate long-term power supply adequacy to San Francisco, and to identify the preferred alternatives to meet future electric demand. This effort was initiated following the December 1998 disturbance that interrupted electric service to a significant portion of San Francisco. 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 CA ISO Board of Governors in October 2000. One key finding in the study group report was that, unless new generation resources are built within the San Francisco area, new transmission facilities to increase the amount of power imported from outside the San Francisco area would be needed to meet customer demand by 2006. The preferred transmission alternative was the Jefferson-Martin 230 kV Transmission Project. Based on this information, CA ISO Management granted final CA ISO approval for this project in April 2002. This project is presently within the CPUC Certificate of Public Convenience and Necessity (CPCN) process for approval prior to the start of construction.

In 2003, the CA ISO considered the potential retirement of generation at HPPP within a study to determine the load serving capability for the San Francisco Peninsula under a verity of transmission and generation scenarios (San Francisco Peninsula Load Serving Capability Study). The CA ISO determined that a combination of transmission system reinforcement within the San Francisco Peninsula and GBA along with the proposed CCSF CT's are required to provide sufficient load serving capability with HPPP Units #1 and #4[15] retired. It has also been documented that at least HPPP Unit #4 can be retired with either the CCSF CT's or the Jefferson-Martin 230 kV Project.

[13] For this study it is assumed that the HPPP is shutdown and retired prior to 2006.
[14] Hunters Point Units 1 (combustion turbine - 50 MW) and Unit 4 (steam - 163 MW), Potrero Power Plant Unit 3 (steam - 207 MW) and Units 4-6 (combustion turbines - 50 MW each). Hunters Point Unit 4 began commercial operation in November 1958. Potrero Unit 3 began commercial operation in December 1965.
[15] HPPP Units #2 & #3 are run as synchronous condensers (converted in 2001) and are scheduled to be replaced by a new Static Var Compensator at Potrero Substation by 2006.

Resolution of issues related to interpretation of ISO Planning Standards (San Francisco Greater Bay Area Generation Outage Standard) as applied to the local San Francisco transmission system could allow for the retirement of HPPP Unit #1 also in combination with either the CCSF CT's or the Jefferson-Martin 230 kV Project. This study constituted the completion of the first Phase of establishing a long-term (10 year) plan for serving electric load growth within CCSF and the San Francisco Peninsula.

While the PPP generation facilities provide load serving capability to the San Francisco Peninsula Area and are very effective in meeting Reliability Must-Run requirements within this area and the GBA, their continued operation cannot be considered without addressing the fact that Potrero Unit #3 is 38 years old and Potrero Units #4, 5 & 6 are simple-cycle CT's whose operation is limited to 877 hours (10% of a year) due to their emission output and are 28 years old. In addition, the impact on load serving capability due to the retirement of old generation facilities elsewhere within the GBA as well as generation that may become unavailable due to stricter GBA Nox limits will also be analyzed, on a limited basis, within this study. PG&E's 2004 annual transmission system studies will provide a more comprehensive analysis on the impact of generator unit retirement within the GBA. To ensure that there continues to be adequate means to meet load growth in the San Francisco and Peninsula areas, decisions must be made about the future mix of transmission system reinforcement, existing and new generation resources (including distributed and renewable), and load management programs required to maintain the ability to reliably serve load within the City & County of San Francisco, the Peninsula and GBA.

The development of the Jefferson – Martin 230 kV Transmission Project represents a first step resulting from a commitment on the part of the CA ISO and stakeholders to develop a long-term plan for reliably serving load in CCSF and the Peninsula. However, in light of electric load, generation, and emission variables, additional work is required by the SFSSG to assure reliable electric service is maintained. The purpose of this study plan is to provide a comprehensive approach for assessing the long-term load serving capability of the CCSF and Peninsula areas and to identify acceptable ways to increase the load serving capability in this region beyond that provided by transmission reinforcement projects, generation resources (including distributed and renewable), and load management programs expected to be in operation by 2006. Since we already know that to determine the real load-serving capability of the next addition will require also a study of the needed transmissions expansion in the Bay Area for various generation retirement scenarios. To a limited extent, we will expand the study scope as necessary to develop a complete picture of the affect of Phase 2 additions for the San Francisco Peninsula on the load serving capability for the GBA. It is expected that PG&E, through their annual transmission assessment and expansion plan process, will also be analyzing the potential retirement of old generator units within the GBA and their impact on maintaining sufficient load serving capability within the GBA. The SFSSG will compare proposed alternatives from technical, economic, environmental, and societal perspectives and prepare recommendations that will achieve the objectives of this study. The SFSSG will prepare a written report that documents the technical study results and includes a recommended long-term preferred alternative solution for reliably serving load within the CCSF and Peninsula areas.

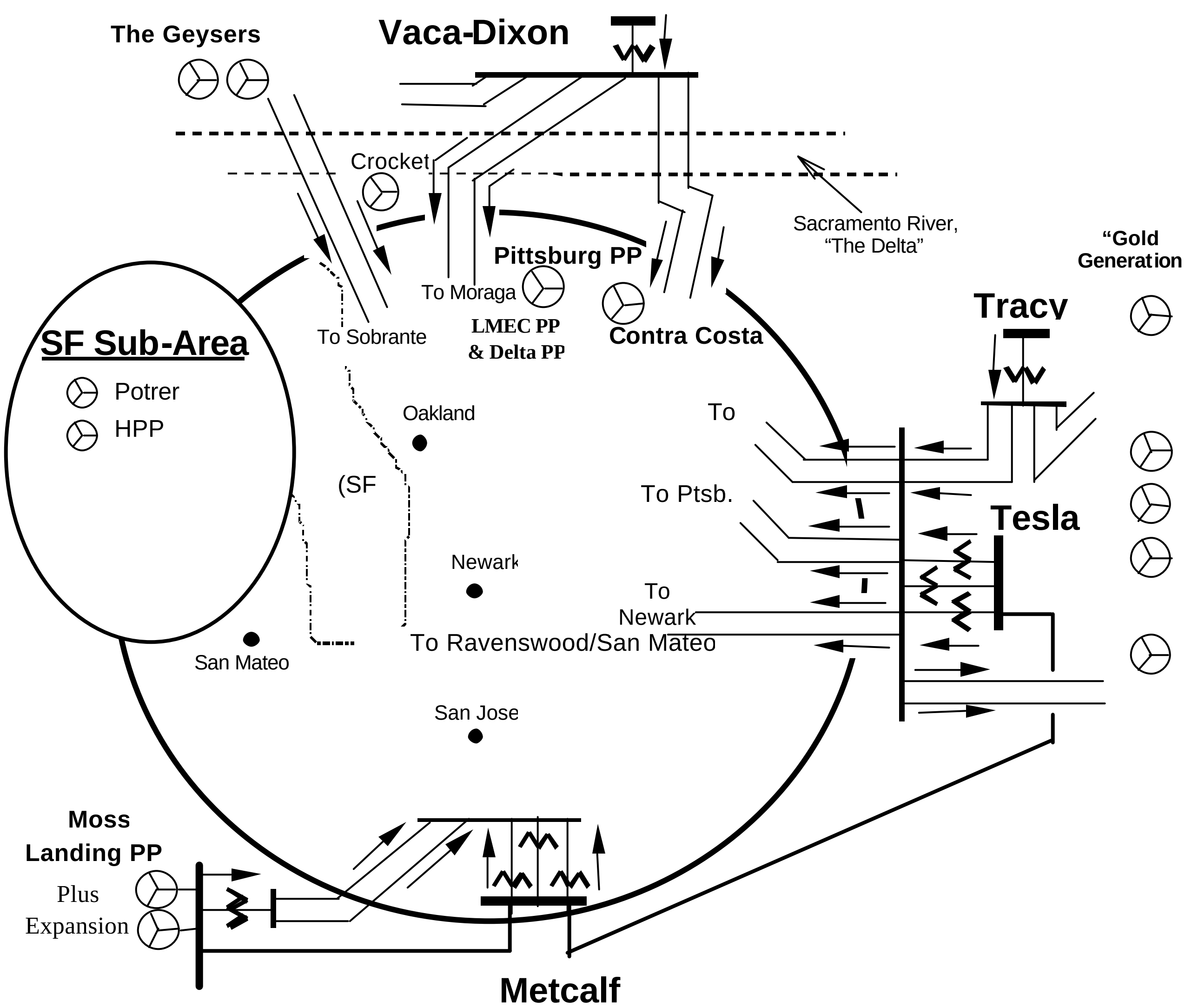
Figure 1

General Geographic Area Constituting the Greater San Francisco Bay Area

Figure 2: San Francisco Greater Bay Area Transmission System Sketch

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

The San Francisco Greater Bay Area (GBA) is defined as a local RMR area. Generator units within the GBA mitigate reliability problems on the electric transmission system associated within importing power into and throughout this area. Load within the GBA is served by a combination of power imported over the transmission system and power produced by local generation. The transmission system through which power is imported into the GBA consists primarily of four major 500/230 kV substations (Vaca-Dixon, Tesla, Metcalf, and Tracy substation) and a network of 230 kV lines.



There are presently twenty-one transmission lines that cross the "cut plane" and are associated with importing power into the GBA. The lines are:

- ?? Lakeville-Sobrante 230 kV
- ?? Crocket-Sobrante 230 kV
- ?? Parkway-Moraga 230 kV
- ?? Bahia-Moraga 230 kV
- ?? USWind-Contra Costa Sub 230 kV
- ?? Peabody Tap-Contra Costa P.P. 230 kV
- ?? Brentwood-Contra Costa PP 230 kV
- ?? Windmaster-Contra Costa PP 230 kV
- ?? Flowind-Pittsburg 230 kV
- ?? JV Enterprises- Pittsburg 230 kV
- ?? Tesla-Newark 230 kV
- ?? Tesla-Ravenswood 230 kV
- ?? Tesla-Metcalf 500 kV
- ?? Moss Landing-Metcalf 500 kV
- ?? Moss Landing-Metcalf #1 230 kV
- ?? Moss Landing-Metcalf #2 230 kV
- ?? Green Valley-Morgan Hill #1 115 kV
- ?? Green Valley-Morgan Hill #2 115 kV
- ?? Oakdale TID-Newark #1 115 kV
- ?? Oakdale TID-Newark #2 115 kV
- ?? Tesla-Newark #2 230 kV

II. Objectives

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

Working in a collaborative and pro-active manner, the SFSSG will complete the following objectives:

With the Jefferson-Martin Project in operation and Hunters Point Power Plant retired, develop a long-term load-serving plan for the City & County of San Francisco and San Francisco Peninsula Areas that takes into account the following:

6. **Considers varying levels of load growth, new generation development, generation retirement, and electric transmission system reinforcement.**

7. **Considers San Francisco Greater Bay Area power import capability and ability to transfer power to the San Francisco Peninsula.**

8. **That will meet established CA ISO Grid Planning Standards at the lowest cost to ratepayers.**

9. **That involves fully utilizing the existing transmission system while recognizing the economics of building a new transmission line into the San Francisco Area.**

10. **That includes economic alternatives to Reliability Must-Run generation requirements.**

11. **That recommends a preferred transmission system reinforcement considering existing and new generation resources (including distributed and renewable), and load management programs within the City & County of San Francisco and the Peninsula Areas.**

III. Responsibilities

In order to complete the objectives of this Phase 2 study effort, participation is required by all SFSSG members. It is expected that the CA ISO and PG&E will undertake the majority of the study responsibility, especially the technical studies, 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:

A. The SFSSG will:

1. Support the CA ISO and PG&E in completing the study in a timely manner;
2. Take meeting minutes on a rotational basis;
3. Develop the Phase 2 study objectives and technical study assumptions;
4. Develop applicable alternatives to be assessed against the identified study objectives;
5. Review and comment on technical study results and provide guidance and suggestions on how the results meet the intent of the study objectives;
6. Prepare conclusions and recommendations that are representative of the technical study results;
7. Support the CA ISO and PG&E in the preparation of a written report that documents the efforts of the SFSSG;
8. As necessary, support the CA ISO in achieving approval from the CA ISO Board of Governors on SFSSG recommendations.

B. PG&E will:

1. Be a proactive member of the SFSSG;
2. Assume a co-leadership role with the CA ISO 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 co-leadership role with the CA ISO in the performance of technical studies required to fulfill the objectives of the SFSSG.

C. The CA ISO will:

1. Be a proactive member of the SFSSG;
2. Assume the leadership role of the SFSSG;
3. Assume a co-leadership role with 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. Assume a co-leadership role with 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 CA ISO Board of Governors.

IV. Reliability Criteria

As with all studies that are performed as part of the CA ISO controlled grid, study results must meet the intent of the CA 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 CA ISO controlled grid. The CA ISO Grid Planning Standards were developed through a stakeholder process and have been approved by the CA ISO Board of Governors. In general, the CA ISO Grid Planning Standards include:

H. CA ISO Grid Planning Criteria
I. Specific Nuclear Unit Standards
J. Combined Line and Generator Outage Standard
K. New Transmission versus Involuntary Load Interruption Standard
L. San Francisco Greater Bay Area Generation Outage Standard
M. Western Electricity Coordinating Council (WECC) Reliability Criteria
N. North American Electric Reliability Council (NERC) Planning Standards

The CA ISO also considers PG&E's "Supplementary Guide for Application of the Criteria for San Francisco" when analyzing the transmission system between San Mateo and Martin Substations.

V. 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 level, line flow, or voltage level. 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 the manner described above. 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. Using these base cases, technical analysis was performed to assess the expected transmission system performance for the alternatives that been proposed. This approach works well as long as there is acceptance of the relationship of the load level to the year it represents. Considering that load is a variable dependent on load projections that are annually revised, load will be considered a "variable" in this Phase 2 study effort. As such, a Load Serving Capability (LSC) approach to assessing the long-term needs of the San Francisco Peninsula Area will be used.

For the Phase 2 study effort, a base case will be developed which represents the San Francisco Greater Bay Area for the 2011 time frame because past history has shown that it could take 7 years lead-time to determine, design, permit, and construct a new 230 kV line into the San Francisco Area. The San Francisco Peninsula Area and GBA loads will be adjusted up or down depending on whether or not a system limit has been reached. Due to the complexity of the transmission system within the GBA and that local areas within the GBA are projected to grow at different rates, the GBA area load will not be scaled up or down with one scaling factor nor in the small increments possible when scaling loads just within the San Francisco Peninsula.

In explaining determination of load serving capability, a base case could be developed with zero generation on-line in the San Francisco Peninsula Area. Using this base case, a power flow analysis could then be performed to determine if the system represented in the base case met all applicable planning standards. If any planning standard(s) were not met, one might surmise that the system was inadequate to handle the load being modeled, therefore system additions might be warranted. Or, from another perspective, the planning standard violations indicate that the load represented in the base case was greater than the transmission system was capable of handling. At this point, it is clear that there are two options that could be pursued. One might be an “added facility” methodology where new facilities are added to the system to resolve the planning standard violation(s). These new facilities might take the form of a new transmission line, replacement of existing facilities, increasing the capability of existing facilities, or some combination of all of these things, among others. Another option might be a “load adjustment” methodology where the load is adjusted up or down until all planning standards were met, a point, which can be characterized as the “Load Serving Capability” of the system. A ‘load adjustment” could be representative of the effectiveness of distributed and renewable generation resources and load management programs. While both methodologies are acceptable to resolve the planning standard violations, their application can lead the observer to different conclusions about how the system performs. For example, the “added facility” methodology may resolve the planning standard violations, but it does not provide the observer with any information about actual system load serving capability or the incremental load serving value of the new facility additions. Whereas the “load adjustment” methodology will provide the observer with information about the load serving capability of the system as well as the performance, in terms of load served, of any proposed facility addition such as transmission, generation, and/or reactive compensation. The “load adjustment” methodology will result in Load Serving Capability quantities being associated with the different alternatives being assessed in the study and would provide the ability to adjust to future changes in projected load growth without requiring a significant amount of additional technical analysis. The value of this approach is that it will allow for an unbiased assessment of the relationship of any proposed alternative to the load benefit that it would provide. In summary, a very important aspect of determining load serving capability under certain transmission and generation conditions, is that the difference between the load serving capability and the projected load can be reduced or replaced with a mix of transmission system reinforcement, existing and new generation resources (including distributed and renewable), and load management programs. In other words, the potential unserved load has been quantified as a reliability concern and can be served in a verity of ways.

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

A. The main focus of this study is maintaining load-serving capability within the area defined by the transmission system within the CCSF and San Francisco Peninsula areas. This combined area is generally delineated as the transmission system from PG&E’s Ravenswood Substation north along the San Francisco Peninsula and including the City & County of San Francisco (see Figure 3). It is recognized that in doing this, consideration is given to reinforcing the various transmission paths through the GBA to the San Francisco Peninsula as well as maintaining the load-serving capability within the entire GBA.

B. It is recognized that in doing this, consideration is given to reinforcing the various transmission paths through the GBA to the San Francisco Peninsula as well as maintaining the load-serving capability within the entire GBA. Therefore, this study will also focus on the San Francisco Greater Bay Area (See Figure 2). Serving load within the CCSF and San Francisco Peninsula is dependent on power flow into and through the electric transmission system within the San Francisco Greater Bay Area.

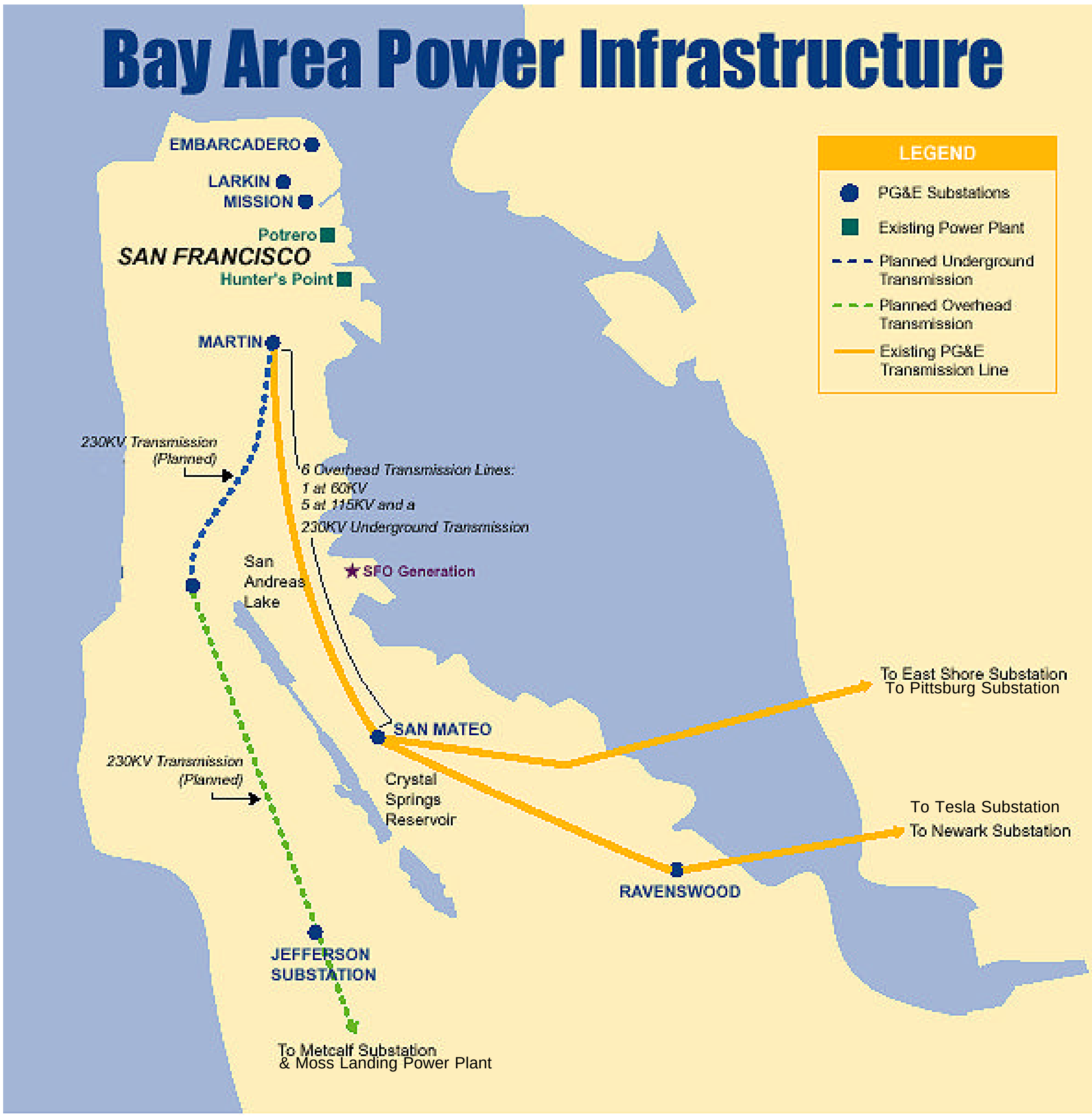
C. Develop power flow base cases representing the 2011 summer season and the various scenarios (described in section G.3. below) for long-term load serving capability. When evaluating the load serving capability results of this study, this study will utilize PG&E most recent load projections, but will include the sensitivity of lower or higher load growth rates. Other seasons may be studied as necessary.

D. The base case should reflect the most up to date WECC System data as well as PG&E’s planned transmission improvements that have been approved by the CA ISO. This case will represent the study “benchmark” base case from which all study cases will be developed.

E. The use of reactive support in appropriate places can increase the Load Serving Capability; therefore, its impact on the Load Serving Capability will need to be assessed. To accomplish this, the benchmark base case will only include reactive power support devices currently included in PG&E's transmission expansion plans. Additional voltage support will be included as necessary to represent new voltage support facilities that may be required. More detailed voltage support analysis will be required before a voltage support project is recommended.

F. Post-benchmark cases will be developed to represent various transmission/generation scenarios. The performance of these scenarios will be measured by their ability to serve load. The Load Serving Capability of a scenario will be determined by adding that scenario to the benchmark case and increasing the load in proportional amounts until an CA ISO Grid Planning Standard is violated for the appropriate single or multiple contingency being taken.

Figure 3



VI. Assumptions

The San Francisco Peninsula Area load corresponds to the CCSF and Peninsula areas referenced earlier in this document.

CCSF and Peninsula loads are presently 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. Four 230 kV lines that can import power to San Mateo Substation are listed below:

- Pittsburg – San Mateo 230 kV line
- East Shore – San Mateo 230 kV line
- Ravenswood – San Mateo #1 & #2 230 kV lines

The San Francisco Peninsula load south of San Mateo Substation is supplied through Ravenswood Substation, which receives power primarily through 230 kV lines across San Francisco Bay from Newark and Tesla Substations, but also through 115 kV lines from Newark Substation (See Figure 3).

The Jefferson-Martin 230 kV Transmission Project was granted final approval by the Cal-ISO on April 25, 2002. PG&E filed a CPCN with the California Public Utilities Commission in September 2002. This project is scheduled to be in service in December of 2005 and will provide another 230 kV transmission line to import power into the CCSF and Peninsula areas from a different area within PG&E's transmission system and therefore improve reliability to serve load within the San Francisco Peninsula and increase the diversity of generation resource locations. Full utilization of the new 230 kV line could be dependent on additional reinforcement of the transmission system between Jefferson and Metcalf Substation. This will be determined during the course of this study. Upon the retirement of the HPPP, additional reactive power support is required and therefore PG&E in the process of installing a Static Var Compensator at Potrero Substation. Table 2 includes a list of projects associated with serving load in the CCSF and Peninsula areas.

The performance of the existing system with the Jefferson-Martin Project in service and HPPP retired will serve as a benchmark for the study results of subsequent years.

A 2011 GE-format base case will be used to develop the Benchmark base case for this Phase 2 study effort.

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

A. Power Flow Base Case Assumptions

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

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

5. Base case representation (system representation, generation, etc.) will be coordinated and prepared by PG&E with the support of the Cal-ISO and will be reviewed and accepted by the SFSSG.

6. The benchmark base case will represent 2011 Heavy Summer conditions. This case will be developed from a recently created 2009 PG&E base case. The primary base case will include representation of only Northern California. A base case for the entire WECC region will be created for the purpose of screening for post-transient and dynamic stability problems.

7. PG&E's proposed Jefferson-Martin 230 kV Project and any related transmission reinforcement required to utilize this line will be represented in the base case. In addition, all transmission projects approved by the CA ISO and scheduled for operation prior to 2011 will be represented.

8. For all areas outside California, the network topology and loads will reflect information that has been provided to WECC through their base case development process.

A summary of base case assumptions will be included in the Phase 2 report.

B. Load-Related Assumptions

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

2. **PG&E Load Level.** As a starting point, PG&E load will be represented in the benchmark case at the peak level projected for the 2011 time period. Load adjustments will be made to the Area Load as discussed in the Study Methodology.

   The mechanics of how the load modeling will be achieved starting with PG&E's 2009 base case as follows:

   c. The San Francisco and Peninsula Planning Areas will be modeled to represent their maximum anticipated 2011 coincident peak load, based on a one-in-ten year high temperature forecast.

   d. The remaining planning areas that constitute the "Greater Bay Area" will be modeled at their expected 2011 one-in-ten load at the time of the San Francisco- Peninsula coincident peak.

   As addressed within the Methodology section above, the primary base caseload within the GBA will be scaled up to define the load serving capability in 2011. From that load level, the load will be scaled up and down to analyze what reliability problems may occur prior to or later than 2011.

4. **Power Factor.** Reactive load Watt/VAR ratios represented in the base cases will reflect reasonable values for the operating conditions being studied.

3. **"Municipality" Loads.** Loads of Non-Participating Transmission Owners within PG&E's service area will be modeled based on the most recent forecast available.

4. **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.

C. Generation-Related Assumptions

8. **High / Low Generation.** This study will include an analysis of different generation resource assumptions within the San Francisco and Peninsula Area. The study group will determine scenarios to be considered in the study. All scenarios will have the Hunters Point Power Plant retired.

9. **Reliability Must-Run Generation.** The most recent and appropriate levels of RMR Generation within the Greater Bay Area will be incorporated into these studies and documented within the study report. It is important to note that the output of combustion turbine and combine-cycle generator units is dependent on the ambient temperature corresponding to the season and load level being studied. The higher the ambient temperature is, the lower the output will be. This fact will be reflected in the unit output levels represented in the various power flow cases within this study. Table 1 is a list of generation resources within the Greater Bay Area that can mitigate RMR reliability problems.

10. **Qualifying Facilities.** QF generation located within PG&E's service area will be modeled at an output that reflects their historic dependable operating capacity. Those QFs, who are expected to either reach the end of their contract or have their contract bought-out within the time frame being studied, will be regarded in the same fashion as other "merchant" or market-driven units. These units will be determined and documented as part of the process in building the power flow base cases for this study.

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

12. **Distribution-Sited Generation.** All generation directly interconnected to PG&E's distribution systems (i.e. not directly interconnected to the CA ISO Controlled Grid) will be netted with the load represented at the nearest CA ISO Grid Take-Out Point. If necessary 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 Section VIII D below.

13. **New Generation.** Consistent with the CA ISO Guidelines for modeling new generation, this Phase 2 study will include the impact of proposed new generation within the CA ISO Controlled Grid Area and Greater Bay Area. Due to the uncertainty of new generation being on-line when scheduled, only new generation projects that are deemed to be moving forward in a manner to meet their planned operating date will be modeled. This is in addition to various potential scenarios involving new generation within the San Francisco Area as outlined in Section VII C below.

7. **Air Quality.** The impact of Greater Bay Area air quality restrictions as described by reduced future NOX limits on existing generation and related SCR retrofitting will be considered within the study.

Table 1: 2004 Greater Bay Area Generation

Generator Unit Name	#	MW		Generator Unit Name	#	MW
Moss Landing - New	1	176		Oakland CT	3	74.5
Moss Landing - New	2	176		Oakland CT	1	75
Moss Landing - New	3	198		Oakland CT	2	75
Moss Landing - New	4	176		LMEC	1	280
Moss Landing - New	5	176		LMEC	2	199
Moss Landing - New	6	198		LMEC	3	199
Moss Landing	6	750		Los Esteros CEF	1	49
Moss Landing	7	750		Los Esteros CEF	2	49
Alameda CT	1	25.6		Los Esteros CEF	3	49
Alameda CT	2	25.6		Los Esteros CEF	4	49
Contra Costa	4	0		Pittsburg	5	330
Contra Costa	5	0		Pittsburg	6	330
Contra Costa	6	345		Pittsburg	7	710
Contra Costa	7	345		Potrero	4	52
DEC	1	320		Potrero	5	52
DEC	2	215		Potrero	6	52
DEC	3	215		Potrero	3	210
DEC	4	215		Tosco (Union Chemical)	1	25
Gianera CT (Santa Clara)	1	26.9		J. Smurfit (Container Corp.)	1	25
Gianera CT (Santa Clara)	2	26.9		Gilroy Peaker	1	45
Hunters Point *	1	52		Gilroy Peaker	2	45
Hunters Point *	2	0		Gilroy Peaker	3	45
Hunters Point *	3	0		Gilroy Energy	1	41
Hunters Point *	4	170		Gilroy Energy	2	89
IBM Cottle	1	50		Valero	1	49
Martinez Refining Co.	1	20		Valero	1	49
Martinez Refining Co.	1	40		Creed	1	48
Martinez Refining Co.	2	40		Lambie	2	48
Riverview Energy Center	1	50		Goosehaven	3	48
Metcalf Energy Center	1	645				

* It is assumed that the entire Hunters Point Power Plant has been retired.

Table 1 does not include about 835 MW of QF and self-gen within the GBA and the Los Medanos Energy Center is already under a contract that also reduces the RMR requirement.

Table 2

Reference List of Projects

1. **Installation of four 45 MW combustion turbines by the City & County of San Francisco.** ***Status:*** *On April 10, 2003 CCSF initiated the generation interconnection study for this project and it's various alternatives. Expected completion date is scheduled for December 2006. The current plan calls for siting three CT's at Potrero Substation and one CT near the San Francisco Airport.*

2. **Jefferson-Martin 230 kV Line Project.** PG&E to increase the import capability into the San Francisco Area through building a new 230 kV line between Jefferson and Martin Substations. This line may be partly or all an underground cable. ***Status:*** *This project has been approved by the CA ISO and is presently within the CPUC CPCN process. The line is scheduled to be in Operation by Dec. 2005*

3. **Newark-Ravenswood 230 kV Line Rerate.** PG&E to increase the emergency rating of the Newark-Ravenswood 230 kV line using a higher wind speed assumption, and replace 230 kV switches. The line's emergency rating will be increased from 2,110 Amps to 2,500 Amps. ***Status:*** *Completed*

4. **Ravenswood-San Mateo 115 kV Line Rerate.** PG&E to increase the emergency rating of the Ravenswood-San Mateo 115 kV line using a higher wind speed assumption. The line's emergency rating will be increased from 522 Amps to 618 Amps. ***Status:*** *Completed.*

5. **Tesla-Newark #2 230 kV Line Rerate.** PG&E to increase the emergency rating of the Tesla-Newark #2 230 kV line using a higher wind speed assumption, and replace 230 kV switches. The line's emergency rating will be increased from 1,714 Amps to 1,954 Amps. ***Status:*** *Completed.*

6. **Tesla-Newark #2 230 kV Line Upgrade.** PG&E to increase the rating by completing the bundling of the Tesla-Newark #2 230 kV line with 954 ACSS conductor for approximately 8 miles out from Tesla Substation. ***Status:*** *Proposed within PG&E's 2003 Transmission Expansion Plan for May 2005 operation.*

7. **Ravenswood 230/115 kV Transformer.** PG&E to install a new second 230/115 kV transformer (420 MVA) at Ravenswood. ***Status:*** *ENGINEERING & PROCUREMENT, completion expected May 2004.*

8. **Ravenswood-Ames #1 & #2 115 kV lines Reinforcement.** PG&E to increase the rating of the Ravenswood-Ames #1 & #2 115 kV lines by reconductoring them with 477 ACSS conductor. ***Status:*** *Proposed within PG&E's 2003 Transmission Expansion Plan for May 2005 operation.*

9. **San Mateo-Martin #4 Line 60-115 kV Voltage Conversion**. PG&E to reconductor and convert the San Mateo-Martin 60 kV circuit to 115 kV operation. Substation modifications are also needed at Burlingame and Millbrae. ***Status:*** *Permit application filed with the CPUC in November 2002; PEA Application deemed complete on March 24, 2003. Expected completion of June 2004 <u>or later</u> depending on permit requirements.*

10. **Potrero-Hunters Point ("AP-1") 115 kV Underground Cable.** PG&E to complete construction of a new 115 kV underground cable between Potrero and Hunters Point. ***Status:*** *PG&E and CCSF are working on a joint project and completing the needed environmental impact report, operation is scheduled for June 2004 <u>or later</u> depending on permit requirements.*

11. **Martin-Hunters Point 115 kV Cable.** This new 115 kV circuit is scheduled for operation by summer 2007 and is required to distribute power imported into Martin Substation in place of power generated at Hunters Point Power plant. New emergency ratings are being developed by PG&E for the 115 kV cable system within San Francisco as an interim measure between the time generation is retired at Hunters Point and the new cable is in operation.

'II. Scope

The scope of the technical analysis will utilize the power system analysis techniques described below.

A. Transmission Network Analysis

4. 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. 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 the seasonal conditions studied. To the extent that unacceptable power flows are seen, transmission system reinforcement, new generation resources, load management or other mitigation measures will be investigated.

5. Voltage Analysis

Voltages levels will be monitored to ensure that they are within the acceptable voltage range per the reliability criteria in Attachment III. To the extent that unacceptable (low) steady-state voltages are seen (pre- or post-contingency), upgrades or other remedial measures will be studied.

6. Reactive Margin Analysis

Detailed technical analysis will be required to assess reactive power support margin requirements. Such requirements affect the ability of the system to withstand the phenomenon known as "voltage collapse". The most recent WECC methodology will be used. The methodology, as applied to this study, involves evaluating reliable system performance at a load level 5% above limiting load serving capability levels for a single contingency (NERC Category B) and 2.5 % for analyzing a double contingency (NERC Category C). (Also see Attachment V.)

7. Transient Stability Analysis

As determined to necessary, transient stability analysis will be performed to ensure that stability is maintained within the San Francisco Bay Area. (See Attachment V for a sample of Transient Stability.)

8. Loss Analysis (Optional)

Transmission system losses (net positive or negative) associated with various transmission system reinforcement proposals will be measured against the base case. The impact of each proposed alternative on losses will be identified and documented in the study report.

III. Potential Transmission / Generation Projects for Consideration

The SFSSG will develop alternative system reinforcements. The development of transmission alternatives will include an evaluation of the reliability risks and consequences of continuing to connect additional transmission lines to Martin Substation. A recommendation to build a new transmission line into the San Francisco Area will be based on first, fully utilizing the existing transmission system along with additional reinforcement of that system while recognizing the economics of building a new line. In addition to any additional reactive voltage support required, it is expected the potential alternatives will include the following:

A. External[16] Transmission Reinforcements

1. San Mateo - Martin Corridor

a. A second San Mateo - Martin 230 kV or Potrero 230 kV underground cable – this alternative would include providing sufficient import capability to San Mateo Substation via the two 230 kV lines crossing SF Bay to San Mateo and Ravenswood Substations and between Ravenswood and San Mateo Substations.

2. East Bay Corridor

a. A 230 kV circuit from Moraga or Sobrante Substations to Potrero or new switching station in CCSF.[17] These new lines could be either AC of DC lines.
b. A DC line between Potrero and Pittsburg Substations.

[16] As it pertains to transmission, "external" is used to describe system reinforcements that allow for power to be transmitted into the SF-Peninsula.
[17] 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 as well as reinforcement of the San Francisco 115 kV cable system.

B. Internal[18] Transmission System Reinforcements

Any potential transmission reinforcements required within the East Bay or San Francisco parts of the Greater Bay Area will be identified as part of this study effort.

C. Generation Scenarios

1. Scenario of no Potrero unit #3
2. Scenario of no Potrero generation
3. Expansion of Generation within the CCSF (135 MW)
4. Vicinity of SF Airport peaking generation (35 MW) as part of #3 scenario above.
5. Other generator unit retirement within the Greater Bay Area will be developed and analyzed?

D. Load Management / Conservation Alternatives / Distributed Generation

Based on the methodology that is being used to perform the Phase 2 study effort, an analysis of specific load management/conservation and distributed and renewable generation alternatives will be incorporated into the load serving capability scaling of load, such that lower load reflects the application of these.

E. Project Cost Estimates

Rough estimated project costs and permitting/construction timelines will be developed for each of the alternatives considered. These estimates will be preliminary and based on available unit costs. These estimates are for the purpose of comparing alternative projects and are not indicative of the final projects costs developed after a through investigation of the project conducted as part of a projects permitting process within California. The potential impact of each alternative to ratepayers (including RMR costs) will be included in recommending a preferred project alternative. Project permitting difficulties related to potential environmental impacts will also be documented in the final report on this Phase 2 effort.

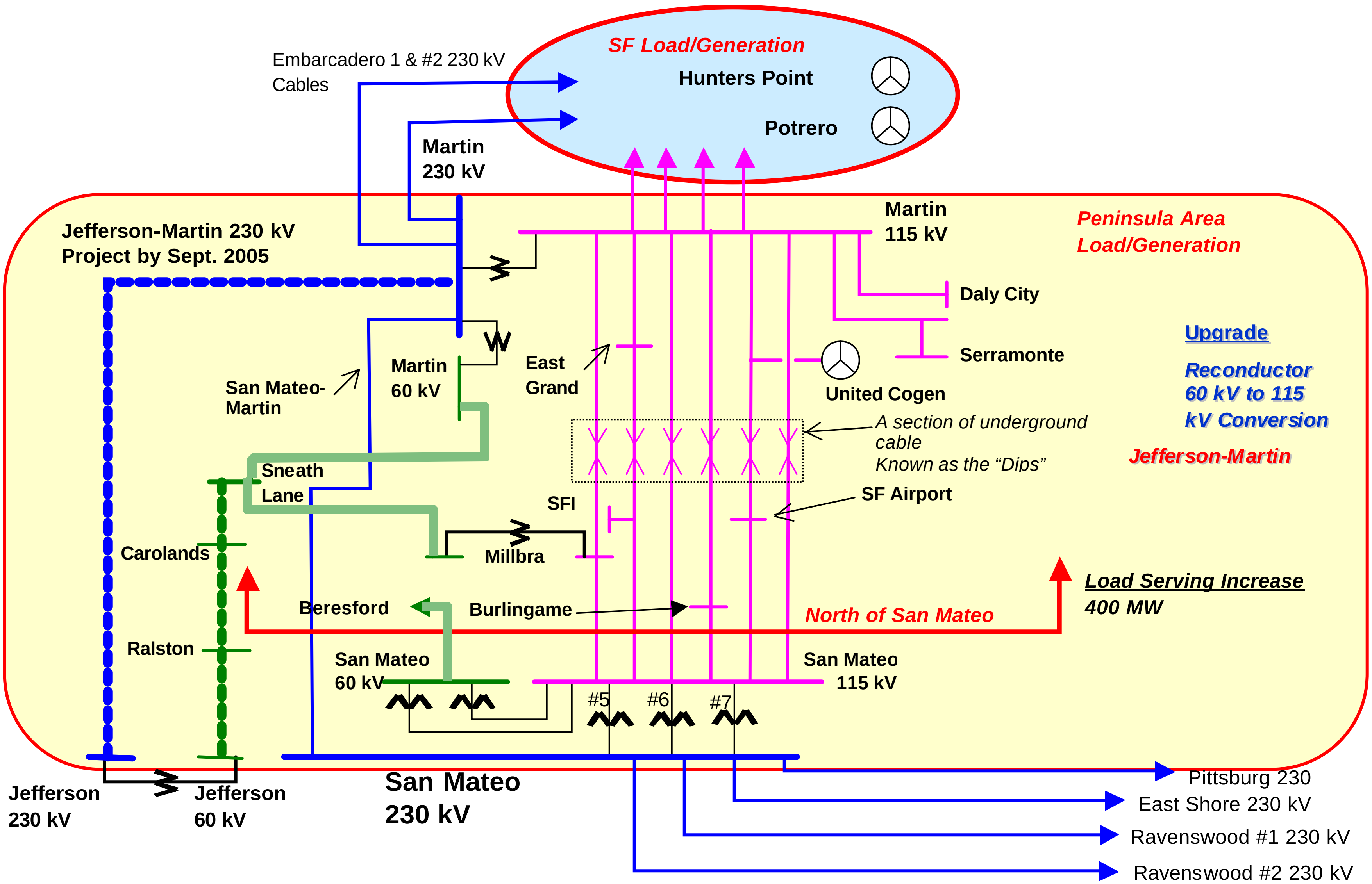
[18] As it pertains to transmission, "internal" is used to describe system reinforcements that allow for power to be transmitted within SF.

IX. Schedule – This schedule is dependent on when PG&E completes development of their power flow base cases for their 2004 annual transmission studies.

Milestone	Date
Draft Study Plan Sent Out	01/30/04
Study Group Meeting #1 – Draft Study Plan & Objectives	02/19/04
Comments on Study Plan Due To CAISO	03/04/04
Final Study Plan Sent Out	03/11/04
Draft Power Flow Base Cases Sent Out For Comments	5/11/04
Power Flow Comments Due to CAISO	5/24/04
Final Power Flow Base Cases Prepared	6/8/04
Study Group Meeting #2 – Preliminary Base Case Generation Analysis	7/22/04
Study Group Meeting #3 - Preliminary Project Technical Studies	9/22/04
Study Group Meeting #4 - Additional Technical Studies	11/18/04
Initial Draft Report Sent Out For Comments	12/17/04
Study Group Meeting #5 - Initial Draft Report	1/6/05
Draft Report Comments Due To CAISO	1/20/05
Second Draft Report Sent Out For Comments	2/10/05
Study Group Meeting #6 To Discuss Second Draft Report	2/17/05
Draft Report Comments Due To CAISO	3/3/05
Final Draft Report Sent Out	4/3/05
Present Final Study Report & Recommendations to ISO Board of Governors for Adoption	5/18/05

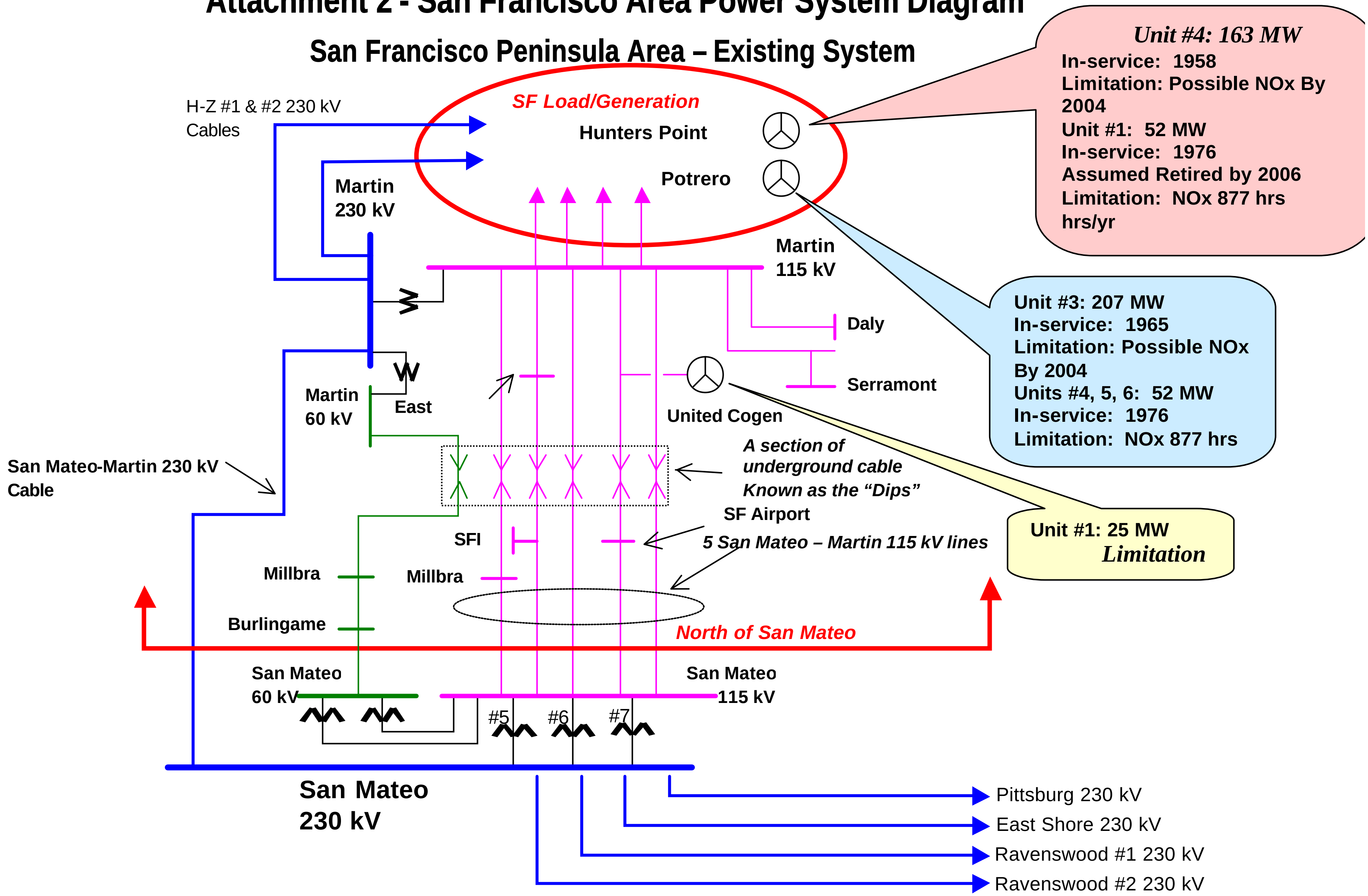
Attachment I
San Francisco Area
Power System Diagram

Attachment 1 - Planned San Francisco Peninsula Area Transmission



Attachment 2 - San Francisco Area Power System Diagram

San Francisco Peninsula Area – Existing System



Attachment II
SF / Peninsula Planning
Study Group Members

Attachment II - SF / Peninsula Planning Study Group Members as of August 29, 2005

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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."[19]

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."[20]

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.

[19] ISO Tariff, April 7, 1998, Section 3.2.1.2, Page 129.
[20] 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.

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.

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 IV - 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 IV - NERC Planning Standards (*excerpt*)

Transmission System Standards - Normal and Contingency Conditions

Category	Contingencies: Initiating Event(s) and Contingency Component(s)	Components Out of Service	System Limits or Impacts: 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:		Applicable Rating [a] (A/R)				
	1. Generator	Single	A/R	A/R	Yes	No [b]	No
	2. Transmission Circuit	Single	A/R	A/R	Yes	No [b]	No
	3. Transformer	Single	A/R	A/R	Yes	No [b]	No
	Loss of a Component without a Fault.	Single	A/R	A/R	Yes	No [b]	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	Multiple	A/R	A/R	Yes	Planned[d]	No
	2. Breaker (failure or internal fault)	Multiple	A/R	A/R	Yes	Planned[d]	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	Multiple	A/R	A/R	Yes	Planned[d]	No
	Fault (non 3Ø), with Normal Clearing:						
	5. Double Circuit Towerline	Multiple	A/R	A/R	Yes	Planned[d]	No
	SLG Fault, with Delayed Clearing:						
	6. Generator	Multiple	A/R	A/R	Yes	Planned[d]	No
	7. Transformer	Multiple	A/R	A/R	Yes	Planned[d]	No
	8. Transmission Circuit	Multiple	A/R	A/R	Yes	Planned[d]	No
	9. Bus Section	Multiple	A/R	A/R	Yes	Planned[d]	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 tower line 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 miss operation 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 systemsmay 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
List of Contingencies

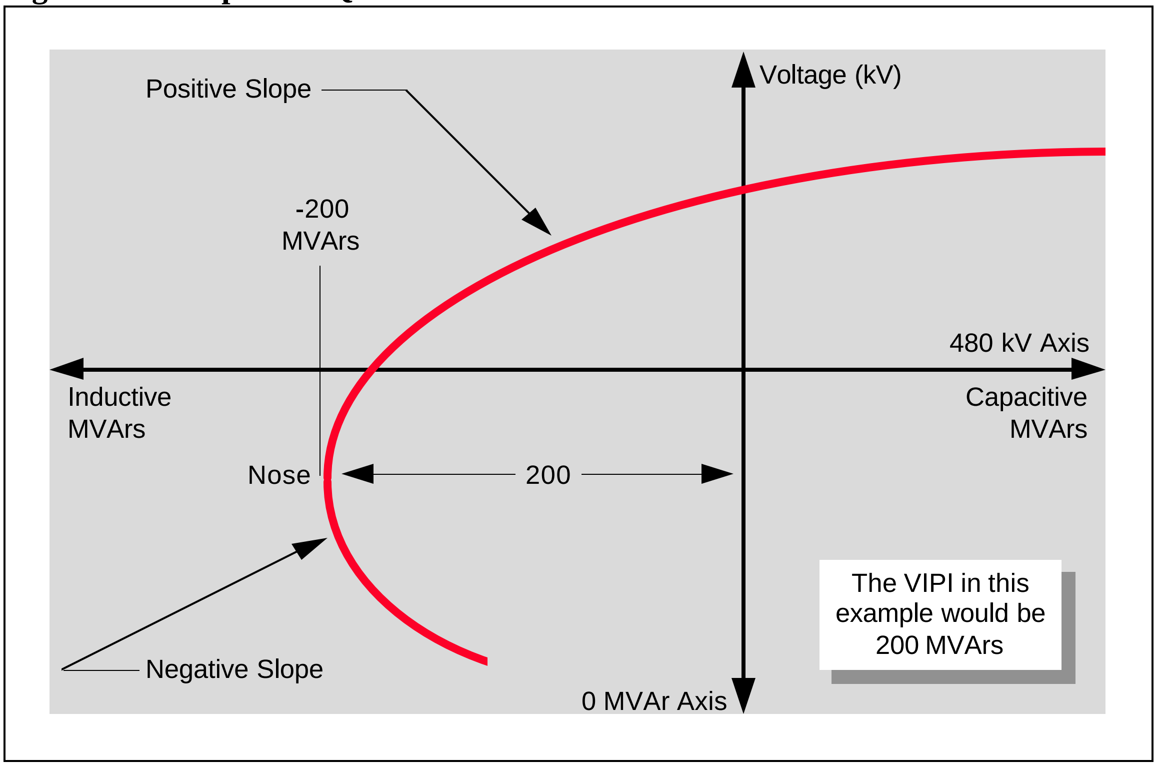
(To be developed separately during the technical analysis)

Attachment V
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



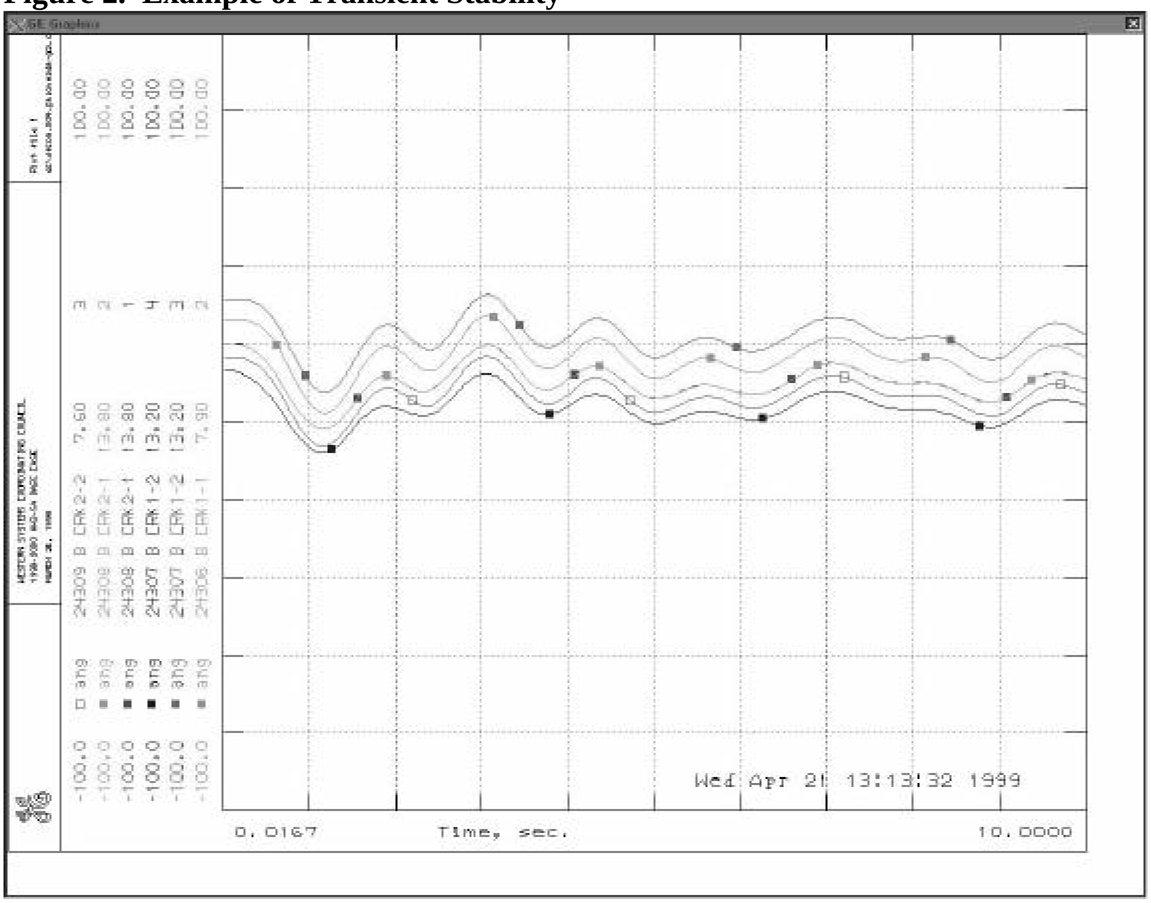
Proximity to the point of certain voltage instability is measured by the amount of additional reactive load at a bus necessary to change the slope of the voltage vs. reactive requirement nose curve (dV/dQ) from positive to negative. A positive slope implies that voltage rises as capacitive support is 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 VI
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), and 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. Generators supply this energy 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)

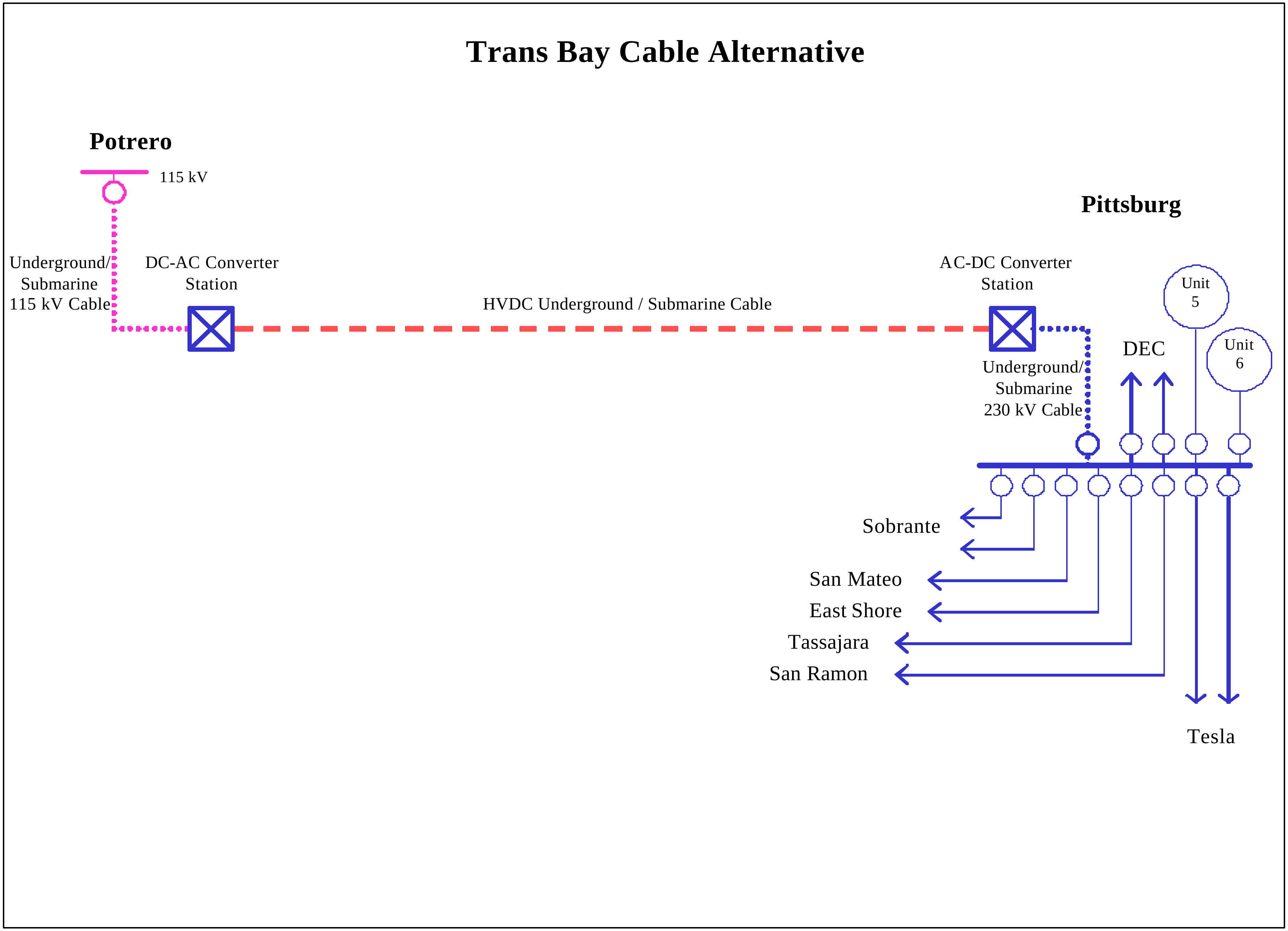
Pump	A hydroelectric generator, which acts as, a motor and pumps water stored in a reservoir to a higher elevation.
RAS	Remedial Action Scheme - An automatic control provision (i.e., trip a generation unit to mitigate a circuit overload).
Reactive Power	Reactive Power is generally associated with the 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

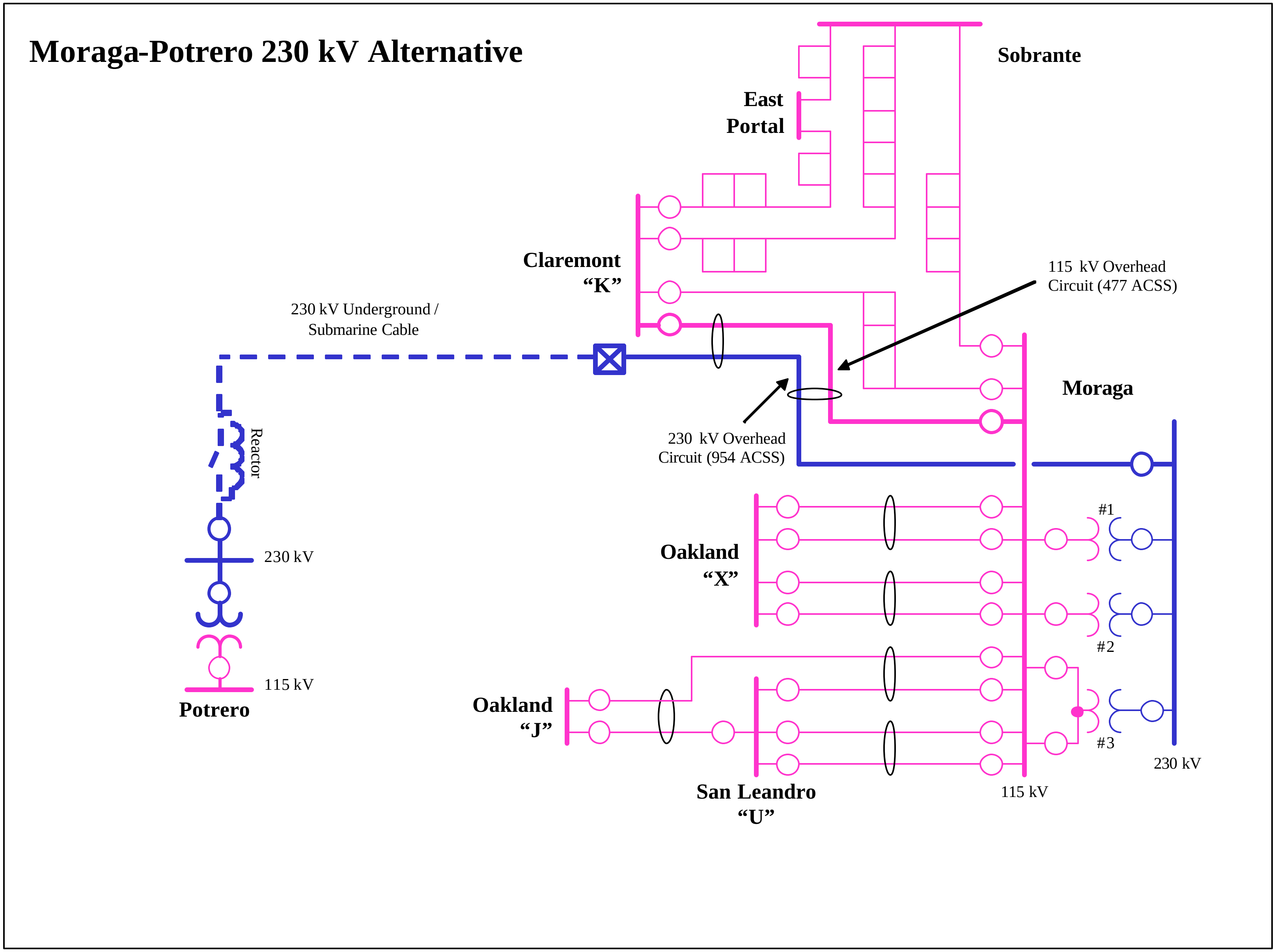
Attachment 3

Single-Line Diagram of Alternatives

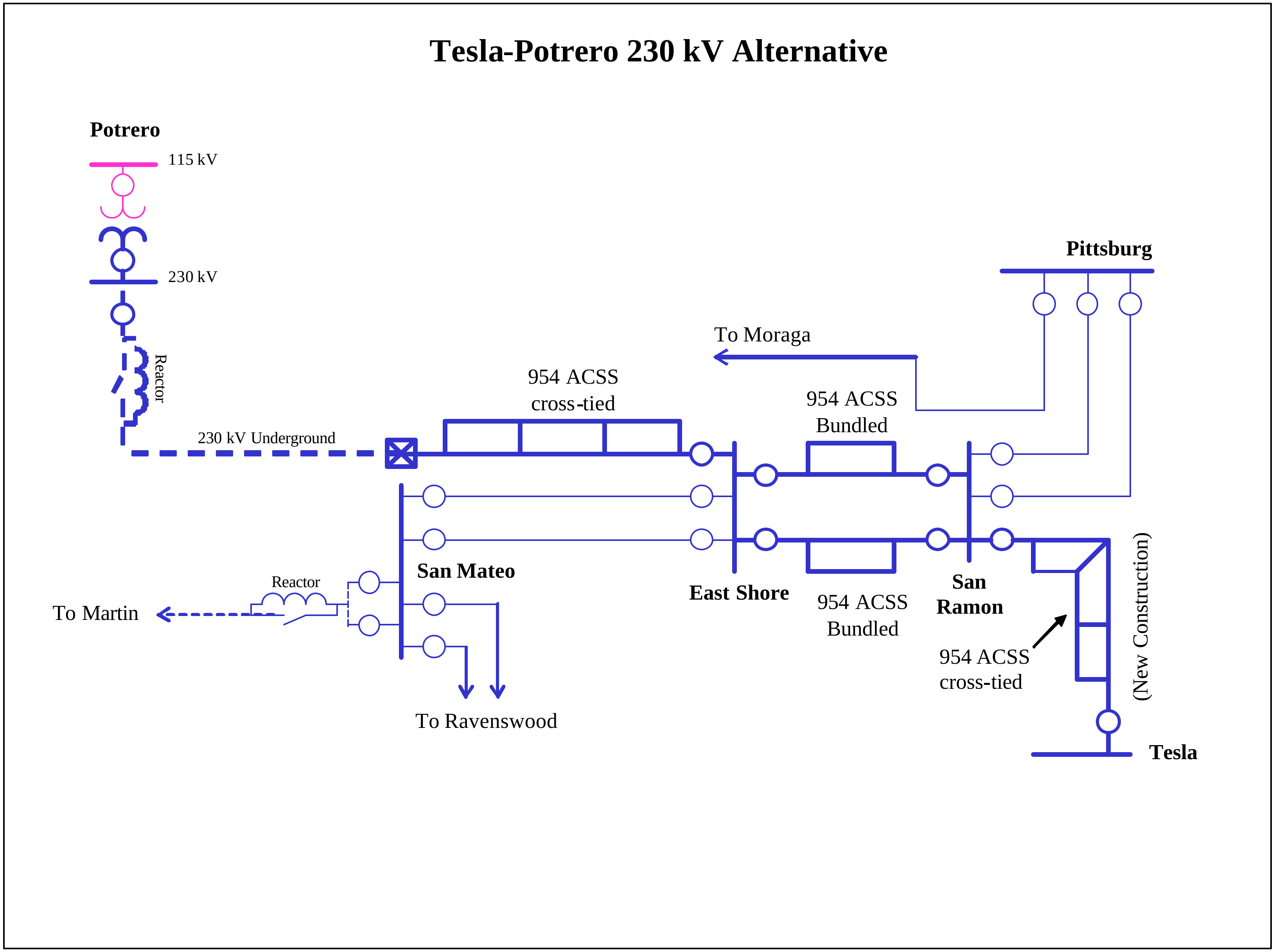
Schematic Diagram: Pittsburg-Potrero DC Line Alternative



Schematic Diagram: Moraga-Potrero 230 kV Alternative



Schematic Diagram: Tesla-Potrero 230 kV Alternative



<u>Attachment 4</u>

ISO Board Memo (Trans Bay Cable Project)

CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Gary L. DeShazo, Director of Regional Transmission

cc: ISO Officers; Board Assistants

Date: September 2, 2005

Re: Approval of the Trans Bay HVDC Cable Project

This memorandum requires Board action.

EXECUTIVE SUMMARY

ISO Management has determined that the Trans Bay Cable Project (Project) is needed to ensure reliable operation of the transmission system within the San Francisco Peninsula Area and is requesting the ISO Board of Governor's approval of the Project as a necessary addition to the ISO Controlled Grid. From among several alternatives, this is the preferred alternative recommended by ISO Management. With approval, the cost of the project would be eligible for recovery as part of the Project Proponent[s] Participating Transmission Owners Transmission Revenue Requirement (TRR) through the ISO High Voltage Access Charge, although the level of costs to be recovered and cost allocation issues would be subject to further proceedings before the Federal Energy Regulatory Commission (FERC).

Babcock and Brown, in collaboration with the City of Pittsburg, are developing the Project. The City of Pittsburg municipal utility will eventually own the Project and will, in turn, apply to become a Participating Transmission Owner (PTO) as defined in the ISO's Tariff and will turn over Operational Control of the Project to the ISO in accordance with the Transmission Control Agreement. In general, the Project consists of a 400 MW High Voltage Direct Current ("HVDC") transmission system that is 59 miles long with its route running under San Francisco Bay from Pittsburg to a location adjacent to Potrero substation in San Francisco. There are associated substation modifications that are necessary to interconnect the Project to the ISO Controlled Grid, but they are not detailed in this memo. Overall, the total cost of the Project, including interconnection to the ISO Controlled Grid, is estimated to be $300 million and is proposed to be in-service by 2009.

This Project is needed for reliability and is being recommended to mitigate violation of reliability planning standards beginning in 2012, but is being recommended for early operation. The Project, as currently structured, is planned to be in-service by 2009. Babcock and Brown has indicated that the financial and contractual arrangements they have with their project partners prohibits delaying the Project's in-service date to 2012 while maintaining the project in its current form and cost. While a reformulation of the Project could theoretically be accomplished, it would require renegotiating numerous contracts for land, equipment, and right-of-way commitments that would result in an increase in the Project's cost. In turn, the ISO performed technical and economic analyses to assess the reliability benefits and the cost to the ISO ratepayers for advancing the in-service date by three years to 2009. ISO's technical analysis concluded that installation of this project in 2009 would significantly improve reliability of the San Francisco Peninsula electrical system. Existing generation within San Francisco is expected to reduce significantly after implementation of ISO Action Plan in late 2007, which will increase San Francisco Peninsula's Operational Constraints and Locational Capacity Requirements. This Project, with a 2009 in-service date, will significantly reduce expected Locational Capacity Requirements and the need for Special Protection Schemes that are currently in place to shed firm load for critical double contingency disturbances for San Francisco Peninsula. Further, ISO's economic analysis concluded that while the Project does have identified benefits, the present value of the revenue requirements of the benefits and costs over the three-year advancement results in a net cost to the ISO ratepayers of $26 million. This "net cost" is viewed as an assurance cost against intangible benefits such as immediate increased reliability to the San Francisco Peninsula Area, unforeseen load forecast errors and consideration of unknowns such as project siting, schedule, cost risks, and economic benefits. Overall, ISO Management considers this assurance cost acceptable in return for the certainty that the Project will be there when it is needed.

Fulfilling a much broader vision, the Project will also establish a long-term transmission solution for load serving needs within the San Francisco Peninsula Area. Overall, the Project will increase the import capability into the San Francisco Peninsula Area by 400 MW via a route independent of the current routes that feed San Francisco load from the south commensurate with this import capability, this project will decrease overall system losses. The Project has been in development over the past 18 months and due to the long lead time required to build new transmission, is the only alternative evaluated by the San Francisco Stakeholder Study Group (SFSSG) that builds new transmission infrastructure into the ISO Controlled grid that can be in-service in time to address the identified reliability planning standard violations. The Project was initially presented to the SFSSG in February 2004 when the Project proponents requested it be considered, along with the other alternatives, as a long-term transmission solution for the San Francisco Peninsula Area load serving needs.

On August 25, 2005 Pacific Gas and Electric Company (PG&E) and ISO Management met to discuss the ISO's intention to recommend the Project as the preferred transmission alternative. At that meeting, PG&E presented a proposal to reconductor existing facilities as a short-term and construct the Moraga – Potrero 230 kV line as a long-term alternative in-lieu of the Project. PG&E related their concerns on the ability of the Project proponents to successfully site its line that spans almost its entire length of 59 miles underneath the San Francisco Bay. While PG&E recognizes that the Project has completed much of the preliminary environmental work required to construct their project, acquiring the necessary permits to construct the line would likely be more difficult and costly than proposed. Specific concerns are related to disturbing the San Francisco Bay sediment and the contaminants it may contain. Further, because of the line's length, there exists a higher probability of encountering unknown obstructions that could delay and increase the cost of the Project beyond what the Project proponents are projecting. Comparatively, their proposed Moraga – Potrero line would go through the City of Oakland and cross approximately five miles under the San Francisco Bay, which will also result in disturbing the sediment, but to a lesser degree. Because of its shorter length and the opportunity to locate the cable in a "no anchor zone", PG&E believes that they have a higher probability of achieving a successful siting across the Bay in a timely manner. PG&E also recognizes that the line would need to be sited through the City of Oakland and that while it would be challenging, they believe that a successful and timely siting and construction is achievable in as little as five years.

On balance, ISO Management believes that the Trans-Bay Cable proposal is the preferred alternative because it not only provides long-term reliable load serving capability to the San Francisco Peninsula area, it increases the diversity and security of the power supply to this area with implementation risks that are considered commensurate with the Moraga – Potrero alternative. Further, its early availability will reduce this area's operational constraints and expected locational capacity requirements immediately upon its operation.

Management recommends that the Board adopt the following motion:

Moved, that the Board of Governors,

> ***Approves the Trans Bay Cable Project (the "Project") as the preferred long-term transmission alternative (without regard for routing) to address the identified reliability concerns in northern San Mateo County and San Francisco beginning in 2012 and supports the early implementation of the project for operation by 2009 provided, however, that this approval shall be subject to change or withdrawal by the ISO so that other projects may be considered as alternative preferred options to address the identified reliability concerns, in the event that all necessary permits and state easements have not been received for construction of the Project by April 2007.***

BACKGROUND

San Francisco Peninsula Area load is served by a combination of in-area generation and power imported into this area over several 230 kV, 115 kV and 60 kV transmission lines. At the present time, two primary generation facilities, Hunters Point and Potrero Power Plants, which together can generate up to 570 megawatts (MW) of power, support the load serving needs of this area. This amount of generation represents approximately 20% of the total load in this area and the balance of the load serving need is delivered through PG&E's transmission system from generation resources outside this area.

In 2004, the ISO closely worked with the City and County of San Francisco (CCSF), PG&E, and interested stakeholders to establish a plan that describes the transmission and generation requirements necessary to reliably serve the San Francisco Peninsula Area load while allowing for the release of all existing generation at Hunters Point and Potrero Power Plants from their Reliability Must-Run (RMR) Agreements. This plan (Attachment 1), called the "Revised Action Plan for San Francisco" (Action Plan) was adopted by the ISO Board of Governors in November 2004 and is currently being implemented by PG&E, the CCSF, and the ISO. Full implementation of the Action Plan is expected by the end of 2007.

THE PROBLEM

Recognizing the need to establish a longer-term transmission plan once the Action Plan was implemented, the ISO, together with the SFSSG, initiated the Long Term Phase 2 (Phase 2) Study to determine the transmission facilities necessary to reliably serve the load in this area through at least 2018. The results of this study indicated that once the Action Plan was fully implemented, it would provide sufficient load serving capability for the San Francisco Peninsula Area through 2011, however, by 2012 reliability planning standard violations would exist in northern San Mateo County and San Francisco. While the ISO Action Plan does achieve the retirement of old generation in San Francisco, it also contributes to increased flows on the transmission facilities that serve the load in the area.

The San Francisco Peninsula Area presently receives all of its imported power from the south through the Peninsula from points as far away as Pittsburg, Contra Costa, Tesla, and Metcalf. Once the ISO Action Plan is fully implemented, this same transmission infrastructure must support an additional 378 MW[21] of San Francisco Peninsula Area load as well as anticipated load growth of approximately 15 to 20 MW per year that is expect to occur in this area. While the increased reliance on this transmission infrastructure was addressed in the ISO Action Plan through various transmission additions, upgrades, and re-rates, the impact on the area's future load serving capability was not assessed beyond 2007 until the Phase 2 study effort was initiated. Due to the long lead times required for building new transmission infrastructure, ISO Staff believes that action to mitigate these limitations must be taken now to assure that the necessary transmission infrastructure is in place by the time the limitations are expected to occur.

Not withstanding the identified reliability planning standard violations that are expected to occur in 2012, there are several operational constraints and locational capacity issues that this area will face once the Action Plan is fully implemented and the existing generation at Hunters Point and Potrero is retired. These issues are discussed below.

Operational Constraints:

Operation of the existing San Francisco Peninsula area's electrical system relies on the use of Special Protection Schemes (SPS) that arm over 540 MW of firm load to trip for critical double contingencies to meet the minimum operating reliability criteria required by the Western Electricity Coordinating Council (WECC). While the Jefferson – Martin 230 kV Project (expected to be in-service by early 2006) will decrease the amount of load shedding required to meet expected WECC operating practices, a significant reduction in generation in this area after implementation of the ISO Action Plan will offset this reduction in load shedding. The need for existing SPS will remain and will continue to increase as the load in the area increases.

Locational Capacity Requirements:

The California Public Utilities Commission (CPUC) and California Energy Commission (CEC) have taken the leadership role in ensuring resource adequacy for the State. The CPUC's Resource Adequacy requirements are designed to ensure that load serving entities have procured sufficient resources to meet their load and that these resources are deliverable to their load. A key requirement for ensuring the deliverability of Load Serving Entity resource portfolios is to ensure that there are sufficient generation resources in transmission constrained local load pockets such as the San Francisco Bay Area, the Los Angeles Basin, and San Diego to reliably serve customer demand.

At the request of the CPUC, the ISO performed a technical analysis to determine the local generation capacity requirements within the transmission constrained local areas of the grid. These studies show that after the San Francisco Action Plan is implemented, the San Francisco Peninsula Area's Locational Capacity requirements will exceed the amount of generation expected to be available in this area by approximately 100 MW. Because it is likely that no new generation can be sited in San Francisco, the only alternatives available to meet this additional locational capacity requirement is to either install a new SPS to

[21] Existing generation at Hunters Point Units 1 and 4 (52 MW and 163 MW, respectively) and Potrero Units 3, 4, 5, and 6 (207 MW, 52 MW, 52 MW, 52 MW, respectively) total 578 MW. The proposed four CCSF Peakers will total 195 MW. The ISO Action Plan will allow for the retirement of all generation at Hunters Point and Potrero and the installation of the CCSF Peakers. As a result, there will be a net increase in transmission import requirements of 383 MW.

trip about 100 MW of firm load when required or build new transmission into the San Francisco load area to replace the area's generation deficit.

SAN FRANCISCO STAKEHOLDER STUDY GROUP

On December 8, 1998, PG&E experienced a severe disturbance initiated at San Mateo Substation that resulted in a blackout of most of the City of San Francisco and nearby communities on the San Francisco Peninsula. Subsequent to this incident and following extensive investigation by the ISO and PG&E, a stakeholder group was formed to provide a public forum in which the ISO could assess long-term transmission solutions for reliably serving load in the San Francisco and Peninsula areas. This stakeholder group, called the San Francisco Stakeholder Study Group, included a variety of entities such as the City and County of San Francisco (CCSF), the Pacific Gas & Electric Company (PG&E), the California Public Utility Commission (CPUC), the California Energy Commission (CEC), various generation developers, representatives of local San Francisco community groups, and others. This group played a key role in identifying the Jefferson-Martin 230 kV Line Project as the preferred alternative for addressing San Francisco's long-term load serving concerns as well as developing the Action Plan that will lead to the eventual retirement of all the old generation facilities at Hunters Point and Potrero.

However, considering the long lead-time to construct new transmission facilities, the ISO continued to utilize the SFSSG to establish a long-term (ten-year) transmission plan beyond the implementation of the Action Plan. This effort, called the Long Term Phase 2 Study, was initiated by the ISO in February 2004. The SFSSG developed the study objectives as well as the transmission alternatives that were to be studied. To be consistent with the ISO Tariff (Section 3.2.1), the Trans Bay Cable Project was included as one of the alternatives to be considered in the overall study effort. The Project's proponents presented the Trans Bay Cable Project, already in its preliminary development stages, to the SFSSG in February 2004 and requested that it be evaluated along with the other alternatives.

Since its initiation, the SFSSG, as it did with Jefferson – Martin and the Action Plan, has played a valuable role in the assessment of the technical results of all transmission Long Term Phase 2 studies performed by PG&E and the ISO. This technical assessment concluded that there would be reliability planning standard violations that would occur in San Francisco and the Northern San Mateo county areas beginning in 2012. The assessment also concluded that all of the transmission alternatives assessed by the SFSSG, but for the "Status Quo" or "Do Nothing" alternative, could address the identified reliability planning standard violations, provided they could be completed by the time they were needed. The SFSSG also concluded that given the transmission alternatives assessed and given the opportunity to do so, constructing a new transmission line to San Francisco from across the San Francisco Bay would be preferred over alternatives that approached the San Francisco Peninsula Area from the south through the peninsular corridor. The Trans Bay Cable Project and the Moraga – Potrero 230 kV line are the only alternatives evaluated by the SFSSG that approach San Francisco fom across the San Francisco Bay, as such, these are the only "across the bay" alternatives that were considered in the ISO's analysis of the preferred long-term transmission solutions for the area. In addition, the SFSSG concluded that given the technical analysis results presented, there was no compelling evidence to conclude that constructing a new transmission line from Moraga (Moraga-Potrero alternative) would be technically superior over a new transmission line built from Pittsburg (Trans Bay Cable Project). Given that the Trans Bay Cable Project was the only alternative being proposed as a viable project, the ISO concluded that siting an alternative such as the Moraga – Potrero alternative through the City of Oakland, while not impossible, would likely be difficult to complete in a timely manner. Based on this and other information discussed in this memorandum, the ISO concluded that the Trans Bay Cable Project was preferred over the other alternatives evaluated by the SFSSG.

Because the Trans Bay Cable Project is proposing an early in-service date (early 2009), the ISO also undertook an analysis of the cost impact to the ISO ratepayers of advancing the in-service date ahead of the reliability need date by three years (2012 to 2009). The ISO's cost analysis is discussed in more detail later in this memo, however, the results did indicate that while the Trans Bay Cable Project does bring economic benefits to the area, the overall costs of advancement would exceed the identified benefits, as calculated by the ISO. While the results of the ISO's cost analysis was presented to and discussed within the SFSSG, there was no clear consensus among all of the stakeholders on the conclusions that should be drawn from the ISO's results other than some stakeholders suggesting a final decision should be postponed to allow for further analysis to be completed.

DIFFERENT APPROACHES TO THE SOLUTION

As discussed earlier, the San Francisco Peninsula Area presently receives all of its imported power from the 230 kV, 115 kV, and 60 kV transmission facilities which emanates south of San Francisco, through the San Francisco Peninsula corridor, and onward to Pittsburg, Contra Costa, Tesla, and Metcalf Substations. Because of its geographical orientation, load in San Francisco and the adjacent peninsula corridor is considered electrically "radial" to the remaining transmission infrastructure in the overall Greater Bay Area. Once the ISO Action Plan is fully implemented, the CCSF Peakers will be the only generation remaining in the San Francisco area but for a 28 MW combustion turbine located adjacent to the San Francisco International Airport. As such, approximately 90% (~1800 MW) of this area's load will be served by importing power from outside the area. As would be expected, during peak load serving periods, these import lines will be heavily loaded such that the ability to serve the load in this area does become constrained for certain critical single and double contingencies.

Given the geographical location of the load in the San Francisco Peninsula Area and the difficulty in locating new generation resources in this area, new transmission infrastructure and/or additional transmission upgrades are required to either be constructed from the south or from the east across San Francisco Bay. Through the SFSSG, the technical aspects of four transmission alternatives were evaluated to determine their viability for addressing the identified reliability planning standard violations. These alternatives are discussed below.

1. **Status Quo** – This alternative proposes to do nothing beyond utilizing the transmission facilities and generation planned to exist once the Action Plan for San Francisco is fully implemented by the end of 2007.

1. Analysis: This alternative does not meet the objective of establishing long-term reliable load serving capability, nor does it meet the reliability Planning Standards.

2. **Upgrade and Replace Existing Facilities** – This alternative proposes to utilize existing transmission infrastructure to support existing and anticipated load growth in the area. When needed, employ replacing, reconductoring, re-rating and operating alternatives to mitigate transmission system overloads and low voltages.

   Analysis: This alternative does not meet the objective of establishing long-term reliable load serving capability. It provides enough load serving capability to serve the San Francisco Peninsula load only up to 2018, beyond which a major new transmission project will be needed in this area. Permitting and building this new transmission in 2018 will be extremely difficult, if not impossible.

All other new transmission alternatives improve this area's load serving capability for a longer duration. This alternative does not improve diversity in supply of power serving the San Francisco load. It relies on increasing the import of power into the San Francisco Peninsula by upgrading existing transmission facilities. San Francisco Peninsula area's Locational Capacity Requirements and its reliance on Special Protection Schemes are expected to increase after full implementation of ISO Action Plan takes place by the end of 2007. This alternative will not reduce this area's operational constraints and will not offset this area's growing locational capacity requirements until 2017, when PG&E's proposed new San Francisco Internal Capacity Project goes in service. To implement this alternative, few key existing transmission facilities need to be removed from service for construction. This coupled with significant reduction in the amount of generation in San Francisco per the ISO Action Plan, can potentially deteriorate the reliability of this area. It is expected that pre-contingency dropping of load in the San Francisco Peninsula area would be necessary to take the clearances that are necessary to perform the construction and that would be a violation of the ISO Planning Standards. The potential capital cost of this alternative through 2018 is estimated at $114 million.

3. **Trans-Bay Cable Project** – This alternative proposes to build a new 400 MW High Voltage Direct Current ("HVDC") submarine DC cable proposed by an independent developer, Babcock & Brown, between PG&E's Pittsburg Substation in the East Bay Area and Potrero Substation in San Francisco for operation by 2009.

   Analysis: This alternative fully meets the objective of establishing long-term reliable load serving capability by adding 400 MW of load serving capability upon its initial operation. This alternative will increase the diversity of transmission routes to San Francisco through installation of controllable transmission capacity from PG&E's Pittsburg Substation in the East Bay to Potrero Substation in San Francisco. It will unload the existing transmission system that serves load in San Francisco and therefore greatly improve the ability to allow transmission facility clearances that are a part of normal day-to-day system operation. This alternative provides for significant savings by reducing power losses within the parallel AC transmission system, deferral of new 115 kV cables within San Francisco as well as facilitates a more economic generation dispatch pattern within the Greater Bay Area. This project is estimated to cost $300 million including Interconnection costs. In addition, there are economic savings associated with the Trans-Bay Cable resulting from transmission system loss savings (capacity and energy) and improved economic dispatch of generation. The ability to permit and build this project in a timely manner requires about half the lead-time (three years) as either the Moraga to Potrero or Tesla to Potrero 230 kV Projects. In addition, development of an Environmental Impact Report is well underway as is filing with the Federal Energy Regulatory Agency for rate recovery.

4. **Moraga-Potrero 230 kV Line** – This alternative proposes to build a new 230 kV AC line from Moraga Substation in the East Bay area to Potrero Substation in San Francisco. This new line would include a combination of overhead or underground facilities from Moraga to the San Francisco Bay and then run beneath San Francisco Bay to Potrero Substation.

   Analysis: While this alternative will provide long-term reliable load serving capability, the ability to successfully permit and construct this project by 2012 is very uncertain. As such, this alternative is not preferred due to its high implementation uncertainty, risks, and costs associated with successful routing and timely permitting. The potential capital cost of this alternative is estimated *at $274 million but could be much higher due to its implementation uncertainties as related to the ability to obtain and permit a route through the congested Oakland area.*

5. **Tesla-Potrero 230 kV Line** –This alternative proposed to build a new 230 kV circuit from Tesla Substation to San Ramon Substation, reconnection at San Ramon Substation, reconductoring of 230 kV circuits between San Ramon and East Shore substations, and installing a new 230 kV circuit from East Shore to Potrero substations. The portion of the project between the East Shore and Potrero Substations would include a new line across and above the San Francisco Bay and a new underground cable approximately parallel to the existing San Mateo - Martin 230 kV cable, which would extend to Potrero Substation.

   Analysis: Similar to the Moraga-Potrero alternative, the ability to permit and construct the Tesla-Potrero alternative is highly uncertain. This alternative parallels existing transmission infrastructure through the San Francisco peninsula corridor that already accommodates numerous 115 kV and 230 kV lines, including the Jefferson – Martin 230 kV Transmission Project. This alternative does not provide the diversity and increased security of power supply that is attainable with the Trans-Bay Cable project. Siting another transmission project through this area would be extremely difficult considering the recent siting of the Jefferson – Martin line in this same area. This alternative will also require the construction of a new transmission facility across and above the San Francisco Bay as well as through the eastern boundary of the Bay Area. This alternative is not preferred due to its high implementation uncertainty and risks associated with new construction through the San Francisco peninsula corridor and across the San Francisco Bay. In addition, the potential capital cost of this alternative is estimated at $457 million, which is significantly more than the Trans-Bay Cable Project or Moraga to Potrero 230 kV Project. Due to the significant increase in capital cost of this alternative over the other alternatives considered, an economic assessment was not performed.

ISO ECONOMIC ANALYSIS OF THE PREFERRED ALTERNATIVE

As discussed in the previous section, the transmission alternatives are designed to satisfy an important San Francisco planning need that is forecasted to start in 2012. The long-term alternatives considered were therefore primarily evaluated from a reliability perspective (i.e. the least-cost alternative that satisfies the reliability need, subject to other considerations such as project risk). The least-cost alternative is determined by considering the projected capital and operating costs, as well as any difference in economic benefits provided by the individual alternatives. Evaluation of the least-cost alternative is the approach used in this economic analysis. ISO staff recognizes that the least-cost analysis is only one of many critical decision criteria that are considered when recommending a transmission project.

ISO staff views the determination of the long-term preferred alternative, and the recommended timing of this preferred alternative, as two separate considerations for supporting the selection of the preferred transmission alternative. ISO staff developed economic data and analyses to assist in assessing these considerations. The economic results are summarized in this section.

Recommended Long-Term Transmission Solution

Three long-term alternatives were evaluated from an economic perspective. These alternatives include the Trans-Bay Cable Project, the Moraga-Potrero line, and the Tesla-Potrero line.

The economic benefits of the Tesla-Potrero alternative were less than the other two alternatives evaluated. Also, the Tesla-Potrero capital costs were almost 50 percent higher than the other two alternatives. Given this significant cost differential and the other issues associated with this alternative and stated within this memorandum, no further economic evaluation was made for this alternative.

The remaining two long-term alternatives (Trans-Bay Cable and Moraga-Potrero) considered are more closely related in economic benefits and capital costs. Both options can provide up to 400 MW of new capacity to the San Francisco Peninsula from East Bay generation. The Trans-Bay Cable, however, is projected to result in lower system losses than the Moraga-Potrero option, since the DC line itself is expected to have lower losses than an AC alternative. The capital costs of the two alternatives are within 2 percent of each other and based on the accuracy of their estimated cost, are deemed to be equivalent for purposes of this analysis. As a result of the projected lower system losses and other issues identified in this memorandum, the Trans-Bay Cable Project was preferred over the other alternatives.

Recommended Timing of Preferred Alternative

Because the Trans Bay Cable Project is proposing an early in-service date (early 2009), the ISO also undertook an analysis of the cost impact to the ISO ratepayers of advancing the in-service date ahead of the reliability need date by three years (2012 to 2009). Once the preferred long-term solution has been identified, the remaining question is whether the online date of the Trans Bay Cable Project should be planned for 2012 or brought online earlier. The primary criteria for this decision for a reliability project are likely to be based on reduced risk of loss of load and other considerations by bringing the project on-line earlier than needed. However, there is also an economic impact of an earlier on-line date that should be considered.

Capital projects are often compared on the basis of the present value of revenue requirements (PVRR). As shown in Table 1, the PVRR increases $63 million if the Trans Bay Cable Project is brought online in 2009 versus 2012. However, the earlier online date provides some distinct benefits including increased reliability to San Francisco, reduction of project schedule and cost risk, and economic benefits. The economic benefits are estimated to be about $14 million per year. The present value of 3 years of economic benefits is approximately $37 million. Thus, the net cost of bring the project online by 2009 as compared to 2012 is $26 million.

This net cost can be viewed as a 6.2 percent Assurance Cost against intangible benefits such as reductions in SPS requirements, unforeseen load forecast errors, Reliability Must-Run/Locational Capacity requirements, reduced project siting costs, schedule, and cost risks (as well as increased San Francisco reliability for the three years. From ISO Management's perspective, this 6% Assurance Cost is considered a prudent investment given the intangible benefits mentioned above and the certainty that the Project will be there when it is needed. Based on these considerations, ISO staff believes the Trans Cable Project's early in-service date is warranted.

Table 1
Economic Comparison of a 2009 or 2012 Trans Bay Cable Online Date

PV of revenue requirements	$483	$420	$63
PV of 2009-2011 economic benefits	$37	$0	$37
NPV of revenue requirements	$446	$420	$26
Revenue requirement assurance cost			**6.2%**

FERC PROCEEDING

Trans Bay Cable LLC (TBC - a wholly-owned subsidiary of Babcock & Brown LP) in conjunction with the City of Pittsburg and Pittsburg Power are proposing the Trans Bay Cable Project (the Project) and filed for rate recovery with FERC on May 19, 2005. On July 21, 2005, FERC issued it's preliminary approval of the rate principles for the Project that is estimated to cost $300 million and bring 400 MW of additional capacity to serve load in the San Francisco Area.

The rate principles accepted by FERC include:

- ?? A 13.5 percent return on equity;
- ?? A three-year rate moratorium from initial transmission revenue requirement;
- ?? A 50/50 debt-equity capital structure; and
- ?? A 30-year depreciation period.

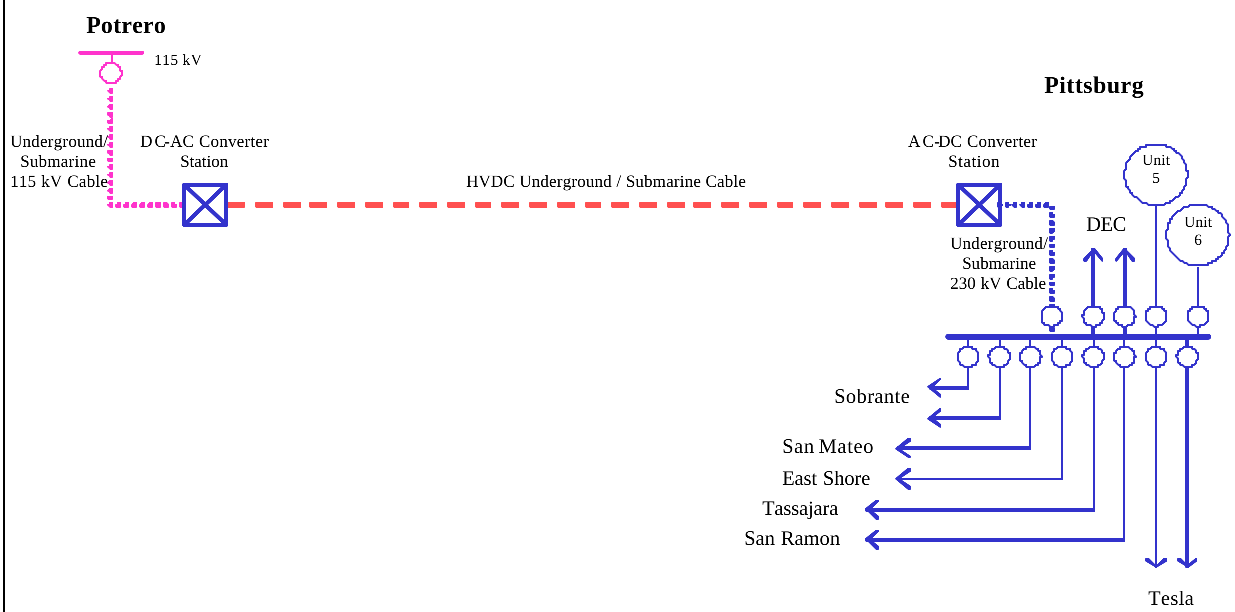
In approving the rate principles, FERC cited the potential for reduced congestion costs and reliability-must-run requirements in San Francisco as well as reducing the need for additional generation in San Francisco. Overall, FERC found that based on enhanced reliability, more efficient generation dispatch and potential environmental benefits, the Project will be beneficial.

TBC is the present sole owner of the Project through project development, permitting and construction phases. The Project will be designed and built by Siemens and Perelli. The City of Pittsburg and Pittsburg Power are expected to exercise an alternative to acquire the Project upon its operation. The City of Pittsburg and Pittsburg Power would, in turn, become a Participating Transmission Owner (PTO) as defined in the ISO's Tariff and will turn over the Operational Control of the Project to the ISO in accordance with the Transmission Control Agreement. The project operation will be coordinated with the existing transmission system and operated in accordance with prudent utility practice as a transmission facility within the ISO's Control Area.

Figure 1
Trans Bay Cable Project – Submarine Cable Route

Figure 2

Trans Bay Cable Alternative



An independent developer (Babcock & Brown) would permit and build a new 400 MW High Voltage Direct Current (HVDC) submarine cable between Pittsburg Substation in the East Bay area and Potrero Substation in San Francisco.

Attachment 1

ISO Revised Action Plan for San Francisco

This action plan was originally presented to the ISO Board of Governors in November 2004 and has been updated to reflect the current status of the identified projects

(The Revised Action Plan is included as Attachment 1 to the main report above)

<u>Attachment 5</u>

Stakeholder Positions on the Alternatives

SF Stakeholder Meeting Notes
July 26, 2005 meeting

CAISO distributed a document with a discussion on CAISO's position on preferred SF Peninsula long-term alternative (attached). The document provided background information on CAISO's Economic Analysis, Pros/Cons of all SF Peninsula Long-Term alternatives, and stakeholder positions on these alternatives (which were gathered at a June stakeholder meeting). Gary DeShazo (CAISO), briefed the group on the CAISO's efforts on assessing the alternatives and the conclusions they have reached with regard to selecting the preferred alternative. He stated that given the information the SFSSG has been addressing the CAISO has concluded that the preferred long-term alternative for the San Francisco Peninsula area is the Trans Bay Cable project. The CAISO is preparing to take this recommendation to its Board of Governors at their September 7-8, 2005 meeting.

Comments received from stakeholders:

Steven Moss: Deferred investment not incorporated as an option in Attachment # 1. How much (MW) is the reliability need in 2012? Why are we spending $300 million to address this need in 2012? We should be able to pursue other alternatives to address this reliability need.

Valarie/Nicholas (Bay Area Municipal Transmission Group – representing Cities of Alameda, Palo Alto & Santa Clara): Our position is that comprehensive Greater Bay Area Study should be done now, instead of choosing a long-term alternative for San Francisco Peninsula. In this study we would like to see new projects, which bring power from outside into the Greater Bay Area, and the impacts of these new projects on RMR.

Ali Amirali (Calpine): The preferred SF Peninsula long-term alternative will not solve the overall Greater Bay Area problem. A new project from outside into the Greater Bay Area should be analyzed.

Karen Kubick (SFPUC): City is project neutral. We would like to suggest that the CAISO should consider all other alternatives that may reduce RMR costs and address concerns of other parties before proposing this preferred alternative.

Dave Parquet (Babcock & Brown): We do not agree with CAISO's Economic Analysis findings. Through another consultant, we have revisited the economic benefits of the Trans Bay Cable project. We see benefits of $50 million, for cost of $50 million per year, meaning the project will pay for itself. We believe that major difference between CAISO's and our Economic benefits numbers is because: (1) We performed our benefit analysis for entire WECC system, whereas CAISO's benefits are limited to only NP15 (2) We do not agree with CAISO's loss saving numbers

We have spent a good deal of time on the details of our project. We are working on a "Basis of Design" document for the project, which is a continually evolving document and will be the basis of Pittsburg's and the environmental consultant's work in preparing the Draft Environmental Impact Report. The proposed in-service date for the Trans Bay Cable project is 01/01/2009. We can however, postpone the schedule and have the project in service by 01/01/2010 instead, without any significant increase in cost.

Manho Yeung (PG&E): PG&E likes the Trans Bay Cable project because of the route and relative ease of permitting and building. However, PG&E doesn't necessarily agree with having this project in service by 2009. PG&E needs some more time to discuss the timing of the Trans Bay Cable Project internally.

Les Pereria (Palo Alto): Extended outage of the submarine Trans Bay cable could cause some issues. This should be analyzed. There should be more justification on why the reconductoring alternative cannot be pursued. The economic analysis shows congestion outside the Greater Bay Area. AC model should be used for performing economic analysis rather than the DC.

Francisco DeCosta: Quality of life issues

Brian Chernack (Seabreeze): Briefed the stakeholders on a new alternative to meet SF Peninsula long-term reliability needs. This would involve the interconnection of the Potrero substation with Moraga substation using HVDC Light™ technology and a combination of terrestrial and submarine cable. The HVDC Light™ interconnection could be configured, as a 330 MW or a 540 MW project, depending upon the optimum transfer needs of the Peninsula and the cost of the project.

In addition, both PG&E and Sea Breeze sent letters just prior to the CAISO September 8, 2005 CAISO Board meeting requesting additional time for further development of their proposed alternatives (either an AC or DC line between Moraga and Potrero Substations. Their request was denied at the Board meeting.