# Eastshore Energy Center (06-AFC-06)

# Supplemental Information

Submitted by:

**Eastshore Energy, LLC**

May 4, 2007

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**EASTSHORE ENERGY CENTER (06-AFC-6)**
**SUPPLEMENTAL INFORMATION**

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# Section 1.0 Data Responses

The Applicant is providing data responses in reply to the data requests received during the Eastshore Energy Center Workshop held on March 19, 2007. The data responses have been organized by issue area.

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## Technical Area: Alternatives

## DATA REQUEST

**WKS-1**: Please explain the use of the name Black Hills for the project and provide an explanation for why PG&E did not identify the project as a Tierra Energy project in its public documents.

**Response:**
Black Hills Energy was the original developer of the Eastshore Energy project in conjunction with a developer, Ramco Generating 2, located in Orinda, California. At the time PG&E made announcements and California Public Utilities Commission (CPUC) filings for all successful projects for the 2005 Request for Offers (RFO), including Eastshore Energy Center, Black Hills Energy was actively negotiating the sale of the project to Tierra Energy, LLC. It would not have been appropriate for PG&E to announce Black Hills Energy as the owner of the project as they had not executed the Power Purchase Agreement (PPA) at that time and PG&E and Black Hills Energy were under a mutual confidentiality and nondisclosure agreement. The Eastshore Energy Center project was subsequently purchased by Tierra Energy, LLC on April 28th, 2006 from Black Hills Energy. Subsequent to the completion of the acquisition, PG&E filings to the CPUC did specifically disclose the project as Tierra Energy Hayward (for example at page 2 of PG&E's opening brief filed September 22, 2006). Any party or member of the public following the CPUC proceeding (A.06-04-012) would have been able to access from the CPUC website electronically filed documents that clearly identified Tierra Energy as the project owner.

**WKS-2**: Please make another attempt with PG&E to obtain additional information or background to expand upon the position outlined in PG&E's letter provided in response to data response 50 and 51. Please document the results of your contact with PG&E, including the names and phone numbers of PG&E individuals contacted and any further explanation obtained.

**Response:**

A representative from the Eastshore Energy Center placed a call to Mr. John Vardanian, PG&E, Senior Project Manager, Generation Interconnection Services, (415) 973-0815. Mr. Vardanian referred Eastshore to a letter sent by PG&E dated March 1, 2007 and signed by Mr. Perry Davis. Additionally, Eastshore contacted Mr. Jeff Williams, PG&E, Land Agent in Corporate Real Estate, (925) 674-6593. Mr. Williams referred Eastshore to Mr. Greg Lamer, PG&E, who is responsible for property entitlements. Eastshore contacted Mr. Lamer's assistant Ms. Debra Hautsman, (510) 874-2612, and subsequently sent a data request to Ms. Hautsman asking for verification of why PG&E chose not to use the land adjacent to Eastshore Substation. Eastshore also requested a copy of the original 2005 letter from PG&E stating the Eastshore substation property was not available. Further, Eastshore was informed by PG&E that the March 1, 2007 letter from Mr. Davis stated that the Eastshore Substation property was not available. Based on the above efforts, it is clear to Eastshore that PG&E has no interest in making the Eastshore Substation property available for the Eastshore Energy Center.

**WKS-3**: Please provide copies of the PG&E RFO documents and explain whether the RFO mentions the Eastshore substation as a preferred point of interconnection.

**Response:**

PG&E's initial Request for Offers (RFO) was issued on November 2, 2004. The RFO was revised and reissued on March 18, 2005. The 2005 RFO documents are attached as Attachment WKS-3. These documents were obtained from the PG&E RFO website at http://www.pge.com/suppliers_purchasing/wholesale_electric_supplier_solicitation/ltpp_rfo2004.html.

As stated on page 8 - 9 of the RFO, PG&E used the following major criteria to complete its evaluation of the bids:

"**Market Valuation** means how an Offer's cost compares to an Offer's benefits, from a market perspective. An Offer's cost is reflected in the Offer's pricing. An Offer's benefits are the market value of the energy, capacity, and ancillary services offered. These costs and benefits may include: fixed and variable costs; transaction costs, such as market bid-ask spreads; location specific value, as represented by zonal or nodal price differentiation; and operating flexibility, as represented by option value. The risks and uncertainties associated with an Offer's costs and benefits will be considered as part of Market Valuation. These costs and benefits do not include the particular costs and benefits associated with the Offer's impact on PG&E's portfolio positions and possible attendant market transactions by PG&E. An important component of market valuation benefit is operating flexibility. PG&E uses option valuation models to quantify how operating flexibility contributes to market valuation.

**Portfolio Fit** means how well an Offer's features match PG&E's portfolio needs. In particular, the value of an Offer's capacity, energy, and ancillary services is adjusted to account for PG&E's portfolio positions, including temporal and locational aspects. Portfolio fit thereby weighs an Offer's costs and benefits in the context of PG&E's portfolio needs. In contrast, the market valuation component considers an Offer's costs and benefits without taking into account PG&E's portfolio needs.

**Credit** means the Participant's capability to perform all of its financial and other obligations under the Agreements, including, without limitation, the Participant's ability to provide performance assurance under the Agreements. PG&E will consider the Participant's financial strength as determined by PG&E as well as any credit enhancements acceptable to PG&E that Participant may offer with its proposal. PG&E will also consider its overall credit concentration with any particular Participant.

**Viability** means the probability that the resource(s) associated with an Offer can be financed and completed as required by the Agreement and will be available to provide capacity and energy and/or ancillary services when called upon.

**Transmission Impact** means the effect of an Offer on the electric transmission system. In evaluating an Offer, PG&E will consider the network upgrade costs as described in Section IX.C. – System Impacts. PG&E will also consider congestion risk, impact on RMR costs, and other locational attributes associated with an Offer.

**Debt Equivalence** in this context refers to the debt-like characteristics of PPAs not classified as interest bearing liabilities under Generally Accepted Accounting Principles. PG&E will consider the debt equivalent impacts of an Offer.

**Environmental Characteristics** includes air emissions including carbon dioxide, nitrogen oxides, sulfur dioxide and particulates, and other potential environmental impacts. The quantities and potential costs to PG&E and to society associated with these characteristics will be considered.

**Participant Qualifications** means the experience and technical expertise of the Participant putting forth the Offer.

**Conformance with PG&E's non-price terms and conditions** means the degree to which the Participant accepts PG&E's proposed terms and conditions.

PG&E will evaluate Offers in a manner consistent with the company's and the corporation's environmental and environmental justice policies."

As noted above, the "Market Valuation" category included location specific value, the "Portfolio Fit" category included how well the offers met PG&E's portfolio needs including temporal and locational aspects, and the "Transmission Impact" category included an evaluation of transmission congestion risk, upgrade costs and other locational attributes.

The only specific references to the Eastshore substation as a point of interconnection in the RFO documents are in a listing of the CAISO Interconnection Application Queue. Item 38 denotes a confidential 118 MW project connecting to the Eastshore substation and item 46 denotes a 361 MW Russell City Energy Center connecting to the Eastshore substation. As noted on part of the RFO process, bidders were required by Appendix H.B.5. to identify their position in the Queue.

The individual responses to PG&E were also reviewed by an Independent Evaluator who concurred with PG&E's selection of the seven projects chosen under the RFO.

**Attachment WKS-3**

# 2005 RFO Documents

# 2004
# Long Term Request For Offers
## Power Purchase

Pacific Gas and Electric Company®

March 18, 2005

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**Appendix K:** Offer Cover Sheet

# I. INTRODUCTION AND OVERVIEW

## A. Overview

Pacific Gas and Electric Company ("PG&E") is issuing this Request for Offers ("RFO") to obtain power resources through a solicitation of interest from power plant owners/developers for a Power Purchase Agreement with PG&E ("Power Purchase"), or, for newly built dispatchable generation facilities for sale to PG&E ("Facility Ownership"). PG&E originally issued RFOs for this purpose on November 2, 2004. PG&E suspended those RFOs on January 7, 2005, in order to evaluate and respond to the California Public Utilities Commission ("CPUC") long–term plan decision (D.04-12-048, issued December 16, 2004 - the "CPUC Long Term Plan Decision"). In accordance with the CPUC Long Term Plan Decision, PG&E will evaluate Offers for Power Purchase or Facility Ownership together. Also in accordance the CPUC Long Term Plan Decision, an independent evaluator ("Independent Evaluator") will be utilized.

PG&E also seeks to replace the 135 megawatt fossil-fuel generation facilities at its Humboldt Bay Power Plant ("HBPP") in Eureka, California. Offers relating to the Humboldt Bay Power Plant replacement described below will be evaluated separately.

PG&E is seeking Power Purchase Agreements and related documentation ("PPA") contracts for Capacity, Energy and Ancillary Services with one or more dispatchable generating facilities meeting the eligibility requirements listed in Section III.

Respondents ("Participants") may reply to either or both of the alternatives under this RFO. If a Participant submits a reply offering both Power Purchase or Facility Ownership for the same generation facility, PG&E would execute only one agreement, either a PPA in the case of Power Purchase, or a Purchase and Sale Agreement and related documentation ("PSA") in the case of Facility Ownership for that facility. A PPA or a PSA, with related documentation, is alternatively or collectively referred to as a "Contract" or "Agreement".

PG&E currently estimates that it will need to acquire, either through PPAs or Facility Ownership, dispatchable capacity of approximately 1,200 MW in 2008, and an additional 1,000 MW in 2010. There is a preference for adding peaking capacity in 2008.

For Participants submitting bids for shaping resources (as defined in Section II.B.), PG&E requests that participants provide proposals that contain an option allowing PG&E to delay the delivery date for up to two years past 2010. For more information see Section II.A.

## B. Expected Schedule

The expected schedule for this RFO process is:

| | |
|---|---|
| March 18, 2005: | PG&E issues RFO |
| March 28, 2005: | Deadline for Participants to initiate electric and gas interconnection studies |
| April 8, 2005 | Participants asked to submit Notices of Intent to Offer if not previously submitted |
| April 27, 2005: | Initial Offers Due |
| July, 2005: | PG&E selects shortlist and distributes supplemental information requests, draft Agreements and other RFO materials |
| September, 2005: | Final Offers Due |
| Nov / Dec, 2005: | PG&E and winning Participants execute Agreements subject to Regulatory Approval |
| December, 2005: | PG&E submits Agreements for Regulatory Approval |

To be considered in this RFO an Offer must be received by PG&E in accordance with this RFO no later than 3:00 P.M. (PPT) on, April 27 , 2005 (an "Initial Offer").

After receipt of the Initial Offers, PG&E will review them and select a short list for a second and final offer (a "Final Offer"; Initial Offers and Final Offers are collectively referred to as "Offers"). See Section V ("RFO Schedule and Approval Process") for additional RFO schedule details.

Separate supply side PG&E RFO processes are under way for renewable resources (the Renewables Portfolio Standard ("RPS") RFO), and for energy call options (the Intermediate Term Capacity and Energy RFO).

PG&E will be seeking CPUC approval of all agreements resulting from this RFO prior to their taking effect to obtain assurances of cost recovery on its long-term commitments.

## C. Disclaimers for Rejecting Offers and/or Terminating this RFO

PG&E's request for Offers through the publication of this RFO does not constitute an offer to buy and creates no obligation to execute any Agreement or to enter into a transaction under a Agreement as a consequence of the RFO. PG&E shall retain the right at any time, in its sole discretion, to reject any Offer on the grounds that it does not conform to the terms and conditions of this RFO. PG&E also retains the discretion, in its sole judgment, to: (a) reject any Offer on the basis that it does not provide sufficient ratepayer benefit or that it would impose conditions that PG&E determines are impractical or inappropriate; (b) formulate and implement appropriate criteria for the evaluation and selection of Offers; (c) negotiate with any Participant to maximize ratepayer benefits; (d) modify this RFO as it deems appropriate to implement the RFO and to comply with applicable law or other direction provided by the CPUC; and (e) terminate the RFO should the CPUC not authorize PG&E to execute Agreements of the type sought through this RFO. Notwithstanding the above, PG&E reserves the right to either suspend or terminate this RFO at any time for any reason whatsoever. PG&E will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this paragraph to any Participant, whether submitting an Offer or not.

In its sole discretion, PG&E may also elect to pursue an Agreement with any Participant that has submitted a selected Offer, subject to PG&E obtaining Regulatory Approval of such Agreement as provided in Section XVIII of this RFO and the Agreement. Under no circumstances shall PG&E be contractually obligated to any Participant prior to PG&E's execution of an Agreement with the Participant nor until Regulatory Approval, as defined herein and in the applicable Agreement, has either been obtained or, in PG&E's sole discretion, waived.

## II. RFO GOALS

### A. PG&E Resource Needs

In December, 2004, PG&E's "2005 – 2014 Long Term Procurement Plan" was approved by the CPUC. The approval authorizes PG&E to procure dispatchable peaking and shaping resources (as defined in Section II.B.) to fill in the gaps between projected production from existing generation and contracted resources and projected demand. Since PG&E's deficit is initially more of a capacity need, PG&E prefers that peaking type resources are added during the first five months of 2008.

To meet this projected need, PG&E welcomes Offers from new generating facilities that meet the specifications noted in Section III. PG&E will also accept offers from Qualifying Facilities that meet the specifications in Section III. Optimal Offers will be those that best allow PG&E to produce energy products that are compatible with PG&E's requirements, and contribute to the other criteria specified in Section IV.

Although PG&E prefers resources that will commence delivering energy in 2008 or no later than 2010, PG&E would place value on an option, exercisable by PG&E in it sole discretion, to delay the initial delivery date for any shaping resource from the guaranteed date up to two years past 2010 (a "Delay Option").

In addition to the above needs, PG&E also needs to replace the 135 megawatt fossil-fuel generation facilities at its Humboldt Bay Power Plant in Eureka, California.

## B. Power Purchase Products

PG&E is seeking peaking and/or shaping products. Peaking type resources, in the context of this RFO, are typically expected to have low annual capacity factors, and usually have relatively higher variable costs or higher heat rates and lower fixed costs. Shaping resources are expected to provide flexible operating capacity with energy production that will vary on a daily, seasonal and annual basis. For example, depending on market conditions, for example, dry hydro, shaping resources could operate a significant amount of the year. Shaping resources are expected to have relatively lower variable costs and higher fixed costs. All resources must be dispatchable. PG&E should be able to schedule the resources in the day-ahead, hour-ahead, and real-time markets, subject to the plant's operational constraints.

PG&E will not consider Offers from partial Units. With the exception of offers from resources with current QF status, Offers for all Products must be 25 MW or greater. Specific operating flexibility must be defined by the Participant. For details, see Appendix F, Offer Data Form – Power Purchase.

For offers from gas-fired facilities, PG&E's preferred contract structure is a fuel conversion (tolling) structure. The documentation requested in this RFO is generally structured to accommodate gas-fired units and a fuel conversion agreement. Participants offering a power purchase arrangement other than a fuel conversion agreement should adapt the documentation as needed to exclude provisions for gas delivery by PG&E. For power purchase arrangements for Units fired by a fuel other than gas, regardless of the pricing structure offered, Participants are requested to break out capacity, fixed O&M, variable O&M and fuel costs to aid PG&E in comparing Offers.

From a long-term strategic portfolio planning perspective, PG&E seeks to develop a diversified portfolio of both ownership and contractual resources as well as resources with varying lives. Such diversity provides flexibility in adapting to a variety of uncertainties including load and price. Given this, PG&E would prefer that PPA contracts resulting from the long term RFO have a five to ten year time frame.

## C. Replacement of Expiring Qualified Facility ("QF") Contracts

In this solicitation, PG&E also will consider offers from existing and new Qualifying Facilities to replace power from QF contracts that will expire between 2006 and 2010. These QF resources must be 1 MW or greater in size. QFs may bid the general generation profiles of typical QF contracts. However, to enhance their competitiveness, QF offers should be priced attractively compared to other solicitation offers and market alternatives. All other things being equal, preference will be given to those projects offering dispatchability. Thus, expiring and new QFs have an opportunity to bid as a dispatchable plant as described above in the Products Section or as replacement power for expiring QF contracts.

A QF participant that has ongoing contract commitments must provide an offer with price, terms and conditions independent of its QF status assuming the ongoing QF commitment is terminated. Termination arrangements must be separately negotiated PG&E's with Power Contracts

Department. The QF bidder must set forth its plan to terminate any ongoing QF commitments in order for PG&E to evaluate the viability of its Long Term RFO QF bid. It is anticipated that any arrangement for the termination of an ongoing QF commitment will be approved by the CPUC when and if a QF offer is a winning offer under the Long Term RFO and a contract is executed and submitted to the CPUC for approval.

## D. Humboldt Bay Power Plant Replacement

PG&E is also seeking to replace the 135 megawatt fossil-fuel generation facilities at its HBPP. This plant is needed for local area reliability, and replacement proposals will be required to satisfy specific functional specifications, and must be located in Humboldt County. Offers to replace the HBPP will generally follow the same protocol as other Offers.

PG&E prefers that the facility have a Commercial Operations Date during 2008, but will consider offers with on-line dates through August 31, 2009.

Current studies indicate that the replacement generation capacity be no less than 135 MWs and no more than 168 MWs assuming the retirement of HBPP and no transmission system upgrades or reinforcements. Generators that are greater than 168 MW may require system reinforcements or other mitigating measures, which would be identified as part of a project's SIS.

In addition, facilities must meet the functional specifications specified in Appendix J.

Participants who wish to arrange a visit to the site should contact Mark Smith, Engineering Manager at the Humboldt Bay Power Plant at (707) 444-0844.

## III. ELIGIBILITY REQUIREMENTS

PG&E will consider offers that meet the specifications noted below:

### A. Power Purchase

1. New generating facilities, must have a Commercial Operations Date (as defined in the RFO Term Sheet, Appendix D) no earlier than January 1, 2007, and no later than May 31, 2010.
2. An existing QF in PG&E's service territory as of November 2, 2004 that meets the requirements of this section. A Qualifying Facility must meet the requirements of the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations Part 292) implementing Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et. seq.) and has not waived these rights as regards to PG&E.
3. Minimum offer term of 5 years.
4. Minimum offers of 25 MW or greater (1 MW for all QFs).
5. Deliveries of the products (capacity, energy and ancillary services) must commence no earlier than January 1, 2007, and not later than May 31, 2010.
6. The Participant must provide for firm physical delivery of its generation to a busbar at a specified delivery point (designated by Seller) within the area designated as NP15, as presently defined by the California Independent System Operator Corporation ("CAISO"). However, QF's may also provide delivery within the area designated as ZP26 by the CAISO.
7. The Participant must initiate a transmission System Impact Study, as defined in Section IX and a Preliminary Application for Gas Service, as defined in Section X. Applications to initiate these studies must be received by March 28, 2005.
8. The Participant must satisfy the Offer Deposit requirements set forth in Section VI.C.
9. Participant must demonstrate no later than the submission of its Final Offer, that it has control by ownership or long-term lease over the proposed site or an option to control the proposed site through ownership or a long-term lease.
10. Only "unit specific" offers will be accepted.
11. Offers shall confer upon PG&E exclusive rights to the unit's capacity based on agreed upon operating flexibility, and subject to CAISO requirements.
12. Participant must agree (i) to schedule and dedicate the contracted amount of electrical output to PG&E, net of station use and electrical losses; and (ii) not sell, deed, grant, convey, transmit, or otherwise provide any energy, capacity, ancillary services or any other related electricity product, including Environmental Attributes, as defined in the Standard Terms Decision (CPUC D-04-06-014), or capacity attributes associated with the output to an entity other than PG&E.

## B. HBPP Replacement

1. New generating facilities, must have a Commercial Operations Date (as defined in the RFO Term Sheet, Appendix D) no earlier than January 1, 2007, and no later than August 31, 2009.
2. Minimum offer term of 5 years.
3. Total Peak Capacity of at least 135 MW on a single site.
4. The Functional Specifications listed in Appendix J.
5. The proposed project's generation must physically interconnect to a busbar within Humboldt County.
6. The Participant must initiate a transmission System Impact Study, as defined in Section IX and a Preliminary Application for Gas Service, as defined in Section X. Applications to initiate these studies must be received by March 28, 2005.
7. The Participant must satisfy the Offer Deposit requirements set forth in Section VI.C.
8. Participant must demonstrate no later than the submission of its Final Offer, that it has control by ownership or long-term lease over the proposed site or an option to control the proposed site through ownership or a long-term lease.
9. Only "unit specific" offers will be accepted.
10. Offers shall confer upon PG&E exclusive rights to the unit's capacity based on agreed upon operating flexibility, and subject to CAISO requirements.
11. Participant must agree (i) to schedule and dedicate the contracted amount of electrical output to PG&E, net of station use and electrical losses; and (ii) not sell, deed, grant, convey, transmit, or otherwise provide any energy, capacity, ancillary services or any other related electricity product, including Environmental Attributes, as defined in the Standard Terms Decision (CPUC D-04-06-014), or capacity attributes associated with the output to an entity other than PG&E.

## IV. EVALUATION OF OFFERS

To evaluate Offers, PG&E will primarily consider Market Valuation, Portfolio Fit, Credit, Viability, Transmission Impact, Debt Equivalence Impact, Environmental Characteristics, Participant Qualifications, and Conformance with PG&E’s non-price terms and conditions. Each of these primary criteria is discussed below.

In accordance with the CPUC Long Term Plan Decision, PG&E will evaluate Offers for Power Purchase or Facility Ownership together, and will utilize an Independent Evaluator.

Offers relating to the HBPP replacement will be evaluated separately.

**Market Valuation** means how an Offer's cost compares to an Offer's benefits, from a market perspective. An Offer's cost is reflected in the Offer’s pricing. An Offer's benefits are the market value of the energy, capacity, and ancillary services offered. These costs and benefits may include: fixed and variable costs; transaction costs, such as market bid-ask spreads; location-specific value, as represented by zonal or nodal price differentiation; and operating flexibility, as represented by option value. The risks and uncertainties associated with an Offer’s costs and benefits will be considered as part of Market Valuation. These costs and benefits do not include the particular costs and benefits associated with the Offer's impact on PG&E's portfolio positions and possible attendant market transactions by PG&E.

An important component of market valuation benefit is operating flexibility. PG&E uses option valuation models to quantify how operating flexibility contributes to market valuation.

**Portfolio Fit** means how well an Offer's features match PG&E's portfolio needs. In particular, the value of an Offer's capacity, energy, and ancillary services is adjusted to account for PG&E's portfolio positions, including temporal and locational aspects. Portfolio fit thereby weighs an Offer's costs and benefits in the context of PG&E's portfolio needs. In contrast, the market valuation component considers an Offer's costs and benefits without taking into account PG&E's portfolio needs.

**Credit** means the Participant’s capability to perform all of its financial and other obligations under the Agreements, including, without limitation, the Participant’s ability to provide performance assurance under the Agreements. PG&E will consider the Participant's financial strength as determined by PG&E as well as any credit enhancements acceptable to PG&E that Participant may offer with its proposal. PG&E will also consider its overall credit concentration with any particular Participant.

**Viability** means the probability that the resource(s) associated with an Offer can be financed and completed as required by the Agreement and will be available to provide capacity and energy and/or ancillary services when called upon.

**Transmission Impact** means the effect of an Offer on the electric transmission system. In evaluating an Offer, PG&E will consider the network upgrade costs as described in Section

IX.C. – System Impacts. PG&E will also consider congestion risk, impact on RMR costs, and other locational attributes associated with an Offer.

**Debt Equivalence** in this context refers to the debt-like characteristics of PPAs not classified as interest bearing liabilities under Generally Accepted Accounting Principles. PG&E will consider the debt equivalent impacts of an Offer.

**Environmental Characteristics** includes air emissions including carbon dioxide, nitrogen oxides, sulfur dioxide and particulates, and other potential environmental impacts. The quantities and potential costs to PG&E and to society associated with these characteristics will be considered.

**Participant Qualifications** means the experience and technical expertise of the Participant putting forth the Offer.

**Conformance with PG&E's non-price terms and conditions** means the degree to which the Participant accepts PG&E's proposed terms and conditions.

PG&E will evaluate Offers in a manner consistent with the company's and the corporation's environmental and environmental justice policies.

## V. RFO SCHEDULE AND APPROVAL PROCESS

**A.** Below is the expected RFO schedule, followed by a discussion of each step:

**Table V.1: PG&E RFO Schedule**

| | | |
|---|---|---|
| October 5, 2004 | 1. | PG&E distributed a Draft RFO; Participants were invited to register online to receive notices regarding the RFO. |
| October 15, 2004 | 2. | Participants' Pre-Offer Conference. |
| November 2, 2004 | 3. | PG&E issued original RFO. |
| March 18, 2005 | 4. | PG&E issues updated RFO. |
| March 28, 2005 | 5. | Deadline for Participants to initiate electric and gas interconnection studies. |
| April 8, 2005 | 6. | Participants asked to submit Notices of Intent to Offer if not previously submitted. |
| April 27, 2005 | 7. | Initial Offers Due. |
| July, 2005 | 8. | PG&E selects shortlist and distributes supplemental information requests, draft Agreements and other RFO materials. |
| September, 2005 | 9. | Final Offers due. |
| Nov. / Dec. , 2005 | 10. | PG&E and winning Participants execute Agreements subject to Regulatory Approval. |
| December, 2005 | 11. | PG&E submits Agreements for Regulatory Approval. |

The RFO schedule is subject to change at PG&E's sole discretion at any time. The RFO schedule may be affected by, among other things, discussions with selected shortlisted Participants, and proceedings before the CPUC, including, but not limited to, proceedings to obtain Regulatory Approval. PG&E will endeavor to notify Participants of any schedule change, but will have no liability or responsibility to any Participant for change in the schedule or for failing to provide notice of any change. In particular, the process relating to the Humboldt Bay Power Plant may proceed on a different, expedited schedule after Initial Offers have been received.

**B. Steps in the RFO:**

1. PG&E Distributed Draft RFO / Online Registration. Participants may register at either of the RFO websites: http://www.pge.com/longtermpprfo or http://www.pge.com/ownershiprfo. Registering will establish the Participant on PG&E's notice list and insure that Participant receives timely announcements and updates. Online Registration is not required to qualify to Offer, but is strongly recommended.

2. Pre-Offer Conference. PG&E held a Pre-Offer Conference to discuss the draft 2004 PG&E Long-Term Facility Ownership and Long-Term Power Purchase RFOs.

3. PG&E issued Request for Offers for each of Power Purchase and Facility Ownership on November 2, 2004. The process for these RFOs was deferred in January, 2005.

4. PG&E re-issues Request for Offers.

5. Deadline to Initiate Electric and Gas Interconnection Studies. Participants must initiate, if needed, a System Impact Study ("SIS") and Facility Study ("FS") with the CAISO, as described in the CAISO Generating Unit Procedure set forth in Section IX; and submit to PG&E California Gas Transmission ("CGT") a request for a Preliminary Application for Gas Service as set forth in Section X if applicable. Participants with gas interconnections outside CGT must demonstrate comparable initiation with their local gas service provider. The Participant is responsible for the cost of each interconnection study or application. Failure of a Participant to provide the information necessary to complete its Application promptly may result in disqualification of the Participant's Offer.

   **Deadline: Monday, March 28, 2005, 3:00 P.M. (PPT)**

6. Notice of Intent to Offer. Participants are requested to complete and submit Appendix C by April 8, 2005 for each individual project, with basic project information. Participants are not requested to submit a duplicate if a notice was previously submitted for such project prior to the temporary suspension of the RFO process on January 7, 2005. Failure to submit a completed Appendix C by the scheduled date will not disqualify a Participant from participating in the RFO process.

7. Initial Offers Due. Participant's Initial Offer must be submitted by the deadline listed below and include without limitation the documents described in Sections VII.B, IX and X. Participant's submission of its Initial Offer constitutes its consent to and authorization of PG&E's electric and natural gas transmission functions providing to PG&E's merchant function any information concerning their evaluation of the Participant's interconnection and transmission system impacts which the Participant provides to them, or, which they provide to the Participant. Submittals must be tendered electronically and in hard copy. If there is disagreement between the electronic and hard copies, the hard copy will prevail. By responding to this RFO as described in Section VI.A, the Participant agrees to be bound by all of the terms, conditions and other provisions of this RFO and any changes or supplements to it that may be issued by PG&E.

   **Deadline: Wednesday, April 27, 2005 , 3:00 p.m. (PPT)**

8. PG&E Selects Shortlist. PG&E intends to select a shortlist of Participants for the submission of Final Offers. Participants who have been selected for the shortlist will be required to execute a Confidentiality Agreement in the form attached as Exhibit 1 to Appendix A, agreeing to keep confidential the terms discussed during the course of finalizing the final Agreements. Shortlisted Participants will be provided a copy of the definitive Agreements and supplemental RFO materials. PG&E reserves the right to add additional Participants to the shortlist following the initial selection.

9. Final Offers Due from Shortlisted Participants including responses to supplemental information requests. Participants must be willing to execute the Agreements submitted with their respective Final Offer.

10. PG&E and Winning Participants Execute Agreements. Each Agreement is subject to Regulatory Approval and any other conditions precedent as set forth in the particular Agreement

11. PG&E Submits Agreements for Regulatory Approval. A Participant executing an Agreement must cooperate with and actively support PG&E, if PG&E requests, in obtaining Regulatory Approval.

## VI. BINDING NATURE OF OFFER

### A. Agreement by Participant

By responding to this RFO, each Participant agrees to be bound by all terms, conditions and other provisions of this RFO and any changes or supplements to it that may be issued by PG&E. Each Participant will be required to have an authorized officer of Participant execute the "Long Term Request for Offer Agreement" attached hereto as Appendix A, which requires that the Participant agree to be bound by the terms of the RFO and to make specified representations and warranties to PG&E. Given the length of the Regulatory Approval process, each shortlisted Participant must agree to be bound by its Final Offer(s) for a period of eight (8) months from the date PG&E files the Agreement(s) with the winning Participant(s) with the CPUC. If the CPUC grants (subject to appeal) Regulatory Approval of the Agreement(s) within the eight-month period, each shortlisted Participant must agree to be bound by its Final Offer(s) for any additional period of time required for the CPUC order granting Regulatory Approval to become final and non-appealable.

### B. Offer

Respondents may submit multiple offers. Each Offer must have a discrete size, location and delivery point.

The Participant is requested to provide a Delay Option to PG&E, as defined above in Section II.A and further detailed in Section XIII – Pricing, Terms and Conditions. PG&E may make the provision of the Delay Option a mandatory requirement for Final Offers.

### C. Offer Deposit

Each Offer will require a separate Offer Deposit. When submitting each Offer, the Participant will be required to provide an initial deposit of cash or a Letter of Credit, (the "Offer Deposit"), as defined below for each Offer, in the amount of $5 per kW of the maximum monthly Capacity as set forth on Participant's completed Appendix F ("Generation Facility Information Form"). Participants may also provide up to four offer variations under a single Offer Deposit. All offers under a given Offer Deposit must be for a project which has the same size, location and delivery point. The variations under a single Offer Deposit are (i) one variation for Facility Ownership and (ii) three variations for Power Purchase which can only vary price and term. Provision of a Delay Option is not considered a separate variation for Offer Deposit calculation purposes.

The initial Offer Deposit is intended to secure the obligations of each Participant during the RFO's evaluation period and the period required to negotiate, execute and obtain regulatory approval of the Agreements(s). It is also intended to insure that each Initial Offer has been carefully considered. Any Initial Offer submitted without an accompanying Offer Deposit will be deemed to be a non-conforming Offer. Offer Deposits will be returned as set forth below in this Section VI.B.

At the date of submission for Regulatory Approval of selected Final Offers, an additional Offer Deposit of $5 per kW (for a total of $10 per kW of the maximum monthly Capacity) will be required from each selected Participant with respect to each selected Offer.

As noted above, the form of the Offer Deposit may be either (a) a cash deposit through a wire transfer; or (b) a Letter of Credit, as described below. **Participants should notify PG&E via email at longtermpprfo@pge.com prior to submitting their Offer Deposits to obtain details of delivery instructions, and routing and account number requirements.**

PG&E will pay interest on each cash deposit, calculated on a monthly basis and compounded at the end of each calendar month, from the date fully deposited to the earlier of (i) the return of the cash deposit to Participant or (ii) any transfer of the Offer Deposit to "Delivery Date Security" required under an executed Agreement. The applicable interest rate will be the rate per annum equal to the Monthly Federal Funds Rate (as reset on a monthly basis based on the latest month for which such rate is available) for each day cash is held by PG&E as reported in Federal Reserve Bank Publication H.15-519 or its successor publication ("Interest Rate"). The Interest Rate shall be calculated based on a 360-day year and payable upon the first to occur of (i) the return of the cash deposit as provided below or (ii) any replacement of the cash deposit with a Letter of Credit as described below.

**Letter of Credit** - The Offer Deposit Letter of Credit and the Delivery Date Security Letter of Credit must be irrevocable, standby letters of credit. The Offer Deposit Letter of Credit must be in the form attached hereto as Appendix B. The Delivery Date Security Letter of Credit must be in form satisfactory to PG&E. Each Letter of Credit must be issued by a U. S. commercial bank or a foreign bank with a U. S. branch with such bank having total assets of at least USD$10 billion and a senior unsecured long term debt rating of no lower than A2 from Moody's Investor Services, Inc., or its successor ("Moody's") or A from Standard & Poor's Rating Group, or its successor ("S&P") ("Letter of Credit").

The Offer Deposit Letter of Credit must remain outstanding for the entire period in which the corresponding offer is pending. The Offer Deposit Letter of Credit submitted with each Initial Offer must have an expiry date of no earlier than December 31, 2005. If a Participant's Initial Offer is shortlisted, the expiry date of the Offer Deposit Letter of Credit for that Offer must, within 15 days after notice to the Participant of the shortlisting, be amended to be no earlier than March 31, 2006. PG&E may require further extensions of the required expiry date of any Offer Deposit Letter of Credit to the extent it deems necessary in its sole discretion to ensure that the Offer Deposit Letter of Credit remains in effect until Regulatory Approval of the corresponding Agreement has been obtained. If any Offer Deposit Letter of Credit has an expiry date earlier than that required by this paragraph, it must specify that PG&E may draw on such Offer Deposit Letter of Credit if, by the date that is thirty (30) days prior to the stated expiry date, PG&E has not received substitute security in the amount of the Offer Deposit Letter of Credit, such security to be in the form of a cash deposit as described above or another Offer Deposit Letter of Credit satisfying the requirements of this paragraph. Costs of the Offer Deposit Letter of Credit shall be borne by Participant. The Offer Deposit Letter of Credit should be sent by overnight delivery to:

**PG&E**
**77 Beale Street, Mail Code B28L**
**San Francisco, CA 94105**
**Attn: Kenneth Lock, Credit Risk Management Unit**

Upon selection of the shortlist for this RFO, the Offer Deposit for rejected Initial Offers with respect to projects which are not shortlisted in the RFO process will be returned within 10 business days. PG&E will continue to hold the Offer Deposit for shortlisted Offers. The Offer Deposit of those shortlisted Offers will be returned under the following conditions:

1. PG&E's rejection of the Offer subsequent to shortlist selection when no variation of the Offer (secured by the same Offer Deposit) is shortlisted for the same project;
2. In the course of negotiation, the parties cannot agree on the terms of the Offer and Agreement, and PG&E rejects the Offer and Agreement as submitted by Participant when no variation of the Offer (secured by the same Offer Deposit) is shortlisted for the same project;
3. Upon execution and approval of the Agreement and Participant's submission of the letter of credit required under the Agreement ("Performance Assurance").
4. To the extent Regulatory Approval of the Offer has not been obtained before it is no longer required to be binding under Section VI.A. of this RFO and the Participant does not agree to be bound for a longer period of time.

The Participant will forfeit the Offer Deposit in its entirety under the following conditions:

1. Participant's withdrawal of the Offer other than as a result of its no longer being binding as required by Section VI.A. of this RFO;
2. Any material misrepresentation of pricing or other information knowingly submitted by Participant.

In the event that Participant forfeits the Offer Deposit, PG&E will be entitled to draw upon the Offer Deposit in its entirety as payment for direct and indirect damages incurred in connection with the Participant's withdrawal of Offer. PG&E shall also be able to draw on any Letter of Credit or retain any cash deposit provided as an Offer Deposit, as Performance Assurance under an Agreement, in the event that Participant fails to provide the Letter of Credit required under such Agreement.

PG&E may also draw on the Letter of Credit in the event (i) the Participant is obligated to, but has not, provided a replacement Letter of Credit from a qualifying issuer, or a cash deposit as set forth above, before the date that is thirty (30) days prior to the stated expiry date of the Letter of Credit, or (ii) the credit rating of the issuer falls below A2 from Moody's and A from S&P and a replacement Letter of Credit from a qualifying issuer, or a cash deposit as set forth above, is not provided to PG&E within seven (7) days. Amounts drawn in such circumstance will be held as cash deposits and be subject to draw or forfeiture as provided in the RFO.

PG&E will not reimburse Participants for their expenses under any circumstances, regardless of whether the RFO reaches a successful conclusion or is terminated early at the sole discretion of PG&E.

## VII. PROTOCOL FOR PARTICIPANT OFFERS

### A. Overview

Participants should submit offers to the RFO based on this March 18, 2005 RFO, not previously issued RFOs. All Initial Offers must be received in *both* hard copy and electronic form by **Wednesday, April 27, 2005 at 3:00 p.m. (PPT)**. If there is disagreement between the electronic and hard copies, the hard copy will prevail.

**Hard copy documents**: Participants must submit two (2) bound and one (1) unbound copy via hand-delivery or overnight delivery to:

**Long Term RFO – Power Purchase**
**Electric Resource Procurement**
**245 Market Street, Room 1280A, Mail Code N12G**
**San Francisco, CA 94105**

**Electronic Documents**: The electronic documents must be in a Microsoft Word and/or Excel file, as applicable, with any proposed changes to the Term Sheet (Appendix D) in a Microsoft Word file marked to show all changes. Electronic Documents must be in the form of a compact disk (CD) accompanying the hard copy documents.

**Telephonic, telegraphic, e-mail or facsimile transmission of an Offer is not acceptable**

### B. Required Information

The following documents, which are located in the Appendices, must be included in any Initial Offer in the order given below:

1. **Completed Offer Cover Sheet (Appendix K)** providing key details of the Participant's Offer.

2. **Signed Long Term Request for Offer Agreement (Appendix A)** attesting to Participant's agreement to be bound by the conditions of the RFO.

3. **A Letter of Credit in the form of Appendix B** from an issuer meeting the criteria set forth in Section VI.C **or a cash deposit,** either in accordance with the requirements of Section VI.C

4. A **Power Purchase Agreement Term Sheet (Appendix D1)** in the form of a Microsoft Word document that is marked to show any proposed changes to the Term Sheet **OR** a statement confirming that *all* of the terms in Appendix D are acceptable. These requested modifications will be considered part of the Participant's Initial Offer; that is, PG&E will assume that the Participant is willing to negotiate and execute an Agreement based on these terms. Any material changes proposed by the Participant to the Term Sheet, and any subsequent

refusal to be bound by its proposed changes, will be given consideration in the overall Offer evaluation process. Non-price terms and conditions for the Delay Option should be provided in a separately marked copy of the Term Sheet, Appendix D.

5. **A completed Offer Data Form (Appendix E).**

6. **A completed Generation Facility Information Form (Appendix F).**

7. **A completed Credit and Finance Information Form (Appendix G).**

8. **A completed Electronic Transmission Data Information Form (Appendix H).** Include a copy of any current SIS/FS for the proposed project, if available.

9. **A completed Gas Interconnection Information Form (Appendix I).**

10. **Functional Specifications Form (Appendix J).** For a Power Purchase Offer for the HBPP Replacement, Offers with a gas-fired generation facility must meet the Functional Specifications described in Appendix J. Offers other than gas fired technologies should provide a letter stating their ability to meet these requirements and provide a markup of Appendix J stating those characteristics they cannot meet and provide the standards they can satisfy.

## VIII. COMMUNICATIONS

PG&E has established a website at http://www.pge.com/longtermpprfo, where Participants may register and where all RFO documents, information, announcements and Q&As are posted and available to Participants.

To promote accuracy and consistency of the information provided to all Participants, PG&E discourages Participants from speaking directly with PG&E employees about this RFO. PG&E strongly prefers that all communications take the form of an email directed to longtermpprfo@pge.com. With respect to matters of general interest raised by any Participant, PG&E may, without reference to the specific Participant raising such matter or initiating the inquiry, post responses on its website. PG&E may, in its sole discretion, decline to respond to any email or other inquiry without liability or responsibility.

PG&E may elect to respond to inquiries or comments by individual Participants concerning purely procedural or administrative matters, but may also decline to do so in its sole discretion without liability or responsibility.

## IX. ELECTRIC TRANSMISSION INTERCONNECTION

Interconnection of a project to the electric system grid and the ability of the project to deliver the resource to serve load reliably will be integral components of PG&E's evaluation of Offers. This section describes the interconnection requirements that the Participants are required to meet. Participant requirements are:

1. The resource must meet all applicable planning and operation standards as described in Section A. "Standards of Care".

2. PG&E's transmission system must be able reliably to deliver the output of the resource to serve load. This ability and the associated costs are determined from the CAISO Generating Unit Interconnection Procedure. For any project that does not have both a current System Impact Study (SIS) and a current Facility Study (FS), as described in the CAISO Generating Unit Interconnection Procedure, the Participants must apply for interconnection as described in Section C. "System Impacts" no later than March 28, 2005.

3. For those projects that have a current SIS and FS (current CAISO queue), each Offer must include both a complete SIS and FS to be considered for selection; no Offer involving a project that has a current SIS/FS will be complete until PG&E has received this information. Any potential Participant that does not want to provide this information to PG&E should not submit an Offer in this RFO.

4. For those projects that do not yet have a current SIS/FS, each Participant must either accept the transmission proxy costs that result from their choice of substation, as provided below, or provide to PG&E the results of preliminary or final studies as those results become available. This information will be used by PG&E solely in ranking and evaluating Offers and will be treated as confidential information by PG&E.

5. Each Participant is solely responsible for any direct assignment costs and transmission charges, as described in Section B. "Direct Assignment Facilities and Transmission Charges".

6. Completion of Appendix H.

Appendix H provides the web links to the documents referred to in this Section.

### A. Standards of Care

All projects will be required to meet the following standards of care.

1. <u>ISO Standards</u>. Facilities must be designed and constructed such that all generation, scheduling and transmission services shall be performed in compliance with all applicable operating policies, criteria, rules, guidelines and tariffs of the CAISO and Prudent Electrical

Practices. The project, at its own expense, shall fulfill all contractual, metering and interconnection requirements as set forth in Participating Transmission Owner's applicable tariffs, the CAISO tariff and implementing CAISO standards and requirements, including but not limited to executing a CAISO Interconnection, Participating Generator and Meter Service agreements and PTO Generator Special Facilities Agreements ("GSFA"), so as to be able to deliver energy to the CAISO controlled grid and bear all costs relating to all metering equipment installed to accommodate the Unit(s). The project will exercise best efforts to comport and comply with any conditions, modifications, amendments or additions to the applicable CAISO tariffs and protocols.

2. Reliability Standard. The project must be designed and constructed to comply with all North American Reliability Council, Western Electricity Coordinating Council ("WECC"), and CAISO reliability requirements. If the project is interconnected directly to the PG&E system, it must meet PG&E's requirements regarding interconnection of the Unit(s), including PG&E's Interconnection Handbook ("PIH"); or, if the project is interconnected to the system of another transmission owner, it must also meet the applicable requirements regarding interconnection of the Unit(s) with such transmission owner's system.

3. Protective Apparatus. The project must include all relays, meters, power circuit breakers, synchronizers and other control and protective apparatus that PG&E, in its sole judgment, determines are reasonably necessary for proper and safe operation of the Unit(s) in parallel with the PG&E or CAISO system.

**B. Direct Assignment Facilities and Transmission Charges**

Direct Assignment facilities are those facilities needed to interconnect the generation facility to the first point of interconnection with the PG&E transmission system. These facilities are referred to as direct assignment facilities, or gen-ties. Direct assignment facilities include the transformer bank used to step-up the generation output to transmission voltage, the outlet line between this step-up transformer bank and the transmission system, and protection and communication facilities needed for interconnection and safe operation of the generator. Direct Assignment transmission charges include any transmission charges the project must pay to a Transmission Owner other than PG&E. The Participant is solely responsible for Direct Assignment and Transmission Charges.

**C. System Impacts**

System Impacts relate to the capability of the transmission system to deliver the full output of the project from the first point of interconnection with the PG&E transmission system to serve the load reliably. If there is insufficient capability, network upgrades would be needed. Network upgrades include transmission lines, transformer banks, special protection systems, substation breakers, capacitors, and other equipment needed to transfer the generation output to the consumer. Pursuant to FERC Order 2003, as modified by FERC in March of 2004, Participants will be required to fund the full cost of all facilities necessary to interconnect to PG&E's system, including network upgrades. A Participant is entitled to a cash equivalent refund of the network upgrades it funds, with interest paid over a five-year period. All Participants in this RFO must apply for interconnection for each project through the CAISO Generation Unit Interconnection Procedure no later than March 28, 2005, including the SIS/FS.

1. Projects With Completed and Current SIS/FS. For projects that have already obtained cost estimates from completed and current SIS/FS through the CAISO Generating Unit Interconnection Procedure, the Participant shall submit copies of the completed studies and the SIS/FS cost estimate for the needed network upgrades with the Offer.

2. Projects Without Completed SIS/FS. For projects that do not yet have completed SIS/FS, pending the availability of the completed studies, PG&E will use the preliminary results of the SIS/FS, and if the preliminary results are not available, PG&E will use transmission proxy costs for interim Offer evaluation. A link to the proxy costs may be found on the following PG&E web site: www.pge.com/longtermpprfo, under the section titled "Transmission Related Information and References", listed as "Electric Transmission Proxy Costs". In either case, copies of the completed studies must be received by PG&E when they are available.

Each Participant without a completed SIS/FS must select from the substations listed on the web site cited above the substation which is the most appropriate point of interconnection for its Unit(s) in its Offer. The transmission costs are proxies for transmission network upgrades that may be needed to transmit the full output of the project to serve load reliably. The transmission costs were determined based on the method that was filed in compliance with CPUC Decision 04-06-013.

The PG&E web site referenced above provides the transmission proxy costs for 230 kV substations during peak and off-peak periods. For each substation, PG&E has identified several levels of possible additional transmission capacity and the related costs. Level 1 reflects the available transmission capacity after taking into account all approved reliability and economic transmission projects as well as upgrades planned for generation projects in the ISO interconnection queue based on their completed SIS/FS studies. Thus, Level 1 would have no network upgrade costs except those associated with reactive power support. The next and subsequent levels reflect the next most cost-effective proxy network upgrade(s). The number of levels depends on the number of proxy network upgrades needed to accommodate up to about 1,000 MW new generation in each substation.

The transmission proxy costs will be used solely for the purpose of ranking and evaluating Offers. The actual transmission network upgrade costs for a specific project, determined by the SIS/FS, may differ from the transmission proxy costs and PG&E is not responsible or liable for the deviation between estimated and actual costs.

## X. GAS SUPPLY AND INTERCONNECTION

If gas is the fuel source, Offers for a Power Purchase Agreement should reflect a Fuel Conversion Agreement arrangement (tolling) where PG&E would procure and deliver the gas commodity to the plant.

Each Offer using natural gas must include a completed form of Appendix I. This information is required regardless of the source of the gas transportation service.

<u>If Interconnected to CGT:</u>

To obtain the information needed to complete Appendix I for a power plant that is located in PG&E's service territory and is served from the PG&E gas transmission system, each Participant must submit to CGT a request for a Preliminary Application for Gas Service by no later than March 28, 2005. The gas interconnection process is described at http://www.pge.com/suppliers_purchasing/new_generator/gas_interconnections/ .

For projects that have already obtained a response for a Preliminary Application for Gas Service within the past 12 months from a previous PG&E application, the Participant shall submit copies of the completed studies and a completed Appendix I with the Offer.

The PG&E Power Plant Connection Process usually consists of 4 steps:

1. Preliminary Request for Information Review,
2. Preliminary Application for Gas Service,
3. Formal Application for Gas Service, and
4. Construction.

However, for this RFO, Participants are asked to use the following expedited process:

1. Submit to PG&E's CGT a formal written request to initiate the Preliminary Application for Gas Service. The normal response time for a Preliminary Application for Gas Service is approximately 12 weeks. Because of the necessity of an expedited response, we suggest the following requests be made in the cover letter:
    a. Notify CGT that you are participating in this RFO.
    b. Request CGT to forgo the Preliminary Informational Review and immediately initiate a Preliminary Application for Gas Service.
    c. Request CGT to provide results of the System Impact Study (SIS) as soon as the study is complete, with a copy to Power Contracts & Electric Resource Development.
    d. Request that, upon completion of the SIS, CGT should proceed with an expedited Preliminary Facilities Study. Request that the study be completed by April 18, 2005. Also state that, because of the timing of this RFO, the request for information should

be treated by CGT on an expedited schedule, and that the Participant will accept order-of-magnitude cost estimates based upon available engineering resources.

2. Provide CGT with a completed Interconnection Information Sheet. This document is included with this RFO, and can also be found at: http://www.pge.com/suppliers_purchasing/new_generator/gas_interconnections/.
3. Provide CGT with two completed and executed originals of PG&E's "Agreement to Perform Tariff Schedule Related Work" (see Exhibit 1 to Appendix I).
4. Provide a site map of the proposed power plant with a proposed meter set location.
5. Include hourly/daily/seasonal projected load curves when the power plant is in-service; (maximum loads are in the interconnection information sheet).
6. Provide the estimated annual gas usage of the proposed Facility; and
7. Enclose a cash advance of $10,000 to initiate engineering.

The date of receipt by CGT of the completed application will establish the Participant's place in the engineering queue. In order to meet the expedited bidding schedule, CGT will not perform a full analysis at this time. PG&E will request that if the Participant is selected for the shortlist, the Participant shall request CGT to provide a detailed Preliminary Application for Gas Service. Additional funding may be required at that time. The Formal Application for Gas Service will not be required until the Final Offers have been selected.

The Participant will be required to pay for the interconnection of the project to the PG&E gas system, subject to the conditions as outlined in PG&E's Gas Rules 15 and 16 (http://www.pge.com/tariffs/GR.SHTML#GR), unless addressed in PG&E'S response to the Preliminary Application for Gas Service.

All cash advances provided by the Participant will be credited against the engineering job. If work does not proceed, the balance of the cash advance will be returned to Participant. Should the costs exceed the project advance, PG&E will stop work and notify Participant accordingly. For this cash advance, PG&E will perform the following:

1. A cost and schedule to build PG&E's recommended Standard Facilities and Special Facilities Designs with an estimated accuracy of +/- 50%;
2. A map showing PG&E's preferred transmission service tap, pipeline route and meter set location; and
3. The expected minimum delivery pressure available at the meter set for PG&E's preferred route.

An additional cash advance may be required to complete the Preliminary Study should the Participant make the short list.

The Application including the initial cash advance made out to PG&E, should be delivered to:

Pacific Gas and Electric Company
Attn: Rod Boschee
Mail Code: B16A
77 Beale Street
San Francisco, CA 94105

If Not Interconnected to CGT:

A completed Appendix I will be required by PG&E from the Participant. The Participant will be responsible for obtaining all required information from the gas service provider, and will include all related documents and studies with the Offer.

## XI. GENERATING FACILITY DESCRIPTION

**Power Purchase**

Participants are required to describe in detail the generation facility that will be providing the specified products. The Participant should demonstrate the ability of the generation facility to be available by the Initial Delivery Date (as defined in the PPA Term Sheet (Appendix D)) and throughout the project life to provide capacity and energy and/or ancillary services when called upon. This reliability will be considered in the evaluation of the Offer.

The detailed project description should be provided in the Generation Facility Information Form, (Appendix F).

In the case of a HBPP replacement, the facility must also meet certain operating performance criteria set forth in Section II and Appendix J.

## XII. FINANCING AND CREDIT

In its evaluation of an Offer, PG&E will consider the Participant's capability to perform all of its financial and other obligations under the PPA, including, without limitation, the Participant's ability to provide Performance Assurance that the resource would be available and operate as required under the executed contract. This assurance is to support performance during plant operations and the ability of the Participant to construct the generation facility by the Initial Delivery Date. This assurance includes the ability of the Participant to fund the construction of the generation facility and cause it to be constructed by the Initial Delivery Date as set forth in the Term Sheet (Appendix D). Participants are required to complete the Credit and Finance Information Form set forth in Appendix G.

The Participant will be required to post collateral to support its ability to construct the generation facility by the expected delivery date and depending on its credit standing, may need to post collateral acceptable to PG&E to support performance of other obligations under the contract. The terms and conditions to provide collateral are set forth in the Term Sheet in Appendix D. As set forth in Section IX, participants will be required to provide funding for any Network Upgrade costs.

To manage credit risk associated with the products being contracted through this RFO after the Initial Delivery Date, PG&E will require a weekly collateral posting based on a computation of the week-to-week change in market value for the product(s). The change in market value will be computed for either a two-year or a five-year time frame. The specific time frame is dependent on the length of time it is expected to take to replace the technology underlying the product contracted through this RFO. Depending on the shift in market value, PG&E or the seller will be required to post collateral beyond their respective collateral threshold amounts as described in the Term Sheet in Appendix D.

The Participant will also be subject to an Independent Amount component as described in the Term Sheet in Appendix D. Depending on a party's credit standing, there may be a requirement to post some or the entire independent amount on the initial delivery date. The independent amount would be based on PG&E's assessment on the potential short-term market value movement of the contract.

## XIII. PRICING, TERMS AND CONDITIONS

Participants are required to complete the Offer Data Form set forth in Appendix E. The Offer Data Form should be completed in conjunction with a review of the Term Sheet provided in Appendix D. Each Participant should also provide any proposed modifications to the Term Sheet. Modifications to the Term Sheet will be considered in the evaluation of each Offer.

Each Participant will be expected to review the Term Sheet and provide a marked copy of any proposed modifications with its Initial Offer, as set forth in Section VII.B. Shortlisted Participants will be provided with a form of Power Purchase Agreement and as part of their respective Final Offers must indicate that they will execute the Power Purchase Agreement or submit a mark-up of the Power Purchase Agreement which they are prepared to execute.

The provisions of the Term Sheet and Power Purchase Agreement may require modification for Offers to replace HBPP to reflect the unique location of that plant and the related reliability issues.

A Participant offering a Delay Option (as described in Section II.A) should specify the terms upon which it would offer a Delay Option, specifying the period during which it would allow the option to be exercised, and the associated terms and conditions (varying by exercise date, if applicable). The pricing set forth in Appendix E for each Power Purchase Offer variation or the pricing for a Facility Ownership Offer should not change due to the Delay Option. Pricing information for the Delay Option should be separately specified in Appendix E, identifying any additional cost of the Delay Option in the form of a lump sum payment(s) prior to the Guaranteed Commercial Availability Date of the facility. Non-price terms and conditions for the Delay Option that are not specified in Appendix E should be provided in a separately marked copy of the Term Sheet, Appendix D. PG&E may make the provision of the Delay Option a mandatory requirement for Final Offers. The detailed structure of the Delay Option will be finalized with shortlisted Participants prior to Final Offers.

Projects should meet the minimum criteria set forth for each Product set forth in Section II.

## XIV. CONFIDENTIALITY

Except as provided below, all information and documents provided to PG&E by a Participant in connection with this RFO shall be considered confidential information, and PG&E and the Participant shall be prohibited from disclosing such information and documents to any and all third parties except as provided below.

It is expressly contemplated that materials submitted by a Participant in connection with this RFO will be provided to the CPUC, its staff, the Independent Evaluator, and PG&E's Procurement Review Group ("PRG"). PG&E will seek confidential treatment pursuant to Public Utilities Code section 583 and General Order 66-C of the CPUC, with respect to any Participant-supplied non-public RFO information and documents ("Participant's Confidential Information") that are submitted by PG&E to the CPUC for the purpose of obtaining Regulatory Approval. PG&E will also seek confidentiality and/or non-disclosure agreements with the PRG applicable to the Participant's confidential information. PG&E cannot, however, ensure that the CPUC will afford confidential treatment to a Participant's confidential information, or that confidentiality agreements or orders will be obtained from and/or honored by the PRG or the CPUC.

PG&E retains the right to disclose any information or documents provided by the Participant to the CPUC, its staff, the Independent Evaluator, the PRG, and to any other entity in order to comply with any applicable law, regulation, or any exchange, control area or ISO rule, or order issued by a court or entity with competent jurisdiction over PG&E at any time even in the absence of a protective order, confidentiality agreement or nondisclosure agreement, as the case may be, without notification to the Participant and without liability or any responsibility of PG&E to the Participant.

As provided in Appendix A, the Long Term Request for Offer Agreement, once a Participant is selected for the Shortlist, the Participant must execute a Confidentiality Agreement in the form attached to Appendix A and return such Confidentiality Agreement within three (3) business days of notification of their selection in order to continue to participate in the RFO.

## XV. SARBANES/OXLEY DISCLOSURE

The following is applicable to Power Purchases Agreements only:

New Security and Exchange Commission rules for reporting power purchase agreements may require PG&E to collect and possibly consolidate financial information for the facility whose output is being purchased under long-term contractual arrangements. Some general guidelines for determining whether consolidation must occur include:

i) Determination of allocation of risk and benefits;

ii) Proportion of total project output being purchased by PG&E;

iii) Proportion of expected project life being committed to PG&E; and

iv) Pricing provisions of contract, that is, does the contract contain fixed long-term prices or does pricing vary over the term of the agreement based on market conditions or other factors.

For any PPA that meets the applicability criteria, PG&E is obligated to obtain information from successful Participants to determine whether or not consolidation is required. If PG&E determines that consolidation is required, PG&E shall require the following during every calendar quarter for the term of a PPA:

i) Complete financial statements and notes to financial statements;

ii) Financial schedules underlying the financial statements, all within 15 days of the end of each quarter and

iii) Access to records and personnel, so that PG&E's independent auditor can conduct financial audits (in accordance with generally accepted auditing standards) and internal control audits (in accordance with Section 404 of the Sarbanes-Oxley Act of 2002).

Any information provided to PG&E shall be treated confidentially and only disclosed on an aggregate basis with other similar entities for which PG&E has power-purchase contracts. The information will only be used for financial statement purposes and shall not be otherwise shared with internal or external parties.

## XVI.  NOTIFICATION TO SELECTED PARTICIPANTS

Assuming that the tentative RFO schedule set forth in Section V above is not modified, PG&E expects to be able to provide e-mail notification to Participants whose Initial Offers have been shortlisted by approximately July, 2005, and invite the shortlisted Participants to conduct discussions and negotiations with PG&E regarding each Participant's Offer.  PG&E anticipates notifying those Participants not shortlisted shortly thereafter.  PG&E also reserves the right to contact selected Participants during the evaluation process to clarify any Offers.

## XVII.  EXECUTION OF AGREEMENT

By submitting an Initial Offer, Participant agrees, if its Initial Offer is selected, to negotiate and execute a definitive Agreement consistent with the Term Sheet submitted with the Participant's Initial Offer and containing such other terms and conditions as may be mutually acceptable to PG&E and the Participant.  By submitting a Final Offer, participant agrees, if its Final Offer is selected, to enter into a definitive Agreement consistent with the mark-up of the Agreement submitted by it with its Final Offer.  PG&E's evaluation of a Participant's Initial Offer or Final Offer, and PG&E's shortlisting of a Participant, will not constitute any agreement by PG&E to any modification made by the Participant to the Term Sheet or PG&E's definitive Agreement form submitted to Participant.

## XVIII.  REGULATORY APPROVAL

The effectiveness of any Agreement as to PG&E is expressly conditioned on PG&E's receipt of Regulatory Approval. "Regulatory Approval" means a final and non-appealable order or orders of each regulatory or other governmental body designated by PG&E, including without limitation the CPUC, without conditions or modifications unacceptable to PG&E, which, in the case of Regulatory Approval by a governmental body other than the CPUC grants the approvals requested in the application therefore, and in the case of Regulatory Approval by the CPUC, does the following:

1. Approves  the Agreement in its entirety, including payments to be made by PG&E and timely cost recovery at the commencement of the facility's dedication to utility service, subject only to CPUC review with respect to the reasonableness of PG&E's administration of the Agreement, and finds PG&E's entry into and performance under the Agreement to be reasonable.

2. Authorizes PG&E to recover payments under the Agreement in utility revenue subject only to CPUC review with respect to the reasonableness of PG&E's administration of the Agreement.

## XIX. PARTICIPANT'S WAIVER OF CLAIMS AND LIMITATION OF REMEDIES

Except as expressly set forth in this RFO, by submitting an Offer, the Participant knowingly and voluntarily waives any rights under statute, regulation, state or federal constitution, or common law to assert any claim or complaint or other challenge in any regulatory, judicial or other forum, including the CPUC, except as expressly provided below, the Federal Energy Regulatory Commission ("FERC"), the Superior Court of the State of California ("State Court") or United States District Court ("Federal Court") concerning or related in any way to the RFO, the RFO and/or any Appendices to the RFO ("Waived Claims"). The assertion of any Waived Claims by Participant at the CPUC, FERC, State Court, Federal Court, or otherwise shall, to the extent that Participant's Offer has not already been disqualified, shall provide PG&E the right, and may result in PG&E electing, to reject such Offer or terminate the RFO.

By submitting an Offer, the Participant further agrees that the sole forum in which Participant may assert any challenge with respect to the conduct or results of the RFO is a protest to PG&E's filing seeking approval by the CPUC of one or more Agreements entered into as a result of the RFO. The Participant further agrees that the sole means of challenging the conduct or results of the RFO is a protest to PG&E's filing before the CPUC seeking approval of one or more Agreements entered into as a result of the RFO. The Participant further agrees that the sole basis for any such protest shall be a challenge to the conduct or results of the RFO on the ground that PG&E failed in a material respect to conduct the RFO in accordance with this RFO, and the exclusive remedy available to the Participant in the case of such a protest shall be an order of the CPUC that PG&E again conduct any portion of the RFO that the CPUC determines was not previously conducted in accordance with the RFO. The Participant expressly waives any and all other remedies, including, without limitation, compensatory and/or exemplary damages, restitution, injunctive relief, interest, costs, and/or attorneys' fees. Unless PG&E elects to do otherwise in its sole discretion, during the pendency of such a protest the RFO and any related regulatory proceedings related to the RFO will continue as if the protest had not been filed, unless the CPUC has issued an order suspending the RFO or PG&E has elected to terminate the RFO.

The Participant agrees to indemnify and hold PG&E harmless from any and all claims by any other Participant asserted in response to the assertion of a Waived Claim by the Participant or as a result of a Participant's protest to an Advice Letter Filing resulting from the RFO.

Except as expressly provided in this RFO, nothing herein, including Participant's waiver of the Waived Claims as set forth above, shall in any way limit or otherwise affect the rights and remedies of PG&E.

## XX. TERMINATION OF THE RFO - RELATED MATTERS

PG&E reserves the right at any time, in its sole discretion, to terminate the RFO for any reason whatsoever without prior notification to Participants and without liability of any kind to or responsibility of PG&E or anyone acting on PG&E's behalf. Without limitation, grounds for termination of the RFO may include the assertion of any Waived Claims by a Participant or a determination by PG&E that, following evaluation of the Offers, there are no Offers that provide adequate ratepayer benefit.

PG&E reserves the right to change the Offer evaluation criteria for any reason, to terminate further participation in this process by any Participant, to accept any Offer or to enter into any definitive Agreement, to evaluate the qualifications of any Participant, and to reject any or all Offers, all without notice and without assigning any reasons and without liability to PG&E or anyone acting on PG&E's behalf. PG&E shall have no obligation to consider any Offer.

In the event of termination of the RFO for any reason, PG&E will not reimburse the Participant for any expenses incurred in connection with the RFO regardless of whether such Participant's Offer is selected, not selected, rejected or disqualified. Return of a Participant’s Offer Deposit in the event of termination will be governed by the provisions of Section VI.C.

Unless earlier terminated, the RFO will terminate automatically upon the execution of one or more Agreements by selected Participants as described herein. In the event that no Agreements are executed, then the RFO will terminate automatically on March 31, 2006.

## XXI. PARTICIPANT’S REPRESENTATIONS AND WARRANTIES

Each Participant submitting an Offer shall execute and provide the Long Term Request for Offer Agreement (Appendix A) attesting to the Participant’s agreement to be bound by the conditions of the RFO in submitting its Offer and making the representations and warranties set forth therein.

**BREACH BY ANY PARTICIPANT OF THE REPRESENTATIONS AND WARRANTIES IN APPENDIX A OF THE RFO APPENDICES IS, IN ADDITION TO ANY OTHER REMEDIES THAT MAY BE AVAILABLE TO PG&E UNDER APPLICABLE LAW, GROUNDS FOR IMMEDIATE DISQUALIFICATION OF SUCH PARTICIPANT FROM PARTICIPATION IN THE RFO AND, DEPENDING ON THE NATURE OR SEVERITY OF THE BREACH, MAY ALSO BE GROUNDS FOR TERMINATING THE RFO IN ITS ENTIRETY.**

# 2004
# Long Term Request For Offers
## Power Purchase
# APPENDICES

Pacific Gas and Electric Company®

March 18, 2005

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## LIST OF APPENDICES

## Appendix A: Long Term Request For Offers Agreement

April [___], 2005

Pacific Gas and Electric Company
Electric Resource Procurement
245 Market Street, Room 1280A (MC-N12G)
San Francisco, CA 94105

Attention: Long Term RFO Project Manager

**Re: Agreement to terms in PG&E Long Term Request For Offers of March 18, 2005 ("RFO")**

Dear PG&E:

[INSERT PARTICIPANT NAME- Full legal name] ("Participant") hereby acknowledges receipt of Pacific Gas and Electric Company's Long Term Request For Offers. Participant has reviewed and agrees to abide by and be fully bound by **all** of the terms and conditions set forth in the RFO by execution of this letter ("Long Term Request For Offers Agreement") and by submission of any Offer in response to the PG&E RFO. All capitalized terms not defined herein shall have the meaning provided in the RFO.

In particular, Participant makes the following representations, which shall confirm and supplement the representations set forth in the RFO:

A. Participant has read, understands, and agrees to be bound by all terms, conditions and other provisions of the RFO.

B. Participant has had the opportunity to seek independent legal and financial advice of its own choosing with respect to the RFO and all Appendices to the RFO.

C. Participant has obtained all necessary authorizations, approvals and waivers, if any, required by Participant as a condition of: (i) submitting its Offer and, if Participant's Offer is selected; (ii) executing an Agreement with PG&E in the form submitted with its Final Offer.

D. Participant is submitting its Offer subject to all applicable laws including, but not limited to, the Federal Power Act and all amendments thereto, and Public Utilities Code section 454.5.

E. Participant has not engaged in and will not engage in, Communications (as defined in the RFO) with any other Participant in the RFO concerning any terms contained in Participant's

Offer, unless explicitly authorized by PG&E, and has not engaged in collusion or other unlawful or unfair business practices in connection with the RFO.

F. Participant is not an affiliate of PG&E, PG&E Corp., or any of their subsidiaries or affiliates.

Participant agrees that it shall execute and return to PG&E the attached form of Confidentiality Agreement (Exhibit 1) within three (3) business days of Participant's receipt of written notice of its selection for PG&E's shortlist under Section V.B.7. of the RFO. The Confidentiality Agreement shall be sent by overnight delivery to the following:

Pacific Gas and Electric Company
Electric Resource Procurement
245 Market Street, Room 1280A (Mail Code:-N12G)
San Francisco, CA 94105

Long Term Request For Offers Project Manager

IN WITNESS WHEREOF, Participant has caused this letter to be duly executed and delivered by its proper and duly authorized officer as of the date set forth below.

[PARTICIPANT NAME]

Name: ______________________________

Title: ______________________________

Date: ______________________________

**Exhibit 1 to Appendix A**

## CONFIDENTIALITY AGREEMENT

This confidentiality agreement ("CA") is entered into by and between Pacific Gas and Electric Company, a California corporation ("PG&E") and ________________ ("Participant"), each of which may be referred to herein separately as a Party or together as the Parties.

In the interest of developing a mutually agreeable purchase and sale agreement and transaction ("PSA") or power purchase agreement and transaction ("PPA"), each an "Agreement" in connection with PG&E's long term request for offers ("RFO") pursuant to California Public Utilities Commission Rulemaking R.01-10-024, the Parties have furnished and are furnishing certain Confidential Information to each other. The term "Confidential Information" shall mean (i) with respect to PG&E, all information described below, and (ii) with respect to Participant, all information, marked "Proprietary and Confidential" pursuant to and in accordance with the terms of the Long Term Request For Offers dated March 18, 2005 that such party ("Provider") has furnished or is furnishing to the other party ("Recipient"), whether furnished before or after the date of this CA, whether intangible or tangible, and in whatever form or medium provided, as well as all information generated by the Recipient or its Representatives, as defined below, that contains, reflects, or is derived from the furnished information.

In consideration of the Provider's disclosure to Recipient of the Confidential Information Recipient agrees to the following:

1. Recipient agrees that it will maintain the Confidential Information in strict confidence and that the Confidential Information will not, without Provider's prior written consent, be disclosed by the Recipient or by its officers, directors, partners, employees, agents, or representatives (collectively, "Representatives") in any manner whatsoever, in whole or in part, and shall not be used by Recipient or by its Representatives other than in connection with the negotiation of the Agreement. Moreover, Recipient agrees to transmit the Confidential Information only to such of its Representatives who need to know the Confidential Information for the sole purpose of assisting the Recipient in evaluating the Agreement; provided that such Representatives shall be informed of the terms of this CA and agree in writing to be bound by its terms hereto. In any event, Recipient shall be fully liable for any breach of this CA by its Representatives.

2. Recipient further agrees that it:

   (a) Shall not disclose any such Confidential Information provided to it by Provider to any third party for any purpose;

   (b) Shall not duplicate or distribute all or any portion of such Confidential Information to any Representative for any purpose other than evaluating the Confidential Information in connection with the RFO; and

(c) Shall destroy or return all such Confidential Information upon Provider's request.

3. For purposes of this CA, Confidential Information does not include: (a) information that is in the public domain through no violation of this CA or any other confidentiality obligation known to the Recipient, (b) information that Recipient can demonstrate was already in its possession and was not acquired, directly or indirectly, from Provider on a confidential basis, or (c) information that is independently developed by Recipient without use of or reference to the Confidential Information.

4. Recipient agrees not to introduce (in whole or in part) into evidence or otherwise voluntarily disclose in any administrative or judicial proceeding, any Confidential Information**,** except as required by law or as Recipient may be required to disclose to duly authorized governmental or regulatory agencies ("Required Disclosure"). In the event that Recipient or any of its Representatives becomes subject to a Required Disclosure, Recipient agrees:

   a. To notify Provider immediately of the existence, terms, and circumstances surrounding such request;

   b. To consult with Provider on the advisability of taking legally available steps to resist or narrow such request; and

   c. If disclosure of such Confidential Information is required to prevent Recipient from being held in contempt or subject to other penalty, to furnish only such portion of the Confidential Information as it is legally compelled to disclose and to exercise its best efforts to obtain an order or other reliable assurance that confidential treatment will be accorded to the disclosed Confidential Information.

   In addition to the Required Disclosure PG&E shall be permitted to disclose Participant's Confidential Information as follows: (a) to PG&E's Procurement Review Group, as defined in California Public Utilities Commission ("CPUC") Decision (D) 02-08-071 and made applicable to this CA by D.04-06-015, subject to a confidentiality agreement, (b) to the CPUC (including CPUC staff) under seal for purposes of review, (c) the Independent Evaluator as specified in the RFO, or (d) in order to comply with (i) any applicable law, regulation, or any exchange, control area or ISO rule or (ii) any applicable regulation, rule, or order of the CPUC, California Energy Commission, or the Federal Energy Regulatory Commission.

5. Recipient acknowledges and agrees that, in the event of any breach of this CA, Provider would be irreparably and immediately harmed and could not be made whole by monetary damages. Accordingly, it is agreed that, in addition to any other remedy to which it may be entitled in law or equity and under the Long Term Request For Offers dated March 18, 2005, issued by PG&E in connection with the RFO, Provider shall be entitled to an injunction or injunctions (without the posting of any bond and without proof of actual damages) to prevent breaches or threatened breaches of this CA and/or

to compel specific performance of this CA, and that neither Recipient nor its Representatives will oppose the granting of such relief.

6. This CA shall be effective as of the date first set forth below and shall terminate two years from such date or earlier upon the mutual written consent of the Parties.

7. No waiver of any provision of this CA or of a breach hereof shall be effective unless it is in writing signed by both Parties, nor shall any waiver of a breach of this CA, whether express or implied, constitute a waiver of a subsequent breach hereof.

8. This CA may not be amended or modified except by a written agreement executed by both Parties.

9. THIS CA SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA. THE PARTIES AGREE THAT ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATED IN ANY WAY TO THIS CA SHALL BE BROUGHT SOLELY IN A COURT OF COMPETENT JURISDICTION SITTING IN THE CITY AND COUNTY OF SAN FRANCISCO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY CONSENT TO THE JURISDICTION OF ANY SUCH COURT AND HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE ANY DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF ANY ACTION OR PROCEEDING IN ANY SUCH COURT, ANY OBJECTION TO VENUE WITH RESPECT TO ANY SUCH ACTION OR PROCEEDING AND ANY RIGHT OF JURISDICTION ON ACCOUNT OF THE PLACE OF RESIDENCE OR DOMICILE OF ANY PARTY THERETO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE THE RIGHT TO A JURY TRIAL IN CONNECTION WITH ANY CLAIM ARISING OUT OF OR RELATED TO THIS CA.

10. If any provision hereof is unenforceable or invalid, it shall be given effect to the extent it may be enforceable or valid, and such enforceability or invalidity shall not affect the enforceability or invalidity of any other provision of this CA.

11. This CA may be signed in counterparts, each of which shall be deemed an original. This CA may be executed and delivered by facsimile and the Parties agree that such facsimile execution and delivery shall have the same force and effect as delivery of an original document with original signatures, and that each Party may use such facsimile signatures as evidence of the execution and delivery of this CA by the Parties to the same extent that an original signature could be used.

12. Any notice given hereunder by either Party shall be made in writing and delivered by facsimile, certified mail, or overnight delivery as follows:

To Participant:

To PG&E:

Either party may periodically change any address to which notice is to be given it by providing written notice of such change.

IN WITNESS WHEREOF, each of PG&E and Participant have caused this CA to be duly executed and delivered by its proper and duly authorized agent as of the date set forth below.

| Pacific Gas and Electric Company | [Insert Company Name] |
|---|---|
| Name:___________________________ | Name: __________________________ |
| Title: ___________________________ | Title: ___________________________ |
| Date: ___________________________ | Date: __________________________ |

## Appendix B:  Form of Letter of Credit

**FORM OF LETTER OF CREDIT**

**Issuing Bank Letterhead Address**

Date: __________

Irrevocable Standby Letter of Credit Number:_________

Beneficiary: Pacific Gas and Electric Company
77 Beale Street, Mail Code B28L
San Francisco, CA 94105
Attn: Credit Risk Management Unit

[Advising Bank, if applicable]
[Confirming Bank, if applicable]

Applicant: _________________
Address: __________________
__________________

Amount: USD [Amount]
US Dollars [Spell out amount in words]

We hereby issue our Irrevocable Standby Letter of Credit at this office in your favor for the account of [insert name of account party] ("Account Party") and at the request of [insert name of applicant] ("Applicant") by sight payment against the following documents:

1. Your sight draft drawn on us marked "drawn under [Issuing Bank] [Letter of Credit Number] dated [Date]";

**AND**

2. Beneficiary's signed statement certifying:

   A. "Account Party has breached the PG&E Long Term Request For Offers Agreement ("Agreement"), dated March 18, 2005, as agreed by Account Party and forfeited the Bid Deposit, as defined by and pursuant to the terms of the PG&E Long Term Request For Offers ("the RFO"), by materially misrepresenting information submitted in its Offer, as defined in the RFO, or withdrawing its Offer other than as permitted in the RFO;" or

   B. "Account Party has entered into a Purchase and Sale Agreement with Beneficiary in connection with the PG&E Long Term Request For Offers issued March 18, 2005 , and has failed to post performance assurance or is otherwise in default pursuant to the terms of such agreement," or

   C. "The date of this certificate is within thirty (30) days of the Expiration Date and, as of the date hereof, PG&E has not received substitute security that satisfies the requirements of Section VI.C. of the PG&E Long Term Request For Offers issued March 18, 2005, " or

D. “The date of this certificate is within seven (7) days of the date the Account Party was obligated to provide replacement security pursuant to the requirements of Section VI. C. of the PG&E Long Term Request For Offers issued March 18, 2005 (the “RFO”), and, as of the date hereof, PG&E has not received replacement security that satisfies the requirements of Section VI. C. of the RFO.”

The **Expiration Date** shall be the earlier of: (i) [insert date consistent with the requirements of Section VI.C. of the RFO]; and (ii) the date on which Applicant receives the original of this Letter of Credit as returned by Beneficiary.

Special Conditions:

1. Partial drawing(s) are permitted.
2. All banking charges associated with this Letter of Credit are for the account of the Applicant.
3. Documents are to be presented to this office no later than the Expiration Date.
4. This Letter of Credit is not transferable.

We hereby engage with you that draft(s) drawn under and in compliance with the terms of this Letter of Credit will be duly honored if drawn and presented for payment at any time before the close of business [Time] at our counters located at [address] on or before the Expiration Date or in the event of Force Majeure, as defined under Article 17 of the Uniform Customs and Practice for Documentary Credits (1993 Revision) International Chamber of Commerce Publication No. 500 (“UCP”), interrupting our business, within fifteen (15) days after resumption of our business, whichever is later.

Except as otherwise stated herein, this credit is subject to the UCP and, with respect to matters not so covered, this Letter of Credit is subject to and governed by the laws of the State of New York.

If you have any questions regarding this Letter of Credit, please call [Telephone No.].

By: ______________________________
Authorized Signature

Name: ______________________________

Title: ______________________________

## Appendix C: Notice of Intent to Offer

### PG&E LONG TERM REQUEST FOR OFFERS

This Notice of Intent to Offer ("NIO") shall serve as notice to PG&E that the company listed below ("Participant") is interested in participating in PG&E's Long Term Request For Offers ("RFO").

PG&E requests that the Participant return the NIO by Friday, April 8, 2005 by email to: either of longtermppprfo@pge.com or ownershiprfo@pge.com

**Participant Full Legal Name:**

Parent company of Participant, if any:

Participant address:

**Contact Name:**

Title:
Address (if different from above):

Phone number:
Cell number:
Fax number:
Email address:

**Facility Description:**

Facility Name:

Offer Type – Power Purchase, Facility Ownership, or Both

Technology Type

Product/Design: (Peaking or Shaping)

Nameplate/Contract Capacity (MW)

Estimated Commercial Operations Date (PPA Only)

Proposed "Initial Delivery Date" (PPA Only)

Proposed "Guaranteed Commercial Availability Date" (Facility Ownership)

Facility Location

Brief Description of Project

Status of application for a transmission System Impact Study (SIS)

Status of Preliminary Application for Gas Service

## Appendix D:  Power Purchase Agreement Term Sheet

[SERVICE PROVIDER]

PACIFIC GAS AND ELECTRIC COMPANY

POWER PURCHASE AGREEMENT

CONFIDENTIAL NON-BINDING SUMMARY OF PRINCIPAL COMMERCIAL TERMS

This Confidential, Non-Binding Summary of Principal Commercial Terms ("**Term Sheet**") is preliminary and is intended to set forth certain basic terms of, and to serve as a basis for further discussions and negotiations between the Parties with respect to, the potential Transaction described herein ("**Transaction**") to be set forth in an agreement ("**Definitive Agreement**"). Refer to Sections VII.B., XIII and XVI of the RFO for a description of the purpose and effect of this Term Sheet.

| | |
|---|---|
| **Parties** | [SERVICE PROVIDER], a _ ("**Seller**") and Pacific Gas and Electric Company, ("**Buyer**"), referred to individually as "Party" or collectively as "Parties". |
| **Transaction** | Seller will provide and make available to Buyer and Buyer will purchase and pay for all Products provided by the Unit(s) pursuant to the terms contained herein. |
| **Unit(s)** | Any Qualifying Facility ("**QF**") generating station with a minimum capacity of 1 MW or a New Unit (non-QF) with a minimum Capacity of 25 MW. The location (street address and county), the technology and fuel type of the Unit are to be specified by Seller in Appendix F.<br><br>To qualify as a "**New Unit**" (non-QF), the date the Unit achieves Commercial Operation, ("**Commercial Operations Date**") shall be no earlier than January 1, 2007 (where "**Commercial Operation**" is defined to mean that commissioning is complete, the Unit(s) have been shown by test to be capable of delivering at least 98% of the relevant monthly Capacity listed by Seller in the Offer Data Forms to the grid on a sustained basis, and the Unit(s) has been released by the contractor to Seller for commercial operations). |

Seller understands and agrees that Buyer will consider no partial Unit(s).

| | |
|---|---|
| **Contract Term and Services Term** | The "**Contract Term**" will commence upon execution and delivery of the Definitive Agreement ("**Execution Date**") and continue until final settlement (after the end of the Services Term, defined below). The Definitive Agreement will include conditions relating to regulatory approvals and the posting of Delivery Date Security (defined below) which must be satisfied prior to the time the remainder of the Parties' obligations become effective. Only upon satisfaction of such conditions will the "**Effective Date**" be deemed to have occurred. The Seller's Offer Deposit (required pursuant to the Request for Offer) must remain in place until the Effective Date and will be returned to Seller upon the occurrence of the Effective Date.<br><br>The "**Services Term**" will be the period over which Products are available to Buyer. Seller will specify the length of the Services Term. The Services Term shall be a minimum of five (5) years, commencing as of the first of January, February, March, April, May or June (Seller to specify), during the years 2007, 2008, 2009 or 2010. However, Buyer has a preference for deliveries beginning between January 1 and June 1 in 2008, 2009 or 2010. The Services Term must begin on the first, and end of the last day of a calendar month. |
| **Product** | "**Product**" shall mean collectively Energy, Capacity, and Other Products, as defined herein. Seller may not commit to provide any Product to any third person from the Unit(s) committed to Buyer; provided that the Seller shall not be prohibited from operating the Unit as required by law or direction of the California Independent System Operator Corporation ("**CAISO**").<br><br>"**Capacity**": Seller shall offer the Capacity of whole Units. Seller's Offer should set forth a monthly schedule showing the maximum MWs of Capacity that the Seller is offering to make available to Buyer in each month of the Services Term ("**Contract Capacity**"). The Contract Capacity values should reflect expected seasonal variations in the Unit's Capacity, if any. The Seller may offer the Capacity of a Unit to Buyer for fewer than 12 months per year. Buyer shall have exclusive rights to each Unit (for each month in which it is offered).<br><br>The amount of Capacity that Buyer will pay for each month will be the lesser of the Contract Capacity, the capacity of the Unit(s) as established by seasonal testing (described below) and the amount the Unit is deemed to contribute to Buyer's Resource Adequacy ("**RA**") requirement, as discussed below ("**Monthly Contract Capacity**"). The Monthly Contract Capacity is therefore subject to prospective adjustment as of the first of the month |

following each seasonal test or the implementation of, or change to, the Unit's (s') RA rating.

"**Energy**": Seller shall offer Buyer the exclusive rights to all electric energy produced by the Unit(s) up to the Monthly Contract Capacity defined above.

"**Other Products**": Seller shall offer Buyer all the capabilities of each Unit, including without limitation, Ancillary Services, other products such as black start capability and replacement reserves that are not defined as Ancillary Services, and rights such as Environmental Attributes. Seller should identify the Other Products that the Unit is capable of providing and set forth in the Term Sheet for its Offer such additional terms and conditions as appropriate for such Other Products for consideration by Buyer.

For clarity:

> "**Ancillary Services**" means all products deemed to be "Ancillary Services" by the CAISO and/or the Federal Energy Regulatory Commission ("**FERC**") as of the Effective Date or a future date during the Contract Term, including but not limited to reactive power, regulation (including load following) spinning reserves, non-spinning reserves, and replacement reserves associated with the Unit(s).
>
> "**Environmental Attributes**" has the meaning set forth in the Standard Terms Decision (CPUC D-04-06-014)

Seller may not add production capability to the Unit(s) without Buyer's consent or add other new production capability, which in any way impairs Buyer's rights to the Products as defined herein. Seller may not commit to provide any Product to any third person from the Unit(s) committed to Buyer.

**Resource Adequacy**

The California Public Utilities Commission ("**CPUC**") or the CAISO or a successor control area operator may, during the term of the Definitive Agreement, put into place an RA requirement whereby eligibility to count MW toward the RA requirement may be determined by identifying specific Unit(s) or a combination of Unit(s) . This RA requires that unit specific capacity be identified and the physical unit be made available to the CAISO for dispatch. Seller agrees that the Unit(s) or combination of Units offered to Buyer here will meet all requirements necessary to qualify as a resouce capable of contributing to Buyer's RA requirement and will consent in the Definitive Agreement to take such measures as necessary to qualify as a resource that counts toward Buyer's RA Requirement. In addition, Seller agrees to comply with all associated bidding/dispatch requirements imposed through either CAISO market design and tariffs, CPUC or FERC. Such bidding requirements may be imposed in the day ahead, hour ahead or real time timeframe. Buyer will also have exclusive rights to all RA related products such as capacity tags, capacity credits, or installed capacity ("**ICAP**") products. Seller shall comply with any CPUC or CAISO requirements for meeting RA.

**Testing for Capacity and Energy Deliverability**

Each Unit will be subject to testing within the 30 days preceding the Initial Delivery Date (as defined below) and seasonally thereafter during the Services Term, as established in the Definitive Agreement, to determine the maximum Capacity of the Units at 100% Base Load and Base Load with full power augmentation to confirm the ability of the Units to achieve the Monthly Contract Capacities and deliverability of the associated Energy. For a combustion turbine, "**Base Load**" is defined as operating on its base load temperature control curve. Seasonal testing under the Definitive Agreement will be done to establish the maximum Capacity of the Units for the periods (1) June 1 through September 30 ("**Summer Months**") based on test results adjusted to July Peak Conditions (as defined below) and (2) January 1 through May 31 and October 1 through December 31 ("**Non-Summer Months**") based on test results adjusted to standard "**ISO Conditions**" (59°F and 60% relative humidity). "**Peak July Conditions**" are the conditions (temperature and humidity for the site) based on the average of the monthly maximum daily peak temperatures of the preceding 10 years for the month of July as provided by the National Climatic Data Center ("NCDC") at http://www.ncdc.noaa.gov/servlets/ULCD. Data from the NCDC should be for a geographically nearby weather station that approximates the conditions at the specific plant site. Buyer shall have the right to approve the weather station employed in the development of the Peak July Conditions.

**Commencement of Services**

The "**Initial Delivery Date**" is the date on which the Seller's obligation to make Capacity available and to deliver Energy and Ancillary Services (as scheduled) commences, and Compensation payable by Buyer to Seller begins to accrue. The Initial Delivery Date shall not occur until the Seller has satisfied all conditions precedent to the Initial Delivery Date, which in the case of new generation, shall include (at minimum):

- completion of the electric transmission interconnection necessary for delivery of electricity to the Buyer at the Delivery Point;
- completion of all equipment necessary for fuel delivery;
- demonstration that Buyer holds all required environmental permits and to the extent required, emission credits;
- each Unit has achieved Commercial Operation; and
- Seller has posted any applicable Collateral Requirement (as set forth in the "Credit Requirements" section below), to be available as of the Initial Delivery Date.

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| **Construction Period Credit Requirements** | As a condition precedent to the occurrence of the Effective Date, Seller shall be required to post collateral in the form of an irrevocable standby letter of credit acceptable in form and content to PG&E ("**Letter of Credit**") to secure Seller's obligations in the period between the Effective Date and the Initial Delivery Date ("**Delivery Date Security**"). Each Letter of Credit provided by Seller in connection with this transaction must be from an issuer satisfying the requirements set forth in Section VI.C. of the RFO and be in a form to be provided that will be similar to that attached as Appendix B to the RFO. The Delivery Date Security shall be an amount equal to the total of $15,000 plus the maximum amount of the Delay Damages (defined below), the sum of which is then to be multiplied with the maximum Contract Capacity committed for the Services Terms. |
| **Early Termination Rights for Permitting Failures** | Buyer will allow Seller to terminate its Definitive Agreement and Buyer will return the Delivery Date Security to Seller less $15,000 per MW as a termination fee, should the Seller, after making all commercially reasonable efforts to do so, be unable to secure the necessary permits: (a) within 18 months of the CPUC decision granting Regulatory Approval of the Definitive Agreement for projects over 100MW; or (b) within 12 months of the CPUC decision granting Regulatory Approval of the Definitive Agreement for projects under 100MW (due to the reduced timeline for securing permits under the California Energy Commission Small Power Plant Exemption). Alternatively, upon a failure to timely secure the necessary permits, Buyer will permit Seller to extend the permitting completion deadline by six months if Seller agrees, going forward, to forfeit the full amount of the Delivery Date Security should it be unable to obtain the necessary permits for construction and operation within the 6 month extension. |
| **Expected Initial Delivery Date and Delay Damages** | Seller shall establish the projected Initial Delivery Date ("**Expected Initial Delivery Date**") consistent with the other provisions of this Term Sheet. Buyer and Seller shall establish milestones with respect to Seller's satisfaction of the conditions precedent to the Initial Delivery Date and the expected date of completion for each milestone. At least three months prior to issuance of the notice to proceed by Seller to its EPC contractor, Seller shall provide Buyer a construction schedule. Seller shall provide Buyer monthly progress reports, including projected time to completion, and Buyer shall have the right, during business hours and upon reasonable notice, to inspect the construction site and otherwise inspect or audit to enforce its rights pursuant to this section.<br><br>Unless the Definitive Agreement is terminated in accordance with the preceding section concerning permitting delays, if Seller falls behind in its schedule by more than 365 days, such event will be deemed an Event of |

Default and Buyer will have the option to exercise the remedies available to it upon an Event of Default by Seller (set forth in the "Remedies" section below). In the event Seller has not satisfied the conditions precedent by the Expected Initial Delivery Date with respect to one or more Units, Seller will be required to pay liquidated damages ("**Delay Damages**") in the amount of $250 per MW per day during the Summer Months and $62.25 per MW per day during the Non-Summer Months, up to a maximum of 365 days; in each case measured by reference to the maximum Contract Capacity committed for the Services Term. If Seller fails to pay liquidated damages when due, Buyer may deduct amounts due from the Delivery Date Security. In the event that Seller has not satisfied the conditions precedent to the Initial Delivery Date within twelve months of the Expected Initial Delivery Date, the Seller's failure to satisfy such conditions will constitute an Event of Default (as defined hereinafter). If such an Event of Default occurs, Buyer may elect at any time to exercise the remedies that are available upon an Event of Default (defined in the "Remedies" section below), or in the alternative, Buyer will have the option to extend the end date of the Services Term by a period equal to the difference between the Expected Initial Delivery Date and actual Initial Delivery Date. Within ten business days following the Initial Delivery Date, Buyer will return the remainder of the Delivery Date Security to Seller (after satisfaction of any liquidated damage amounts then due).

In the event that Seller fails to meet any of the milestone target dates or the Expected Initial Delivery Date due to Force Majeure, the applicable date may be extended by an additional period equal to the period by which performance was delayed due to Force Majeure without penalty, not to exceed twelve months in the aggregate for all Force Majeure delays.

**Scheduling Rights**

Buyer shall have day-ahead, hour-ahead and real-time scheduling rights, within the defined operational limitations of the Unit(s).

Buyer shall have the right to schedule deliveries of Energy and Ancillary Services from the Unit(s) throughout the Services Term. Notwithstanding the foregoing sentence, depending on the Initial Delivery Date and then-applicable standard scheduling protocols, Buyer will have the right, in accordance with then-applicable standard scheduling protocols, to schedule the Unit(s) in advance of the Initial Delivery Date as necessary to commence deliveries of Energy and Ancillary Services on the Initial Delivery Date.

**Scheduling Protocols**

Seller shall provide complete and accurate notice of each Unit's availability on a month-ahead, week-ahead and day-ahead basis. In addition, Seller shall notify Buyer of any event that would constrain or reduce the output of the Unit as soon as practicable but at least within 10 minutes of the event, and shall provide an estimate of the expected duration of such event within 1 hour thereafter. If the event duration is greater than 24 hours, the Seller will update Buyer daily with any revised estimates regarding the Unit's(s') return to full output capability. Seller must notify Buyer of any event constraining or reducing output whether or not the unit is scheduled for operation. Seller shall notify Buyer promptly at the time the availability of Capacity previously unavailable is restored, whether or not the unit is scheduled for operation.

Buyer will be the Scheduling Coordinator ("SC") for the Unit. Scheduling shall be in full compliance with CAISO Tariffs protocols and WECC scheduling practices for day-ahead,, hour-ahead and real-time Energy and/or Ancillary Services.

Seller will agree to adhere to Buyer's schedule (provided that Buyer's schedule may be superseded by instruction of the CAISO and by law).

<u>The following provision is applicable only to Fuel Conversion Agreements</u>: Buyer shall have no obligation or liability of any kind with respect to any uninstructed deviations. Should Seller fail to operate the Units in a manner to comply with Buyer's dispatch schedule (unless due to an Unscheduled Outage or CAISO instructed operations) and a deviation occurs between the scheduled Energy and the delivered Energy or between scheduled Ancillary Services and delivered Ancillary Services ("**Seller's Deviation**"), Seller shall reimburse Buyer for any charges Buyer incurs as a result of Seller's Deviation, including charges imposed on Buyer as the SC, by the CAISO for Seller's uninstructed deviations, including but not limited to the costs of real-time or replacement Products and penalties; Buyer's additional gas costs (determined using Guaranteed Heat Rates and Start-Up Fuel Amounts); and any amounts paid by Buyer to Seller for Products not delivered; net of the revenues Buyer receives due to Seller's Deviation ("**Deviation Charges**"). However, all CAISO-instructed deviations from Buyer's Schedule shall be for the account of Buyer.

<u>The following provision is applicable to Definitive Agreements that are not Fuel Conversion Agreements</u>: Buyer shall have no obligation or liability of any kind with respect to any uninstructed deviations. Should Seller fail to operate the Units in a manner to comply with Buyer's dispatch schedule (unless due to an Unscheduled Outage or CAISO instructed operations) and a deviation occurs between the scheduled Energy and the delivered Energy or between scheduled Ancillary Services and delivered Ancillary Services ("**Seller's Deviation**"), Seller shall reimburse Buyer for any charges Buyer incurs as a result of Seller's Deviation, including charges imposed on Buyer as the SC, by the CAISO for Seller's uninstructed deviations, including but not limited to the costs of real-time or replacement Products and penalties; Buyer's additional gas costs (determined using Guaranteed Heat Rates and

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| | Start-Up Fuel Amounts); and any amounts paid by Buyer to Seller for Products not delivered; net of the revenues Buyer receives due to Seller's Deviation ("**Deviation Charges**"). However, all CAISO-instructed deviations from Buyer's Schedule shall be for the account of Buyer. |
| **Operational Constraints** | The operational constraints of the Unit(s) shall be those set forth in response to the RFO on Appendix F. |
| **Delivery Point** | The "**Delivery Point**" for any non-QF is a specified interconnection point on PG&E's transmission system (to be specified by Seller in Appendix F) within what is presently defined as NP15. The point of interconnection of the substation must be within the CAISO-controlled grid. For QFs, the "Delivery Point" (the point of interconnection) must be within PG&E's service territory (NP15 or ZP26). |
| **Electric Interconnection and Transmission Service** | Seller shall be responsible for all costs related to upgrades to transmission facilities and construction of interconnection facilities required to interconnect the Unit(s) to the Delivery Point and enable Energy to be delivered to the grid at the Delivery Point, consistent with all standards and provisions set forth by the FERC, CAISO or any other applicable governing agency and the interconnecting transmission owner.<br><br>Seller will be responsible for funding any upgrade(s) to the transmission network as required by the CAISO and be entitled to receive a funding return, if applicable, pursuant to its arrangements with, and the applicable tariffs of, the transmission owner and the CAISO. Regardless of whether PG&E is the interconnecting transmission owner, PG&E in its capacity as Buyer shall not be responsible for Seller's interconnection arrangements or costs.<br><br>Seller shall be responsible for the costs of delivering its power to the Delivery Point consistent with all standards and provisions set forth by the FERC, CAISO or any other applicable governing agency or tariff. |
| **Gas Interconnection** | Seller shall be responsible for all costs related to upgrades to transmission facilities and construction of interconnection facilities required to interconnect the Unit(s) to the natural gas system and enable delivery of fuel to the Unit(s), consistent with all standards and provisions set forth by the FERC, CPUC, California Department of Transportation or any other applicable governing agency. (For non-gas facilities, Seller also shall be responsible for all fuel delivery facilities). |

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| **Fuel Supply and Transportation** | For Fuel Conversion Agreements: During the Services Term, Buyer shall be responsible for providing transportation of natural gas to the Unit(s), and all costs related to providing such transport including inter-state, intra-state and Local Distribution Company ("LDC") charges. Buyer will only agree to Fuel Conversion Services with plants connected to CPUC or FERC-jurisdictional pipelines. Buyer shall directly pay all charges associated with inter-state or intra-state transport. Seller shall pay all LDC charges associated with delivering natural gas to the Unit(s), and Buyer shall reimburse Seller for such LDC costs. During the Services Term, Seller shall provide Buyer timely access to gas records and bills associated with gas LDC services.<br><br>During the Services Term, Buyer will provide and schedule, at Buyer's expense, all pipeline quality natural gas for all of Buyer's dispatched start up, operations to meet Buyer's or CAISO's schedules, and Buyer's requested testing. Fuel for non-dispatch operations, Seller's other testing, and all other fuel will be arranged by Buyer, at Seller's expense, provided Seller provides Buyer appropriate notice (to be established by contract). Fuel (and all fuel-related services) required prior to the Initial Delivery Date, including fuel needed for commissioning and pre-operational testing, will be arranged and scheduled by Seller, at Seller's expense.<br><br>During the Services Term, Seller shall assign all LDC balancing rights to Buyer. During the Services Term, Buyer shall be responsible for managing gas deliveries at its expense, provided that each Party will seek to mitigate gas imbalances and Seller will reimburse Buyer for gas imbalance charges other than gas imbalances that arise due to Buyer's failure to provide timely nomination or scheduling services. Notwithstanding the foregoing, the commodity-related component of imbalance charges, penalties and cash-out costs incurred due to variations in gas consumption due to heat rate variations are addressed through the Heat Rate Payment provisions and thus only the additional component of such costs shall be Seller's responsibility pursuant to this imbalance provision.<br><br>For Definitive Agreements other than Fuel Conversion Agreements: Seller shall be responsible for all arrangements for and costs of fuel supply and delivery, including all ancillary services such as balancing or storage. (The preceding is without prejudice to such pricing proposals as Seller wishes to offer, which may tie the price of energy to the cost of fuel). |
| **Guaranteed Availability** | Seller shall meet the following "**Guaranteed Availability**" requirements:<br>Summer Months:<br>98.0% Availability<br>Non Summer Months:<br>94.0% Availability |

The calculation for "**Availability**" is:
$totpotenrgy_m/[cap_m*(mnthhrs_m-mainthrs_m)]$

Where:
$totpotenrgy_m$ is the total amount of Energy (measured in MWh) that the Unit(s) could have produced for the month to which the calculation applies if it had been scheduled at its full Monthly Contract Capacity ("**MCC**") for such month (measured in MW) for every hour in which the Unit(s) was available to operate for Buyer, exclusive of hours in which the Unit(s) was unavailable due to Planned Maintenance. Hours in which the Units were unavailable to Buyer (in whole or in part) due to outages other than Planned Maintenance, including forced outages and Force Majeure, or due to failure of Seller to provide notice to Buyer of the Unit's(s') availability and capability to operate or due to a failure of the Unit(s) to deliver Energy or Ancillary Services in accordance with the schedules established by Buyer (or CAISO instruction), unless attributable to ambient conditions, shall be excluded from the determination of $totpotenrgy_m$ to the extent of such unavailability (which may be less than 100%). Accordingly, $totpotenrgy_m$ will reflect a proportional downward adjustment from the MCC for deratings, partial outages of Unit(s) and partial hours of unavailability, as well as for full hours in which the Unit(s) were entirely unavailable. To the extent the Unit(s) were unavailable to Buyer due to instruction of the CAISO, the Unit(s) shall be deemed to have been available for purposes of determining $totpotenrgy_m$. If Seller's availability notice is not timely enough to permit Buyer to schedule the Unit in the Day-Ahead Market (or such other period as the Parties agree), the Unit will be deemed to be unavailable for purposes of determining $totpotenergy_m$.

$cap_m$ is the Monthly Contract Capacity of the Unit(s) committed to Buyer for the applicable month, as defined in the Definitive Agreement

$mnthhrs_m$ is the total amount of hours for the month

$mainthrs_m$ is the total amount of hours that the plant was unavailable due to Planned Maintenance, taken in accordance with the Maintenance Outage protocol.

**Non-Availability Discount**

Every month the Capacity Payments and Fixed O&M Payments due Seller from Buyer for that month will be subject to reduction for shortfalls in Guaranteed Availability for that month. The applicable "**Non-Availability Discount**" will be equal to:

Summer Months: If Availability is 97% or less, then 2% reduction in Capacity Payments and 2% reduction in Fixed O&M Payments for every 1%

reduction in Availability below 98%; and
Non-Summer Months: If Availability is 93% or less, then 2% reduction in Capacity Payments and 2% reduction in Fixed O&M Payments for every 1% reduction in Availability below 94%.

In the event that the availability drops below 70% in any Summer Month or 60% in any Non-Summer Month, Buyer shall have no obligation to make Capacity Payments and Fixed O&M Payments for the month when Availability dropped below the above thresholds.

An Event of Default may result under the following conditions:
1) The Unit(s) are below 70% Availability for a period of 6 consecutive months, and such reductions in Availability are not due to a Force Majeure event; or
2) An event of Force Majeure that prevents the unit from achieving at least 70% Availability for a period of 12 consecutive months.

In addition to the above, in the event that the Unit(s) fails to meet the standards established by the CAISO for the provision of Ancillary Services (e.g., Section 2.5.25 of the CAISO, or such additional or substitute standards as may be applicable from time to time), the Capacity Payment shall be reduced by an amount equal to the charges assessed on Buyer due to such failure.

**Availability Bonus Structure**

Every Summer Month that Seller exceeds Guaranteed Availability for such month the Capacity Payment for such month shall be determined in accordance with the following:

- Summer Month at 99% or above = 102.0% of Capacity Payment

**Start-Up Adjustment**

If a Unit has not been scheduled to start at least 50 times in a calendar quarter, the monthly calculation of Availability shall be subject to a Start-Up Adjustment based on its Start-Up Factor. The "**Start-Up Factor**" is defined as:

CNS/NSR

where "**CNS**" is the completed number of successful starts as scheduled by the Buyer over a quarter and "**NSR**" is the number of starts requested by the Buyer over a quarter.

The "**Start-Up Adjustment**" will be determined from the table set forth in Attachment 3 by locating the appropriate percentage based on the NSR and the Start-Up Factor

The Start-Up Adjustment will be subtracted from the calculated Availability value for each month in the quarter (determined in accordance with the procedure set forth in the "Guaranteed Availability" section above) and the resulting number shall be the final Availability value that is applied to the Non-Availability Discount and the Availability Bonus.

To the extent that the previous months' Availability was decreased because of a Start-Up Adjustment and a Non-Availability Discount would apply, the resulting reduction in the previous months' Capacity and Fixed O&M payments will be calculated and divided by 12 and applied monthly to reduce the next 12 month's Capacity and Fixed O&M payments owed to Seller.

**Maintenance Outages**

Seller will be responsible for all operation and maintenance of the Unit(s) and will bear all costs related thereto. The Parties shall agree to, and include in the Definitive Agreement, detailed "**Maintenance Protocol**" for the Unit(s), subject to inclusion of the following:

- Seller shall provide a schedule of its expected annual planned partial or full maintenance outages ("**Planned Maintenance**") for the next calendar year by September 1 of each year of the Services Term; and shall update such schedule for each calendar quarter no later than 30 days before the commencement of such quarter.
- Planned Maintenance lasting longer than five consecutive days may be taken only after a minimum of 50 business days advance notice prior to the month in which the Planned Maintenance will occur. Planned Maintenance lasting longer than two consecutive days but shorter than five may be taken only after a minimum of 30 business days advance notice prior to the month in which the Planned Maintenance will occur. Planned Maintenance lasting less than two days may be taken only after a minimum of 15 business days advance notice prior to the month in which the Planned Maintenance will occur.
- There shall be no Planned Maintenance during Hours Ending ("HE") 7-22, Monday through Sunday, of the Summer Months and December and January, absent written pre-approval of Buyer;
- Planned Maintenance outages, be they full or partial Planned Maintenance Outages, may not exceed 1,000 hours total in any consecutive 12 month period when major maintenance overhauls are required or 250 hours total in any consecutive 12 month period without the written consent of Buyer;
- Seller may schedule only one major maintenance overhaul during a consecutive 60 month period without the written consent of Buyer;
- Any Planned Maintenance outage shall be scheduled and

- coordinated with Buyer and the CAISO (and if Buyer is the SC, Buyer shall schedule Planned Maintenance with the CAISO); and
- Outages taken outside of the times permitted for Planned Maintenance or not otherwise in accordance with the Maintenance Protocol shall be treated as forced outages and the Unit(s) will be deemed to be unavailable during such periods for purposes of determining Availability; Capacity Payment and Fixed O&M Payment reductions due to reduced Availability may apply.

**Guaranteed Heat Rate**

The efficiency of the Unit's(s') ability to convert fuel into power will be guaranteed by Seller over a range of operational levels at standard "ISO Conditions" (59°F, 60% relative humidity) and the mean site elevation as well as Peak July Conditions.

Seller should specify the "Guaranteed Heat Rates" in Appendix F based on Higher Heating Value ("HHV") and on net generation delivered at the Point of Delivery at which the Unit(s) will convert pipeline quality natural gas into power at the following efficiencies (MMBtu/MWh) at ISO Conditions and Peak July Conditions:

- at Base Load with full power augmentation;
- at 100% of Base Load on the combustion turbine(s);
- at 75% of Base Load on the combustion turbine(s);
- at 50% of Base Load on the combustion turbine(s); and if applicable
- at minimum load on the combustion turbine(s), if less than 50%.

"Base Load" has the meaning set forth under "Testing for Capacity and Energy Deliverability."

To incorporate heat rate degradation as the plant ages, Seller may provide a different Guaranteed Heat Rate set of data for every year of the contract. The Seller shall specify this data in Appendix F.

For the purposes of scheduling the output of the plant, Seller will also provide detailed heat rate curves to Buyer that will be consistent with the guarantee points described above. These curves will also provide additional information as to the amount of fuel consumed and the amount of electrical energy produced at various temperature conditions and throughout the full range of operational levels.

**Heat Rate Testing**

Prior to the Initial Delivery Date and thereafter on a seasonal basis (Summer/Non-Summer), Buyer shall schedule, with no more than 24 hours of advance notice, a heat rate test. The tests will be for every operating point specified in the Guaranteed Heat Rate section above and will be conducted simultaneously with the capacity tests described in the Testing for Capacity and Energy Deliverability section. The tests will be performed in general accordance with ASME Performance Test Code #46. The test results will be adjusted by standard and accepted engineering methods to coincide with ISO Conditions (applicable if the test occurs during a Non-Summer Month) or Peak July Conditions (applicable if the test occurs during a Summer Month). The cost of such test shall be shared equally by Buyer and Seller. The average tested heat rate ("**ATHR**") shall be simple average of the tested heat rate at each of the operating points specified above.

Should operational data that includes fuel consumption and net plant output provide indications that the plant fuel conversion efficiency does not equal the Guaranteed Heat Rate, Buyer or Seller shall have the right to request and schedule heat rate tests on the Unit(s) for purposes of assessing the efficiency of fuel conversion and establishing a new ATHR. Heat rate tests requested by Buyer shall be performed within 24 hours of the time of request. The costs of the test will be borne by the requesting Party. As is the case for a seasonal test, the tests will be for every operating point specified in the "Guaranteed Heat Rate" section; the test results will be adjusted by standard and accepted engineering methods to coincide with ISO conditions (applicable if the test occurs during a Non-Summer Month) or Peak July Conditions (applicable if the test occurs during a Summer Month); and the ATHR shall be the simple average of the tested heat rate at each of the operating points specified in the "Guaranteed Heat Rate" section.

**Heat Rate Payment**[2]

A "**Heat Rate Payment**" will be based on the ATHR (whether established through a seasonal test or a test requested by a Party) compared to the simple average of the Guaranteed Heat Rate at the same operating points for the same conditions ("**AGHR**"). If the ATHR is 1% or more higher than the simple average of the AGHR ("**High Test**") Seller shall compensate Buyer as follows:

Compensation shall be based on daily cost of replacement fuel, the historical daily volume of MWh produced and the difference, in MMBtus between the ATHR and the AGHR.

For each day, the following formula will apply:

DCMP = DCRF x ADV x DMMBTU
Where:
DCMP = the total compensation for one day in $s
DCRF = the daily cost of replacement fuel in $/MMBtu

[2] A Seller offering a power purchase agreement that is not a Fuel Conversion Agreement may propose an alternative heat rate guarantee structure as appropriate with respect to its proposed pricing structure.

ADV = the actual daily volume of MWhs produced
DMMBTU = the difference in MMBtus between the ATHR and the AGHR in MMBtus

This DCMP will be calculated for each historical day from (i) the date of the last heat rate test during which the ATHR was found to be less than 1% higher than the simple average of the AGHR until (ii) the date of the High Test. These DCMPs will be summed and multiplied by 50 percent as the Heat Rate Payment from Seller to Buyer for the time period since the last actual heat rate test and the date of the High Test. Additional Heat Rate Payments will continue to be calculated per the above formula for periods following the High Test without the 50 percent multiplier and will continue to accrue for the benefit of Buyer until a new heat rate test shows otherwise.

The daily cost of fuel will be based on the applicable gas distribution charges and the index cost of gas as published by Platt's Gas Daily (in the internet publication currently accessed through www.platts.com) in the table entitled "Daily price survey" under the heading "Midpoint" for the applicable date of delivery. The index will be for the applicable gas trading point (e.g. PG&E Citygate).

An event of Default may result if the ATHR, as tested, is 10% greater than the AGHR unless Seller is able to cure the deviation and demonstrate by testing, within the following 30 consecutive days, that the ATHR, as tested, is less than 10% greater than the AGHR.

**Heat Rate Bonus**

A "**Heat Rate Bonus**" will be based on the ATHR (whether established through a seasonal test or a test requested by a Party) compared to the AGHR (at the same operating points for the same conditions). If the ATHR is 1% or more lower than the AGHR, Buyer shall pay a bonus to Seller as follows:

This bonus shall equal $0.10 per MWh of actual production for every percent that the ATHR is less than the AGHR during the period from the day following the test in which such ATHR was determined until the day on which a subsequent test demonstrates that the ATHR is less than 1% less than the AGHR.

**Compensation:**

A. "**Capacity Payment Rate**"—specify the annual values in Appendix E as $ per kW-year (price to include right to Other Products, including without limitation, Ancillary Services, Resource Adequacy, and Environmental Attribute products);

B. "**Fixed O&M Rate**"—specify the annual values in Appendix E as $ per

KW-year (price to include right to Other Products, including without limitation, Ancillary Services and Resource Adequacy products);

C. "**Variable O&M Rate**"—specify the rate or rates in Appendix E as $ per MWh;

D. "**Variable Energy Rate"** (if applicable)—specify the rate or rates in Appendix E as $ per MWh

The monthly Capacity Payment Rate and the Fixed O&M Rate are allocated monthly per the schedule in Attachment 1 and multiplied by the Monthly Contract Capacity of the Unit(s) committed to Buyer for the specific month to determine the applicable monthly capacity payment ("**Capacity Payment**") and fixed O&M payment ("**Fixed O&M Payment**") (before adjustment). The Capacity Payment and Fixed O&M Payment will be paid monthly, in arrears, for each month of the Services Term. Each of the Capacity Payment and Fixed O&M Payment are subject to the Non-Availability Discount, as applicable for that month, including Non-Availability Discount Amounts due to the Start-Up Adjustment (if applicable). If the Services Term includes partial years, the Capacity Payment and the Fixed O&M above shall reflect the cost for such partial year, and the payment rate shall be allocated monthly based on the relative value of the partial year's monthly allocation factors. Ninety days prior to a start of a full calendar year, Buyer may notify Seller of modifications to Attachment 1. Buyer may not modify Attachment 1 such that any individual month has a percentage allocation of less than 2.5% or greater than 25%; and the total in any calendar year must equal 100%.

"**Variable O&M Payment**": For each month of the Services Term, the Variable O&M Payment will equal the Variable O&M Rate multiplied by the amount of Energy scheduled by Buyer in the applicable month.

F. "**Losses**"
Seller shall not be responsible for transmission losses at or after the Delivery Point.

**Start-Up Costs**

A "**Start-Up**" is any schedule adjustment by Buyer that will require that the Unit(s) begin producing power at no less than minimum dispatch level output from a state of no or zero production. Start-Ups can be classified in the following manner:

- Hot start: "x"number of hours or less since shutdown;
- Warm start: Greater than "x," up to and including "y," number of hours since shutdown; and
- Cold start: greater than "y" hours since shutdown.

Where the "x" and "y" are defined in Appendix F.

Buyer will provide Seller the quantities of gas per start for Unit(s) Start-Ups ("**Start Up Fuel Amounts**") (i) necessary to meet Buyer's schedule and (ii) following a shutdown of the Unit(s) at the end of a Buyer requested scheduling period, for each of the following:

- Hot start;
- Warm start; and
- Cold start.

The MMBtu values per start, by year for each of the above starts will be specified in the appropriate field in Appendix F; specified per combustion turbine and steam turbine, as applicable.

Buyer will also pay Seller the associated costs for each Start-Up ("**Start-Up Charge**")of the amount per start, specified by year in Appendix F for each of the following:

- Hot start;
- Warm start; and,
- Cold start.

The amount of time, in minutes, required for Start-Up (from zero schedule to Minimum Schedule) will be no more than the amount per start, specified by year, in Appendix F for each of the following:

- Hot start;
- Warm start; and
- Cold start.

The maximum number of starts allowed per year for each year of the contract are specified in Appendix F for each of the following:

- Hot starts;
- Warm starts; and
- Cold starts.

Buyer will not provide fuel or pay for Start-Up if the preceding shutdown was caused by an outage that was not scheduled by Seller.

**Billing and Payment**

Each month during the Services Term, Seller shall invoice Buyer, in arrears, for all Compensation amounts, including the Non-Availability Discount on Capacity Payments and Fixed O&M Payments, the Start-Up Charges, and the Heat Rate Bonus (if applicable). Each month during the Services Term, Buyer shall invoice Seller, in arrears, for the Deviation Charges, including those CAISO charges which have been charged to Buyer and not previously invoiced to Seller for which Seller is responsible for paying to Buyer pursuant to the Definitive Agreement (which due to delays in CAISO billing, may relate to months prior to that most recently ended); and in addition, any fuel related expenses (including without limitation the Heat Rate Payment and gas imbalance charges) for which Seller is responsible, the Non-Availability Discount as it applies to Ancillary Services and Liquidated Damages due to failure to meet the Expected Initial Delivery Date, if applicable, for such month. If each Party is required to pay the other an amount in the same month pursuant to the Definitive Agreement, then the Party owing the greater aggregate amount will pay to the other Party the difference between the amounts owed. Payment of all undisputed amounts owed shall be due by the later of ten days after delivery of the owed Party's invoice or the twentieth day of the month (or, in each case, if the due date is not a business day, on the next following business day). The Parties shall resolve disputed amounts pursuant to a dispute resolution process to be included in the Definitive Agreement. In the event of termination, Buyer, as calculation agent, shall determine the amount of the Termination Payment, and either (a) if Seller is the owing Party, provide Seller an invoice within ten business days of the termination date, which shall be due within 10 business days after receipt; or (b) if Buyer is the owing Party, pay Seller the Termination Payment within 20 business days of the termination date.

**Events of Default**

Either Party will be in Default under the Definitive Agreement upon the occurrence of, including but not limited to any of the following:

Applicable only to Seller:

- Any material asset of Seller is taken upon execution or by other process of law directed against Seller or if taken upon or subject to any attachment by any creditor of or claimant against Seller and the attachment is not disposed of within twenty-one (21) days after its levy.
- Upon the occurrence of any material misrepresentation or omission in any metering or any report or notice of availability required to be made or delivered by Seller to Buyer by the provisions of the Definitive Agreement, which misrepresentation or omission is caused by Seller's willful misconduct, gross negligence or bad faith.
- Seller fails to post, supplement or renew when due the Offer Deposit or the Delivery Date Security.
- Seller fails to comply with Resource Adequacy requirement of the Definitive Agreement.
- During the Services Term, the Unit(s) are below 70% Availability for a period of 6 consecutive months, and such reductions in Availability is not due to a Force Majeure event;
- During the Services Term, an event of Force Majeure prevents the unit from achieving at least 70% Availability for a period of 12 consecutive months.

- During the Services Term, the ATHR, as tested, is 10% greater than the AGHR unless Seller is able to cure the deviation and demonstrate by testing, within the following 30 consecutive days, that the ATHR, as tested, is less than 10% greater than the AGHR.
- A failure to complete the conditions precedent to the Initial Delivery Date on or before the earlier of 365 days after the Expected Initial Delivery Date or a delay in the construction schedule of more than 365 days.

Applicable to both Parties:

- A Party fails to pay an amount when due and such failure continues for ten business days after notice thereof is received.
- A Party fails to perform any of its material obligations under the Definitive Agreement and such default continues for thirty (30) Days after notice thereof is received, specifying the Event of Default; provided, however, that such period shall be extended for an additional reasonable period if cure cannot be effected in thirty (30) days and if corrective action is instituted by the defaulting Party within the thirty (30) day period and so long as such action is diligently pursued until such default is corrected.
- A Party applies for, consents to, or acquiesces in the appointment of a trustee, receiver, or custodian of its assets (including, in the case of Seller for a substantial part of the Unit(s)), or the initiation of a bankruptcy, reorganization, debt arrangement, moratorium or any other proceeding under bankruptcy laws.
- Absent the consent or acquiescence of a Party, appointment of a trustee, receiver, or custodian of its assets (including in the case of a Seller, for a substantial part of the Unit(s)), or the initiation of a bankruptcy, reorganization, debt arrangement, moratorium or any other proceeding under bankruptcy laws, which in either case, is not dismissed within sixty (60) days.
- A Party fails to comply with Credit Requirement provisions of the Definitive Agreement including without limitation failure to post the initial Collateral Requirement when due.
- Any governmental approval necessary for a Party to be able to perform all of the transactions contemplated by the Definitive Agreement expires, or is revoked or suspended and is not renewed or reinstated within a reasonable period of time following the expiration, revocation, or suspension thereof, by reason of the action or inaction of such Party and such expiration, revocation or suspension creates a material adverse impact on the other Party.
- Upon the occurrence of any material breach of any representation, covenant, or warranty made by a Party made in the Definitive Agreement, thirty (30) days after the written notice from the other Party that any material representation, covenant or warranty made in the Definitive Agreement is false, misleading or erroneous in any

material respect.

**Remedies:** Upon the occurrence of an Event of Default, the non-Defaulting Party may elect to exercise any or all remedies available to it, including but not limited to, the following:

- Terminate the Definitive Agreement.
- Prior to the Initial Delivery Date, if Seller is the Defaulting Party, Seller will pay a Termination Payment equal to the undrawn portion of the Delivery Date Security and if Buyer is the Defaulting Party, Buyer will pay a Termination Payment of $15,000 per MW multiplied with the maximum Contract Capacity committed for any month of the Services Terms.
- On and after the Initial Delivery Date, the Termination Payment will be the aggregate of all Settlement Amounts netted into a single amount, where the Settlement Amount is equal to the Losses or Gains, and Costs, expressed in U.S. dollars, which the Non-Defaulting incurs as a result of the liquidation of the transaction, where the Settlement Amount, Losses, Gain and Costs, have the meanings set forth in the Master Power Purchase & Sale Agreement published by EEI. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.
- Exercise any other right or remedy available at law or in equity, other than specific performance.

The rights and remedies of a Party pursuant to the Remedies Section of the Definitive Agreement shall be cumulative and in addition to the rights of the Parties otherwise provided in the Definitive Agreement.

**Force Majeure** "**Force Majeure**" shall mean any event or circumstance to the extent beyond the control of, and not the result of the negligence of, or caused by, the Party seeking to have its performance obligation excused thereby, which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it has been unable to overcome, including but not limited to: (1) acts of God, including but not limited to landslide, lightning, earthquake, storm, hurricane, flood, drought, tornado, or other natural disasters and weather related events affecting an entire region which caused failure of the Unit(s); (2) fire or explosions; (3) transportation accidents affecting delivery of equipment only if such accident occurs prior to the Commercial Operation Date; (4) sabotage, riot, acts of terrorism, war and acts of public enemy; or (5) restraint by court order or other governmental authority. Force Majeure shall not include (i) a failure of performance of any Third Party, including any party providing electric transmission service or natural gas transportation, except to the extent that such failure was caused by an event that would otherwise satisfy the definition of a Force Majeure event as defined above, (ii) failure to timely apply for or obtain Permits or (iii) breakage or malfunction of equipment, (except to the extent that such failure was caused by an event that would otherwise satisfy the definition of a Force Majeure event as defined above).

A Party shall not be considered to be in default in the performance of its obligations under the Definitive Agreement to the extent that the failure or delay of its performance is due to an event of Force Majeure; and the non-affected Party shall be excused from its corresponding performance obligations to the extent due to the affected Party's failure or delay of performance. Notwithstanding the forgoing, (i) a failure to make payments accrued prior to the event of Force Majeure when due shall not be excused; and (ii) the unavailability of the capacity of the Units due to Force Majeure shall be deemed to be unavailability for purposes of determining Availability and the Non-Availability Discount

**Metering**

Seller shall install, maintain, operate and replace (as needed) electric meters and back-up meters at the Delivery Point to determine energy, and gas meters at the interconnection point for fuel deliveries, in each case at its sole cost and expense. The meters will be sealed by both Parties, which seals will only be broken by both Parties for inspection, testing or adjustment. The electric meters shall meet all specifications of the CAISO, and shall be checked annually by Seller, who shall provide Buyer with not less than 14 days prior notice of such tests. Similarly, gas meters must meet applicable specification of the service provider and shall be checked annually by the Seller or the service provider; and Seller shall provide Buyer with not less than 14 days prior notice of such tests. Buyer will have the right to have a representative(s) present during such tests.

Either Party may from time to time request a retest of the meters if it reasonably believes that the meters are not accurate within the tolerance limits established by the CAISO or the applicable service provider. The requesting Party shall pay for any such retest and shall provide the other Party with not less than 14 days prior notice of such retest. Such other Party will have the right to have a representative present during such retest. If any tested or retested meter is found to be not accurate within the tolerance limits established by the CAISO or the applicable service provider, Seller shall promptly arrange for the correction or replacement of the meter, at its expense, and the Parties shall use the measurements from the back-up meters to determine the amount of the inaccuracy. If the back-up meters are found to be not accurate within the tolerance limits and the Parties cannot otherwise agree as to the amount of the inaccuracy, the inaccuracy will be deemed to have occurred during the period from the date of discovery of the inaccuracy to the earlier of (a) one-half of the period from such discovery to the date of the last testing or retesting of the meters or (b) 180 days. Any amounts due by Buyer or to be refunded by Seller as a result of any meter that is not accurate within the tolerance limits will be invoiced by such Party within 15 days of the discovery of such inaccuracy, with payment due within 30 days.

To support invoice settlement purposes, Seller shall provide Buyer with access to all real-time meters, billing meters and back-up meters (i.e., all metering). Seller shall authorize Buyer to view the Project's CAISO on-line meter data and any gas real-time metering. Within Schedule 3 of Seller's Meter Service Agreement with the CAISO, Seller shall identify Buyer as an authorized user with "read only" privileges.

**Compliance with Law, Environmental Risk and Indemnity**

Seller, as owner and operator of the Unit(s), will be responsible for complying with all applicable requirements of law, the CAISO, NERC and the WECC, whether imposed pursuant to existing law or pursuant to changes enacted or implemented during the Contract Term, including all risks of environmental matters relating to the Unit(s) or the site. Seller will indemnify Buyer against any and all claims arising out of or related to such environmental matters and against any costs imposed on Buyer as a result of Seller's violation of any applicable law, or CAISO, NERC or WECC requirements. For the avoidance of doubt, Seller will be responsible for procuring, at its expense, all permits and all emissions credits required for operation of the Unit(s) in compliance with law.

**Credit Requirements (as of the Initial Delivery Date)**

The amount of unsecured credit to be extended to a Party by the other Party will be determined based on the senior unsecured long-term debt rating or the issuer credit rating of the Party ("**Collateral Threshold Amount**"). The Collateral Threshold Amount may be set at zero. Buyer intends to compute a market value for the products sold under the Definitive Agreement, with weekly collateral posting requirements (in excess of the Collateral Threshold Amount) tied to changes in market value of the products. From the Initial Delivery Date, Seller will also be subject to an amount equal to the product of $30,000 multiplied by the maximum Monthly Contract Capacity to be provided in any month of the Services Term during the first two years for a 24 month generation technology and $60,000 multiplied by the maximum number of MW of Capacity to be provided in any month of the Services Term during the first five years for a 60-month generation technology (the "**Independent Amount**"). The Parties agree that each Party will post Collateral equal to the Collateral Requirement in accordance with the formula below (when positive for such Party), which is based on an on-going rolling two (2) or five (5) year Mark to Market (MtM) Value, calculated in accordance within Attachment 2. If Buyer has to post, the Collateral will be in the form of a Letter of Credit. If Seller has to post Collateral, Seller will have the option to post in the form of a Letter of Credit or cash. The determination of two or five years is dependent on the generation technology underlying the Definitive Agreement and the length of time that would be required to procure a like-kind replacement of the Definitive Agreement in the market. The Parties also agree that during the rolling two or five year term the Mark-to-Market Value shall equal the difference between the initial monthly intrinsic value ("**Initial MIV**") and the current monthly intrinsic value ("**Current MIV**") as set forth in Attachment 2. During each week during the term of the Definitive Agreement, the Current MIV shall be calculated according to the formula set forth in Attachment 2 for the next twenty-four (24) or sixty (60) months. PG&E shall be the calculation agent and will provide notice weekly to Buyer of the Collateral Requirement amount to be posted by Buyer or Seller, as applicable. Within three business day of such notice, the Party required to post shall post the Collateral Requirement or the non-posting Party shall return such collateral previously posted that is in excess of the posting Party's then current Collateral Requirement. The following shall apply for the full term of the Definitive Agreement:

The "**Collateral Requirement**" at any point in time for Seller after the Initial Delivery Date is the amount calculated which is equal to (x) less (y), but no less than zero, where:

(x) is

the positive amount of the Mark-to-Market Value as determined pursuant to Attachment 2.
plus
the Independent Amount

(y) is

the amount of Collateral previously provided by Seller plus

the Collateral Threshold Amount applicable to Seller.

The "**Collateral Requirement**", at any point in time, for Buyer after the Initial Delivery Date is the amount calculated which is equal to (x) less (y), but no less than zero, where:

(x) is

the product of the negative amount of the Mark-to-Market Value as determined pursuant to Attachment 2 multiplied by (-1)

(y) is

the amount of Collateral previously provided by Buyer

plus

the Collateral Threshold Amount applicable to Buyer.

**Confidentiality** Seller shall maintain all commercial terms confidential for the greater of

(1) the term of the Confidentiality Agreement dated ___________ by and between Seller and Buyer, if any;
(2) three years from the date of this Term Sheet; or
(3) the Contract Term.

Neither Party shall disclose the terms or conditions of this Term Sheet to a third party (other than either Party's employees, lenders, counsel, accountants, advisors or ratings agencies, and in the case of PG&E, the Procurement Review Group, who, in each case, have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding or request applicable to such Party, or as Buyer deems necessary in order to demonstrate the reasonableness of its actions to duly authorized governmental or regulatory agencies, including, without limitation, the California Public Utilities Commission ("CPUC") or any division thereof; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation. The confidentiality obligation hereunder shall not apply to any information that was or hereafter becomes available to the public other than as a result of a disclosure in violation of this Section. This confidentiality provision shall become binding upon delivery of the completed Term Sheet.

**Dispute Resolution:** All disputes that cannot be resolved after referral to senior management of the Seller and Buyer shall be resolved by mediation or arbitration. If arbitration is used, the resolution shall be determined exclusively through "baseball-style" arbitration conducted in San Francisco, California under the rules of the American Arbitration Association before a panel of three (3) arbitrators.

**Other Terms and Conditions** The Parties will be expected to make customary representations and warranties.

The Definitive Agreement will be governed by California law.

Seller will agree to maintain customary books and records, including without limitation, operating logs, meter readings and financial records and make such books and records available for audit.

The right of Seller to assign the Definitive Agreement or to transfer control of the Units (directly or indirectly) to another person, whether or not affiliated, shall be subject to Buyer's consent, not to be unreasonably withheld upon a showing of the proposed assignee's technical and financial capability to fulfill the requirements of Seller. Assignment of the Definitive Agreement and liens upon the Units for purposes of project financing shall be permitted; and Buyer will execute such additional consents as reasonably required by Seller in connection with such assignment; provided that Buyer shall not be required to consent to any additional terms or conditions, including extension of the cure periods or additional remedies for lenders; and provided further, Seller shall be responsible for Buyer's reasonable costs associated with review, negotiation, execution and delivery of such documents, including attorneys fees.

Seller will agree that the Units and the Products will be free of liens other than permitted liens as agreed to by the Parties.

Each Party shall be responsible for taxes assessed upon it, including any new taxes that may be imposed during the Contract Term.

| | |
|---|---|
| **Non-Inclusive; Non-Binding; Definitive Agreement** | This Term Sheet does not contain all matters upon which agreement must be reached in order for the Transaction to be completed. Except for the Confidentiality provision herein, this Term Sheet does not create and is not intended to create a binding and enforceable contract between the Parties with respect to the Transaction. Refer to Sections VII.B., XIII and XVI of the RFO for a description of the purpose and effect of this Term Sheet. A binding commitment with respect to the Transaction can only result from the execution and delivery of a mutually satisfactory Definitive Agreement ("Definitive Agreement") and the satisfaction of the conditions set forth therein, including the approval of such Definitive Agreement by all applicable governing and/or regulatory body(ies) and the management of PG&E, which approval shall be in the sole subjective discretion of the respective governing and/or regulatory body(ies) and management. |

## Attachment 1 – Fixed Payment Allocations by Month

| | |
|---|---|
| January | 8% |
| February | 5% |
| March | 4% |
| April | 4% |
| May | 4% |
| June | 8% |
| July | 14% |
| August | 15% |
| September | 11% |
| October | 9% |
| November | 9% |
| December | 9% |

## Attachment 2—Valuation Formulas for Credit Requirements

Formula Definitions:

*t0* – date Definitive Agreement approved by the appropriate regulatory bodies
*t* - ongoing Transaction date after Initial Delivery Date
*Ppeak(i, t)* - price of monthly forward NP-15 defined peak power for month *i* as observed at the moment of time *t* measured in $/MWh
*Poff-peak(i, t)* - price of monthly forward NP-15 defined off-peak power for month *i* as observed at the moment of time *t* measured in $/MWh
*Pgas(i, t)* - price of monthly forward gas for month *i* as observed at the moment of time *i* measured in $/MMBtu
*VOM,* - Variable O&M (measured in $/MWh) for year of current month set forth in Definitive Agreement for month *i*
*HR* – the Heat Rate at Maximum Capacity set forth in the Definitive Agreement at ISO Conditions
*HourlyVolume* – Maximum MW size set forth the Definitive Agreement for the specific month
*NumberofPeakHours(i)* - number of WECC defined peak hours in month *i*
*NumberofOff-PeakHours(i*) - number of WECC defined off-peak hours in month *I*

Calculation of "Mark-to-Market Value":

Mark-to-Market Value = Sum Over next twenty-four (24) or sixty (60) Months[Gains or Losses(i)]

Gains or Losses(i) = MIV(i,t0) – MIV(i,t)

Initial MIV calculation formula:

MIV(i,t0) = [NumberOfPeakHours(i) * max[(Ppeak(i,t0) - HR*Pgas(i,t0) - VOM,), 0] * HourlyVolume] + [NumberOfOff-PeakHours(i) * max[(Poff-peak(i,t0) - HR * Pgas(i,t0) - VOM,), 0] *HourlyVolume]

Initial MIV will be calculated once at *t0* for the expected delivery life of the contract.

Current MIV calculation formula:

MIV(i,t) = [NumberOfPeakHours(i) * max[(Ppeak(i,t) - HR*Pgas(i,t) - VOM(i)), 0] * HourlyVolume] + [NumberOfOff-PeakHours(i) * max[(Poff-peak(i,t) - HR * Pgas(i,t) - VOM(i)), 0] *HourlyVolume]

Start-Up Adjustment Table

| Start-Up Factor | NSR less than 10 | NSR = 10 to 20 | NSR = 20 to 30 | NSR = 30 to 50 |
|---|---|---|---|---|
| 95% or more | no penalty* | no penalty** | no penalty | 10% |
| 80% to 94% | 10% | 15% | 20% | 25% |
| 60% to 79% | 30% | 40% | 50% | 60% |
| 40% to 59% | 60% | 70% | 80% | 90% |
| less than 40% | 100% | 100% | 100% | 100% |

# Appendix E: Offer Pricing Data Forms

**Long Term Offer Data Sheet**
**Compensation**

Seller ________________________
Plant Address ________________________
Delivery Location* ________________________ *Nearest substation or transmission line
CAISO ID ________________________
Fuel Type ________________________
Fuel Delivery Point* ________________________ *Meter Set Location
Technology Type ________________________

| | | Compensation | | | |
|---|---|---|---|---|---|
| | Calendar year | Capacity Payment ($/kW-year)* | Fixed O&M ($/KW-Year)** | Variable O&M ($/MWh)** | Variable Energy Price ($/MWh) |
| | | | | | |
| 1 | 2007 | | | | |
| 2 | 2008 | | | | |
| 3 | 2009 | | | | |
| 4 | 2010 | | | | |
| 5 | 2011 | | | | |
| 6 | 2012 | | | | |
| 7 | 2013 | | | | |
| 8 | 2014 | | | | |
| 9 | 2015 | | | | |
| 10 | 2016 | | | | |
| 11 | 2017 | | | | |
| 12 | 2018 | | | | |
| 13 | 2019 | | | | |
| 14 | 2020 | | | | |
| 15 | 2021 | | | | |
| 16 | 2022 | | | | |
| 17 | 2023 | | | | |
| 18 | 2024 | | | | |
| 19 | 2025 | | | | |
| 20 | 2026 | | | | |
| 21 | 2027 | | | | |
| 22 | 2028 | | | | |
| 23 | 2029 | | | | |
| 24 | 2030 | | | | |
| 25 | 2031 | | | | |
| 26 | 2032 | | | | |
| 27 | 2033 | | | | |
| 28 | 2034 | | | | |
| 29 | 2035 | | | | |
| 30 | 2036 | | | | |

*Note: $/kw-year values should reflect ratings at ISO conditions.

**Delay Option Price:** ______________

** Please provide any operating assumptions underlying the calculation of Fixed O&M and Variable O&M including, but not limited to:annual capacity factor, overhaul cycles, maintenance schedules, daily operational hours, cycling start/stops and any others.

# Appendix F: Generation Facility Information Forms

## Exhibit F1: Project Data Sheets

## Exhibit F2: Project Description

For a Power Purchase Offer, the data below should be provided for the length of the proposed PPA.

## Appendix F1: Project Data Sheets

**Long Term Request For Offers Data Sheet**
**Capacity**

Seller ____________________
Plant Address ____________________
Delivery Location* ____________________ *Nearest substation or transmission line
CAISO ID ____________________
Fuel Type ____________________
Fuel Delivery Point* ____________________ *Meter Set Location
Technology Type ____________________

| | | Capacity Under Expected Operating Conditions* | | | | | | | | | | | | Capacity Under Peak Conditions* | Capacity At ISO Conditions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Calendar year | Jan. (MWs) | Feb. (MWs) | Mar. (MWs) | Apr. (MWs) | May (MWs) | Jun. (MWs) | Jul. (MWs) | Aug. (MWs) | Sep. (MWs) | Oct. (MWs) | Nov. (MWs) | Dec. (MWs) | Peak Jul. (MWs) | (MWs) |
| | | | | | | | | | | | | | | | |
| 1 | 2007 | | | | | | | | | | | | | | |
| 2 | 2008 | | | | | | | | | | | | | | |
| 3 | 2009 | | | | | | | | | | | | | | |
| 4 | 2010 | | | | | | | | | | | | | | |
| 5 | 2011 | | | | | | | | | | | | | | |
| 6 | 2012 | | | | | | | | | | | | | | |
| 7 | 2013 | | | | | | | | | | | | | | |
| 8 | 2014 | | | | | | | | | | | | | | |
| 9 | 2015 | | | | | | | | | | | | | | |
| 10 | 2016 | | | | | | | | | | | | | | |
| 11 | 2017 | | | | | | | | | | | | | | |
| 12 | 2018 | | | | | | | | | | | | | | |
| 13 | 2019 | | | | | | | | | | | | | | |
| 14 | 2020 | | | | | | | | | | | | | | |
| 15 | 2021 | | | | | | | | | | | | | | |
| 16 | 2022 | | | | | | | | | | | | | | |
| 17 | 2023 | | | | | | | | | | | | | | |
| 18 | 2024 | | | | | | | | | | | | | | |
| 19 | 2025 | | | | | | | | | | | | | | |
| 20 | 2026 | | | | | | | | | | | | | | |
| 21 | 2027 | | | | | | | | | | | | | | |
| 22 | 2028 | | | | | | | | | | | | | | |
| 23 | 2029 | | | | | | | | | | | | | | |
| 24 | 2030 | | | | | | | | | | | | | | |
| 25 | 2031 | | | | | | | | | | | | | | |
| 26 | 2032 | | | | | | | | | | | | | | |
| 27 | 2033 | | | | | | | | | | | | | | |
| 28 | 2034 | | | | | | | | | | | | | | |
| 29 | 2035 | | | | | | | | | | | | | | |
| 30 | 2036 | | | | | | | | | | | | | | |

*Note: Peak July Conditions are based on the average of the monthly maximum daily peak temperatures of the preceding 10 years for the month of July as provided by the National Climatic Data Center ("NCDC") at http://www.ncdc.noaa.gov/servlets/ULCD. Data from the NCDC should be for a geographically nearby weather station that approximates the conditions at the specific plant site.
Expected operating conditions are the average of the monthly temperature for the preceding 10 years.

**Long Term Request For Offers Data Sheet**
**Heat Rate**

Seller ____________________
Plant Address ____________________
Delivery Location* ____________________ *Nearest substation or transmission line
CAISO ID ____________________
Fuel Type ____________________
Fuel Delivery Point* ____________________ *Meter Set Location
Technology Type ____________________

| | | Guarantee at ISO Conditions MMBtus/MWh (HHV) @ | | | | | | | | | | | | | | Guarantee at Peak July Conditions* MMBtus/MWh (HHV) @ | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Calendar year | Max Output with DF and PA** | | Max Output with Duct Firing*** | | Max Output | | 90% Output | | 75% Output | | 50% Output | | Minimum Output | | Max Output with DF and PA** | | Max Output with Duct Firing** | | Max Output | | 90% Output | | 75% Output | |
| | | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs | Heat Rate | MWs |
| 1 | 2007 | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | 2008 | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | 2009 | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | 2010 | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | 2011 | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | 2012 | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | 2013 | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | 2014 | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | 2015 | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | 2016 | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | 2017 | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | 2018 | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | 2019 | | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | 2020 | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | 2021 | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | 2022 | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | 2023 | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | 2024 | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | 2025 | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | 2026 | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | 2027 | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2028 | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | 2029 | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | 2030 | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | 2031 | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | 2032 | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | 2033 | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | 2034 | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | 2035 | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | 2036 | | | | | | | | | | | | | | | | | | | | | | | | |

*Note: Peak July Conditions are based on the average of the monthly maximum daily peak temperatures of the preceding 10 years for the month of July as provided by the National Climatic Data Center (“NCDC”) at http://www.ncdc.noaa.gov/servlets/ULCD. Data from the NCDC should be for a geographically nearby weather station that approximates the conditions at the specific plant site. Expected operating conditions are the average of the monthly temperature for the preceding 10 years.

**Note: Only applicable if the unit incorporates duct firing and power augmentation technology. All other points should not include any duct firing.

***Note: Only applicable if the unit incorporates duct firing technology. All other points should not include any duct firing.

**Long Term Request For Offers Data Sheet**
**Ancillary Services**

Seller ______________________
Plant Address ______________________
Delivery Location* ______________________ *Nearest substation or transmission line
CAISO ID ______________________
Fuel Type ______________________
Fuel Delivery Point* ______________________ *Meter Set Location
Technology Type ______________________

| | | Ancillary Services | | |
|---|---|---|---|---|
| | Calendar year | Spinning Reserve (Max MWs) | Non-Spinning Reserve (Max MWs) | Regulating Reserves (Max MWs) |
| | | | | |
| 1 | 2007 | | | |
| 2 | 2008 | | | |
| 3 | 2009 | | | |
| 4 | 2010 | | | |
| 5 | 2011 | | | |
| 6 | 2012 | | | |
| 7 | 2013 | | | |
| 8 | 2014 | | | |
| 9 | 2015 | | | |
| 10 | 2016 | | | |
| 11 | 2017 | | | |
| 12 | 2018 | | | |
| 13 | 2019 | | | |
| 14 | 2020 | | | |
| 15 | 2021 | | | |
| 16 | 2022 | | | |
| 17 | 2023 | | | |
| 18 | 2024 | | | |
| 19 | 2025 | | | |
| 20 | 2026 | | | |
| 21 | 2027 | | | |
| 22 | 2028 | | | |
| 23 | 2029 | | | |
| 24 | 2030 | | | |
| 25 | 2031 | | | |
| 26 | 2032 | | | |
| 27 | 2033 | | | |
| 28 | 2034 | | | |
| 29 | 2035 | | | |
| 30 | 2036 | | | |

**Long Term Request For Offers Data Sheet**
**Operating Flexibility**

Seller ______________________
Plant Address ______________________
Delivery Location* ______________________ *Nearest substation or transmission line
CAISO ID ______________________
Fuel Type ______________________
Fuel Delivery Point* ______________________ *Meter Set Location
Technology Type ______________________

| | | Operating Flexibility | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Calendar year | Annual Maintenance (Hours) | Equivalent Forced Outage Rate (%) | Annual Energy Limit (GWh) | Minimum Scheduled (MWs) | Maximum Ramp Rate (MWs/Min) | Minimum UpTime after start (Hours) | Minimum DownTime after shutdown (Hours) | Cold Start Fuel (MMBtus) | Warm Start Fuel (MMBtus) | Hot Start Fuel (MMBtus) |
| | | | | | | | | | | | |
| 1 | 2007 | | | | | | | | | | |
| 2 | 2008 | | | | | | | | | | |
| 3 | 2009 | | | | | | | | | | |
| 4 | 2010 | | | | | | | | | | |
| 5 | 2011 | | | | | | | | | | |
| 6 | 2012 | | | | | | | | | | |
| 7 | 2013 | | | | | | | | | | |
| 8 | 2014 | | | | | | | | | | |
| 9 | 2015 | | | | | | | | | | |
| 10 | 2016 | | | | | | | | | | |
| 11 | 2017 | | | | | | | | | | |
| 12 | 2018 | | | | | | | | | | |
| 13 | 2019 | | | | | | | | | | |
| 14 | 2020 | | | | | | | | | | |
| 15 | 2021 | | | | | | | | | | |
| 16 | 2022 | | | | | | | | | | |
| 17 | 2023 | | | | | | | | | | |
| 18 | 2024 | | | | | | | | | | |
| 19 | 2025 | | | | | | | | | | |
| 20 | 2026 | | | | | | | | | | |
| 21 | 2027 | | | | | | | | | | |
| 22 | 2028 | | | | | | | | | | |
| 23 | 2029 | | | | | | | | | | |
| 24 | 2030 | | | | | | | | | | |
| 25 | 2031 | | | | | | | | | | |
| 26 | 2032 | | | | | | | | | | |
| 27 | 2033 | | | | | | | | | | |
| 28 | 2034 | | | | | | | | | | |
| 29 | 2035 | | | | | | | | | | |
| 30 | 2036 | | | | | | | | | | |

**Long Term Request For Offers Data Sheet**
**Operating Flexibility (Continued)**

Seller ______________________
Plant Address ______________________
Delivery Location* ______________________ *Nearest substation or transmission line
CAISO ID ______________________
Fuel Type ______________________
Fuel Delivery Point* ______________________ *Meter Set Location
Technology Type ______________________

| | | Operating Flexibility *(continued)* | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Calendar year | Cold Start Cost ($s) | Warm Start Cost ($s) | Hot Start Cost ($s) | Cold Start Time (minutes) | Warm Start Time (minutes) | Hot Start Time (minutes) | Cold Start Shut Down Time (> # Hours) | Hot Start Shut Down Time (< # Hours) | Cold Start Number Allowed Per year | Warm Start Number Allowed Per year | Hot Start Number Allowed Per year |
| | | | | | | | | | | | | |
| 1 | 2007 | | | | | | | | | | | |
| 2 | 2008 | | | | | | | | | | | |
| 3 | 2009 | | | | | | | | | | | |
| 4 | 2010 | | | | | | | | | | | |
| 5 | 2011 | | | | | | | | | | | |
| 6 | 2012 | | | | | | | | | | | |
| 7 | 2013 | | | | | | | | | | | |
| 8 | 2014 | | | | | | | | | | | |
| 9 | 2015 | | | | | | | | | | | |
| 10 | 2016 | | | | | | | | | | | |
| 11 | 2017 | | | | | | | | | | | |
| 12 | 2018 | | | | | | | | | | | |
| 13 | 2019 | | | | | | | | | | | |
| 14 | 2020 | | | | | | | | | | | |
| 15 | 2021 | | | | | | | | | | | |
| 16 | 2022 | | | | | | | | | | | |
| 17 | 2023 | | | | | | | | | | | |
| 18 | 2024 | | | | | | | | | | | |
| 19 | 2025 | | | | | | | | | | | |
| 20 | 2026 | | | | | | | | | | | |
| 21 | 2027 | | | | | | | | | | | |
| 22 | 2028 | | | | | | | | | | | |
| 23 | 2029 | | | | | | | | | | | |
| 24 | 2030 | | | | | | | | | | | |
| 25 | 2031 | | | | | | | | | | | |
| 26 | 2032 | | | | | | | | | | | |
| 27 | 2033 | | | | | | | | | | | |
| 28 | 2034 | | | | | | | | | | | |
| 29 | 2035 | | | | | | | | | | | |
| 30 | 2036 | | | | | | | | | | | |

**Long Term Request For Offers Data Sheet**
**Emissions**

Seller ______________________
Plant Address ______________________
Delivery Location* ______________________ *Nearest substation or transmission line
CAISO ID ______________________
Fuel Type ______________________
Fuel Delivery Point* ______________________ *Meter Set Location
Technology Type ______________________

| | | Emissions at Max. Operational Cap. with DF & Power Augmentation (lbs./hour) | | | | | Emissions at Max.Operational Capacity with Duct Firing (lbs./hour) | | | | | Emissions at Maximum Operational Capacity (lbs./hour) | | | | | Emissions at 90% Operational Capacity (lbs./hour) | | | | | Emissions at 75% Operational Capacity (lbs./hour) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Calendar year | NOX | $SO_2$ | CO | $CO_2$ | PM10 | NOX | $SO_2$ | CO | $CO_2$ | PM10 | NOX | $SO_2$ | CO | $CO_2$ | PM10 | NOX | $SO_2$ | CO | $CO_2$ | PM10 | NOX | $SO_2$ | CO | $CO_2$ | PM10 |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 | 2007 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | 2008 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | 2009 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 | 2010 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | 2011 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | 2012 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | 2013 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 8 | 2014 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | 2015 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | 2016 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 11 | 2017 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 12 | 2018 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 13 | 2019 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 14 | 2020 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | 2021 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 16 | 2022 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 17 | 2023 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | 2024 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 19 | 2025 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 20 | 2026 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 21 | 2027 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2028 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 23 | 2029 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 24 | 2030 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 25 | 2031 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 26 | 2032 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 27 | 2033 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 28 | 2034 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | 2035 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 30 | 2036 | | | | | | | | | | | | | | | | | | | | | | | | | |

## Appendix F2: Project Description

### A. New Generation Facility Description

Please provide the following project information in the order requested.

1. The technology/configuration being proposed, e.g. Combined Cycle Gas Turbine (1 x 1, 2 x 1, 3 x 1), Simple Cycle Peaker (Number of units), Renewable generation (specify fuel type/source), Hydroelectric Facility, Reciprocating engine(s), Conventional Fossil (boiler/steam turbine) etc.

2. Describe the assumptions used in the development of heat rate and capacity guarantees.
   a. Provide the historical peak July temperature and relative humidity data from the National Climatic Data Center (NCDC) employed in the peak capacity and heat rate calculation that support the Appendix F data.
   b. Provide the historical monthly temperature and relative humidity data from the NCDC employed in the monthly capacity calculation.
   c. Provide the elevation used in deriving heat rates and capacity values.

3. Provide a complete equipment description for all major components including: CTG, STG, HRSG, plant control system, air emissions control equipment, GSUs and auxiliary transformers, switchgear, fuel compressor module and preheater, cooling system, major pumps, water treatment system, fuel storage facilities, etc.
   a. Equipment manufacturer/model/date of manufacture.
   b. Equipment source, e.g. existing owned inventory, new manufacturer order, resale market purchase.
   c. State whether any proposed equipment has been previously operated. If so, list operating hours.
   d. Terms and expiration of warranties/guarantees.

4. To give PG&E an understanding and confidence that cycling service is achievable with shaping units, provide the following information:
   a. Describe specific design considerations and provide, where appropriate, significant design detail to confirm that the unit has been designed to accommodate frequent cycling. Components that should be specifically addressed include: combustion and steam turbine systems, HRSGs and water chemistry control systems. Comments should emphasize minimizing maintenance down time, thermal fatigue effects and associated wear and tear.
   b. Describe plant design to meet water balance requirements.

c. Provide historic emissions data for combustion turbine technology to demonstrate ability to meet permit limits.

d. If applicable, list historic reliability data for the proposed combustion turbine technology to demonstrate restart capability from a hot-start.

5. List the proposed project site.

   a. Include map showing site location and key project facilities.

   b. List address and site parcel size.

   c. Identify neighboring property uses/owners

.

6. Current permitting status of the facility:

   a. Provide a permit plan for the facility that identifies the permits required, status of approvals, and plans to finalize all required permits for construction and operation of the facility, including California Energy Commission certification and land use approvals. Provide copies of the final or draft permits that have been issued by regulatory agencies.

   b. If the project is permitted, list the following:

      i. Permit source and expiration date.

      ii. Operating hours

      iii. Emissions limitations

      iv. Start/stop limitations

      v. Minimum run times

      vi. Other embedded permit limitations, e.g. zero discharge requirement, air-cooled condenser requirement, recycled cooling water requirement, etc.

   c. If project has started construction, describe completion status, EPC contract status.

7. List the Air Quality Management District this proposal is located in.

   a. Does the project require ERC's and if so, do you currently own or control sufficient ERC's for this project?

   b. If not, how do you propose to obtain them?

   c. Does the project meet Best Available Control Technology requirements?

8. If you are proposing water cooling, what is the water source?

   a. Indicate if you have firm water rights for the life of the project.

   b. Indicate if reclaimed water sources been evaluated for the project.

9. Description of control of the land at the proposed site

a. If you have site control, how is it exercised, e.g. ownership, leasehold interest, site option (terms?) Include copies of documents proving site control and ability to operate project as proposed.

b. List the site's current zoning.

c. Will the project require lease or special use agreements with local, state or federal agencies, e.g. Bay Conservation and Development Commission, State Lands Commission, U.S. Forest Service and if so, what is the status of obtaining these agreements?

10. Description of site conditions

a. Has a Phase I or Phase II Environmental Site Assessment been conducted for the property, if so please provide?
b. Are there any Corrective Action Consent Agency Agreements, or other agency actions associated with the site?
c. Describe any groundwater monitoring at the site and provide copies of the latest sample results.

11. Describe the site's proximity to any environmentally sensitive areas.

a. Identify any known wetlands.

b. Have sensitive species and habitat surveys been conducted in the project area, if so, please provide copies. Have resource agencies determined potential affects of the project action on sensitive species and habitat?

c. Will construction result in impact to navigable waters of the United States?

12. Describe the site's proximity to potentially sensitive receptors or culturally sensitive areas

a. List any cultural clearances obtained from state and federal agencies and any tribal interests in the project.

b. Describe the site's proximity to sensitive populations, such as schools, residential areas, commercial areas or areas of high security risk.

13. List any other cultural, commercial, security, or other potential sensitivities.

14. Describe any litigation or settlement agreement discussions applicable to the project

15. List the proposed fuel gas interconnection point.

a. Indicate whether the Preliminary Request for Gas Service has been applied for or completed.

b. List the approximate distance to the fuel gas interconnection point.

16. List the PG&E transmission system interconnection point. (i.e. switchyard or substation, with primary equipment listed; interconnecting voltages and interconnecting transmission lines; bus configuration: collector bus, ring bus, breaker and a half).

    a. Has a transmission System Impact Study (SIS) been applied for or completed for the proposal?

    b. What is the approximate distance to the electric interconnection point?

    c. Provide a proposed transmission interconnection plan including any existing approvals or agreements. Describe anticipated transmission system upgrades, and milestone activities and timeline for interconnection approval.

17. Submit a development and commissioning schedule consistent with your proposal. The schedule must provide a Commercial Operations Date that is consistent with the Eligibility Requirements listed in Section III of the RFO. The schedule should provide milestones for the following activities:

    a. Site procurement

    b. Design development

    c. Permitting and licensing

    d. Offer financing obtained

    e. Construction plan

    f. Performance testing and acceptance

18. Indicate whether Participant has entered into Project Labor Agreements (“PLA”) or Maintenance Labor Agreements (“MLA”) in California for the proposed project and specify when and where.

19. List Participant’s design, development, and operating experience with the proposed technology; particularly in California. To the extent that Participant has retained EPC contractors in the past, indicate which have experience building generating plants in California.

20. List the Participant’s proposed management team including key subcontractors such as proposed EPC contractor. Include:

    a. Resumes

    b. Documentation of relevant generation development and construction experience; particularly experience with projects in California.

21. Include a complete projected cost proforma for the Offer which includes at least the following:

    a. Capital budget with cost breakout for major components.

    b. Proposed spare parts inventory.

c. Plant O&M staffing plan with budget showing the following:
    i. Plant organization chart. Include a proposed O&M shift organization and headcount.
    ii. Staffing buildup plan. For the proposed headcount shown in the organization chart, prepare a plant hiring plan for the 12 months prior to the Guaranteed Commercial Availability Date.
    iii. Indicate any staffing augmentation that may be necessary during plant startup and performance testing.
    iv. Prepare a staff training plan for the proposed O&M organization.

22. Describe the potential for additional generation development at the site.

**B. Existing Generation (QF's for PPA ONLY) Should Also Provide the Following Additional Information:**

1. What is the proposal's current operating status? Please list any/all proposal operating limits including:
    a. Operating hours
    b. Emissions limitations
    c. Start/stop limitations
    d. Run times or ramp rates
    e. Other embedded permit limitations
    f. Equipment manufacturer/model/date of manufacture.

2. Any remaining warranties/guarantees.
    a. Is the proposal under a Long Term Service Agreement of any kind?

3. Provide last two unit overhaul reports covering major plant components as well as balance-of-plant components including any OEM reports and recommendations

4. Number of personnel and their classification currently employed at the facility.
    a. Is the facility operated by union personnel?

5. Describe the present maintenance management process and how maintenance records are kept
    a. A list of any predictive maintenance processes in use

6. A list of any on-going or planned capital improvements

7. A list of any on-going or planned major maintenance

8. Are there any long term contracts or agreements that a new owner of the plant would be obligated to honor? (i.e., that would extend past the proposed commencement date of the agreement with PG&E)? If so, please describe the nature of the existing commitment, its expiration date (and any renewal or extension rights) and how the plant would be able to reconcile its commitment to PG&E with the existing commitment.

9. If the plant capacity or energy is currently subject to a contract of more than one-year duration, explain the nature of the contractual commitment (e.g., number of MWs committed, RMR, energy-only, etc.), provide the expiration date of the current contract and specify the rights , if any, that the current parties have to renew or extend the existing agreement.

10. A list of outstanding work required to comply with current and known future regulatory requirements that will be in effect within the next three years.

11. Has any work been performed on the plant that is likely to trigger a new source review?

12. Heat rate curves of each unit from minimum to maximum load

13. Forced outage rate for each unit over the past 6 years

14. The equivalent availability for each unit over the past six years

## Appendix G: Credit and Finance Information Form

Provide the following information for assessment of the financial viability of Participant. Include additional sheets and other materials with this Appendix as necessary. Financial information must be provided for the participant/project and any entity providing credit enhancement to the Participant. As necessary, please specify whether the information provided is for the Participant, its parent or an entity providing on Participant's behalf security, under any of the provisions of the PPA. All capitalized terms not defined herein, shall have the meaning provided in the RFO.

### A. Participant Identification and Credit Information:

1. Full Legal Name Of Participant.
2. Describe in detail Participant's ultimate corporate parent if Participant is a direct or indirect subsidiary or affiliate of any other corporation; and/or each of Participant's general partners if Participant is a partnership; and/or each of Participant's joint ventures if Participant is a joint venture (identifying the controlling entity of the joint venture); and/or each of Participant's members if Participant is a limited liability company (identifying all manager(s) and officers); and/or each member of a consortium or other association, organization or group of persons acting in concert if Participant is a group or a member of a group acting in concert for purposes of this RFO (identifying the controlling group member(s)). In each case, provide full legal names. In the case of partnerships, joint ventures, consortia, or other associations or groups, the Participant must provide information sufficient for PG&E to identify the ultimate corporate parent if the general partner, joint venture, controlling member or other relevant actor or agent is a direct or indirect subsidiary or affiliate of another corporation.
3. Provide copies of or URLs to Participant's most recent Annual Report to shareholders or Annual Report on Form 10-K as filed with the Securities and Exchange Commission ("SEC") for the past two years containing audited financial statements of Participant and Participant's most recent quarterly report on Form 10-Q as filed with the SEC, and, if applicable, for each entity identified in paragraph 2 above that is required to file reports under the Securities Exchange Act of 1934, the most recent Annual Report to shareholders or Annual Report on Form 10-K as filed with the SEC containing audited financial reports and the most recent quarterly report on Form 10-Q as filed with the SEC for each such entity. If none of the foregoing applies, Participant shall supply either (a) copies of the most recent audited financial statements, including a certified independent accountant's report thereon, of the Participant, or, if applicable, for each person or entity identified in the paragraph 2 above for at least the three prior full fiscal years or, if shorter, the life of the relevant entity; or (b) a description of the business of each such person or entity and of the material matters relating to such business, including all matters that would be required to be disclosed if such entity were subject to the disclosure requirements of Items 3 and 7 of Form 10-K.
4. List the legal name of all owners of the project and their relative percentage ownership.

5. Entity providing Security on behalf of Participant. Describe all anticipated credit support arrangements and appropriate parental, subsidiary and partnership relationships pertinent to the Offer.
6. Address for each entity referred to in Item 5. above.
7. Current S&P and Moody's debt ratings of the Participant or its guarantor, if any
8. Bank Contact:  Name, Title, Address, Phone number.
9. Pending Legal Disputes (Describe).

**B. Financing Plan For Proposed Offer**

Provide a description of the project's financing plan during development and construction phases. The plan should include:

1. Amount, source and timing of equity financing.
2. Amount of debt financing.
3. Balance sheet versus limited recourse financing.
4. Willingness and ability to equity and/or balance sheet finance construction until financing is secured in order to ensure project schedule.
5. Outline of anticipated major terms and conditions of debt service:
    i. Term of Loan:  (years)
    ii. Interest Rate(s)  (%/year)
    iii. Other key terms and conditions
    iv. Amortization Schedule

**C. Financial Commitment**

1. Any commitment letters or letters of undertaking from project participants (including financial institutions) indicating that the project is able to obtain the construction and permanent financing it will require.  Describe any caveats and conditions to financing commitments such parties may require.
2. The qualifications of such parties to provide, arrange or assist in obtaining necessary financing and credit support arrangements.
3. The significant conditions on which the financing depends.
4. The milestones that need to be achieved to secure both construction and term financing.

**D. Prior Project Financing by Participant ($000)**

1. List the project name; date placed; who financed the project; the amount of debt, equity and total capital; and the major financial terms.

## E. Sources and Uses of Funds During Construction

1. Provide a Sources and Uses of Funds schedule through construction period similar to the following:.

Financial Pro forma Template - Construction Uses and Sources of Funds

**$000**

| **Uses of Funds** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
|---|---|---|---|---|---|---|
| **Capital Costs** | | | | | | |
| Development Costs | | | | | | |
| Land Purchase | - | - | - | - | - | - |
| Title Insurance | - | - | - | - | - | - |
| Project Management | - | - | - | - | - | - |
| Engineering Services | - | - | - | - | - | - |
| Construction Costs | | | | | | |
| Turbine Vendor Equipment | - | - | - | - | - | - |
| Balance of Plant Equipment | - | - | - | - | - | - |
| EPC Contract Cost | - | - | - | - | - | - |
| Emissions Equipment | - | - | - | - | - | - |
| Transmission & Gas Interconnection | - | - | - | - | - | - |
| Building and Structures | - | - | - | - | - | - |
| Equipment Sales Tax | - | - | - | - | - | - |
| Construction Permits & Licenses | - | - | - | - | - | - |
| Property Taxes During Construction | - | - | - | - | - | - |
| Emission Reduction Credit Cost | - | - | - | - | - | - |
| Site Preparation | - | - | - | - | - | - |
| Builders Risk & ALOP Insurance | - | - | - | - | - | - |
| Start-up Testing | | | | | | |
| Credit for sales of start-up test power | - | - | - | - | - | - |
| Start-up Fuel Cost | - | - | - | - | - | - |
| Initial Spare Parts | - | - | - | - | - | - |
| O&M Mobilization | - | - | - | - | - | - |
| Initial Debt Service Reserve Fund | - | - | - | - | - | - |
| Initial Working Capital | - | - | - | - | - | - |
| Contingency | - | - | - | - | - | - |
| Total Capital Costs | - | - | - | - | - | - |
| | | | | | | |
| **Financing Costs** | | | | | | |
| Construction Loan Closing Costs/Fees | - | - | - | - | - | - |
| Non-Recourse Loan Interest | - | - | - | - | - | - |
| Equity Bridge Loan Interest | - | - | - | - | - | - |
| Lenders Closing Costs | - | - | - | - | - | - |
| Construction Loan Commitment Fees | - | - | - | - | - | - |
| Working Capital Facility Commitment Fee Construction | - | - | - | - | - | - |
| Debt Service Reserve Commitment Fee | - | - | - | - | - | - |
| Term Loan Fees | - | - | - | - | - | - |
| Total Financing Costs | - | - | - | - | - | - |
| | | | | | | |
| **Total Project Costs** | - | - | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Sources of Funds** | | | | | | |
| Financing | | | | | | |
| Equity | - | - | - | - | - | - |
| Senior Debt | - | - | - | - | - | - |
| Other Sources | - | - | - | - | - | - |
| Total | - | - | - | - | - | - |

## F. Pro Forma Financial Projections

Provide a Pro Forma financial projection showing the project cash flow, income statement, and balance sheet, sources and uses of funds, construction draw schedule, and including all financing assumptions. At a minimum the pro forma should include the following

| | Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Generation Assumptions** | | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** |
| Guaranteed Electrical Output | Mw | - | - | - | - | - | - | - | - | - |
| Net Capacity Factor | % | - | - | - | - | - | - | - | - | - |
| Net Annual Generation | GWH | - | - | - | - | - | - | - | - | - |
| Major Scheduled Outages | Hours | - | - | - | - | - | - | - | - | - |
| **Revenues** | $000's | - | - | - | - | - | - | - | - | - |
| **O&M Expense** | | | | | | | | | | |
| Operating Costs | | | | | | | | | | |
| Operating Labor | $000's | - | - | - | - | - | - | - | - | - |
| Consumables | $000's | - | - | - | - | - | - | - | - | - |
| Utilities | $000's | - | - | - | - | - | - | - | - | - |
| Major Maintenance | | | | | | | | | | |
| Maintenance Labor | | | | | | | | | | |
| Maintenance - Inside | $000's | - | - | - | - | - | - | - | - | - |
| Maintenance - Contract (LTSA) | $000's | - | - | - | - | - | - | - | - | - |
| Spare Parts | $000's | - | - | - | - | - | - | - | - | - |
| Other | $000's | - | - | - | - | - | - | - | - | - |
| Total O&M | $000's | - | - | - | - | - | - | - | - | - |
| **General & Administration Expense** | | | | | | | | | | |
| Admin Salaries and Labor | $000's | - | - | - | - | - | - | - | - | - |
| Licenses and Permits | $000's | - | - | - | - | - | - | - | - | - |
| Property Lease / Land | $000's | - | - | - | - | - | - | - | - | - |
| Professional Services | $000's | - | - | - | - | - | - | - | - | - |
| Insurance | $000's | - | - | - | - | - | - | - | - | - |
| Taxes | $000's | - | - | - | - | - | - | - | - | - |
| Total G&A | $000's | - | - | - | - | - | - | - | - | - |
| **Total Operating Expenses** | $000's | - | - | - | - | - | - | - | - | - |
| **Financing** | | | | | | | | | | |
| Interest | $000's | - | - | - | - | - | - | - | - | - |
| Principal Repayment | $000's | - | - | - | - | - | - | - | - | - |
| **Debt Coverage Ratio*** | X.X:1 | - | - | - | - | - | - | - | - | - |
| **Incremental Capital Expenditures** | $000's | - | - | - | - | - | - | - | - | - |
| **Capitalization** | | | | | | | | | | |
| Construction Loan Balance | $000's | - | - | - | - | - | - | - | - | - |
| Term Loan Balance | $000's | - | - | - | - | - | - | - | - | - |
| Equity | $000's | - | - | - | - | - | - | - | - | - |

$$\text{*Debt Coverage Ratio} = \frac{\text{Operating Costs + Interest - Incremental Capital Expenditures}}{\text{Total Debt Service (principal + interest)}}$$

**Financial Pro forma Template - Capital Structure**

**Initial Capital Structure**

| Construction Financing ($ in thousands): | | % of Total | $ 000 |
|---|---|---|---|
| | Debt (list all debt) | - | - |
| | Equity | - | - |
| Total Project Cost | | - | - |

| Permanent Financing ($ in thousands): | | | |
|---|---|---|---|
| | Debt (list all debt) | - | - |
| | Equity | - | - |
| Total Project Cost | | - | - |

## Appendix H: Electric Transmission Information Sheet and Web Links

Participants should supply the following information to allow PG&E to assess the transmission impact.

**A.** For new generators, **with** a current and completed SIS/FS PG&E will extract the interconnection and generator data from the System Impact Study/Facility Study (SIS/FS). The interconnection and generator data required for SIS/FS can be found in Appendices M and N of the PG&E Interconnection Handbook (there is a web link below to this document).

**B**. For new generators **that do not have** a current and completed SIS/FS, please provide the following additional information, in the sequence requested:

1. Project Name

2. Please state who will perform your SIS and FS study.

3. Proposed interconnection point (substation or transmission line with voltage level)

4. List the approximate distance from the project to the electric interconnection point.

5. Please identify your queue position on the attached queue. If not listed on the attached CAISO Queue, please identify the following the queue information (name of queue management organization, position on queue as of April 18, 2005. Please also provide size, location and substation as listed on that queue.

6. Describe current land usage of the property required for the proposed project interconnection including any environmental concerns.

7. Does the project require use of any new or existing rights-of-way? If so, who will obtain these rights for the transmission interconnection, and have these rights been obtained.

8. Generator Characteristics

    a. Number of generators in project and rated output and net output (MW) of each;

    b. Interconnection voltage

    c. Other relevant characteristics (Please specify)

9. Specify the proxy bus that will be used to determine the proxy costs for the project

a. If the substation chosen from the transmission proxy cost report is not the nearest proxy bus from a geographical perspective, please explain why this is the appropriate proxy bus.

**C. For existing generators** (QFs only), please provide the following information, in sequence requested:

a. Project Name

b. Interconnection Point (name and address) with existing PG&E grid

c. If the generator is currently interconnected with the transmission grid, please provide the applicable power generation agreement, power purchase agreement and/or interconnection agreement with PG&E.

d. Generator Characteristics
   i. Number of generators in the project and the rated output and the net output (MW) of each;
   ii. Interconnection voltage
   iii. Other relevant characteristics (*Please specify)*

### D. Generation Interconnection Web Links and References

**NERC**

**NERC Planning Standards and Operating Policies**
http://www.nerc.com/standards/

**WECC**

**WECC Reliability Criteria**
http://www.wecc.biz/committees/PCC/RS/documents/WECC_Reliability_Criteria_1203.pdf

**WECC Web page on information for Generators**
http://www.wecc.biz/docs_pubs.html

**WECC Progress Report Policies And Procedures**
http://www.wecc.biz/documents/policy/Progress_Report_Procedures_2002.pdf

**Recently approved WECC Standards and Policies**

WECC MORC Section 1.C.1 Frequency Bias
http://www.wecc.biz/documents/standards/recently_approved/Comments_MORC_Section_1.C._clean.pdf

WECC Power System Stabilizer Design and Performance Criteria
http://www.wecc.biz/documents/standards/recently_approved/WECC_PSS_Design_and_Perf_Criteria%202-2-04_clean.pdf

WECC Power System Stabilizer Design and Performance Criteria
http://www.wecc.biz/documents/standards/recently_approved/WECC_PSS_Design_and_Perf_Criteria%202-2-04_clean.pdf

**CAISO**

**Web Page on CAISO New Generator Interconnection**
http://www2.caiso.com/docs/2002/06/11/2002061110300427214.html

**Web page for CAISO Grid Planning Standards (Applicable Planning Criteria)**
http://www1.caiso.com/docs/2001/06/04/2001060418221123496.html

**CAISO Grid Coordinated Planning Process**
http://www1.caiso.com/docs/2001/06/11/2001061116583410598.pdf

**PG&E**

**PG&E Generation Interconnection Handbook**
http://www.pge.com/biz/transmission_services/contracts_tariffs/interconnection_handbook_toc.html

**PG&E – Wholesale generator Interconnections**
http://www.pge.com/suppliers_purchasing/new_generator/wholesale_generators/index.html **E. Generation Interconnection Information and References**

**CAISO Interconnection Application Queue**

In June of 2002, FERC approved Amendment 39 to the ISO tariff which transfers the responsibility for queuing new Generators Interconnection Applications from the Participating Transmission Owners to the California ISO. Here is the current status of the ISO queue:

| Queue Pos. | Applicant Name | Project Name | Nearest Substation | Capacity (MW) | Yr. Ops. To Begin | Status |
|---|---|---|---|---|---|---|
| 1 | CONFIDENTIAL | CONFIDENTIAL | SCE Mountain Pass Substation | 63 | 2004 | Active |
| 2 | CONFIDENTIAL | CONFIDENTIAL | High Winds/Contra Costa PP | 150 | 2005 | Active |
| 3 | San Diego County Water Authority | Olivenhain-Hodges Pumped Storage | Escondido | 40 | 2007 | Active |
| 4 | Calpine | Otay Mesa | Miguel-Tijuana *615 -total capacity, 550 MW in SDGE queue | 615 | 2004 | Active |
| 5 | CONFIDENTIAL | CONFIDENTIAL | Mountain Pass | 50 | 2004 | Active |
| 6 | Gaviota Energy/Global Renewable | Lompoc Wind Power Project | Cabrillo | 120 | 2006 | Active |
| 7 | CONFIDENTIAL | CONFIDENTIAL | Devers | 560 | 2006 | Active |
| 8 | CONFIDENTIAL | CONFIDENTIAL | Antelope | 200 | 2005 | Active |
| 9 | Eurus Energy | Eurus Oasis Project | West Wind - Vincent | 65 | 2004 | Active |
| 10 | Kings River Conservation District | KRCD Malaga Peaking Plant | Malaga | 97 | 2004 | Active |
| 11 | CONFIDENTIAL | CONFIDENTIAL | Crestwood | 46 | 2005 | Active |
| 12 | CONFIDENTIAL | CONFIDENTIAL | Antelope | 300 | 2006 | Active |
| 13 | FPL Energy, LLC | High Winds III | Birds Landing Switching Station | 38 | 2005 | Active |
| 14 | Mountainview Power Co. LLC | Mountainview Power Project | San Bernadino * 72 Additional MW | 72 | 2004 | Active |
| 15 | CONFIDENTIAL | CONFIDENTIAL | High Winds/Contra Costa PP | 150 | 2006 | Active |
| 16 | CONFIDENTIAL | CONFIDENTIAL | Crestwood | 117 | 2005 | Active |

| | | | | | | |
|---|---|---|---|---|---|---|
| 17 | CONFIDENTIAL | CONFIDENTIAL | Warner | 64.5 | 2006 | Active |
| 18 | CONFIDENTIAL | CONFIDENTIAL | Crestwood | 36 | 2006 | Active |
| 19 | Duke Energy South Bay, LLC | South Bay Replacement - Option 1 | 138/69 kV South Bay (650 MW CC) | 650 | 2010 | Active |
| 20 | Duke Energy South Bay, LLC. | South Bay Replacement - Option 2 | 138/69 kV South Bay (640 MW CT-SC) | 640 | 2010 | Active |
| 21 | City and County of San Francisco | S. F. Electric Reliability Generating Plant | Potrero 115 kV Sub | 145.1 | 2006 | Active |
| 22 | CONFIDENTIAL | CONFIDENTIAL | Collector Substation at Geysers #17 & Fulton 230 kV line | 201 | 2006 | Active |
| 23 | City and County of San Francisco | San Francisco Airport Electric Reliability Plant | SF Airport Substation | 48.7 | 2006 | Active |
| 24 | CONFIDENTIAL | CONFIDENTIAL | Monolith Substation | 201 | 2007 | Active |
| 25 | CONFIDENTIAL | CONFIDENTIAL | Boulevard - Crestwood 69-kV transmission line | 201 | 2008 | Active |
| 26 | Caithness Dixie Valley, LLC | Caithness Dixie Valley, LLC | Bishop Control Sub | 10 | 1988 | Active |
| 27 | CONFIDENTIAL | CONFIDENTIAL | Monolith Substation | 300 | 2007 | Active |
| 28 | CONFIDENTIAL | CONFIDENTIAL | Miramar GT Substation | 48.5 | 2005 | Active |
| 29 | Envirepel | Envirepel | TL698 69 kV SDG&E Line | 70 | 2006 | Active |
| 30 | NRG Energy Center San Francisco LLC | San Francisco Cogeneration | Mission Sub @ 8th & Mission or Embarcadero Sub @ 1st & Flsm | 13.76 | 2006 | Active |
| 31 | CONFIDENTIAL | CONFIDENTIAL | PG&E 115 KV Panoche Sub | 99.9 | 2006 | Active |
| 32 | CONFIDENTIAL | CONFIDENTIAL | PG&E's 115 kV Tesla - Stockton Cogen Trans. | 99.9 | 2006 | Active |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | Line. | | | |
| 33 | D. Milne Associated, LLC | Ripon Generation | PG&E Tesla Substation | 96.9 | 2007 | Active |
| 34 | Duke Energy North America, LLC | Duke Energy Oakland, LLC Option 1 | Oakland "C" 115 kV Stubstation | 320 | 2009 | Active |
| 35 | Duke Energy North America, LLC | Duke Energy Oakland, LLC Option 2 | Oakland "C: 115kV Stubstation | 315 | 2009 | Active |
| 36 | CONFIDENTIAL | CONFIDENTIAL | Humboldt Power Plant Substation | 146.4 | 2008 | Active |
| 37 | CONFIDENTIAL | CONFIDENTIAL | Proposed Birds Landing Switching Station | 200 | 2008 | Active |
| 38 | CONFIDENTIAL | CONFIDENTIAL | Eastshore Substation | 118 | 2007 | Active |
| 39 | CONFIDENTIAL | CONFIDENTIAL | Pease Sub Station | 99.9 | 2007 | Active |
| 40 | Pastoria Energy Center LLC | Pastoria Expansion | Pastoria | 158.8 | 2006 | Active |
| 41 | CONFIDENTIAL | CONFIDENTIAL | PG&E's McCall Substation | 300 | 2007 | Active |
| 42 | CONFIDENTIAL | CONFIDENTIAL | PG&E Borden Substation 230 kV Bus | 126.5 | 2008 | Active |
| 43 | CONFIDENTIAL | CONFIDENTIAL | PG&E Tesla-Bellota 230 kV line | 168.7 | 2008 | Active |
| 44 | Three Mountain Power, LLC | Three Mountain Power Project | PG&E Pit1-Pit 3 & Pit 1-Cottonwood 230kV | 295 | 2007 | Active |
| 45 | CONFIDENTIAL | CONFIDENTIAL | FMC Sub Station | 300 | 2007 | Active |
| 46 | Calpine | Russell City Energy Center | Eastshore substation | 361 | 2006 | Active |
| 47 | Calpine | Wolfskill II | Vaca-Dixon - Suisun 115 kV line | 50 | 2007 | Active |
| 48 | Calpine | East Altamont Energy Center - Option 1 | Tracy (WAPA) | 806 | 2008 | Active |
| 49 | Calpine | East Altamont | Tesla-Tracy #1 | 541 | 2006 | Active |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | Energy Center - Option 2 | 230 kV Line - Tracy Sub | | | |
| 50 | CONFIDENTIAL | CONFIDENTIAL | Evergreen-San Jose "B" 115 kV line | 94.5 | 2008 | Active |
| 51 | CONFIDENTIAL | CONFIDENTIAL | Herndon - Kearney 230 kV line | 200.6 | 2008 | Active |
| 52 | CONFIDENTIAL | CONFIDENTIAL | Contra Costa Power Plant 230 kV Substation | 590 | 2009 | Active |
| 53 | Cal Peak Power, LLC | Vaca-Dixon | Vaca-Dixon Sub | 52 | 2008 | Active |
| 54 | CONFIDENTIAL | CONFIDENTIAL | Devers Substation | 100.5 | 2006 | Active |
| 55 | Fresno Cogeneration Partners, LP | Fresno Cogen ICE Unit | 70 kV Kerman-Helm transmission line | .55 | 2005 | Active |
| 56 | Calpine Corporation | Inland Empire Energy Center | SCE Valley Substation | 810 | 2008 | Active |
| 57 | Cummins West, Inc. | Willits Power Plant | Adjacent to Mendocino-Ft. Bragg-Willits 60kV lines | 32 | 2007 | Active |
| 58 | Cummins West, Inc. | West Sacramento Peaker | 115kV Rio Oso-West Sac | 49 | 2007 | Active |
| 59 | CONFIDENTIAL | CONFIDENTIAL | Panoche Sub Station | 428 | 2008 | Active |
| 60 | CONFIDENTIAL | CONFIDENTIAL | Pleasant Grove Sub Station | 116.8 | 2008 | Active |
| 61 | Cal Peak Power, LLC. | Lodi | City of Lodi Sub | 104 | 2008 | Active |
| 62 | Northwest Energy Systems Co. | Oroville Energy II, LLC | Palermo-Oroville #2 60 kV | 65 | 2008 | Active |
| 63 | CONFIDENTIAL | CONFIDENTIAL | Round Mountain-Cottonwood 230kV transmission line | 99.4 | 2008 | Active |
| 64 | CONFIDENTIAL | CONFIDENTIAL | Glenn-Vaca-Dixon 230 kV transmission line | 99.4 | 2008 | Active |
| 65 | CONFIDENTIAL | CONFIDENTIAL | Logan Creek - | 99.4 | 2008 | Active |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | Vaca-Dixon 230 kV transmission line | | | |
| 66 | Ramco Generating Two | West Fresno Energy Facility | PG&E West Fresno Substation | 118 | 2007 | Active |
| 67 | CONFIDENTIAL | CONFIDENTIAL | Malaga-McCall 115 kV | 116 | 2008 | Active |
| 68 | CONFIDENTIAL | CONFIDENTIAL | Los Banos Substation | 165 | 2008 | Active |
| 69 | CalPeak Power, LLC | Panoche | PG&E Panoche Sub | 104 | 2008 | Active |
| 70 | CONFIDENTIAL | CONFIDENTIAL | PG&E California Ave tap into West Fresno-McCall 115 kV t lin | 99.9 | 2006 | Active |
| 71 | Calpine | San Joaquin Valley Energy Center - Option 1 | PG&E Helm substation | 791 | 2008 | Active |
| 72 | Calpine | Calpine Pittsburg Power Plant - Unit 1 | Pittsburg Swichyard | 83.7 | 2007 | Active |
| 73 | Sempra Energy Resources | Copper Mountain Project | SEC El Dorado Switchyard (230 kV) | 581 | 2007 | Active |
| 74 | E & L Westcoast, LLC | CPV Colusa | Between Cottonwood and Vaca-Dixon | 715 | 2010 | Active |
| 75 | CONFIDENTIAL | CONFIDENTIAL | Bishop-Control Substation | 62 | 2007 | Active |
| 76 | Wellhead Power Panoche, LLC | Wellhead Power Panoche ICE | Panoche Sub | .35 | 2005 | Active |
| 77 | Wellhead Power GAtes, LLC | Wellhead Power Gates ICE | Gates Sub | .35 | 2005 | Active |

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Last Update: March 18, 2005 1:58 A.M.

## Appendix I: Gas Interconnection Information Sheet

Participants should supply the following information, in the sequence requested:

1. Plant Name:

2. Plant Location:

3. Meter Set Location (if not at plant):

4. Projected Gas Load:
    a. Annual load
    b. Peak hourly use profile for each season of operation

5. Gas Service Tap Location off Transmission Pipeline:

6. Name of Transmission Pipeline Tapped for Gas Service:

7. Length of Gas Service Pipeline:

8. Reinforcement Required to Existing Gas Transmission System:

9. Diameter of Gas Service Pipeline:
    a. Standard Facilities Design
    b. Special Facilities Design

10. Minimum and Maximum Gas Service Pressure Upstream of Meter Set:
    a. Standard Facilities Design
    b. Special Facilities Design

11. Participant’s Cost of Gas Service Pipeline and Meter Set:
    a. Standard Facilities Design
    b. Special Facilities Design

12. If taking gas from PG&E, under which Transportation/Distribution Tariff will the project be receiving gas?

13. If not connected to PG&E, provide the name of the company providing gas service:

14. If not connected to PG&E, provide a copy of the relevant Transportation/Distribution Tariff:

**Gas System Operations - Transmission System Planning**
Interconnection Information Sheet

Application Date: ________________ Natural Gas Service Start Date: ________________

Applicant Name: ______________________________

Project Name: ______________________________

Project Location: ______________________________
*(County, City, Street Number - Attach Project Vicinity Map)*
______________________________

***A. Existing host thermal load gas service data:***

1. Customer Name: ______________________________

2. Customer Meter Number(s): ______________________________

3. **Winter Season Load (Nov 1 - Mar 31)**

| | Curtailable | | Non-curtailable |
|---|---|---|---|
| Total Peak Demand (MMbtu/h): | ________ | | ________ |
| Total Average Demand (MMbtu/h): | ________ | | ________ |
| Days / Hours of Operation: | ________ | / | ________ |

4. **Summer Season Load (April 1- Oct 31)**

| | Curtailable | | Non-curtailable |
|---|---|---|---|
| Total Peak Demand (MMbtu/h): | ________ | | ________ |
| Total Average Demand (MMbtu/h): | ________ | | ________ |
| Days / Hours of Operation: | ________ | / | ________ |

5. Name plate rating of all existing gas fired equipment:

| Device / Function | Rating (MMbtu/h) |
|---|---|
| ______________________________ | ________ |
| ______________________________ | ________ |
| ______________________________ | ________ |

6. What equipment will remain after the cogen plant is operational and how will it be used?

________________________________________

7. What existing equipment will operate coincident with the cogen plant gas turbine ?

________________________________________

8. What existing equipment will operate coincident with the cogen plant auxiliary boilers?

***B. Proposed gas service data for cogeneration / power plant:***

1. Service Requirements for all proposed gas fired equipment:

| Device / Function | Service Pressure (psig) | Rating (MMbtu/h) |
| --- | --- | --- |
| | | |
| | | |
| | | |
| | | |

2. When will the auxiliary boiler(s) and/or duct burner(s) operate and at what load?

________________________________________

________________________________________

________________________________________

3. **Winter Season Load Profile (Nov 1 - Mar 31)**
*(attach hourly gas load / electric generation profiles)*

| | MMbtu/h | Time of Day |
| --- | --- | --- |
| Total Plant Peak Demand: | | |
| Total Plant Off-Peak Demand (MMbtu/h): | | |
| Days per week / Hours per day of operation: | | / |

4. **Summer Season Load Profile (April 1- Oct 31)**
*(attach hourly gas load / electric generation profiles)*

| | MMbtu/h | Time of Day |
| --- | --- | --- |
| Total Plant Peak Demand: | | |
| Total Plant Off-Peak Demand (MMbtu/h): | | |
| Days per week / Hours per day of operation: | | / |

5. Other service requirements PG&E should be aware of, such as absolute minimum pressure requirements, right-of-way issues, CEC requirements and schedule, project schedule, etc.…

____________________________________________________________

____________________________________________________________

6. Expected total gas load for first year of gas service (MMbtu):

____________________________________

________________________________________

(Type Name)

________________________________________

(Signature)

________________________________________

(Title) (Date)

PG&E
Pacific Gas and Electric Company

**Agreement to Perform**
**Tariff Scheduled Related Work**

| DISTRIBUTION: | REFERENCE: |
|---|---|
| o APPLICANT (Original) | Preliminary Application |
| o DIVISION (Original) | GSO - CGT - PG&E |
| o ACCTG. SVCS. | |

(Bidder Name)________________, (Applicant) has requested **PACIFIC GAS AND ELECTRIC COMPANY**, a California corporation (PG&E), to perform the tariff schedule related work as located and described in paragraph 3 herein.

PG&E agrees to perform the requested work and furnish all necessary labor, equipment, materials and related facilities required therefor, subject to the following conditions:

1. Whenever part or all of the requested work is to be furnished or performed upon property other than that of Applicant, Applicant shall first procure from such owners all necessary rights-of-way and/or permits in a form satisfactory to PG&E and without cost to it.

2. Applicant shall indemnify and hold harmless PG&E, its officers, agents and employees, against all loss, damage, expense and liability resulting from injury to or death of any person, including but not limited to, employees of PG&E, Applicant or any third party, or for the loss, destruction or damage to property, including, but not limited to property of PG&E, Applicant or any third party, arising out of or in any way connected with the performance of this agreement, however caused, except to the extent caused by the active negligence or willful misconduct of PG&E, its officers, agents and employees. Applicant will, on PG&E's request, defend any suit asserting a claim covered by this indemnity. Applicant will pay all costs that may be incurred by PG&E in enforcing this indemnity, including reasonable attorneys' fees.

3. The location and requested work are described as follows: (Describe in detail the materials and facilities to be furnished and/or work to be performed by PG&E. If more space is required, use other side and attach any necessary drawings as Exhibits A, B, C, etc):

   LOCATION: (Facility Address)
   DESCRIPTION OF WORK: Initiate preliminary engineering for proposed gas pipeline and meter set to serve the (Facility Name)________________. PG&E will initiate engineering to identify:
   - o PG&E's preferred pipeline service route and alternative routes;
   - o Pipeline and meter set size for Standard and Special Facilities design;
   - o Expected minimum delivery pressure available at the meter set for PG&E's preferred route;
   - o Order of magnitude cost for PG&E's recommended Standard and Special Facilities;
   - o Map showing PG&E's preferred transmission service tap and meter set location;
   - o Costs, if any, to proceed with further engineering.

4. Applicant shall pay to PG&E, promptly upon demand by PG&E, as the complete contract price hereunder, the sum of Ten Thousand Dollars ________ dollars ($ 10,000.00 ________).

   Upon completion of requested work, ownership shall vest in: ☑ PG&E ☐ Applicant

Executed this ________ day of ____________ 20

| | |
|---|---|
| ________________ | PACIFIC GAS & ELECTRIC COMPANY |
| Applicant | |
| By: ________________ | By: ________________ |
| ________________ | Wayman Pon |
| (Print/Type/Name) | (Print/Type Name) |
| Title: ________________ | Title: Director, Gas Service Operations |
| Mailing Address: | |

Automated Document, Preliminary Statement, Part A

62-4527 (Rev 1/91)
Service Planning
Advice No. 1633-G/1342-E
Effective 4/02/91

## Appendix J: Functional Specifications for the Humboldt Bay Power Plant

**Humboldt Bay Power Plant ("HBPP") Replacement Generation**

Offers to replace HPBB generation must include the following functional specifications

- Total Peak Capacity of at least 135 MW.

- Multiple independent generation units such that any single common mode failure would be no greater than 50 megawatts.

- Fast Start/Ramp Capability (i.e. must be capable of picking up at least 40 MW in three minutes.) Units shall be capable of operating at partial loads and remain in compliance with all emission requirements over all operating loads. Due to likely significant operation at partial load, proposals shall provide an estimate of partial load range capability and heat rates over the available load range for individual units, and will be evaluated for the both the ability to operate at part loads and cost of doing so.

- Load following capability (i.e. ability to operate under governor control and maintain system voltage and frequency if the local area is separated from the rest of the PG&E grid.)

- Dual fuel capability with approximately four days backup fuel storage on site. (Overall oil/fuel inventory on-site shall not exceed Oil Spill Prevention Act of 1990 (OPA-90) maximum volumes.) Generating units must be capable of switching between natural gas primary fuel and 100% liquid fuel while remaining synchronized to the grid and be capable of returning to full load within 15 minutes of initiating the full switch.

- Black Start capability in accordance with Cal ISO "Ancillary Services Requirements Protocols".

- Existing generation at HBPP must continue to be available to operate during construction, startup and acceptance testing of new generation projects.

# Appendix K:  Offer Cover Sheet

## 2004 Long Term RFO
**OFFER COVER SHEET**

**Participant Legal Name:** ___________________________________________

**Name of Project:** _________________________________________________

**Participant Ultimate Corp. Parent(s) (if any):** ______________________________________

**Facility Location:** ___________________________________

**County:** ___________________________________________

**Generating Technology:** ____________________________
(Combined Cycle, Combustion Turbine, Reciprocating Engine, etc.)

**Variations Submitted Under this Offer Deposit:**
(Check all that apply)

**Power Purchase Variation A** ______

**Power Purchase Variation B** ______

**Power Purchase Variation C** ______

**Facility Ownership** ______

**DESCRIPTIVE OFFER DATA**

**Megawatts (MW)** **(ISO Conditions)** _________

**Offer Deposit at $5 per kW:** $_____________

**Is the Project an Eligible Qualifying Facility? Yes:** _____

**No:** _____

**Will Project Be an Eligible Qualifying Facility? Yes:** _____

**No:** _____

**Initial Delivery Date for Power Purchase:** ______________

**Guaranteed Commercial Availability Date for Facility Ownership:** ______________

**Length of Contract Term For Power Purchase:**

Variation A: __________

Variation B: __________

Variation C: __________

**For Facility Ownership Purchase Price:** $______________

**Primary Contact for Participant RFO:**

Name: ______________________________________

Phone: __________________________

E-mail: ___________________________

**Alternate Contact:**

Name: ______________________________________

Phone: __________________________

E-mail: ___________________________

**Technical Area: Air Quality**

**WKS-4**: The CEC does not wish to review the applicant's partial cumulative analysis including only Eastshore and RCEC. Please provide the complete cumulative air quality impact analysis requested under data request 17 after a complete inventory of cumulative sources has been obtained from the BAAQMD to allow the full analysis.

**Response:**

This evaluation was completed to determine whether there is a potential for significant cumulative impacts from combined Eastshore Energy Center (Eastshore) emissions and other facilities in the project area. A dispersion modeling analysis of potential cumulative air quality impacts were performed for $SO_2$, CO, $NO_x$, $PM_{10}$, and $PM_{2.5}$. A cumulative multisource modeling analysis was performed for the proposed Eastshore emission sources combined with emissions for the Russell City Energy Center (RCEC), another energy project proposed in the immediate vicinity of the Eastshore facility, and an inventory provided by BAAQMD of emission sources in the project vicinity that have not yet begun operation.

The proposed Eastshore facility was modeled in conjunction with the impacts of existing facilities and facilities not yet in operation but that are reasonably foreseeable. The BAAQMD provided an inventory of these types of sources (other than Eastshore and RCEC) within 6 miles of the proposed project site. Since the impacts of projects that exist and have been in operation are already reflected in the ambient air quality data establishing representative background air quality levels; no dispersion modeling of emissions from this category of facilities was performed. The cumulative multisource modeling analysis added the modeled impacts of unconstructed but reasonable foreseeable facilities in the project area to the maximum measured background air quality levels, thus ensuring that existing and proposed projects are taken into account.

**Cumulative Impacts Dispersion Modeling Input Data**

Given the potentially wide geographic area over which the dispersion modeling analysis may be performed, the ISCST3 model was used for the cumulative impacts analysis for all pollutants other than the 1-hour nitrogen dioxide ($NO_2$) concentrations. For 1-hour $NO_2$ concentrations, impacts were evaluated with the ISCOLM model (an enhanced version of ISCST3 incorporating short-term $NO_2$ conversion limitations reflected by ambient ozone levels) as was done for the facility only analyses. The detailed modeling procedures, model options, and meteorological data used in the cumulative impacts dispersion analysis were the same as those used for the proposed facility as described in the AFC Air Quality section. In addition to the receptor grids used in the original Eastshore modeling analysis, the 10-meter spaced downwash and fenceline receptor grids from the RCEC modeling analysis were included. Since 1-hour CO and 1-hour $SO_2$ maximum multisource impacts were predicted to occur in the 180-meter spaced coarse grids, additional 10-meter spaced refined receptor grids were modeled for these pollutants and averaging times.

Cumulative impacts predicted by the dispersion modeling analysis were added to background air quality levels attributable to existing emission sources and compared to state and federal air quality standards to determine significance. The maximum modeled concentrations were used in the comparison with California ambient air quality standards (CAAQS) and Federal (USEPA) National ambient air quality standards (NAAQS).

Supporting information used in the analysis included the following:

- Each source's respective coordinate locations;
- Stack parameters for sources included in the cumulative air quality impacts dispersion modeling analysis; and
- Output files for the dispersion modeling analysis.

For Eastshore and RCEC, stack locations and building dimensions used for downwash considerations were the same as the facility modeling analyses for each project. Worst-case source identified in the screening analyses for both Eastshore and RCEC were used to define stack conditions analyzed. For CO, worst-case impacts were shown in the RCEC modeling analyses to occur for RCEC start-up conditions (RCEC fire pump assumed not to run concurrently). The stack parameters and emission rates modeled for each averaging period are shown below:

TABLE WKS 4-1
Stack Parameters and Emission Rates for Eastshore Facility**

| | Stack Height (m) | Stack Diam (m) | Stack Temp (deg K) | Exhaust Velocity (m/s) | Emission Rates (g/s) for each Engine and Diesel Emer. Generator | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | $NO_X$ | $SO_2$ | CO | $PM_{10}/PM_{2.5}$ |
| **Averaging Period: 1-hour** | | | | | | | | |
| Engines | 21.336 | 1.208 | 628.71 | 22.42 | 1.2424 | 0.03024 | 1.8698 | N/A |
| Black Start Diesel Engine | 10.0 | 0.1778 | 735.37 | 41.02 | 0.226 | 4.79E-4 | 0.0270 | N/A |
| **Averaging Period: 3-hours** | | | | | | | | |
| Engines | 21.336 | 1.208 | 628.71 | 22.42 | N/A | 0.03024 | N/A | N/A |
| Black Start Diesel Engine | 10.0 | 0.1778 | 735.37 | 41.02 | N/A | 1.60E-4 | N/A | N/A |
| **Averaging Period: 8-hours** | | | | | | | | |
| Engines | 21.336 | 1.208 | 628.71 | 22.42 | N/A | N/A | 1.8698 | N/A |
| Black Start Diesel Engine | 10.0 | 0.1778 | 735.37 | 41.02 | N/A | N/A | 3.38E-3 | N/A |
| **Averaging Period: 24 hours** | | | | | | | | |
| Engines | 21.336 | 1.208 | 628.71 | 22.42 | N/A | 0.03024 | N/A | 0.284655 |
| Black Start Diesel Engine | 10.0 | 0.1778 | 735.37 | 41.02 | N/A | 2.0E-5 | N/A | 5.60E-4 |
| **Averaging Period: Annual** | | | | | | | | |

TABLE WKS 4-1
Stack Parameters and Emission Rates for Eastshore Facility**

| | Stack Height (m) | Stack Diam (m) | Stack Temp (deg K) | Exhaust Velocity (m/s) | Emission Rates (g/s) for each Engine and Diesel Emer. Generator | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | $NO_X$ | $SO_2$ | CO | $PM_{10}/PM_{2.5}$ |
| Engines | 21.336 | 1.208 | 641.48 | 22.27 | 0.11535 | 1.395E-2 | N/A | 0.1474 |
| Black Start Diesel Engine | 10.0 | 0.1778 | 735.37 | 41.02 | 7.728E-4 | 1.640E-6 | N/A | 4.596E-5 |

**All averaging periods include worst-case operating assumptions; for lean burn engines, also includes start-up emissions, where applicable.

TABLE WKS 4-2
Stack Parameters and Emission Rates for RCEC Facility*

| | Stack Height (meter) | Stack Diam. (meter) | Stack Temp (deg K) | Exhaust Velocity (m/s) | Emission Rates (g/s) for each turbine/HRSG and cooling tower cell | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | $NO_x$ | $SO_2$ | CO | $PM_{10}/PM_{2.5}$ |
| **Averaging Period: 1-hour** | | | | | | | | |
| Turbines/HRSGs | 44.196 | 5.4864 | 355.39 | 22.175 | 2.0379 | 0.7812 | 169.946 | N/A |
| Fire Pump Diesel Engine | 4.572 | 0.1524 | 665.37 | 53.340 | 0.3558 | 3.942E-4 | N/A | N/A |
| **Averaging Period: 3-hours** | | | | | | | | |
| Turbines/HRSGs | 44.196 | 5.4864 | 355.39 | 22.175 | N/A | 0.7812 | N/A | N/A |
| Fire Pump Diesel Engine | 4.572 | 0.1524 | 665.37 | 53.340 | N/A | 1.314E-4 | N/A | N/A |
| **Averaging Period: 8-hours** | | | | | | | | |
| Turbines/HRSGs | 44.196 | 5.4864 | 355.39 | 22.175 | N/A | N/A | 80.2353 | N/A |
| **Averaging Period: 24 hours** | | | | | | | | |
| Turbines/HRSGs | 44.196 | 5.4864 | 350.68 | 14.075 | N/A | 0.4284 | N/A | 1.1340 |
| Fire Pump Diesel Engine | 4.572 | 0.1524 | 665.37 | 53.340 | N/A | 1.640E-5 | N/A | 4.167E-4 |
| Cooling Tower | 18.288 | 9.7536 | 298.17 | 10.308 | N/A | N/A | N/A | 0.0396 |
| **Averaging Period: Annual** | | | | | | | | |
| Turbines/HRSGs | 44.196 | 5.4864 | 356.83 | 21.655 | 1.9350 | 0.1755 | N/A | 1.0742 |
| Fire Pump Diesel Engine | 4.572 | 0.1524 | 665.37 | 53.340 | 2.112E-3 | 2.339E-6 | N/A | 5.936E-5 |
| Cooling Tower | 18.288 | 9.7536 | 300.27 | 10.308 | N/A | N/A | N/A | 0.0387 |

* Annual averaging periods include startup/shutdown emissions, where applicable.
deg K = degree Kelvin, g/s = grams per second, m/s = meters per second

The BAAQMD provided an emissions inventory of sources located within six (6) miles of Eastshore that were not yet in operation, but reasonably foreseeable. These additional sources, listed below, were included in the cumulative impact modeling assessment.

TABLE WKS 4-3

Modeled Stack Parameters for Proposed Sources Within 6 Miles of Eastshore (provided by BAAQMD)*

| Facility#-Source | Stack Height (meter) | Stack Diam. (meter) | Stack Temp (deg K) | Exhaust Velocity (m/s) | Stack Coordinates (meters)–NAD27 | | |
|---|---|---|---|---|---|---|---|
| | | | | | X | Y | Z** |
| #00698-Georgia Pacific Gypsum Emer. Gen | 2.134 | 0.500 | 750.37 | 46.94 | 572807 | 4173361 | 7.8 |
| #16440-Hayward Public Works Emer. Gen*** | 5.486 | 0.500 | 763.71 | 46.94 | 579654 | 4163912 | 3.1 |
| #16451- Hayward Public Works Emer. Gen | 2.591 | 0.250 | 740.37 | 56.29 | 575910 | 4168060 | 2.4 |
| #17037-Elder Care Alliance Emer. Gen | 2.286 | 0.333 | 844.26 | 49.63 | 585526 | 4160731 | 12.2 |
| #17548-Alameda County Nat. Gas Boiler**** | 6.096 | 1.674 | 422.04 | 4.96 | 577886 | 4174623 | 129.9 |
| #17553-Rohm & Haas Pyrolysis Furnace | 7.925 | 1.167 | 1033.15 | 6.42 | 577238 | 4165215 | 3.4 |
| #17553-Rohm & Haas Reg. Thermal Oxidizer | 9.144 | 2.498 | 377.59 | 4.15 | 577238 | 4165215 | 3.4 |
| #17621-Skywest Emer. Gen | 11.582 | 1.333 | 733.15 | 47.03 | 578142 | 4168365 | 11.6 |
| #18189-Astra Zeneca Emer. Gen | 2.134 | 0.500 | 710.37 | 27.19 | 577689 | 4166266 | 7.8 |

*Those facilities with emissions of pollutants other than VOC only.

**Source elevations taken from nearest point in USGS DEM datafiles with 10-meter spacing.

***Exit velocity conservatively revised to match previous similar source (BAAQMD velocity too high).

****Facility emissions given for three sources (two identical boilers and one emer. gen). All emissions modeled from one of the two boilers. Stack flowrate and temperature revised to reflect available information for similar sized boilers (BAAQMD values were unrealistic).

TABLE WKS 4-4

Modeled Emissions for Proposed Sources Within 6 Miles of Eastshore (provided by BAAQMD)

| Facility#-Source | Emission Rates (g/s) | | | |
|---|---|---|---|---|
| | $NO_x$ | $SO_2$ | CO | $PM_{10}/PM_{2.5}$ |
| #00698-Georgia Pacific Gypsum Emer. Gen | 0.001927 | 0.000086 | 0.000777 | 0.000058 |
| #16440-Hayward Public Works Emer. Gen | 0.001093 | 0.000058 | 0.000173 | 0.000029 |
| #16451- Hayward Public Works Emer. Gen | 0.000748 | 0.000029 | 0.000058 | 0.000029 |
| #17037-Elder Care Alliance Emer. Gen | 0.001093 | 0.000058 | 0.000173 | 0.000029 |
| #17548-Alameda County Nat. Gas Boiler | 0.080001 | 0.001985 | 0.158421 | 0.010701 |
| #17553-Rohm & Haas Pyrolysis Furnace | 0.004603 | 0.000288 | 0.008371 | 0.002273 |
| #17553-Rohm & Haas Reg. Thermal Oxidizer | 0.041137 | 0.000086 | 0.003279 | N/A |
| #17621-Skywest Emer. Gen | 0.019878 | 0.000633 | 0.002359 | 0.000403 |
| #18189-Astra Zeneca Emer. Gen | 0.000863 | N/A | 0.000432 | 0.000029 |

### Cumulative Impacts Dispersion Modeling Results

The table below summarizes the results of the cumulative modeling analysis.

TABLE WKS 4-5
Cumulative Impacts Modeling Results (µg/m³)

| Pollutant | Averaging Time | Maximum Multisource Concentration (µg/m³) | Background (µg/m³) | Total Ambient Concentration (µg/m³) | State Standard (µg/m³) | Federal Standard (µg/m³) |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-hour | 316.03 | 143.0 | 459.03 | 470 | - |
| | Annual | 3.36 | 32.0 | 35.36 | - | 100 |
| $SO_2$ | 1-hour | 9.16 | 102.2 | 111.36 | 655 | - |
| | 3-hour | 7.65 | 49.4 | 57.05 | 1300 | 1300 |
| | 24-hour | 4.87 | 23.5 | 28.37 | 105 | 365 |
| | Annual | 0.53 | 8.0 | 8.53 | | 80 |
| CO | 1-hour | 1254.23 | 3680.0 | 4934.23 | 23,000 | 40,000 |
| | 8-hour | 393.88 | 2178.0 | 2571.88 | 10,000 | 10,000 |
| $PM_{10}$ | 24-hour | 45.61 | 51.7 | 97.31 | 50 | 150 |
| | Annual | 5.62 | 18.1 | 23.72 | 20 | 50 |
| $PM_{2.5}$[1] | 24-hour | 28.00 | 37 | 65.00 | - | 35 |
| | Annual | 5.62 | 9.4 | 15.02 | 12 | 15 |

[1]Modeled and Background $PM_{2.5}$ 24-hour averages, for comparison to the federal standard, are the maximum 3-year average of the annual 98th percentile 24-hour concentrations (i.e., for modeled impacts equal to the 8th highest concentration at each receptor). The 24-hour federal standard was lowered to 35 µg/m³ in December 2006. The cumulative project impacts of the projects without background are less than the revised standard and the combined impacts do not cause or contribute to a new standard violation.

As can be seen, maximum modeled concentrations without background are less than the CAAQS and NAAQS for all pollutants and all averaging times. Maximum total ambient (modeled plus background) concentrations are greater than the CAAQS for 24-hour and annual $PM_{10}$. Maximum total ambient (modeled plus background) concentrations are also greater than the CAAQS/NAAQS for annual $PM_{2.5}$. Maximum total ambient (modeled plus background) concentrations for all other pollutants and averaging times are less than the CAAQS and NAAQS.

Maximum ambient (modeled plus background) concentrations exceed the applicable $PM_{10}$ and $PM_{2.5}$ CAAQS/NAAQS because the background concentrations already are very nearly equal to or exceed the applicable standards (e.g., there were no modeled $PM_{10}$ or $PM_{2.5}$ concentrations without background greater than the CAAQS or NAAQS). The project is located in a state non-attainment area for $PM_{2.5}$ and $PM_{10}$. Since the modeled multisource impacts by themselves, without considering background, are less than the $PM_{10}$ or $PM_{2.5}$ ambient air quality standards, the projects do not cause or contribute to the regional non-attainment status. Because the projects are located in a state non-attainment area, project emissions of nonattainment pollutants will be mitigated.

All electronic input and output modeling files for the cumulative air quality impact analysis have been submitted to the CEC on a separately provided CD.

**WKS-5**: Please provide a written air quality mitigation plan including the specific details of the emissions to be mitigated, an identification of the specific ERCs to be surrendered by Eastshore, a complete description of any additional emission reduction programs to be implemented, and any supporting materials establishing the basis and efficacy of the program.

**Response:**

A $PM_{10}/PM_{2.5}$ Air Quality Mitigation Plan has been prepared and is included as Attachment WKS-5.

**Attachment WKS-5**

# $PM_{10}$/$PM_{2.5}$ Air Quality Mitigation Plan for Eastshore Energy Center, May 3, 2007

# $PM_{10}$/$PM_{2.5}$ Air Quality Mitigation Plan for Eastshore Energy Center
# May 3, 2007

## 1.0 Background and Purpose

This air quality mitigation plan for $PM_{10}$/$PM_{2.5}$ emissions has been prepared as offered in Eastshore's supplemental response to Data Request #17 (January 15, 2007) and a request articulated by CEC Staff at the March 19, 2007 workshop.

Data Request #17 stated:

> *"Please identify sufficient $PM_{10/2.5}$ mitigation for the proposed maximum $PM_{10/2.5}$ emission rate for each engine at the proposed annual capacity factor of 45.7 percent. Staff suggests a one-to-one ratio of $PM_{10}$ reductions for the proposed total of $PM_{10}$ and $SO_2$ emissions."*

Eastshore's response to Data Request #17 on January 15, 2007 stated in part:

> *Eastshore will work with the CEC and the Bay Area AQMD to develop a mutually acceptable mitigation plan reflective of local air quality improvement goals. This plan will detail the source of mitigations. The mitigation plan may include a combination of banked emission reduction credits (ERCs) of $PM_{10}$ and/or SOx, as well as projects that reduce $PM_{10/2.5}$ emissions and result in actual contemporaneous offsets. Eastshore will use banked ERCs for mitigation to the extent that sufficient quantities can be identified and secured to mitigate $PM_{10}$ and $PM_{2.5}$ emissions. Eastshore will identify specific credits to offset the projected 6.38 tons of actual emissions during the non-attainment season in the final mitigation plan.*

This plan describes the quantity of emissions to be mitigated, sources to be used for the mitigation, and the expected amounts of emission reductions.. As described in this document, Eastshore proposes to use $PM_{10}$ and/or $SO_2$ ERCs to mitigate 10.2 tons of $PM_{10}$/$PM_{2.5}$ emissions, and 1.0 ton of $SO_2$ ERCs to mitigate $SO_2$ emissions. PM mitigation is proposed for the four-month winter $PM_{10}$/$PM_{2.5}$ non-attainment season. If sufficient $PM_{10}$ ERCs are not available to mitigate $PM_{10}$/$PM_{2.5}$ emissions, Eastshore proposes to fund a wood burning stove and fireplace retrofit program. A proposed condition of certification is included that would limit actual non-attainment season emissions.

## 2.0 California Environmental Quality Act (CEQA) Requirements for Mitigating $PM_{10}$ (including $PM_{2.5}$) and $SO_2$ Emissions

Under CEQA, mitigation is required whenever a project would potentially cause significant impacts either individually or cumulatively. Project impacts would be considered significant if they could potentially violate any air quality standard or contribute substantially to an existing or projected air quality violation. As discussed in the Application for Certification, Eastshore will not cause a violation of any air quality standard. Supplemental cumulative impact modeling submitted in response to Data Request #17 also shows that cumulative impacts associated with Eastshore would not cause a violation of any air quality standard. However, it is possible that Eastshore may be required to operate during a very limited number of days each year when background $PM_{10}$ or $PM_{2.5}$ exceed the air quality standards.

Mitigation of project $PM_{10}$/$PM_{2.5}$ and $SO_2$ emission impacts during these limited non-attainment periods is appropriate under CEQA. Because $SO_2$ emissions are considered to partially contribute to formation of secondary ambient $PM_{10}$/$PM_{2.5}$ concentrations, the plan will also include mitigation of $SO_2$ emissions during non-attainment periods.

## 3.0 Existing Air Quality - Ambient Air Quality Standards

The United States Environmental Protection Agency (US EPA) and the State of California have established ambient air quality standards (AAQS) for certain air pollutants, including particulate matter. Standards for sub 10-micron particulate matter ($PM_{10}$) and sub 2.5-micron particulate matter ($PM_{2.5}$) are shown in Table 1.

**TABLE 1**
**California and National Ambient Air Quality Standards**

| Pollutant | Averaging Time | California Standards Concentration | National Standards Concentration |
|---|---|---|---|
| Suspended particulate matter or $PM_{10}$ (10 micron) | 24 hours | 50 $\mu g/m^3$ | 150 $\mu g/m^3$ |
| | Annual Arithmetic Mean | 20 $\mu g/m^3$ | -[1] |
| Suspended particulate matter or $PM_{2.5}$ (2.5 micron) | Annual Arithmetic Mean | 12 $\mu g/m^3$ | 15 $\mu g/m^3$ (3-year average) |
| | 24 hours | - | 35 $\mu g/m^3$ (3-year average of 98th percentiles) [1] |

[1] Federal Annual $PM_{10}$ standard (50 $\mu g/m^3$) revoked and Federal $PM_{2.5}$ standard lowered (from 65 $\mu g/m^3$ to 35 $\mu g/m^3$) effective December 17, 2006.

The Bay Area is currently classified as non-attainment with the California annual standards for $PM_{10}$ (20 µg/m$^3$) and $PM_{2.5}$ (12 µg/m$^3$) and non-attainment with the California 24-hour standard for $PM_{10}$ (50 µg/m$^3$). The Bay Area is currently classified as attainment with the Federal annual standard for $PM_{2.5}$ (15 µg/m$^3$) and unclassified for the Federal 24-hour standard for $PM_{10}$ (150 µg/m$^3$) and 24-hour standard for $PM_{2.5}$ (35 µg/m$^3$).

The Bay Area Air Quality Management District (BAAQMD) operates ambient air monitoring stations throughout the Bay Area Air Basin to monitor compliance with the AAQS. The nearest particulate monitoring station to the Eastshore site is located in Fremont. Data for the Fremont monitoring station is summarized in Table 2.

**TABLE 2**

**Monitoring Data Summary – Fremont**

| $PM_{10}$ (µg/m$^3$) | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|
| Maximum 24-hour concentration | 51.7 | 37.1 | 46.3 | 51.7 | 54.0 |
| Annual Average (Federal) | 22.6 | 17.7 | 18.1 | 17.2 | 19.7 |
| Days above state 24-hour standard | 1 | 0 | 0 | 1 | 1 |
| Days above national 24-hour standard | 0 | 0 | 0 | 0 | 0 |
| **$PM_{2.5}$ (µg/m$^3$)** | **2002** | **2003** | **2004** | **2005** | **2006** |
| Max 24–hour Concentration (Federal) | 48.0 | 33.5 | 39.9 | 33.4 | 43.9 |
| 98$^{th}$ % 24–hour Concentration (Federal) | 41.5 | 22.1 | 33.0 | 27.6 | 30.4 |
| Annual Average | 12.5 | 8.7 | 9.4 | 9.0 | 11.0 |

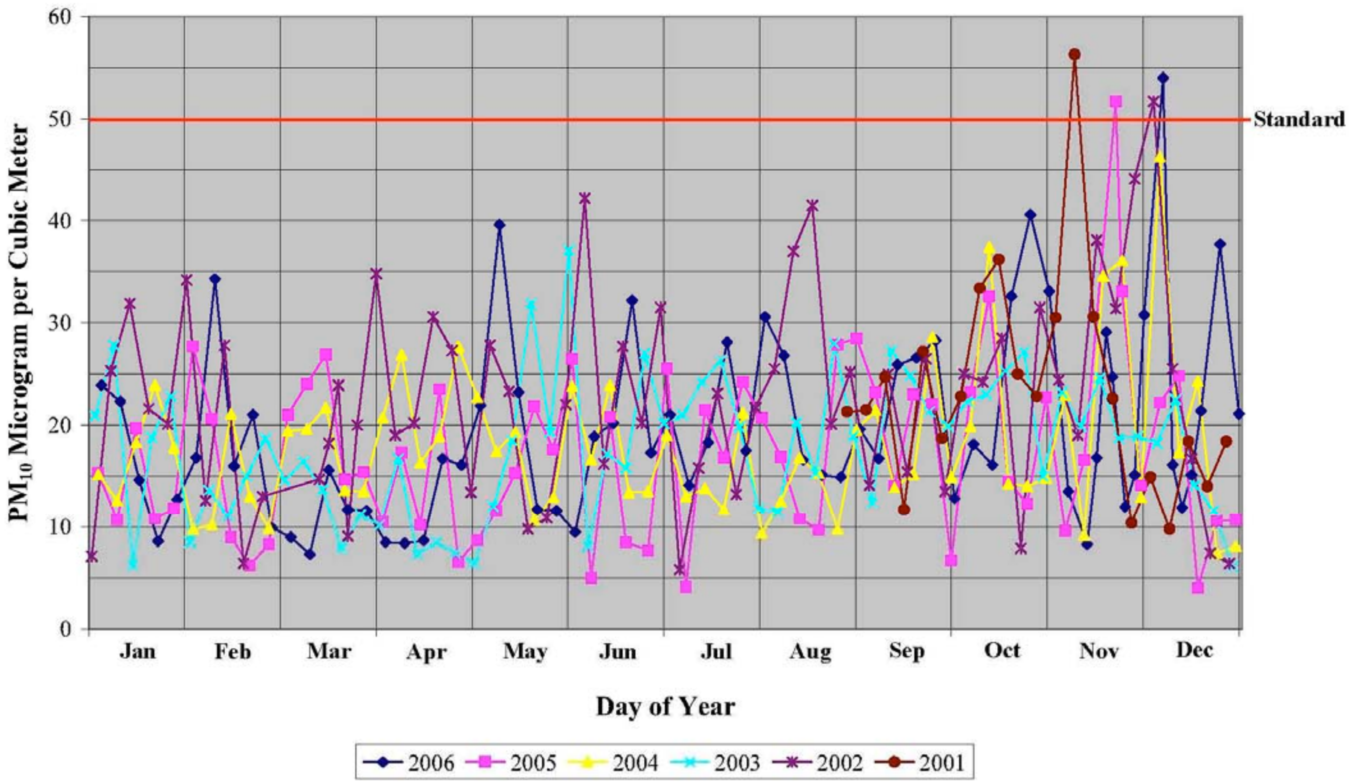
[1] Federal Annual $PM_{10}$ standard (50 µg/m$^3$) revoked effective December 17, 2006.

[2] Federal $PM_{2.5}$ standard lowered (from 65 µg/m$^3$ to 35 µg/m$^3$) effective December 17, 2006.

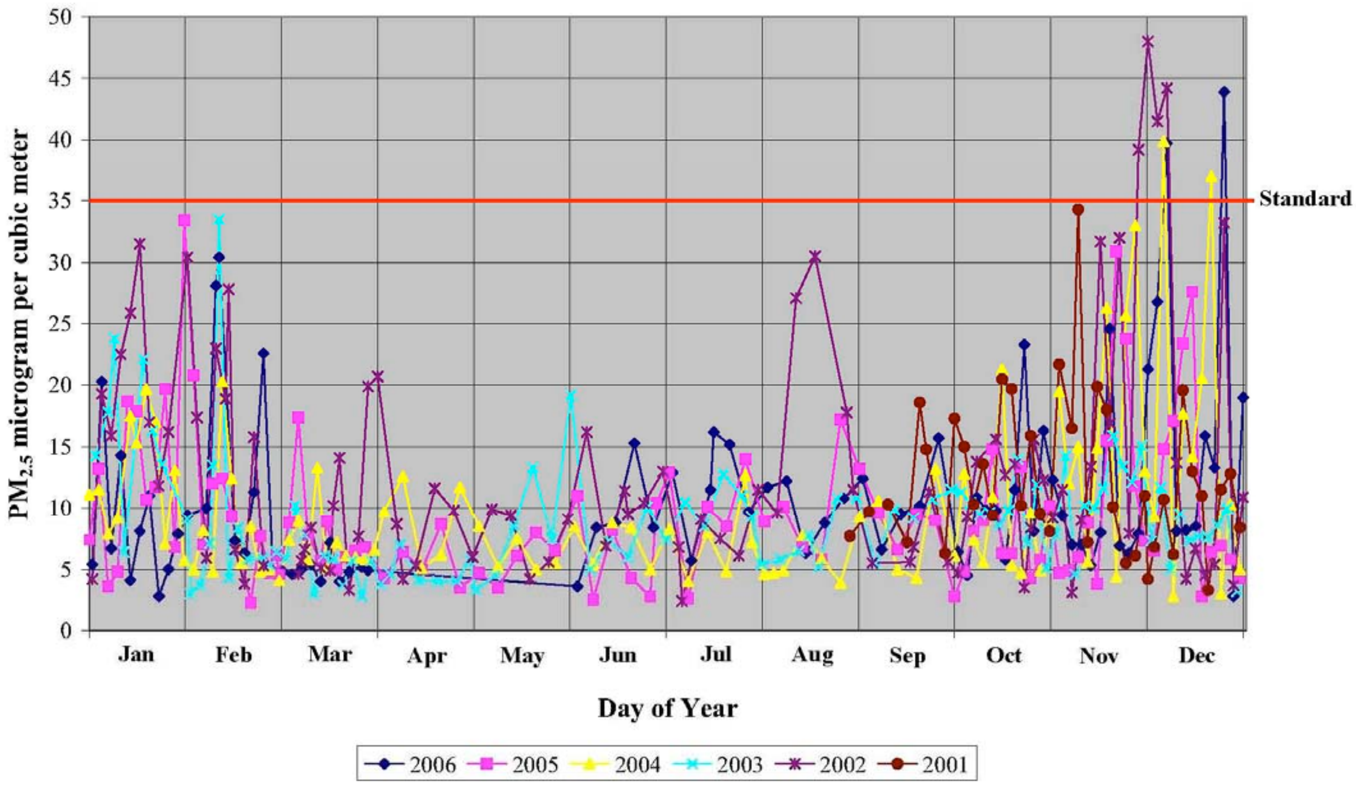
Five years of historical ambient air quality data (obtained from the California Air Resources Board at http://www.arb.ca.gov/aqd/aqdpage.htm) for the Fremont station were reviewed to evaluate the seasonality of exceedances of the 24-hour $PM_{10}$ and $PM_{2.5}$ standards. The five years of data from fall of 2001 through the end of 2006 are shown graphically in Figure 1 for $PM_{10}$, and in Figure 2 for $PM_{2.5}$. For each year, the figures show the variation in particulate concentration from January through December.

During most of the year, the $PM_{10}$ and $PM_{2.5}$ concentrations are well below the State and federal standards. As shown in Table 3, exceedances of 24-hour standards occur on a very limited number of days during only two months, November and December. BAAQMD has identified and established a winter "Spare the Air" program to provide forecasts to the public, and request voluntary reductions in polluting activities (such as refraining from burning wood and limiting automobile use) on days with predicted unhealthy levels of particulate matter.

**Figure 1 - Fremont Monitoring Station 24 Hour $PM_{10}$ Values**



## Figure 2 - Fremont Monitoring Station 24 Hour $PM_{2.5}$ Values



The most recent winter "Spare the Air" season ran from November 20, 2006 through February 16, 2007, a three-month period.

The highest monitoring results for 24-hr $PM_{10}$ and $PM_{2.5}$ during the past 5 years are summarized in Table 3. During the past 5 years, the 24-hr $PM_{10}$ standard has been exceeded or approached (within 10%) 5 times, always in November or December. During the past 5 years, the 24-hr $PM_{2.5}$ standard has been exceeded or approached (within 10%) 16 times, always in the months from November through February. The highest $PM_{2.5}$ monitoring results outside of November through February were 30.5 $\mu g/m^3$ and 27.1 $\mu g/m^3$ during August of 2002. No other monitoring results, outside of November through February, have come within 10 $\mu g/m^3$ of the 24-hr $PM_{2.5}$ standard. Since the 24-hr $PM_{2.5}$ standard is based on the 98$^{th}$ percentile of data, a few outlier results may be ignored.

The historical air monitoring data for Fremont conclusively demonstrates that over the most recent 5- year period significant or near-significant levels of ambient $PM_{2.5}$ and $PM_{10}$ have been confined to the 4-month winter season from November through February. Because of the marked seasonality of the background levels supported by the monitoring data, under CEQA requirements, mitigation should be obtained for $PM_{2.5}$, $PM_{10}$ emissions, and the particulate precursor $SO_2$ during the 4-month period from November through February.

**TABLE 3**

**24 Hour $PM_{10}$ and $PM_{2.5}$ Highest Monitoring Results – Fremont**

| Date | $PM_{10}$ ($\mu g/m^3$) [1] |
|---|---|
| November 9, 2001 | 56.3 |
| December 7, 2006 | 54.0 |
| November 22, 2005 | 51.7 |
| December 4, 2002 | 51.7 |
| December 5, 2004 | 46.3 |
| **Date** | **$PM_{2.5}$ ($\mu g/m^3$) [2]** |
| December 1, 2002 | 48.0 |
| December 7, 2002 | 44.2 |
| December 25, 2006 | 43.9 |
| December 4, 2002 | 41.5 |
| December 5, 2004 | 39.9 |
| December 7, 2006 | 39.7 |
| November 28, 2002 | 39.2 |
| December 20, 2004 | 37.0 |
| November 9, 2001 | 34.3 |
| February 11, 2003 | 33.5 |
| January 31, 2005 | 33.4 |
| December 25, 2002 | 33.2 |
| November 26, 2004 | 33.0 |
| November 22, 2002 | 32.0 |
| November 16, 2002 | 31.7 |
| January 17, 2002 | 31.5 |

[1] Listed $PM_{10}$ monitoring results either exceed or are within 10 percent of the California 24-hr $PM_{10}$ standard (50 $\mu g/m^3$).
[2] Listed $PM_{2.5}$ monitoring results either exceed or are within 10 percent of the current Federal 24-hr $PM_{2.5}$ standard (35 $\mu g/m^3$).

## 4.0 Estimate of Emissions to be Mitigated

## 4.1 Potential Emissions from Eastshore Engines

This section documents the calculation of total maximum $PM_{10}$ and $SO_2$ emissions from the Eastshore facility, including refinements that have been made since the AFC was filed. The manufacturer guarantee and $PM_{10}$ emission estimates for the lean burn engines are as follows:

2.2 lb $PM_{10}$/hr (manufacturer guarantee for full load operation)
2.425 lb $PM_{10}$/cold start (manufacturer estimate for 30 minute cold startup)
2.74 lb $PM_{10}$/cold start cycle (manufacturer estimate for 38.5 minute cold startup/shutdown cycle)

($PM_{10}$ emission estimates provided in Appendix 8.1A of the application for certification were based on 2.426 lb $PM_{10}$/hr (original guarantee) and 2.52 lb $PM_{10}$/cold start. The manufacturer guarantee for full load operation only was recently lowered to 2.2 lb $PM_{10}$/hr).

Based on the same operational assumptions provided in Appendix 8.1 of the application for certification, emission scenarios are:

Maximum 24-hour $PM_{10}$ for each lean burn engine: First 30 minutes with cold catalyst start-up followed by 23.5 hours at full load.

(2.425 lb $PM_{10}$) + (23.5 hr * 2.2 lb $PM_{10}$/hr) = 54.1 lb $PM_{10}$/day

Annual $PM_{10}$ for each lean burn engine: Based on 4,000 hr/yr limit, 300 cold start-up cycles (each 38.5 minutes), and remaining 3,807.5 hr/yr at full load.

(300 * 2.74 lb $PM_{10}$/cold start cycle) + (3,807.5 hr * 2.2 lb $PM_{10}$/hr) = 9,199 lb $PM_{10}$/yr

Potential emissions for all 14 engines are:

(9,199 lb $PM_{10}$/yr) * (14 engines) / (2000 lb/ton) = 64.4 tons $PM_{10}$/yr

Lean burn engine potential emissions for $SO_2$ provided in the application for certification were:

(0.23 lb $SO_2$/hr) * (4,000 hr/yr) = 920 lb $SO_2$/yr per engine
(920 lb $SO_2$/yr) * (14 engines) / (2000 lb/ton) = 6.44 tons $SO_2$/yr

Black start diesel engine potential emissions provided in the application for certification were:

3.17 lb $PM_{10}$/yr (0.002 ton $PM_{10}$/yr based on 30 hr/yr operation)
0.114 lb $SO_2$/yr (<0.001 ton $SO_2$/yr based on 30 hr/yr operation)

Maximum potential emissions are summarized in Table 4 below.

**TABLE 4**
**Potential Emission Estimates**

| **Pollutant** | **14 Lean Burn Engine Emissions (tons/yr)** | **Standby Generator Emissions (tons/yr)** | **Total Project Emissions (tons/yr)** |
|---|---|---|---|
| $PM_{10}$ | 64.4 | 0.002 | 64.4 |
| $SO_2$ | 6.44 | <0.001 | 6.44 |

### 4.2 Potential Emissions during the $PM_{10}/PM_{2.5}$ Non-attainment Season

This section provides the mitigation emission estimates, accounting for the $PM_{10}/PM_{2.5}$ non-attainment season, which is limited to the four (4) months from November through February, and expected operations.

Because the facility will operate for peak shaving and grid reliability rather than for base load, the facility operations will vary with the seasons, with much greater operation during high energy demands of late summer, and reduced operation during the winter.

Based on an analysis conducted by Global Energy Decisions and summarized in Appendix 8.1A of the Application for Certification, annual operating hours during the $PM_{10}/PM_{2.5}$ non-attainment season months were modeled to average 155.1 hours in November, 165.2 hours in December, 110.2 hours in January, and 106.4 hours in February. Total predicted operating hours during the $PM_{10}/PM_{2.5}$ non-attainment season of November through February are 537 hours. In addition, a conservative number of cold starts, 100, were assumed for this 4-month period.

Annual $PM_{10}$ for each lean burn engine: Based on 537 full load operating hr/non-attainment season and 100 cold start-up cycles (each 38.5 minutes).

(100 * 2.74 lb $PM_{10}$/cold start cycle) + (537 hr * 2.2 lb $PM_{10}$/hr) = 1,455 lb $PM_{10}$/non-attainment season

Potential emissions for all 14 engines are:

(1,455 lb PM10/non-attainment season) * (14 engines) / (2000 lb/ton) = 10.2 tons $PM_{10}$/non-attainment season

Lean burn engine potential emissions for $SO_2$ for 537 hr plus 100 cold starts are:

(0.23 lb $SO_2$/hr) * [(537 hr) + (100 starts x (38.5 min/start)/(60 min/hr))] = 138 lb $SO_2$/non-attainment season per engine
(138 lb $SO_2$/non-attainment season) * (14 engines) / (2000 lb/ton) = 0.97 ton $SO_2$/non-attainment season

Black start diesel engine potential emissions provided in the application for certification are unchanged.

3.17 lb $PM_{10}$/yr (0.002 ton $PM_{10}$/yr based on 30 hr/yr operation)
0.114 lb SO2/yr (<0.001 ton SO2/yr based on 30 hr/yr operation)

Potential emissions during the four-month non-attainment season are summarized below in Table 5. These are the $PM_{10}$/$PM_{2.5}$ and $SO_2$ amounts Eastshore proposes to mitigate following CEQA requirements. The proposed mitigation amounts are conservative, mitigating greater than expected actual emissions. This is due to the fact that $PM_{10}$ calculations are based upon the worst-case vendor guarantee of 2.2 lb/hr per lean burn engine. Actual emission rates are expected to be less than half of this estimated value. The actual PM emission rate will be confirmed from source test data during engine commissioning.

**TABLE 5**
**Potential Emission Estimates During the Non-attainment Season**

| Pollutant | 14 Lean Burn Engine Emissions (tons) | Standby Generator Emissions (tons) | Total Project Emissions (tons) |
|---|---|---|---|
| $PM_{10}$ | 10.2 | 0.002 | 10.2 |
| $SO_2$ | 0.97 | <0.001 | 1.0 |

## 5.0 Mitigation Options

Several mitigation options were considered, including BAAQMD $PM_{10}$ and $SO_2$ emission offsets, a wood stove and fireplace insert replacement / retrofit program, road paving, pollution control retrofits on nearby stationary sources, and mobile source emission reductions. Of these options, only use of BAAQMD ERCs, possibly supplemented by a wood stove and fireplace insert replacement / retrofit program would be considered feasible for providing needed mitigation. Other options would not be expected to practicably achieve the mitigation required under CEQA.

## 5.1 Emission Offsets

A preferred option for mitigating $PM_{10}$/$PM_{2.5}$ emissions is the purchase of emission offsets. For facilities that exceed annual emission thresholds under BAAQMD Rules 2-2-302 and 303, the use of emission offsets is required for non-attainment pollutants ($PM_{10}$ and ozone) and their precursor pollutants (NOx, POC, and $SO_2$) when project emissions exceed threshold levels (10 tons/yr of NOx or POC and 100 tons/yr of $PM_{10}$ or $SO_2$).

As shown in Table 6, project emissions do not exceed BAAQMD emission thresholds for $PM_{10}$ or $SO_2$ offsets, so use of emission offsets is not mandatory.

**TABLE 6**
**Offset Requirements for Eastshore per Regulation 2-2-303**

| Pollutant | New Facility Offset Threshold | Eastshore Emission Rates[1] | Offsets Required | Offset Ratio | Amount of Offsets Required by BAAQMD |
|---|---|---|---|---|---|
| $SO_2$ | 100 tpy | 6.4 | No | 1.0:1.0 | 0 |
| $PM_{10}$ | 100 tpy | 64.4 | No | 1.0:1.0 | 0 |

[1] Eastshore potential emission rates as listed in Application for Certification for $SO_2$ and as revised (due to lower manufacturer guarantee) for $PM_{10}$.

Emission offset transactions must be reported to air districts, then compiled by CARB in an annual Emission Reduction Offsets Transaction Cost Summary Report (available at www.arb.ca.gov/nsr/erco/erco.htm). No $PM_{10}$/$SO_2$ transactions were reported from 2003 through 2005. The 2006 report is not yet available. The lack of transactions is an indication of tight supply, (ERC owners that are not offering to sell) high market prices for offsets, or both. This information underscores the important point that there is very little liquidity in the BAAQMD offsets. This creates a high degree of uncertainty that any new facility can obtain offsets from the BAAQMD bank.

Due to limited supply, the use of emission offsets is best suited to projects needing to mitigate relatively small quantities of emissions. For small projects, start-up and administration expenses can make it less practical to manage an alternative mitigation program.

The BAAQMD emission bank (www.baaqmd.gov/pmt/emissions_banking/banking.htm) status is provided in Appendix A. As of April 10, 2007, there were 611 tons/yr of $PM_{10}$ and 1,309 tons/yr of $SO_2$ of offsets potentially available. Based on recent BAAQMD permit activity, $SO_2$ can be substituted for $PM_{10}$, as a $PM_{10}$ precursor, at a 3 ton $SO_2$ per 1 ton $PM_{10}$ ratio (see response to Data Request #8).

Although a cursory examination of the BAAQMD ERC bank registry would suggest adequate offset availability, the great majority of these emission offsets are not for sale. Total quantity of emission offsets held by parties with linked contact information are 22.3 tons/yr of $PM_{10}$ and 5.5 tons/yr of $SO_2$. In addition, at least 2.6 tons/yr of $PM_{10}$ and 15.3 tons/yr $SO_2$ are directly held by emissions brokers or investment funds. Eastshore has retained an ERC broker to assist in identifying and securing additional $PM_{10}$ or $SO_2$ ERCs for the project. To date, the ERC broker has not identified additional ERCs that could be purchased to mitigate project $PM_{10}$ impacts.

Eastshore will make a good faith effort to procure emission offsets at market price. As stated above, it is highly uncertain whether enough offsets can be obtained to cover the proposed mitigation amounts. Even if some offsets can be obtained, it is likely that mitigation will need to be supplemented with the Wood Stove and Fireplace Insert Replacement / Retrofit Program described in Section 5.2.

## 5.2 Wood Stove and Fireplace Insert Replacement/Retrofit Program

If sufficient ERCs are not located to mitigate winter season $PM_{10}/PM_{2.5}$ emissions, Eastshore proposes to work with BAAQMD staff to fund an expansion of the existing wood stove and fireplace insert retrofit/replacement program. The program has a well-established and successful track record, and provides local mitigation of particulate sources that directly contribute to exceedances of the air quality standards. Under the proposed retrofit/replacement program, financial incentives would be provided to encourage residents of Alameda County to replace existing wood stoves with gas stoves or to retrofit existing wood-burning fireplaces to gas fireplaces. A more detailed description of the program is provided below.

BAAQMD has identified wood burning in fireplaces and wood stoves as one of the major sources of $PM_{10}$ emissions during the wintertime. The wood stove and fireplace retrofit/replacement program will be patterned after the ongoing Santa Clara County Woodsmoke Rebate Program funded from the Silicon Valley Power (or Pico Power) project. Similar programs have been proposed or implemented for mitigation for the Three Mountain Power project in Northern California, and the Los Esteros Energy Facility, and the Russell City Energy Center within the BAAQMD.

The primary advantage of a wood stove and fireplace retrofit/replacement program is that the emission reductions occur during the winter at the time of greatest need for reductions. In addition, the advertising and incentives can be focused in the closest communities to provide for local mitigation. Furthermore, the emission reductions occur near ground level in residential communities providing for direct health benefits. Finally, the program would also provide sizeable reductions of $NO_x$, CO and POC emissions.

For the first three years under the program, Eastshore will provide financial incentives for the replacement or retrofit of older, uncertified wood stoves and fireplaces within the communities of Hayward, San Leandro, and Union City. After three years, homes and businesses within the broader Alameda County area may be allowed to participate if there are remaining funds. This will be a voluntary program that will be on a first-come, first-served basis and will last for approximately five years. During that time, any resident of the local communities will be able to replace an existing, operational uncertified stove or fireplace with a natural gas-fired stove or fireplace insert and receive an incentive (i.e., rebate payment of \$100 to \$300). BAAQMD will administer the program through approved local retailers and approved professional, licensed installers. The retailers who participate in the program will provide certificates to participants. Eastshore will pay an administration fee to the BAAQMD to assist in generated marketing materials and processing rebates. The BAAQMD will track the number of replacements and retrofits funded and will report periodically to Eastshore and to the CEC CPM.

Potential emission reductions from fireplace and wood stove retrofit were determined as follows:

Total Emissions from Residential Wood Burning

Emissions were last updated on a county-wide level in the 2002 National Emissions Inventory (NEI) (www.epa.gov/ttn/chief/net/2002inventory.html).

Emission categories tracked in the 2002 NEI, and estimated 2002 wood combustion, include:

Source Classification Code (SCC)
2104008001 Fireplaces (without inserts) -- 7058 tons wood
2104008002 Fireplaces: Inserts; non-EPA certified -- 16312 tons wood
2104008003 Fireplaces: Inserts; non-catalytic, EPA certified -- 1011 tons wood
2104008004 Fireplaces: Inserts; catalytic, EPA certified -- 408 tons wood
2104008010 Wood Stoves: General -- 21656 tons wood
2104008030 Catalytic Wood Stoves: General (EPA certified) -- 541 tons wood
2104008050 Non-catalytic Wood Stoves: General (EPA certified) -- 1342 tons wood

The equipment that would be eligible for retrofit include the fireplaces without inserts (2104008001), the fireplaces with non-EPA certified inserts (2104008002), and the non-EPA certified wood stoves (2104008010).

The wood combustion emission factors used in the 2002 NEI are shown in Table 7:

**TABLE 7**
**Wood Combustion Emission Factors**

| SCC | Type of Device | VOC (lb/ton) | NOX (lb/ton) | CO (lb/ton) | $SO_2$ (lb/ton) | $PM_{10}$ $PM_{2.5}$ (lb/ton) |
|---|---|---|---|---|---|---|
| 2104008001 | Fireplaces without Inserts | 229 | 2.6 | 64.1 | 0.4 | 11.8 |
| 2104008002 | Fireplaces with non-EPA certified Inserts | 53 | 2.8 | 230.8 | 0.4 | 30.6 |
| 2104008010 | Wood Stoves, non-EPA certified | 53 | 2.8 | 230.8 | 0.4 | 30.6 |

The above yields Alameda county-wide emissions from non-certified residential wood combustion as shown in Table 8:

**TABLE 8**
**Alameda County Wood Combustion Emission Totals**

| SCC | Type of Device | VOC (ton/yr) | NOX (ton/yr) | CO (ton/yr) | $SO_2$ (ton/yr) | $PM_{10}$ $PM_{2.5}$ (ton/yr) |
|---|---|---|---|---|---|---|
| 2104008001 | Fireplaces without Inserts | 808 | 9 | 226 | 1.4 | 42 |
| 2104008002 | Fireplaces with non-EPA certified Inserts | 432 | 23 | 1,882 | 3.3 | 250 |
| 2104008010 | Wood Stoves, non-EPA certified | 574 | 30 | 2,499 | 4.3 | 331 |
| Total | | 1,814 | 62 | 4,608 | 9.0 | 623 |

Based on 2000 Census data (www.BayAreaCensus.ca.gov), with 523,366 total households in Alameda County, Hayward is 8.56% of the Alameda County households (44,804 households). Accordingly, approximately 53 tons of $PM_{10}/PM_{2.5}$ emission reductions could come from 100 percent participation in fireplace and woodstove retrofits by Hayward residents. Thus, there is sufficient availability of local emission reductions using this program.

Quantification of Eligible Emission Reductions

The 1998 American Housing Survey of the Oakland Metropolitan Area (including Alameda County and Contra Costa County at www.census.gov/hhes/www/housing/ahs/metropolitandata.html) determined the number of households actively using a fireplace or wood stove for home heating: 73,000 households with fireplaces without inserts, 47,500 households with fireplaces with inserts, 25,000 households with wood stoves. The Alameda households represent 60.6% of the households in the survey, so the number of households within Alameda county actively using a fireplace or woodstove for home heating is approximately: 44,000 households with fireplaces without inserts; 29,000 households with fireplaces with inserts; 15,000 households with wood stoves.

Based on the 2002 NEI wood consumption data, and the 1998 AHS fireplace counts (assuming negligible increase since 1998), the wood burning per device is approximately 0.16 ton/yr per fireplace without insert, 0.61 tons per year per fireplace with insert, and 0.78 tons per year per wood stove. Applying the above emission factors, eligible emission reductions would be about 2 lb $PM_{10}/PM_{2.5}$ per year per fireplace without insert, 19 lb $PM_{10}/PM_{2.5}$ per year per fireplace with insert, and 24 lb $PM_{10}/PM_{2.5}$ per year per woodstove. The emission reductions per device are shown in Table 9:

**TABLE 9**
**Emission Reductions by Wood Burning Device Type**

| Type of Device | Process Rate | VOC (lb/yr) | NOX (lb/yr) | CO (lb/yr) | $SO_2$ (lb/yr) | $PM_{10}$ $PM_{2.5}$ (lb/yr) |
|---|---|---|---|---|---|---|
| Fireplaces without Inserts | 0.16 ton wood/yr | 36.6 | 0.4 | 10.3 | 0.1 | 1.9 |
| Fireplaces with non-EPA Certified Inserts | 0.61 ton wood/yr | 32.3 | 1.7 | 140.8 | 0.2 | 18.7 |
| Wood Stoves, non-EPA certified | 0.78 ton wood/yr | 41.3 | 2.2 | 180.0 | 0.3 | 23.9 |

The emission reductions would need to be adjusted little for the emissions increases for an equivalent natural gas heater used in place of wood combustion. A typical ton of wood produces 12 MMBtu useful heat in a 60% efficient wood stove (www.baaqmd.gov/pio/wood_burning/woodburning_handbook.pdf, assuming 2 tons per cord). An 80 percent efficient natural gas heater would need to burn 15,000 scf gas to produce the same 12 MMBtu useful heat as one ton of wood. Using EPA AP-42 emission factors (Section 1.4 Natural Gas Combustion), the emissions increase is shown in Table 10:

**TABLE 10**
**Emission Increases from Natural Gas-Fired Devices**

| Type of Device | Process Rate | VOC (lb/yr) | NOX (lb/yr) | CO (lb/yr) | $SO_2$ (lb/yr) | $PM_{10}$ $PM_{2.5}$ (lb/yr) |
|---|---|---|---|---|---|---|
| Natural Gas Heater | 15,000 scf/yr (1 ton/yr wood) | 0.1 | 1.4 | 0.6 | 0.0 | 0.1 |

For $PM_{10}$/$PM_{2.5}$, the emissions for a natural gas heater are less than 1 percent of the emissions for a wood stove or fireplace.

Assuming the that current Spare the Air Program funding amounts apply, that most funds used under the program would be applied to non-EPA certified fireplace inserts or wood stoves, and that most emissions occur in November through February, approximately 953 devices (10.2 tons / 0.0107 tons average per device) would need to be replaced to fully mitigate Eastshore's non-attainment $PM_{10}$ emissions. At $300 per device, the funding amount for a wood stove program alone (without any ERCs provided) would be about $286,000, before administrative fees.

## 6.0. $PM_{10}$ / $PM_{2.5}$ Mitigation Proposal

Eastshore proposes to provide mitigation at a one-to-one ratio for up to 10.2 tons of seasonal $PM_{10}$ emissions. Eastshore will use a combination of available market $PM_{10}$ or $SO_2$ ERCs and a wood stove and fireplace insert replacement / retrofit program. If sufficient ERCs are available to provide the mitigation, then the wood stove and fireplace insert replacement / retrofit program will not be needed. Otherwise, if sufficient ERCs cannot be procured by start of construction, Eastshore will implement the wood stove / fireplace program. If the program is needed, details of the wood stove / fireplace program will be developed and implemented in consultation with CEC and BAAQMD.

Eastshore proposes to provide seasonal mitigation at a one-to-one ratio for up to 1.0 ton of $SO_2$ emissions using $SO_2$ ERCs.

Eastshore will commit to emitting no greater actual $PM_{10}$ and $SO_2$ emissions than calculated in this proposed plan. Actual emissions will be tracked and additional ERCs provided if emissions exceed the limit. Sample language for a Condition of Certification is the following:

> *$PM_{10}$ emissions during the November through February non-attainment season shall not exceed 10.2 tons except as provided below. $SO_2$ emissions during November through February shall not exceed 1.0 ton except as provided below. Compliance with this condition will be established by use of the most recent BAAQMD-approved source test data, and the average load-based (grams/bhp-hr) $PM_{10}$ emission rate from all engines tested. Owner shall notify, the CEC CPM within 10 days of exceeding either the $PM_{10}$ or $SO_2$ emission limits. Owner shall surrender additional ERCs or other CPM-approved mitigation for any excess emission (equaling the difference between calculated actual emissions and the emission limit) within 60 days of the date that actual emissions exceed an emission limit. Fireplace or wood burning stove retrofits in the BAAQMD may be used to satisfy any additional mitigation requirement and shall be credited using the following factors for each certified unit retrofit: 2 lb $PM_{10}$/$PM_{2.5}$ per year per fireplace without insert, 19 lb $PM_{10}$/$PM_{2.5}$ per year per fireplace with insert, and 24 lb $PM_{10}$/$PM_{2.5}$ per year per woodstove.*

# Appendix A
# BAAQMD Emission Bank Status

# BAAQMD Emission Bank Status

Emission Reduction Credits Available (tons/yr)

April 10, 2007

(The link in the Certificate Owner column provides contact information for the sale of ERCs.)

| ***No.*** | ***Certificate Owner*** | ***PM*** | ***POC*** | ***NOX*** | ***SO2*** | ***CO*** | ***NPOC*** | ***PM10*** |
|---|---|---|---|---|---|---|---|---|
| 11 | Hewlett-Packard Co; Printed Circuit Divsn | | | | | | 159.500 | |
| 17 | Allied Corporation | | | | 182.900 | | | |
| 18 | Rexam Beverage Can Company | | 31.100 | | | | | |
| 28 | Carnation Company | 3.700 | | | | | | |
| 36 | United Airlines | | | | | | 1.800 | |
| 37 | Morton International Inc | | | 0.400 | | 0.400 | | |
| 38 | FMC Corporation | | | | | | 53.700 | |
| 39 | FMC Corporation | | 5.800 | | | | | |
| 53 | A O Smith Corporation | | 10.800 | | | | | |
| 57 | Phillips 66 Company | 3.600 | | | | 4.900 | | |
| 68 | FMC Corporation | | 0.400 | | | | | |
| 69 | FMC Corporation | | 1.000 | | | | | |
| 70 | Chevron Products Company | | 29.300 | | | | | |
| 96 | U.S. Navy | | 1.018 | | | | | |
| 132 | U.S. Navy | | | 0.390 | | 0.340 | | |
| 135 | Gallagher & Burk; Inc | | | | | | | 6.230 |
| 141 | Phillips 66 Company - San Francisco Refinery | | 0.373 | | | | | |
| 142 | Phillips 66 Company - San Francisco Refinery | | 0.340 | | | | | |
| 149 | Varian Oncology Systems | | | | | | 12.250 | |
| 151 | Lawrence Livermore National Laboratory | | | | | | 1.660 | |
| 155 | U.S. Navy | | 0.065 | 1.878 | 10.660 | 0.939 | | 0.375 |
| 157 | Bay Area Air Quality Management District | | 862.010 | 130.590 | | | | |
| 160 | National Semiconductor Corporation | | 1.747 | | | | | |
| 168 | Martinez Refining Company | | 11.620 | | | | | |
| 172 | Chevron Products Company | | | | | | | 0.384 |
| 173 | Varian Oncology Systems | | 0.235 | | | | 4.469 | |
| 180 | United Technologies Corporation | | 0.076 | | | | 4.397 | |
| 181 | Advanced Micro Devices Inc | | 10.880 | | | | | |
| 182 | Chevron Research and Technology Co | 0.070 | 0.039 | 0.700 | 0.008 | 0.003 | | |
| 183 | Chevron Research and Technology Co | | 0.310 | | | | | |
| 194 | RMC Lonestar | 0.730 | | | | | | 0.440 |
| 195 | RMC Lonestar | 0.400 | | | | | | 0.240 |
| 205 | U.S. Navy | | | | | | 6.034 | |
| 207 | Owens Corning | 17.900 | 23.300 | 9.500 | | 3.900 | | |
| 215 | Monsanto Company | | | | | | | 0.067 |
| 218 | New United Motor Manufacturing; Inc | | 78.830 | | | | | |
| 223 | Chevron Products Company | | 60.122 | 20.674 | 1.047 | 9.129 | | 5.370 |
| 227 | HMT Technology Corporation | | 0.200 | | | | 2.240 | |
| 239 | IBM Corporation | | | | | | 24.370 | |
| 241 | Dexter Hysol Aerospace; Inc | | 4.700 | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 251 | Triangle Wire & Cable; Inc | | | 0.594 | | | | |
| 252 | General Electric Co | | 0.003 | | | | | |
| 259 | Burke Industries; Inc | | 3.026 | | | | 24.850 | |
| 262 | Lawrence Livermore National Laboratory | | | | | | 1.050 | |
| 265 | Solectron Corporation | | 3.710 | | | | 3.350 | |
| 266 | Santa Rosa Memorial Hospital | | | 0.970 | | | | 0.300 |
| 270 | Stanford University | | | 17.300 | | | | |
| 280 | California Canners & Growers | 0.800 | | | | 6.000 | | |
| 302 | Chevron Products Company | | 7.948 | | | | | |
| 325 | New United Motor Manufacturing; Inc | | 20.790 | | | | | |
| 328 | Crockett Cogeneration; A Cal Ltd Partnership | | 11.050 | 0.840 | | 0.200 | | |
| 329 | Advanced Micro Devices Inc | | 9.615 | | | | | |
| 333 | U.S. Navy | | 13.490 | | | | | |
| 350 | Hewlett-Packard Company | | 3.290 | | | | | |
| 351 | U.S. Navy | | 22.786 | | | | 54.600 | |
| 360 | Gallagher & Burk; Inc | | 0.200 | 0.170 | 0.170 | 0.530 | | 0.180 |
| 370 | Pacific Refining Company | | 1.000 | | | | | |
| 371 | Zanker Road Resource Management;Ltd | | 0.650 | 10.700 | 0.770 | | | |
| 372 | Pacific Refining Company | | 0.440 | 0.224 | | | | |
| 381 | Laidlaw Environmental Services, Inc | | 1.400 | | | | 1.460 | |
| 382 | California Oils Corporation | | 0.195 | | | | | |
| 385 | Quantum Corporation | | | | | | 3.200 | |
| 387 | Martinez Refining Company | | 0.096 | | | | | |
| 392 | Richard Mariani | 0.600 | | | | 3.300 | | |
| 410 | IBM Corporation | | | | | | 13.980 | |
| 414 | Intel Corporation | | 13.920 | | | | 2.140 | |
| 423 | Ciba Corning Diagnostics Corp | | 0.530 | | | | | |
| 424 | Chevron Products Company | | 1.608 | | | | | |
| 425 | Beckman Coulter | | | | | | 3.110 | |
| 428 | Martinez Refining Company | | 6.288 | | | | | |
| 443 | Lawrence Livermore National Laboratory | | | | | | 0.121 | |
| 445 | Stanford University | | 3.790 | 14.840 | | | | |
| 446 | Red Wing Co /California Div | 0.070 | 0.052 | 0.419 | 0.002 | 0.083 | | 0.091 |
| 452 | Solectron Corporation | | 2.674 | | | | | |
| 465 | Ball Metal Beverage Container Corporation | | | 0.275 | | | | |
| 475 | U.S. Navy | | 0.300 | 0.130 | | 0.420 | | 0.300 |
| 477 | U.S. Navy | | 7.911 | | | | | |
| 478 | Central Contra Costa Sanitary District | | 0.581 | 2.243 | | 30.937 | | |
| 483 | The Glidden Company | | 4.700 | | | | | |
| 486 | U.S. Navy | | 3.440 | 1.210 | 1.200 | 2.710 | | 0.980 |
| 487 | Chevron Chemical Company | 3.504 | | 3.028 | | | | 5.254 |
| 489 | Chevron Products Company | | | 71.400 | | | | |
| 491 | U.S. Navy | | 1.620 | 5.762 | 0.460 | 1.241 | 1.030 | 0.405 |
| 501 | U.S. Navy | | 0.315 | 8.432 | 0.135 | 9.001 | | 0.563 |
| 503 | U.S. Navy | | 0.354 | 4.342 | 0.347 | 0.935 | | 0.305 |
| 505 | New United Motor Manufacturing; Inc | | 18.470 | | | | | |
| 510 | U.S. Navy | | 3.490 | 2.430 | 0.210 | 0.580 | 0.220 | 0.590 |
| 514 | Owens Corning | | 6.457 | | | | | |
| 520 | New United Motor Manufacturing; Inc | | 112.760 | | | | | |
| 525 | Central Contra Costa Sanitary District | | 0.153 | 1.120 | | 8.158 | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 529 | U.S. Navy | | 2.880 | 14.750 | 1.430 | 11.470 | | 3.710 |
| 531 | Crown Cork & Seal Company | | 20.249 | 4.595 | | 0.965 | | 0.345 |
| 532 | Martinez Cogen Limited Partnership | | | 50.200 | | | | |
| 538 | New United Motor Manufacturing; Inc | | 131.900 | | | | | |
| 540 | New United Motor Manufacturing; Inc | | 0.218 | | | | | |
| 541 | Chevron Chemical Company | | 0.047 | | | | 1.600 | |
| 545 | U.S. Navy | | 2.495 | | | | | |
| 546 | Alameda Reuse & Redevelopment Authority | | 29.970 | | | | | |
| 554 | Lawrence Livermore National Laboratory | | | | | | 2.400 | |
| 555 | U.S. Navy | | | 1.050 | 0.020 | 0.890 | | 0.110 |
| 557 | U.S. Navy | | 0.650 | 9.090 | 0.140 | 8.160 | | 0.700 |
| 559 | U.S. Navy | | 0.340 | 2.110 | | | | |
| 560 | Criterion Catalysts Company LP | | 0.340 | | | | | |
| 561 | Pechiney Plastic Packaging; Inc | | 1.249 | | | | | |
| 563 | Owens Corning | | 1.245 | | | | | |
| 564 | Owens Corning | | | 504.000 | | | | |
| 578 | Chevron Chemical Company | | 0.212 | 1.802 | 0.046 | 0.357 | | 0.570 |
| 583 | WinCup Holdings;L P | | 0.426 | | | | | |
| 588 | Chevron Chemical Company | | | 31.771 | | 2.069 | | |
| 598 | USS-POSCO Industries | | | | 0.140 | 0.790 | | 0.700 |
| 600 | U.S. Navy | | 0.550 | 3.210 | 0.060 | 8.430 | | 0.760 |
| 602 | Calpine Corporation | 0.200 | 40.970 | 2.143 | | 0.357 | | |
| 603 | Port of Oakland | | | 2.450 | | | | |
| 613 | Martinez Refining Company | | | 89.783 | | | | |
| 617 | Chevron Products Company | | 68.898 | 8.790 | 0.473 | 7.449 | | 1.514 |
| 619 | Raisch Products | | | | | 0.840 | | |
| 640 | New United Motor Manufacturing; Inc | | 27.940 | | | | | 13.630 |
| 643 | Homestake Mining Company | 87.530 | | | | 86.970 | | |
| 645 | Calpine Corporation | | | 107.900 | | | | |
| 648 | Emerald Packaging Inc | | | | | | 40.000 | |
| 656 | Duke Energy Oakland LLC | | 324.810 | | | | | |
| 658 | Calpine Corporation | | 10.000 | 32.900 | | 14.380 | | |
| 661 | Calpine Corporation | | 31.750 | | | | | |
| 662 | Calpine Corporation | | | 73.620 | 46.300 | | | |
| 674 | Calpine Corp. & Bechtel Enterprises Hold | | | | | 9.797 | 0.669 | |
| 675 | Calpine Corp. & Bechtel Enterprises Hold | | | | 18.285 | | | |
| 684 | Stapleton - Spence | | 0.028 | 0.312 | 0.006 | 0.008 | 0.030 | 0.140 |
| 687 | Calpine Corp. & Bechtel Enterprises Hold | | 43.819 | 0.581 | | | | |
| 688 | Calpine Corp. & Bechtel Enterprises Hold | | 52.270 | | | | | |
| 691 | Burns Philp Food Inc. | | 0.001 | | | | | |
| 696 | Siliconix; Incorporated | | | | | | 0.001 | |
| 699 | Calpine Corporation | | | 20.900 | | | | |
| 708 | Exar Corporation | | | | | | 4.689 | |
| 710 | Midway Power, LLC | | 5.140 | | | | | |
| 716 | Calpine Corporation | | 0.200 | 11.660 | 0.040 | 1.130 | | 0.670 |
| 718 | Midway Power, LLC | | 44.995 | | | | | |
| 719 | Midway Power, LLC | | 4.900 | | | | | |
| 720 | Midway Power, LLC | | | 48.962 | | | | |
| 722 | Catalytica Energy Systems Inc | | 0.011 | | | | | |
| 723 | Catalytica Energy Systems Inc | | | 0.015 | | 1.632 | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 724 | Calpine Corporation | | | 7.100 | | | | |
| 726 | New United Motor Manufacturing; Inc | | | 0.343 | | | | |
| 729 | Valero Refining Company - California | | 28.326 | | | | | |
| 730 | Del Monte Foods | | 0.176 | 2.194 | 0.038 | 1.562 | | 0.887 |
| 734 | Catalytica Energy Systems Inc | | | | | 10.424 | | |
| 735 | San Mateo Water Quality Control Plant | | 1.053 | 3.720 | 0.225 | 13.562 | | |
| 740 | Pacific Gas and Electric Company | | 9.790 | 32.680 | 1.070 | 12.930 | | 13.530 |
| 744 | Applied Biosystems | | 0.144 | 1.472 | 0.015 | 1.682 | | 0.186 |
| 746 | Stauffer Management Company | | 0.700 | | | 9.100 | 0.400 | 0.700 |
| 748 | Zeneca; Inc. | 0.200 | | | | 0.200 | | |
| 749 | Calpine Corporation | | | 13.670 | | | | |
| 750 | Calpine Construction Finance Co.;L.P. | | | | 4.120 | | | |
| 756 | Mirant California | 4.200 | 0.390 | 1.173 | | 14.602 | | 6.443 |
| 757 | Gaylord Container Corp. | | 0.135 | | | | | |
| 758 | Gilroy Foods, Inc. | | 0.203 | | | | | |
| 762 | Midway Power, LLC | | 38.993 | | | | | |
| 763 | Rexam Beverage Can Company | | 13.083 | | | | | |
| 766 | Chevron Products Company | | 65.300 | | | | | |
| 767 | Midway Power, LLC | | 5.862 | 1.300 | | | | |
| 769 | Amdahl Corporation | | | | | | 5.120 | |
| 773 | Midway Power, LLC | | | 21.000 | | | | |
| 774 | Conagra Energy Services; Inc. | | | | | 1.800 | | 1.000 |
| 777 | Chevron Products Company | | 15.345 | | | | | |
| 778 | Midway Power, LLC | | 0.086 | 1.564 | 0.009 | 1.308 | 0.036 | 0.119 |
| 780 | Midway Power; LLC | | 2.880 | 4.960 | 0.030 | 4.880 | | 0.390 |
| 782 | Owens Brockway Glass Containers | 11.200 | | | | 11.520 | | |
| 785 | Philips Semiconductor | | | | | | 0.320 | |
| 786 | Calpine Corporation | | 0.017 | 1.026 | | | | |
| 787 | Conagra Energy Services; Inc. | | 61.138 | 2.070 | 0.024 | 1.161 | | 0.538 |
| 788 | Gilroy Foods, Inc. | | 0.422 | 7.653 | 0.046 | 6.439 | | 0.583 |
| 793 | Amdahl Corporation | | | | | | 11.818 | |
| 798 | Midway Power, LLC | | 0.148 | 2.691 | 0.016 | 2.261 | | 0.205 |
| 800 | Midway Power; LLC | | | | | | | 1.197 |
| 813 | Ball Metal Beverage Container Corporation | | 8.692 | 3.571 | 0.021 | 2.999 | | 0.271 |
| 819 | USS-POSCO Industries | 3.000 | | 5.011 | 0.290 | 4.910 | | 0.360 |
| 821 | Waste Management of Alameda County | | | | | | | 98.010 |
| 822 | Calpine Corporation | | 1.029 | | | | | |
| 823 | Crown Cork & Seal Company | | 71.000 | | | | | |
| 831 | Mirant California | | 72.280 | 66.060 | | 450.600 | | 202.530 |
| 833 | Valero Refining Company - California | | 80.000 | | | | | |
| 835 | Calpine Corp. & Bechtel Enterprises Hold | 0.210 | | | 0.030 | 1.650 | | |
| 840 | Calpine Corporation | | | | 0.090 | 2.610 | | |
| 842 | Fleischmann's Yeast | | 11.120 | | | | | |
| 844 | Homestake Mining Company | | | | | | | 1.222 |
| 846 | Fleischmann's Yeast | | 0.106 | 0.670 | 0.012 | 0.569 | | 0.147 |
| 847 | Shell Chemical LP | | 6.590 | | | | | |
| 848 | Myers Container Corporation | | 20.030 | | | | 7.390 | |
| 849 | Myers Container Corporation | | 10.787 | 0.559 | | 0.112 | 4.850 | 0.028 |
| 850 | Norcal Waste Systems | | 0.077 | 8.312 | 0.418 | 0.155 | | 0.173 |
| | Myers Container Corporation | | | 0.316 | 0.002 | 0.265 | | 0.024 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 854 | | | | | | | | |
| 856 | Calpine Corporation | | 26.522 | | | | | |
| 858 | Midway Power, LLC | | 2.353 | | | | | 0.094 |
| 859 | C & H Sugar Company; Inc | | | | | 37.282 | | |
| 863 | Mirant California | | 5.300 | 247.500 | 130.179 | 114.000 | | 25.270 |
| 867 | Chevron Products Company | | 1.573 | | | | | |
| 870 | Burns Philp Food, Inc. | | 16.259 | | | | | |
| 871 | LSI Logic Corporation | | 3.904 | | | | 0.195 | |
| 875 | Cunningham Graphics a Subdiary of ADP | | 4.704 | | | | | |
| 879 | BP West Coast Products, LLC | | 0.787 | | | | | |
| 880 | Intel Corporation | | | 28.130 | | | | |
| 884 | Martinez Refining Company | | 2.980 | | | | | |
| 894 | United Airlines | | 45.000 | | | | | |
| 900 | Chevron Products Company | | | 1.027 | 0.060 | 0.537 | | 0.312 |
| 901 | Chevron Products Company | | 6.463 | | | | | |
| 903 | Ball Corporation | | 0.301 | | | | | |
| 915 | Tesoro Refining & Marketing Company | | | 9.671 | 4.584 | 2.938 | | 0.327 |
| 918 | Mirant California | | | 171.000 | | | | |
| 920 | ConocoPhillips | 0.400 | | 13.270 | | 64.620 | | 6.650 |
| 921 | ConocoPhillips | | 69.877 | | 0.100 | | | |
| 927 | BP West Coast Products, LLC | | 2.576 | | | | | |
| 928 | Tesoro Refining & Marketing Company | | 0.271 | | | | | |
| 929 | City of Santa Clara dba Silicon Valley Power | | | 8.200 | | | | |
| 930 | City of Santa Clara dba Silicon Valley Power | | 0.300 | | | | | |
| 933 | Martinez Refining Company | | | | 15.100 | | | 8.804 |
| 934 | Genentech, Inc | | | | | 7.798 | | 2.660 |
| 938 | Hanson Permanente Cement | | 2.000 | | | | | |
| 941 | Shell Martinez Refinery | | 0.690 | | | | | |
| 942 | United Technologies Corporation | 0.840 | | 0.250 | | | | 1.670 |
| 943 | United Technologies Corporation | | 1.460 | | | | | |
| 944 | Napa Redevelopment Partners, LLC | | 0.090 | 1.640 | | | | |
| 945 | William Gonsalves | | 5.930 | | | | | |
| 946 | Dow Chemical Company | | 14.355 | | | | | |
| 948 | UTC, P&W Space Propulsion | | | 0.610 | 2.180 | 0.153 | | 0.061 |
| 951 | Martinez Refining Company | | | | 50.110 | | | |
| 952 | Hanson Permanente Cement | | | | | | | 23.937 |
| 953 | UTC, P&W Space Propulsion | | | 0.450 | 1.599 | 0.113 | | 0.045 |
| 954 | Hexcel Corporation | | 0.060 | 1.160 | | | | 0.090 |
| 956 | Lockheed Martin Space Systems | | 0.522 | | | | | |
| 957 | Hitachi Global Storage Technologies | | 5.490 | | | | | |
| 963 | Crown Cork & Seal Company | | 1.500 | | | | | |
| 964 | Pacific Atlantic Terminals LLC | | 3.546 | 11.352 | | | | |
| 965 | Pacific Atlantic Terminals LLC | | 0.185 | | | | | |
| 966 | Pacific Recovery Corporation | | 0.495 | 0.699 | 0.023 | 1.630 | | 1.425 |
| 967 | United Airlines | | 31.560 | | | | | |
| 968 | Tesoro Refining and Marketing Company | | 28.407 | | | | | |
| 969 | East Bay Municipal Utility District | | 1.074 | | | | | |
| 970 | Midway Power, LLC | | 1.127 | 17.786 | 22.635 | 17.779 | | 5.099 |
| 971 | Valero Refining Company | | 8.381 | | | | | |
| 972 | BP West Coast Products, LLC | | 0.539 | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 973 | Lockheed Martin Space Systems | | 2.407 | | | | | |
| 974 | Valero Refining Company - California | | | | | | | 2.250 |
| 975 | Valero Refining Company - California | | 0.112 | | | | | |
| 976 | Valero Refining Company - California | | | | 1.163 | | | |
| 977 | Valero Refining Company - California | | | | 5.068 | | | |
| 979 | Air Liquide Large Industries U.S. LP | | | | | | | 18.600 |
| 980 | Midway Power, LLC | | | 135.530 | 136.290 | 45.180 | | |
| 985 | Hitachi Global Storage Technologies | | 10.706 | | | | | |
| 986 | Midway Power, LLC | | | | | | | 7.265 |
| 987 | Calpine Corporation | | | | 1.030 | 33.320 | | |
| 988 | Midway Power, LLC | | | | | | | 20.500 |
| 989 | Calpine Corporation | | | 352.094 | 90.000 | 33.000 | | |
| 990 | Pechiney Plastic Packaging; Inc | | 6.090 | | | | | |
| 991 | Midway Power, LLC | | | | 6.514 | | | 3.192 |
| 993 | Shell Martinez Refinery | | 18.921 | 13.800 | 0.100 | | | |
| 994 | SFPP; LP | | 0.158 | | | | | |
| 995 | Waste Management of Alameda County, Inc. | | 12.087 | | | | | |
| 996 | Hexcel Corporation | | 0.060 | 1.060 | | | | 0.080 |
| 997 | Pacific Atlantic Terminals LLC | | 16.395 | | | | | |
| 998 | Owens Corning | 1.300 | | 40.020 | | 32.750 | | 6.800 |
| 1000 | Midway Power, LLC | | | | 51.750 | | | |
| 1001 | Calpine Corporation | | | 96.813 | 350.610 | 54.340 | | |
| 1002 | Waste Management Inc. | | 8.816 | | | | | |
| 1003 | Waste Management Inc. | | 6.153 | | | | | |
| 1004 | Waste Management Inc. | | 1.000 | | | | | |
| 1005 | Waste Management Inc. | | 12.367 | | | | | |
| 1006 | Koch Supply & Trading LP | | 23.400 | | | | | |
| 1007 | United States Pipe & Foundry Company | | 0.900 | | | | | |
| 1008 | Chevron Products Company | | 20.129 | 30.492 | 133.322 | 488.571 | | 31.831 |
| 1010 | Olduvai Gorge LLC | | 0.300 | 3.800 | 9.200 | 3.800 | | 1.000 |
| 1011 | Calpine Corporation | | | | | | | 42.800 |
| 1012 | Calpine Corporation | | | | | | | 19.600 |
| 1014 | Trumbull Asphalt Company | | | 0.400 | 5.000 | 24.200 | | |
| 1015 | Koch Supply & Trading LP | | 22.778 | | | | | |
| 1016 | Koch Supply & Trading LP | | 15.518 | | | | | |
| 1017 | Koch Supply & Trading LP | | 4.400 | | | | | |
| 1019 | Koch Supply & Trading LP | | 15.856 | | | | | |
| 1022 | Koch Supply & Trading LP | | 19.718 | | | | | |
| 1023 | Calpine Corporation | | 66.145 | | | | | |
| 1024 | Kinder-Morgan Energy Partners, LP | | 2.000 | | | | | |
| 1025 | Grey K Environmental Fund, LP | | 40.860 | 17.770 | 0.310 | 0.080 | | 2.600 |
| 1026 | Chevron Products Company | | 1.100 | 1.310 | | | | 0.378 |
| 1027 | Koch Carbon, LLC | | 45.000 | | | | | |
| 1028 | Koch Carbon, LLC | | 46.930 | | | | | |
| 1029 | Koch Carbon, LLC | | 0.070 | | | | | |
| 1030 | Koch Supply & Trading LP | | 29.730 | | | | | |
| 1031 | Pacific Recovery Corporation | | 0.214 | 2.469 | 0.076 | 4.757 | | |
| 1032 | Air Liquide, L.P. | | | | 5.920 | | | 4.200 |
| 1033 | Element Markets Partners LP | | 8.900 | | 14.980 | | | |
| | | **140** | **3554** | **2731** | **1309** | **1764** | **459** | **611** |

## Technical Area: Traffic and Transportation

**WKS-6**: Provide analysis of vehicle safety issues at Clawiter/I-92E exit and Industrial Blvd/I-92E exit, in conjunction with evaluation of traffic conditions and suitability of routes for hazardous materials transport for both Clawiter Road and Industrial Blvd, as requested in DR #56. Provide similar analysis for any other proposed alternative routes.

**Response:**

The analysis previously submitted showed that the traffic impacts from construction traffic would be reduced with the Industrial Boulevard route.

However, because of the residences located along Industrial Boulevard at the exit of SR-92, the risks incurred if there was an accident involving hazardous materials would be greater for the local population. Clawiter Road serves industrial areas, so there would be minimal impacts on residents if there was such an accident.

While there is a low likelihood of any accident during ammonia deliveries, the applicant's primary concern is to avoid potential impacts on residents. Therefore, Eastshore will use Clawiter Road as the main route for trucks delivering hazardous materials. In addition, the public comments have suggested that preventing trucks delivering hazardous material from exiting at the Industrial Boulevard/SR-92 interchange would be preferable. These deliveries would take place during off-peak periods, to minimize any conflict with the ammonia deliveries already taking place at Berkeley Farms. Although a left turn into the site will be required, the minor operations issue that would result is less important than the assuring residents' safety. The rest of the construction traffic will use Industrial Boulevard as the main route.

**WKS-7**: Provide turning radius/encroachment design diagram for plant entrance (encroachment onto Clawiter Road). This is a clarification of DR #57.

**Response:**

To generate the design diagrams, the Auto Turn 5 for AutoCAD 2005 software has been used with the following parameters:

- Design Standards for turning movements are a minimum turning radius of 41 feet as per **A Policy on Geometric Design of Highways and Streets**, AASHTO 2001.
- Vehicle is a WB-67D double-trailer truck as per AASHTO 2004 (US) Standards (see Figure WKS-7-1).
- Lane width is 12 feet.

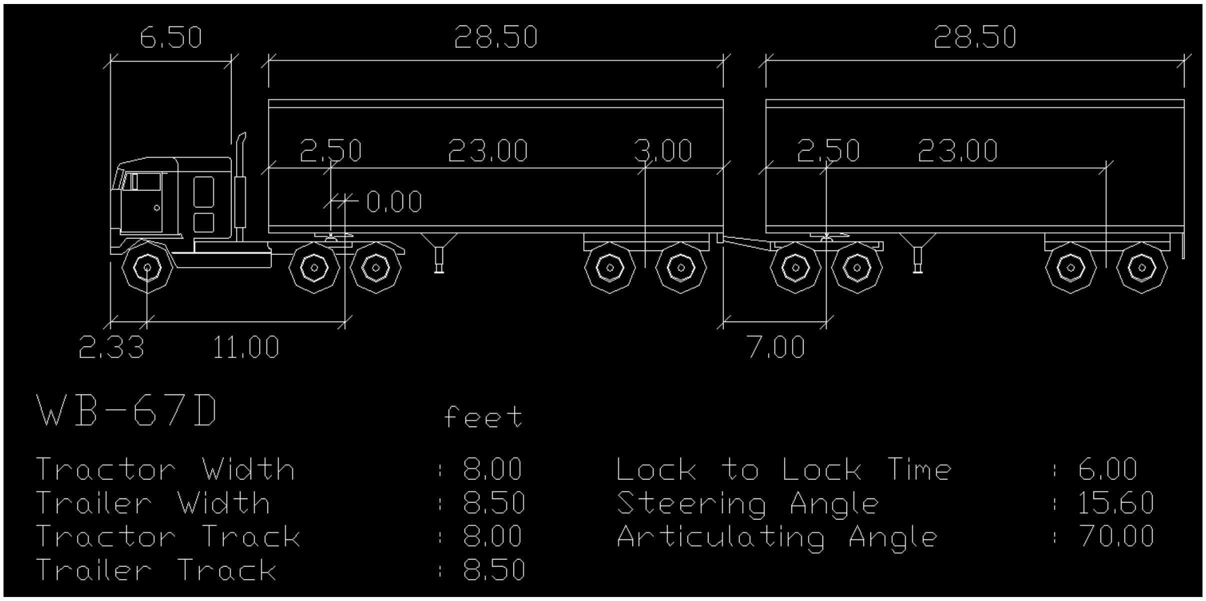



FIGURE WKS-7-1
Details of the typical truck used for the Auto Turn v.5 simulation

Figure WKS-7-2 depicts the most common situation where trucks travel through the northern part of Clawiter Road only. The site entrance will be widened about 30 feet to accommodate the right turn movements when trucks enter the site. The turning radii shown comply with the minimum requirements (41 feet).


FIGURE WKS-7-2
Design diagram for trucks (during Construction deliveries)

The configuration shown in Figure WKS-7-3 is a worst-case analysis assuming double-trailer delivery of hazardous materials (see Response to WKS 6). The site entrance can accommodate the standard minimum turning radius of 41 feet, provided that no vehicle is exiting the site at the same time. This could be easily accomplished with advance communication between the hazardous materials delivery vehicle and the site. Eastshore also anticipates that all hazardous materials deliveries will be single trailer vehicles thereby further reducing the required turning radius.


FIGUREWKS-7-3
Design diagram for worst-case delivery of double-trailer trucks carrying Hazardous Materials

**WKS-8**: Provide data and method(s) of analysis for revised traffic impact analyses and consistency with City of Hayward methods of evaluation, per DRs #60 and #63.

**Response:**

The following work files have been submitted under separate cover to the CEC and the City of Hayward:

- Trip generation/traffic distribution assumptions;
- Background volumes AM/PM (2 Synchro files);
- Results of the analyses – Without Cumulative Impacts AM/PM (4 Synchro files);
- Results of the analyses – With Cumulative Impacts AM/PM (4 Synchro files).

Tables WKS-8-1 to WKS-8-8 include updated summaries of the results. These updates include corrections to the construction volumes from Russell City Energy Center (from 311 to 292 average daily vehicles), adjustments to the construction traffic assignments, and corrections to typos. Differences from the Second Round Data Request are shown on the tables.

TABLE WKS-8-1
Existing Conditions AM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | B | |
| Clawiter Road and Industrial Boulevard | A | |
| Clawiter Road and Depot Road | A | |
| Industrial Boulevard and Depot Road | B | |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | B | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | C | |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | B | |
| Clawiter Road/To Project Site | A | |
| Clawiter Road/To Temporary Parking Lot | A | |

TABLE WKS-8-2
Existing Conditions PM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | B | |
| Clawiter Road and Industrial Boulevard | B | |
| Clawiter Road and Depot Road | A | |
| Industrial Boulevard and Depot Road | B | |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | B | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | E | |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | C | |
| Clawiter Road/To Project Site | A | |
| Clawiter Road/To Temporary Parking Lot | A | |

TABLE WKS-8-3
Construction Conditions, Traffic Routed via Industrial Boulevard AM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | B | |
| Clawiter Road and Industrial Boulevard | A | |
| Clawiter Road and Depot Road | B | |
| Industrial Boulevard and Depot Road | C | |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | B | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | C | |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | D | |
| Clawiter Road/To Project Site | C | Construction traffic assignment (previously LOS A) |
| Clawiter Road/To Temporary Parking Lot | C | Construction traffic assignment (previously LOS A) |

TABLE WKS-8-4
Construction Conditions, Traffic Routed via Industrial Boulevard PM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | B | |
| Clawiter Road and Industrial Boulevard | B | |
| Clawiter Road and Depot Road | C | Typo (previously LOS B) |
| Industrial Boulevard and Depot Road | B | |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | B | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | E | |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | D | |
| Clawiter Road/To Project Site | D | Construction traffic assignment (previously LOS C) |
| Clawiter Road/To Temporary Parking Lot | C | Construction traffic assignment (previously LOS D) |

TABLE WKS-8-5
Cumulative Impacts with Russell City, Eastshore Construction Traffic Routed via Industrial Boulevard AM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | A | Volumes from RCEC (previously LOS B) |
| Clawiter Road and Industrial Boulevard | A | |
| Clawiter Road and Depot Road | B | |
| Industrial Boulevard and Depot Road | B | Volumes from RCEC (previously LOS C) |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | B | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | D | |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | D | |
| Clawiter Road/To Project Site | C | Volumes from RCEC and construction traffic assignment (previously LOS A) |
| Clawiter Road/To Temporary Parking Lot | C | Volumes from RCEC and construction traffic assignment (previously LOS A) |

TABLE WKS-8-6
Cumulative Impacts with Russell City, Eastshore Construction Traffic Routed via Industrial Boulevard PM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | B | |
| Clawiter Road and Industrial Boulevard | B | |
| Clawiter Road and Depot Road | C | |
| Industrial Boulevard and Depot Road | B | |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | B | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | E | Volumes from RCEC (previously LOS F) |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | D | |
| Clawiter Road/To Project Site | D | Volumes from RCEC (previously LOS C) |
| Clawiter Road/To Temporary Parking Lot | C | |

TABLE WKS-8-7
Cumulative Impacts with Russell City, Eastshore Construction Traffic Routed via Clawiter Road AM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | B | |
| Clawiter Road and Industrial Boulevard | A | |
| Clawiter Road and Depot Road | A | |
| Industrial Boulevard and Depot Road | B | |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | C | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | D | Typo (previously LOS F) |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | B | |
| Clawiter Road/To Project Site | A | |
| Clawiter Road/To Temporary Parking Lot | A | |

TABLE WKS-8-8
Cumulative Impacts with Russell City, Eastshore Construction Traffic Routed via Clawiter Road PM

| Intersection | LOS | Reason of change, if any |
|---|---|---|
| Clawiter Road and West Street | B | |
| Clawiter Road and Industrial Boulevard | B | |
| Clawiter Road and Depot Road | A | |
| Industrial Boulevard and Depot Road | B | |
| Clawiter Road/Breakwater Avenue at SR-92 Westbound ramps | B | |
| Clawiter Road/Eden Landing Road at SR-92 Eastbound ramps | F | |
| Industrial Boulevard/Cryer Street at SR-92 Westbound ramps | C | |
| Clawiter Road/To Project Site | A | |
| Clawiter Road/To Temporary Parking Lot | D | |

**WKS-9**: Provide draft of Transportation Management Plan, Pedestrian Traffic Management Plan, and Heavy Haul Plan or, as an alternative, provide detailed project-specific measures that would be incorporated into the plans to mitigate potential impacts. Info is to be received before PSA is completed. This is a clarification of responses to DRs #55, #61, and #62.

**Response:**
The following provides additional details on the key elements that would support the Transportation Management Plan (TMP), which would address requirements for vehicles, pedestrians, and trucks. Following the information on the TMP, additional information related to transporting heavy loads is provided.

- *Require contractor to use Industrial Boulevard as the primary access route to project site for construction-related traffic*. This would avoid further congestion and delays on Clawiter Road without significant impacts along Industrial Boulevard. The contractor would be required to identify the routes for all delivery vehicles, specifying the exact routes from the freeways (I-880 and SR-92), and directions from the SR-92/Industrial Boulevard interchange.

- *Schedule construction shift hours to avoid peak commute hours.* The construction workers would use Clawiter Road to access the employee parking provided at that location. Since Clawiter Road traffic volumes are highest during peak commute hours, there would not be any significant impact on this roadway outside these peak commute hours. Peak hours are generally 7:30 to 8:30 AM, and 4:30 to 5:30 PM. Construction work hours would be set outside of this period, so that most construction workers would arrive before 7:30 AM and leave the site before 4:30 PM.

- *Schedule heavy equipment and building material deliveries during off-peak periods*. This would avoid having construction-related traffic added to the high volumes throughout the street network during peak periods. As deliveries are scheduled, the contractor can require deliveries to take place during specific hours, so that both contractor staff and outside deliveries do not arrive at the project site during the highest-volume traffic periods. This particularly applies to the oversized/heavy loads to be delivered (including 14 engine-generator sets, 2 large auxiliary power transformers, 2 large main power transformers and 4 pressure vessels). Delivery times for these heavy loads are expected to be between 10:00 p.m. and 4:00 a.m. and to the extent possible, coordinated to not overlap with the delivery of other permit loads. For details of the draft Heavy Haul Plan, please refer to the following portion of WKS-9.

- *Place traffic control devices, signing, lighting to mitigate the impacts associated with street or lane closures during the construction of the transmission line*. Construction of the transmission line in streets would likely require short-term lane closures. To manage these closures, applicable standards from Caltrans and the City of Hayward would be followed; where City of Hayward standards are more prescriptive, these would be followed. The Manual of Uniform Traffic Control Devices (MUTCD) is the Caltrans standard, and it includes detailed requirements for managing traffic during construction activities. Any construction on local streets would require encroachment permits from the City of Hayward, and the City's review would consider the placement of traffic control devices, signing, lighting, and other features to minimize impacts and maximize safety during any street/lane closures.

- *Schedule lane closure according to the transmission line construction schedule*. Lane closures would be restricted to construction periods only. The City encroachment permits would be applicable for a specified period; the contractor would describe the construction activities during that period. The contractor would also demonstrate that the transmission line construction activities are focused, so that there are not unnecessary extensions of closures without any construction in progress.

- *Conduct construction along affected roadways at night where permitted*. Subject to requirements and in coordination with City staff reviewing the encroachment permits, construction activities in industrial activities could take place on night and on weekends to minimize traffic impacts. This is particularly important for closures affecting lanes at signalized intersections.

- *Provide a flagperson for safe pedestrian crossing*. Construction workers would be required to park their personal vehicles at a temporary parking area located across the street from the project site on property owned by Berkeley Farms with frontage on Clawiter Road. To reach the construction site, they would cross Clawiter Road (on foot) two times each day. There is no nearby signalized intersection or crosswalk at the site. To mitigate the potential safety issue associated with unauthorized mid-block crossing, the contractor would be required to provide a flagperson during the arrival and departure times for workers. Depending on shift scheduling, this would likely be for 30 to 60 minutes in the morning and evening (work-day start and work-day end). Workers are expected to remain onsite during breaks and lunch. Construction workers would be informed about the requirement to wait for the flagperson prior to crossing Clawiter Road.

- *Flagperson for turns into the site entrance for heavy vehicles, as needed.* Regardless of the design of the driveway, it is expected that specific trucks may not be able to safely turn into the driveway off Clawiter Road without blocking or slowing traffic on Clawiter Road, or causing traffic to slow or stop while exiting the driveway. The same applies to vehicles exiting the driveway. Once the specifics of the driveway design are finalized, a maximum length vehicle would be identified; this would be the largest truck that can turn into or out of the driveway without affecting other traffic. Any vehicle larger than this minimum would be required to call or radio ahead to the plant site before entering the driveway. Onsite staff would also be required to check for oncoming trains (if the truck is coming from the north). Then, a trained flagperson would direct traffic at the intersection to ensure that the turns are made safely and efficiently.

- *Inform City of Hayward staff throughout the construction*. The TMP would address all known and likely traffic operations and safety considerations. If the contractor is considering or planning changes to the TMP activities (for whatever reason), the City of Hayward would be informed of the potential changes and given opportunity to provide input. Similarly, if the City identifies potential operations or safety issues, they would have a direct contact with the contractor to discuss those issues and identify strategies to minimize them.

The following heavy haul information is preliminary and subject to review and approval by Wartsila and future project contractors responsible for delivering heavy loads.

While many standard truck deliveries will be required during the course of Eastshore's construction, the number of oversized and/or heavy ("Heavy Haul") deliveries requiring Caltrans permits ("permit" loads) is fairly limited. Eastshore expects that the total quantity will be about twenty-two (22). Of these 22, 16 will be Wartsila items: fourteen engine-generator sets and two large auxiliary power transformers. The other 6 will be shipped by two of the suppliers serving Eastshore's General Contractor (GC): two large main power transformers, and four pressure vessels.

Since Eastshore is in the process of selecting its GC, and since Wartsila has yet to procure its material and finalize a transport plan with its vendors, a final Heavy Haul plan has not been prepared. Eastshore has discussed with Wartsila their expected transport methods for their loads. Wartsila and Eastshore agree that the following is the most likely scenario. A final Heavy Haul Plan will be provided when their respective contractors and vendors have been selected, and transport plans finalized.

With respect to Wartsila's permit loads:

> The Engine-Generator sets will be ocean freighted from Finland, with Houston being the expected port of entry into the U.S. From there, they will be transported via Rail by Union Pacific Rail Road (UPRR) to a railhead within 2 to 3 miles of the Clawiter site. There are several railheads within this vicinity that can be used; final selection will be based on the recommendation of UPRR, availability of the railhead sites at time of shipment, and the number of Engine Generator sets sent in the given shipment. It is currently anticipated that there will be three separate Engine-Generator shipments of two (2), five (5), and seven (7) sets, respectively.

Off-loading from each railcar to truck transport will be done by a gantry lifting system at the railhead site. From the railhead, each Engine-Generator set will be truck transported to Eastshore. Delivery times are expected to be between 10:00 .pm. and 4:00 a.m. Permit conditions for these deliveries will be as established by Caltrans.

Final truck routing is not known at this time, as the precise route will depend on the location of the railhead. However, the final approach to the plant is expected to be from SR 92 to Clawiter Road.

The first group of Engine-Generator sets is expected to arrive in Hayward in late May/Early June of 2008, the second in July, and the last in September. For any given group, one Engine-Generator will be truck transported to the site about once every two days, with delivery of the first set in the group about a day after arrival of that group at the railhead. As for the auxiliary transformers, their expected arrival on site is late May/early June by truck. These transformers will be trucked from the supplier's factory direct to the site. As with the Engine-Generator sets, auxiliary transformer delivery will be between 10:00 p.m. and 4:00 a.m. Their delivery will be coordinated to not overlap with the delivery of other permit loads.

With respect to GC permit loads:

As with Wartsila's heavy loads, permit conditions for the GC's heavy haul deliveries will be established by Caltrans. The GC's permit loads are expected to be limited to the two main plant power transformers (GSUs), and to four pressure vessels. Since the GC has not been selected and none of this equipment has been ordered, the point of origin of the equipment is not known at this time. It is possible that the GSUs will ship from outside the US. If this occurs, the port of entry will likely be Oakland, from which the GSUs would be offloaded by port equipment and onto heavy haul trucks, and then trucked to the site as permit loads. If the point of origin is not offshore, truck transport will be used from the factory location to the site. Eastshore currently expects that these GSUs would arrive on site in August 2008. As with the Wartsila equipment, delivery would occur at night between the hours of 10:00 p.m. and 4:00 a.m., and would be coordinated to avoid other permit load deliveries.

The four pressure vessels (start air receivers) will be fabricated within the US and then truck transported from their fabrication factory to Eastshore. Vessel delivery is expected in July or August and, as with the other permit loads, will arrive on site between 10:00 p.m. and 4:00 a.m. on the day(s) of delivery.

**WKS-10**: Supply breakout of truck and passenger vehicle traffic from total peak traffic counts and projected construction traffic counts. Include construction truck traffic counts from Russell City project in cumulative analysis. This is a clarification of response to DR #59.

**Response:**
As presented in the original AFC, Table WKS-10-1 shows the percentage of trucks and passenger vehicles from existing traffic counts on selected roadway segments. Table 10 is the number of trucks and passenger vehicles for projected construction traffic counts.

The number of trucks needed during the construction of Russell City Energy Center was provided in the Amendment to the AFC. An excerpt is provided in Table WKS-10-1.

TABLE WKS-10-1 (TABLE 8.10-4 FROM 06-AFC-6)
Existing Roadway Daily Volume/Capacity Assessment

| Roadway Segment | Between | Road Class | Median | Number of Lanes | ADT | Percent Truck | Peak Design Capacity | Peak Hour Demand | Peak V/C | Peak LOS |
|---|---|---|---|---|---|---|---|---|---|---|
| I-880 | Winton & SR-92 | Freeway | Divided | 8 | 256,000 | 7.0% | 2,000 | 16,900 | 1.08 | F |
| I-880 | SR-92 & Tennyson | Freeway | Divided | 8 | 229,000 | 6.7% | 2,000 | 14,900 | 0.95 | E |
| SR-92 | I-880 & Hesperian | Highway | Divided | 8 | 109,000 | 7.0% | 1,800 | 9,300 | 0.75 | C |
| SR-92 | Hesperian & Clawiter | Highway | Divided | 8 | 99,000 | 7.0% | 1,800 | 8,500 | 0.69 | B |
| SR-92 | Clawiter & San Mateo Bridge | Highway | Divided | 6 | 93,000 | 6.5% | 1,800 | 8,000 | 0.86 | D |
| Clawiter Rd | Industrial & SR-92 WB Ramp | Arterial | Undivided | 2 | 18,600 | 12.0% | 800 | 1,293 | 0.91 | E |
| Clawiter Rd | SR-92 WB Ramp & SR-92 EB Ramp | Arterial | Undivided | 2 | 14,700 | 12.0% | 800 | 1,014 | 0.63 | B |
| Depot Rd | Dodge & Clawiter | Arterial | Undivided | 2 | 8,400 | 12.0% | 800 | 639 | 0.52 | A |
| Depot Rd | Clawiter & Viking | Arterial | Undivided | 4 | 11,900 | 12.0% | 800 | 771 | 0.35 | A |
| Industrial Blvd | Clawiter & Depot | Arterial | Divided | 4 | 10,600 | 12.0% | 800 | 966 | 0.32 | A |
| Industrial Blvd | Depot & SR-92 WB Ramp | Arterial | Divided | 4 | 18,500 | 12.0% | 800 | 1,411 | 0.48 | A |
| Eden Landing Rd | SR-92 EB Ramp & Arden | Collector | Undivided | 2 | 8,200 | 12.0% | 800 | 624 | 0.49 | A |

**Freeway/Highway:** A road with limited access, designed to serve regional through traffic.

**Arterial Road:** A road whose principal function is to serve major through-traffic movements between major traffic generators.

**Collector Road:** A road whose principal function is to provide direct access between local roads and arterials. Collectors may provide access to adjacent properties; however, more restrictions are placed on on-street parking and driveway placement.

**Level of Service Criteria for Urban Streets, Highway Capacity Model, Transportation Research Board, 2000:**

| | | |
|---|---|---|
| A | 0.00 – 0.60 | Free flow; insignificant delays |
| B | 0.61 – 0.70 | Stable operation; minimal delays |
| C | 0.71 – 0.80 | Stable operation; acceptable delays |
| D | 0.81 – 0.90 | Approaching unstable; queues develop rapidly but no excessive delays |
| E | 0.91 – 1.00 | Unstable operation; significant delays |
| F | > 1.00 | Forced flow; jammed conditions |

TABLE WKS-10-2 (TABLE 8.10-5 FROM 06-AFC-6)
Construction Worker and Truck Summary for Eastshore Energy Center

| Month No. | Generating Station | | Forecast No. of Commuting Worker Vehicles (1.106 Occupancy) |
|---|---|---|---|
| | No. of Commuting Workers | No. of Trucks | |
| 1 | 43 | 21 | 39 |
| 2 | 64 | 21 | 58 |
| 3 | 71 | 23 | 64 |
| 4 | 82 | 16 | 74 |
| 5 | 85 | 16 | 77 |
| 6 | 132 | 15 | 119 |
| 7 | 183 | 18 | 165 |
| 8 | 216 | 18 | 195 |
| 9 | 218 | 18 | 197 |
| 10 | 233 | 18 | 211 |
| 11 | 235 | 18 | 212 |
| 12 | 211 | 18 | 191 |
| 13 | 152 | 12 | 137 |
| 14 | 91 | 10 | 82 |
| 15 | 77 | 9 | 70 |
| 16 | 67 | 9 | 61 |
| 17 | 55 | 10 | 50 |
| 18 | 32 | 8 | 28 |

TABLE WKS-10-3
Average and Peak Construction Traffic on Russell City Energy Center Project

| Vehicle Type | Average Daily Round Trips | Peak Daily Round Trips[a] |
|---|---|---|
| Construction Workers[b] | 292 | 585 |
| Delivery | 14 | 27 |
| Heavy Trucks | 6 | 26 |
| Total | 312 | 638 |

[a] "Peak" refers to scheduled peak months of construction (month14). Peak workforce during this month is expected to be up to 650 persons.

[b] Assumes that 10 percent of the workforce will carpool.

**WKS-11**: Specify actual window time for off-peak construction operations, including worker arrival/departure times. This is a clarification of response to DR #62 and public requests.

**Response:**

Data Request # 62 asked for information regarding the Traffic Management Plan for the project. Eastshore's response to WKS-9 expands the measures identified in Data Request # 62. Additionally, Eastshore's response to WKS-12 addresses construction times. With the implementation of the TMP measures, project-related traffic impacts are expected to be reduced to acceptable levels.

**WKS-12**: Specify conditions that would support 24-hour operation. Identify frequency and portions of the construction timeline when these conditions would be reasonably expected to occur. Address compatibility with City of Hayward construction restrictions. Response to public request.

**Response:**

During the construction phase of the project, the following situations may be encountered that would require night-time site work (e.g. work at times other than the normally-expected period of 7:00 a.m. to 7:00 p.m.):

- Delivery to the site of outsized and/or heavy ("permit") loads. Night-time deliveries of permit loads will be made during the middle portion of the project in the late evening hours, and are further discussed in the response to WKS-9.
- In the event that the project schedule is delayed, and as a result Eastshore's ability to meet its contractual commitments to PG&E are jeopardized, then either extended first shift, second shift (night-time), and/or week-end work may be required. These additional shifts/work hours would be expected to be limited to the final mechanical and/or electrical installation phases of the project, which occur during the last six months of the twelve month main construction duration, and prior to the six month project startup and testing phase.
- Project startup, tuning and initial testing, and performance testing will likely require periods of extended plant operations at various levels. The extent that these extended hours are needed will, to a significant degree, be dictated by the scheduling needs of various entities other than Eastshore (e.g. PG&E, the BAAQMD, the CAISO, the CEC, or others). In addition, Eastshore is required, under the terms of its PG&E contract, to demonstrate to PG&E's reasonable satisfaction the reliability of plant operations. This will be demonstrated by a 240 hour (10 day) continuous operating

period near the end of the plant performance testing period and prior to release of the plant for commercial operation.

After the completion of plant performance testing and its release for commercial operation, Eastshore will only run commercially when requested by PG&E. These periods of commercial operation are typically expected to occur during day time hours to support PG&E's peak power needs. However, they can extend into evening hours, and in the worse case, for periods of 24-hours or longer duration. Eastshore expects that these extended operating periods will be very infrequent, and that they will only occur during periods of very high electric energy demand. When not called on by PG&E to run and unless required for testing purposes, Eastshore will be shut down, with only plant auxiliaries in operation. These auxiliaries will receive power from PG&E and will not require operation of any of the fourteen Wartsila engines for that purpose.

On infrequent occasions, Eastshore will need to operate for other than commercial purposes. These include periods for plant testing needed to meet regulatory (e.g. BAAQMD) or contractual (PG&E) requirements. Eastshore expects that the vast majority of these "test" runs will be during day time hours, but night time operation is possible, depending upon the requirements of the entity requiring the test, and on PG&E's requirements for availability of Eastshore for commercial purposes.

**WKS-13**: Address impact of Caltrans I-880/SR-92 Interchange Reconstruction Project road closures and construction delays on off-peak worker arrivals and departures. This is a clarification of response to DR #64.

**Response:**

*Please note that the final Transportation Management Plan for the Route 92/I-880 Interchange reconstruction project is not available yet.*

The majority of work on the interchange should take place while traffic continues to flow uninterrupted on temporary adjacent ramps. Lane closures are expected when the final phases of construction are reached, and are scheduled from Friday evenings through Monday mornings. Therefore, there will not be any impact from Caltrans I-880/SR-92 Interchange Reconstruction Project when the construction traffic uses the interchange during day time on regular work days.

No construction on Eastshore is currently scheduled during the night, and therefore, there should not be any conflicts that cause delays. Should construction run behind schedule and workers might be commuting outside peak periods, Caltrans' measures in the Transportation Management Plan should be sufficient to handle this traffic, since it is taking place during off-peak periods and does not conflict with peak-hour commutes.

**WKS-14**: Provide proposed mitigation measures to address project-related traffic impacts on already impacted roads. This is a revisitation of DR #65. No mitigation was proposed.

**Response:**
DR #65 requested information for the 1-880/92 improvements. WKS-13 requested information on the impact of Caltrans I-880/SR-92 Interchange Reconstruction Project road closures and construction delays on off-peak worker arrivals and departures associated with Eastshore project-related traffic. Please refer to our response to WKS-13.

**Technical Area: Hazardous Materials**

**WKS-15**: Please provide a narrative description and preliminary design drawings of the piping system that will be used to transfer aqueous ammonia from the ammonia tank to the ammonia skid and then ammonia vapor from the skid to the individual engine exhaust stacks. The narrative and design drawings shall describe and show the following:

a. locations of these three components to one-another,
b. distances between them,
c. length of pipe between these components,
d. total length of piping at the power plant that will carry ammonia,
e. locations of secondary containment structures,
f. pipe materials,
g. proposed use of double-walled pipes (if any),
h. locations of ammonia sensors (if any),
i. operating pressures and temperatures of each segment of the piping, and height clearances of pipes above passage ways (if any)

**Response:**
The Eastshore Energy Center will be using 19% aqueous ammonia for its fourteen individual SCR systems. The aqueous ammonia will be stored in two 10,000 gallon tanks located approximately 80 feet southwest of the southwest corner of the power plant building. The tanks will have secondary containment capable of holding 110% of the contents of a full rupture of one tank plus 24 hours of rainfall from a 25 year storm. Note that the piping will, by design, convey aqua ammonia as a liquid throughout its length. Ammonia vaporization will not occur until injection of the liquid into the engine exhaust ductwork upstream of the SCR catalyst. Also, since the final design process has not begun, design drawings of the ammonia piping system are not yet available.

With respect to items a-j above:

a-c) Please refer to the scaled, preliminary general arrangement (Figure 2.2-1), included with Eastshore Energy Center's AFC. This drawing indicates the location of the two ammonia tanks and the ammonia pump skid, which is proximate to the tanks. The fourteen individual engine exhaust/SCR trains are various distances from the tank area. Note that the pump skid will be located in the containment area and will pressurize the aqueous ammonia to approximately 25 psig and forward it to the plant building in 1½-inch schedule 80 steel pipe located in a pipe rack common with the plant's oil piping. This supply line will run northward along the west side of the lube oil tanks, and then eastward to the north wall of the plant building and below the engine exhaust penetrations. Individual heavy wall steel lines, approximately ¾-inch diameter and about 20 feet in length, will tap off of this supply line and feed the injection header and associated nozzles in each engine's exhaust ducting. The ammonia is vaporized after being injected into the engine's exhaust stream and therefore a separate vaporizer is not required on this system.

d) The total run length for the main 1½-inch ammonia delivery header, from the point that it exits the tank containment area until it terminates at the east end of the power block, is about 650 ft.

e) Secondary containment is provided for the two main storage tanks.

f) Piping materials will be a combination carbon and stainless steels, all heavy wall construction. Stainless will be used for all piping downstream of the last filter set.

g) The use of double-walled piping is not proposed, since: 1) the ammonia system will be operating at a very low pressure and at ambient temperature (see item h); 2) no evaporation of ammonia will occur until injection into the exhaust ductwork; 3) repairs to double walled piping, in the event they should ever become necessary, would be more complex and time consuming than that for single wall pipe; and 4) Eastshore has committed to the use of heavy wall piping for the entire system.

h) Since flow rates are low (about 151 GPH at plant full load), operating pressures and temperatures will be fairly uniform over the length of the supply header. The operating temperature of the system will be ambient; pressure will be about 25 psig.

i) Ammonia sensors will be located in the storage tank area, and at various locations along the supply line as required to ensure prompt leak detection. All piping will be either in a pipe rack or secured to the building wall. There will be no exposed ammonia piping suspended over passage ways.

**Technical Area: Cultural Resources**

**WKS-16**: Please provide clarification regarding the disturbance boundary of the construction laydown area to confirm that the northernmost portion of the laydown area will not be impacted (potential site of Mt. Eden Railroad Depot)

**Response:**

Figure WKS-16-1, shows a photograph that delineates the expected boundary of the construction laydown area. Based upon earlier discussions with Beverly Bastion and Clint Helton during the Data Response Workshop held in January, we expect that this photograph will be adequate to address the question regarding avoidance of the northernmost apex of the "triangle" where there is a concern about possible remnants of the Mt. Eden railroad depot.


FIGURE WKS-16-1 AERIAL PHOTOGRAPH SHOWING EASTSHORE ENERGY CENTER SITE AND CONSTRUCTION LAYDOWN AREA

**Technical Area: Visual Resources**

**WKS-17**: Please provide photosimulations from one or more additional viewpoints.

**Response:**
Consistent with the requests from CEC staff and members of the public, Eastshore has prepared additional simulations. The attached 11 x 17 materials include a map of the locations of the new viewpoints, context photos and simulations, a conceptual landscape plan, and a planting palette. The new simulations are from the following locations:

- View from Life Chiropractic College, at exit from parking lot – landscaping height at planting
- View from Life Chiropractic College, at exit from parking lot – at 5-years of landscaping growth
- View from Residence on Depot Road
- View from Depot Road at Monte Vista Drive
- View from Hayward Shoreline Interpretive Center
- View from Hayward-San Mateo Bridge toll plaza

**Attachment WKS-17**

# New Visual Simulation Materials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Viewpoint A: Existing view from Life Chiropractic College, west entrance (photo taken on steps, about 4 feet above ground surface)

Viewpoint A: Simulated view of facility from Life Chiropractic College, west entrance



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Viewpoint B: Existing view from Life Chiropractic College, at exit from parking lot

Viewpoint B: Simulated view of facility from Life Chiropractic College, at exit from parking lot – landscaping height at planting


Viewpoint B: Simulated view of facility from Life Chiropractic College, at exit from parking lot – at 5-years of landscaping growth


Viewpoint C: Residence on Depot Road

Note: Due to the presence of intervening vegetation and structures, photo simulation results in the Eastshore facility not being visible from this viewpoint.

Viewpoint D: Depot Road at Monte Vista Drive

Note: Due to the presence of intervening vegetation and structures, photo simulation results in the Eastshore facility not being visible from this viewpoint.



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Viewpoint E: Existing view from Hayward Shoreline Interpretive Center


Viewpoint E: Simulated view of facility from Hayward Shoreline Interpretive Center

Viewpoint F: Hayward-San Mateo Bridge toll plaza

Note: Due to the presence of intervening vegetation and structures, photo simulation results in the Eastshore facility not being visible from this viewpoint.



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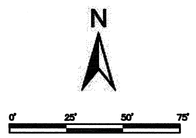
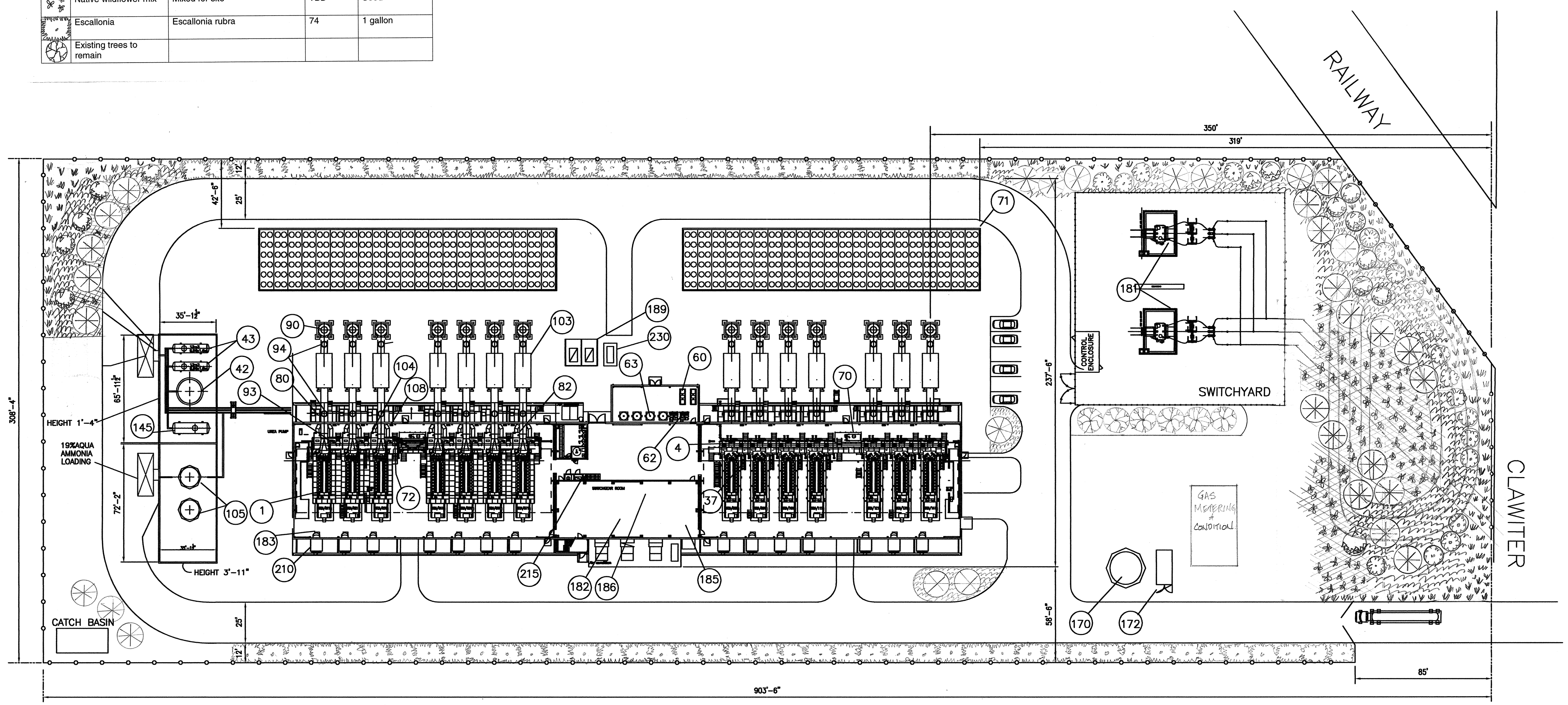



| | Common Name | Botanical Name | Quantity | Size |
|---|---|---|---|---|
| | Redwood | Sequoia sempervirens | 33 | 15 gallon |
| | No common name | Arbutus andrachne 'Marina' | 12 | 5 gallon |
| | Saucer Magnolia | Magnolia soulangeana | 20 | 15 gallon |
| | California lilac | Ceanothus griseus horizontalis 'Yankee Point' | 300 | 1 gallon |
| | Agapanthus - white | Agapanthus orientalis 'Albus | 150 | 5 gallom |
| | Matillija Poppy | Romneya coulteri | 200 | 1 gallon |
| | Native wildflower mix | Mixed for site | TBD | Seed |
| | Escallonia | Escallonia rubra | 74 | 1 gallon |
| | Existing trees to remain | | | |




| Species | Container Size | Height at Planting | Height at 5 years | Height at 10 Years | Notes |
|---|---|---|---|---|---|
| Redwood | 15 gallon | 7' | 20' | 40' | Maintains conical shape throughout life |
| Arbutus 'Marina" | 5 gallon | 6' | 10' | 25' | Initially much taller than wide, dense canopy fills out over time |
| Saucer Magnolia | 15 gallon | 4' | 8' | 15' | Open, rounded shape |
| Escallonia | 1 gallon | 1' | 5' | 12' | Assume is sheared to planter width, dense |
| Ceanothus 'Yankee Point' | 1 gallon | 6" | 3' | 3' | Sparce intitially, then covers ground completely with mounding shape |
| Matillija Poppy | 1 gallon | 1' | 6' | 6' | Stays tall and thin, but covers area |
| Agapanthus | 1 gallon | 3' | 3' | 3' | Will fill in to be solid mass |
| Wildflowers | Seed | 0' | 1'-2' | 1'-2' | Depict as colorful masses at the base of the matillija poppies |

## Project Landscaping Plan

Arbutus 'marina'

Escallonia

Ceanothus 'yankee point'

Matillija Poppy

California Poppy

Wildflower mix

Agapanthus

Saucer Magnolia

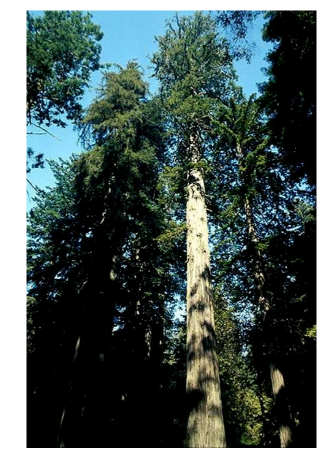


Photo Courtesy of National Park Service

Photo Courtesy of Edward Z. Yang

Redwood

**Plant Notes:**

Arbutus Marina: Evergreen tree; to 40', usually less
Escallonia: Evergreen shrub; fast growing, upright, compact 6'-15' tall and wide but can be sheared; blooms intermittently all year
Ceanothus 'Yankee Point': Evergreen groundcover; 2'-3' tall x 8'-10' wide
Matillija Poppy: Perennial, dies back in late fall; 6'-8' tall x 2'- 3' wide
Wildflower mix: Annuals and perennials mixed for site; sow in fall
Agapanthus: Evergreen perennial; 3'x3' blooms white in early summer
Saucer Magnolia: Deciduous small tree; up to 25' x 25' soft leaves, pink flowers in late winter and early spring before and during leafing
Redwood: Evergreen conical large tree; fast growth in early years (3'-5' per year), 70' – 90' tall x 15' – 30' wide in 25 years.

# Project Plant Palette

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