
2004
Long Term Request For Offers
Power Purchase
APPENDICES



March 18, 2005

TABLE OF CONTENTS

LIST OF APPENDICES

Appendix A: Long Term Request For Offers Agreement	1
Exhibit A1: Confidentiality Agreement	
Appendix B: Form of Letter of Credit	7
Appendix C: Notice of Intent to Offer.....	9
Appendix D: Power Purchase Agreement Term Sheet.....	10
Appendix E: Offer Pricing Data Forms	38
Appendix F: Generation Facility Information Forms	39
F1: Project Data Sheets	
F2: Project Description	
Appendix G: Credit and Finance Information Forms	52
Appendix H: Electric Transmission Information Form and Web Links	57
Appendix I: Gas Interconnection Information Form	65
Exhibit I1: Interconnection Information Sheet	
Exhibit I2: Agreement to Perform Tariff Schedule Related Work	
Appendix J: Functional Specifications for the Humboldt Bay Power Plant Replacement	70
Appendix K: Offer Cover Sheet	71

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: _____

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

Applicant: _____
Address: _____

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

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 longtermpprfo@pge.com or ownershipprfo@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.
- 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.

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**").

"**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).

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 resource 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.

**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.

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).

The following provision is applicable only to Fuel Conversion Agreements: 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.

The following provision is applicable to Definitive Agreements that are not Fuel Conversion Agreements: 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.

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.

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.

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).

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.

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.

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.

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:
Summer Months:
98.0% Availability
Non Summer Months:
94.0% Availability

The calculation for "**Availability**" is:

$$\text{totpotenrgy}_m / [\text{cap}_m * (\text{mnthhrs}_m - \text{mainthrs}_m)]$$

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 totpotenrgy_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 Payment²

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:

$$\text{DCMP} = \text{DCRF} \times \text{ADV} \times \text{DMMBTU}$$

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:

t_0 – date Definitive Agreement approved by the appropriate regulatory bodies

t - ongoing Transaction date after Initial Delivery Date

$P_{peak}(i, t)$ - price of monthly forward NP-15 defined peak power for month i as observed at the moment of time t measured in \$/MWh

$P_{off-peak}(i, t)$ - price of monthly forward NP-15 defined off-peak power for month i as observed at the moment of time t measured in \$/MWh

$P_{gas}(i, t)$ - 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:

$MIV(i,t_0) = [NumberOfPeakHours(i) * \max[(P_{peak}(i,t_0) - HR * P_{gas}(i,t_0) - VOM(i)), 0] * HourlyVolume] + [NumberOfOff-PeakHours(i) * \max[(P_{off-peak}(i,t_0) - HR * P_{gas}(i,t_0) - VOM(i)), 0] * HourlyVolume]$

Initial MIV will be calculated once at t_0 for the expected delivery life of the contract.

Current MIV calculation formula:

$MIV(i,t) = [NumberOfPeakHours(i) * \max[(P_{peak}(i,t) - HR * P_{gas}(i,t) - VOM(i)), 0] * HourlyVolume] + [NumberOfOff-PeakHours(i) * \max[(P_{off-peak}(i,t) - HR * P_{gas}(i,t) - VOM(i)), 0] * HourlyVolume]$

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 _____

	Calendar year	Guarantee at ISO Conditions MMBtus/MWh (HHV) @												Guarantee at Peak July Conditions* MMBtus/MWh (HHV) @											
		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																								
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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			
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23	2029			
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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										
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19	2025										
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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											
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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 _____

	Calendar year	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)					
		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																										
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28	2034																										
29	2035																										
30	2036																										

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

<u>Uses of Funds</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>
<u>Capital Costs</u>						
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	-	-	-	-	-	-
<u>Financing Costs</u>						
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	-	-	-	-	-	-
<u>Sources of Funds</u>						
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
		<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>
<u>Generation Assumptions</u>										
Guaranteed Electrical Output	Mw	-	-	-	-	-	-	-	-	-
Net Capacity Factor	%	-	-	-	-	-	-	-	-	-
Net Annual Generation	GWH	-	-	-	-	-	-	-	-	-
Major Scheduled Outages	Hours	-	-	-	-	-	-	-	-	-
<u>Revenues</u>										
	\$000's	-	-	-	-	-	-	-	-	-
<u>O&M Expense</u>										
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	-	-	-	-	-	-	-	-	-
<u>General & Administration Expense</u>										
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	-	-	-	-	-	-	-	-	-
<u>Financing</u>										
Interest	\$000's	-	-	-	-	-	-	-	-	-
Principal Repayment	\$000's	-	-	-	-	-	-	-	-	-
<u>Debt Coverage Ratio*</u>										
	X.X:1	-	-	-	-	-	-	-	-	-
<u>Incremental Capital Expenditures</u>										
	\$000's	-	-	-	-	-	-	-	-	-
<u>Capitalization</u>										
Construction Loan Balance	\$000's	-	-	-	-	-	-	-	-	-
Term Loan Balance	\$000's	-	-	-	-	-	-	-	-	-
Equity	\$000's	-	-	-	-	-	-	-	-	-

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

Financial Pro forma Template - Capital Structure

Initial Capital Structure

<u>Construction Financing (\$ in thousands):</u>	<u>% of Total</u>	<u>\$ 000</u>
Debt (list all debt)	-	-
Equity	-	-
Total Project Cost	-	-

<u>Permanent Financing (\$ in thousands):</u>		
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](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](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.ht
ml](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 Substation	320	2009	Active
35	Duke Energy North America, LLC	Duke Energy Oakland, LLC Option 2	Oakland "C": 115kV Substation	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 Switchyard	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

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)



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____

Applicant

PACIFIC GAS & ELECTRIC COMPANY

By: _____

By: _____

(Print/Type/Name)

Wayman Pon

Title: _____

(Print/Type Name)
Director, Gas Service Operations

Mailing Address: _____

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: _____