PG&E's Description of its RPS Bid Evaluation, Selection Process and Criteria

I. Introduction

A. Establishment of the Least Cost Best Fit ("LCBF") Process

Decision D.03-06-071 and D.04-07-029 adopted criteria for the rank ordering and selection of least cost, best fit renewable resources for use in RPS solicitations. Furthermore, D.05-07-039 directed the IOUs to make their bid evaluation process transparent to their Procurement Review Groups (PRG) and the California Public Utilities Commission (CPUC).

In addition, D.06-05-039 required "each utility to provide a report when it submits its short list of bids. Each utility should also serve a copy on the service list, and make the report available to the fullest extent possible to any other person or party expressing interest, subject to confidential treatment of protected information. The report shall explain each utility's evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected."

D.06-05-039 also required each IOU to hire an Independent Evaluator ("IE") "to separately evaluate and report on the IOU's entire solicitation, evaluation and selection process for this and all future solicitations. This will serve as an independent check on the process and final selections. The Independent Evaluator's preliminary report should be provided with the IOU's shortlist, and a final report with the AL for approval of selected bids."

The Scoping Memo for R.06-05-027, issued August 21, 2006, required that the IOUs submit their first written report describing their bid evaluation criteria and selection process on September 29, 2006, and that IOUs resubmit the report with their short lists (including more information, such as bid analysis, as necessary). Additionally, in the RPS Transparency Workshop held on December 15, 2006, the CPUC's Energy Division staff proposed, pursuant to D.06-05-039, a template to be used for future evaluation criteria and selection reports ("LCBF Written Report").

D.06-05-039 further required that each IOU include certain elements, subject to confidential treatment of protected information, in each report. These elements include bid-specific price information, the evaluation and scoring of each bid, and the decision rationale with respect to each bid, both selected and rejected. D.11-04-030 added that each utility should describe LCBF treatment of congestion, and to certain price data available.

B. Goal of PG&E's bid evaluation, selection criteria, and processes

The goal of the bid evaluation, selection criteria, and selection processes is to produce a short list of offers for negotiations consistent with the procurement goals set forth in the 2014 RPS Plan.

II. Bid Evaluation and Selection Criteria

A. Overview of the Ranking Methodology

PG&E evaluates each bid in terms of the following quantitative and qualitative attributes:

1. Net Market Value
   a. Benefits (Energy, Capacity, Ancillary Services)
   b. Contract Payments
   c. Transmission Network Upgrade Costs (also called a "transmission adder")
   d. Congestion Cost
2. Portfolio-Adjusted Value
   a. Location
   b. RPS Portfolio Need
   c. Energy Firmness
   d. Curtailment
3. Project Viability
4. RPS Goals
5. Supplier Diversity

Solicited bids are evaluated using the following step-by-step process:

The Net Market Value (NMV) is computed for each Offer. NMV will be adjusted by other attributes, such as location, RPS portfolio need, energy firmness, and curtailment, to arrive at the Portfolio-Adjusted Value (PAV). After the calculation of PAV is complete, PG&E considers project viability, contribution to RPS goals, supplier diversity, and the other qualitative criteria listed below. Project viability has the greatest qualitative effect on the ranking. The set of highest ranked Offers which allow for a reasonable probability of satisfying PG&E's procurement goal is selected for the Shortlist.

1. Market Valuation

a. Overview of the Market Valuation Criterion

Market valuation considers how an Offer's costs compare to its market benefits. Costs include Transmission Network Upgrade Cost, Congestion Cost and Integration Cost as well as contract payments. Benefits include energy, capacity, and ancillary services values. Specifically, Market Valuation computes NMV for each offer as follows:

$$\text{Net Market Value: } R = (E + C) - (P + T + G + I)$$
$$\text{Adjusted Net Market Value: } A = R + S$$

Where
E = Energy Value
C = Capacity Value
P = Post-Time-Of-Delivery (TOD) Adjusted Power Purchase Agreement (PPA) Price
T = Transmission Network Upgrade Cost
G = Congestion Costs
I = Integration Costs
S = Ancillary Service Value

Costs and Benefits are each quantified and expressed in terms of levelized dollars per MWh. NMV is Benefits minus Costs, and is expressed in terms of levelized dollars per MWh.

The calculation of Benefits, Costs, and Market Value is described below.

b.   Calculation of Benefits and PPA Costs

Energy benefit (E), for each hour of delivery, is the value of energy delivered at the market energy price at the corresponding Trading Hub (NP15, SP15, ZP26, Palo Verde), adjusted for Losses. As-available (or must-take) energy delivery for each hour from an Offer is determined by the hourly generation profile of the Offer. To the extent that the Offer provides dispatchable capacity, the value of the option from the dispatchability will be captured in the energy benefit calculation. The option value calculation depends on the particular characteristics of the dispatchable capacity. If an Offer includes energy storage that allows PG&E to schedule the discharge and charge of the storage, the energy benefit will also include the additional value that PG&E can realize from being able to shift the RPS energy from the Project to more valuable hours given the constraints of the energy storage.

Losses vary by location of the project and are assessed using the Locational Marginal Price (LMP). The Loss Multiplier for a project delivered to Palo Verde will be 100%. The average Loss Multipliers for a project delivered to CAISO are provided in Table 1. A higher Loss Multiplier implies less loss, thus more value associated with a project located in the corresponding load zone. PG&E may further update the Loss Multipliers prior to the evaluation of bids in the 2014 RPS Solicitation.

Discounted hourly energy benefit is summed across hours of delivery, and summed across years. The total benefit is then scaled by the delivered energy to be expressed in terms of levelized dollars per MWh.

For offers providing Buyer Curtailment, **energy benefit** will include the option value of the difference between the (presumably negative) wholesale market spot price avoided for the Project and PG&E's cost when Buyer Curtailment occurs.

Capacity benefit (C) for Resource Adequacy (RA), for year of availability, is the projected monthly quantity of qualifying capacity multiplied by the projected monthly capacity price,

discounted and summed across years. To the extent that an Offer provides flexible capacity, the capacity that is expected to count for flexible RA and provide the ISO's must-offer requirement for flexible capacity resources will be evaluated at the projected monthly premium (which can be zero or positive) for flexible RA and then added to the Capacity Benefit. There currently exists significant uncertainty regarding the specifics of generic and flexible RA markets in California, especially for delivery years beyond 2015. Therefore, the calculation of capacity benefit may evolve as more information is known about market design or as uncertainty lingers.

For an Offer in a location that is projected to contribute to PG&E's satisfaction of a Local Capacity Requirement, the capacity attributable to the Offer may be valued at a premium relative to the value of capacity that satisfies only system needs.

Ancillary Services benefit (S) is assumed to be zero if an Offer doesn't provide any Ancillary Services (A/S) capability. For Offers that provide PG&E the ability to schedule Ancillary Services, the incremental benefit of having A/S capability will be captured, not to be double counted with the energy benefit.

PPA Payments (P) are determined by the expected payments under each Offer including associated debt equivalence costs. The PPA Payment for each hour is calculated by multiplying expected delivery quantity by the Offer's price. The Offer's price is the contract price of the Offer multiplied by the applicable Time of Delivery (TOD) factors specified in the RPS Solicitation Protocol. The hourly PPA Payment is expressed in units of levelized dollars per MWh.

For Offers with capacity payments, the PPA Payment will include PG&E's capacity payments for each Offer as determined by the Offer's capacity price multiplied by the applicable capacity adjusted by appropriate Time Of Availability (TOA) factors specified in the PPA. Cost is measured in units of levelized dollars per MWh.

c. Calculation of Transmission Network Upgrade Costs

The Transmission Network Upgrade Costs (T) is the cost, if any, of bringing the power from the generating facility to PG&E's network. PG&E expects to use results from Participants' interconnection studies.

A Present Value Revenue Requirement (PVRR) is calculated from the Interconnection Study for each evaluated bid. If the Seller is offering an energy-only resource, PG&E will use the reliability network upgrades identified in the interconnection study for calculation of the transmission adder. If the Seller is offering a full deliverability resource, PG&E will use both the reliability network upgrades and delivery network upgrades in the calculation.

The PVRR captures from a ratepayer perspective the risk and cost to construct and maintain transmission upgrades to accommodate the generation from the renewable resource.

This PVRR of the costs of the Network Upgrades is converted into levelized dollars per MWh.[1]

PG&E may take into account on a qualitative basis the additional value for projects that have no transmission risk.

d. Congestion Costs

Congestion cost (G) for each hour is calculated by the multiplication of (1) a Congestion Cost Multiplier for the corresponding time period and load zone, (2) the Locational Marginal Price (LMP) of the corresponding Trading Hub, and 3) expected energy delivery.

A project delivered to Palo Verde would be evaluated with Congestion Cost of 0%. A summary of Congestion Cost Multipliers for each load zone in CAISO is included in Table 1. A higher Congestion Cost Multiplier indicates a higher Congestion Cost (G). Specifically, a Congestion Cost Multiplier greater than zero indicates that generation in the corresponding area serves load outside of the area by congested lines and thus a new generation in the corresponding area is expected to increase the congestion. A zero Congestion Cost Multiplier implies there is no congestion in the transmission lines connecting the area. A Congestion Cost Multiplier less than zero indicates that loads in the corresponding area are served by the constrained transmission line(s) and thus a new generation in the area may reduce congestion. PG&E may seek approval from the California Public Utilities Commission to update the Congestion Cost multipliers prior to evaluation of bids in the 2014 RPS Solicitation.

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[1] For the 2014 RPS RFO, sellers offering full capacity offers may specify when full capacity is to begin and as a result, costs will be reflected accordingly in the PVRR calculation.

2014 RPS RFO   **Detailed Least Cost Best Fit Evaluation Criteria**

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TABLE 1
Congestion Cost Multipliers and Loss Multipliers[2]

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	Descriptive Names	CAISO	Loss Multipliers for E		Congestion Cost Multipliers for G		LMP Multipliers for E-G	
			On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
1	PG&E Central Coast	PGCC	102.4%	100.5%	2.2%	1.6%	100.2%	98.9%
2	PG&E East Bay	PGEB	101.9%	99.9%	2.1%	1.4%	99.8%	98.5%
3	PG&E Fresno	PGF1	103.1%	102.7%	-2.3%	-6.4%	105.4%	109.0%
4	PG&E Fulton	PGFG	101.5%	98.6%	2.7%	1.3%	98.8%	97.3%
5	PG&E Humboldt	PGHB	103.8%	104.2%	2.6%	2.0%	101.2%	102.2%
6	PG&E Los Padres	PGLP	100.1%	98.3%	3.0%	1.9%	97.0%	96.3%
7	PG&E North Bay	PGNB	102.0%	99.5%	2.8%	1.4%	99.2%	98.0%
8	PG&E North Coast	PGNC	103.0%	98.5%	4.8%	3.6%	98.2%	95.0%
9	PG&E North Valley	PGNV	98.0%	97.4%	2.3%	0.9%	95.7%	96.5%
10	PG&E Peninsula	PGP2	103.0%	100.7%	2.7%	1.3%	100.3%	99.4%
11	PG&E Sacramento	PGSA	100.4%	99.3%	1.8%	0.9%	98.6%	98.4%
12	PG&E South Bay	PGSB	102.6%	100.6%	2.5%	1.2%	100.1%	99.3%
13	PG&E San Francisco	PGSF	104.8%	101.6%	1.7%	1.3%	103.1%	100.3%
14	PG&E Sierra	PGSI	99.9%	99.1%	1.1%	0.9%	98.8%	98.2%
15	PG&E San Joaquin	PGSN	96.7%	96.4%	2.8%	1.4%	93.9%	95.0%
16	PG&E Stockton	PGST	101.0%	99.8%	2.7%	1.4%	98.3%	98.5%
17	So Cal Edison Core	SCEC	96.9%	98.7%	-1.6%	-0.6%	98.5%	99.3%
18	So Cal Edison North	SCEN	96.4%	99.4%	-5.8%	-2.9%	102.2%	102.2%
19	So Cal Edison West	SCEW	98.9%	100.1%	-3.7%	-1.0%	102.6%	101.1%
20	So Cal Edison High	SCHD	92.8%	95.2%	-0.5%	-0.9%	93.3%	96.1%
21	So Cal Edison Low	SCLD	96.0%	97.7%	0.2%	-0.8%	95.8%	98.4%
22	So Cal Edison North	SCNW	96.6%	98.7%	-0.5%	-0.9%	97.1%	99.6%
23	San Diego Gas &	SDG1	99.0%	99.7%	-2.6%	-0.3%	101.7%	100.1%

Overall locational value of the project delivered to CAISO should be assessed by looking at the LMP multipliers provided in Table 1. LMP Multiplier for a project delivered to Palo Verde will be 1. The LMP multipliers imply the relative value of 1 MWh in each load zone compared with the corresponding Trading Hub (NP15, SP15, ZP26, or Palo Verde) price. For example, PG&E could consider Offer A located in Sierra and Offer B located in San Francisco, with everything else the same. Offer B will have higher Energy Value (E) because the Loss Multipliers in San Francisco are higher than for the Sierra. On the other hand, Offer A has lower Congestion

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[2] Multipliers shown are a simple average over hours and months. Contract valuations use disaggregated values for different months.

Cost (G) because the Congestion Cost Multiplier for Sierra is lower than San Francisco. Overall, Offer B scores higher than Offer A, because E-G will score higher due to higher LMP Multipliers in San Francisco compared with Sierra.

The map for CAISO APNodes is for illustrative purposes only.

Sub-Load Aggregation Point
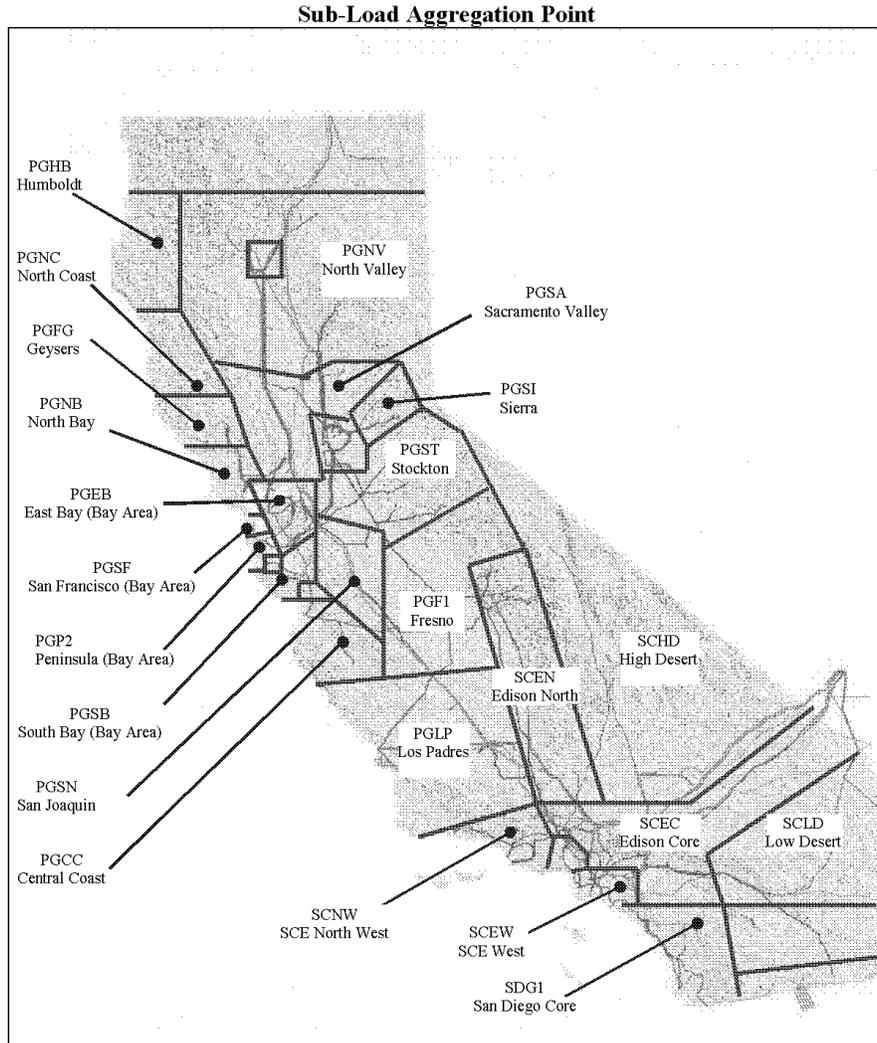
e. **Integration Costs**

The renewable integration cost adder (RICA) is calculated using the methodology adopted in D.14-11-042. Renewable integration cost is used in the derivation of Net Market Value per Section 1.a of this document.

The RICA is calculated as the sum of two cost components: 1) variable costs; and 2) fixed costs.

The variable cost component is set at $4/MWh for wind and $3/MWh for solar.

The fixed cost component is calculated as the product of two parameters: 1) PG&E's internal/confidential projection of a monthly premium (which can be zero or positive) for flexible RA expressed as $/kW-month; and 2) the monthly increase (or decrease) in the need for flexible RA associated with one MW of installed capacity of wind or solar ("Contribution to Flexible Capacity Needs") expressed as MW of flex capacity needed/MW of wind or solar capacity.

The Contribution to Flexible Capacity Needs is determined in the following way:
1. Obtain the hourly aggregate system profile for load, wind, and solar.[3]
2. Calculate the hourly three hour net-load ramp for each hour of the year.[4]
3. Identify the maximum three hour net-load ramp for each month, and determine the relative contributions from load, wind, and solar to that ramp.
4. Determine the monthly increase (or decrease) in the need for flexible capacity associated with one MW of installed capacity of wind and solar. This is determined based on the contribution of wind / solar in step 3 and the total installed capacity of wind / solar in the system. For example, if there is 5,000 MW of installed wind and wind's contribution to the maximum three hour net-load ramp in July is 500 MW, then wind's contribution to flexible capacity need is 500 MW / 5,000 MW, or 0.1 MW per 1 MW of installed wind. In this example, 0.1 MW would be the Contribution to Flexible Capacity Needs attributed to a bid for wind generation expected to deliver in that month.

For this 2014 RPS solicitation, PG&E has calculated the Contribution to Flexible Capacity Needs using the four steps above and hourly data from the 2014 Long Term Procurement Plan (LTPP) Trajectory Scenario[5]. The maximum (single hour) wind / solar output from these 2014 LTPP hourly data is used to estimate the total installed capacity for wind / solar in the system. The resulting Contribution to Flexible Capacity Needs for solar and wind are presented in Table 2 below.

TABLE 2
Contribution to Flexible-RA Requirement Per 1 MW of Installed Capacity (MW)

Month	Solar	Wind

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[3] Consistent with the CAISO Flexible Capacity Study, the solar PV and solar thermal components are combined. (http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf)
[4] Consistent with the CAISO Flexible Capacity Study, this is the three hour contiguous ramp starting in a given hour of the year, where net-load is defined as load minus wind minus solar
[5] The hourly data can be obtained from the results of the CAISO's 2014 LTPP Production Cost runs. The CAISO posted these results on its LTPP File Transfer Protocol (FTP) website at http://12.200.60.146:990 on July 31, 2014. To help parties access this information, PG&E is also providing these publicly available hourly profiles on its website at www.pge.com/rfo under 2014 Renewables RFO.

JAN	0.52	0.12
FEB	0.75	0.09
MAR	0.63	0.15
APR	0.78	0.13
MAY	0.66	0.01
JUN	0.58	0.07
JUL	0.58	0.04
AUG	0.61	0.05
SEP	0.78	0.20
OCT	0.66	0.02
NOV	0.59	0.00
DEC	0.63	0.20

f.   Market Valuation for Offers with Storage

PG&E evaluates the market value from dispatchable storage bundled in an Offer for its ability to (1) shift renewable energy to more valuable hours, (2) provide A/S from stored energy and storage capacity, and (3) provide flexible RA.

PG&E solves for the charge, discharge and A/S schedules that would maximize the value from the project starting from the generation profile without using the energy storage, and the storage constraints provided by the Seller. In order to maximize the spot market value from the project given the assumed market prices for energy and A/S, PG&E will use an optimization technique to obtain the best time and amount to charge, discharge and provide A/S capacity. The spot market value consists of the revenue from energy to be delivered to the grid (the sum of energy that is directly generated from the renewable resource and the energy discharged from storage) and the revenue of A/S capacity to be provided, net of the variable cost from operating. Depending on the energy and A/S prices for a given time period, it may be better to provide A/S, charge renewable energy, discharge stored energy, or do nothing from storage. The Energy Value, A/S Value and PPA Costs in Net Market Value are computed from the assumed market prices as well as the optimized charge, discharge, generation, and A/S schedules.

For Ancillary Services, PG&E asks bidders to specify capability, ramp rates and operating ranges for providing Regulation Up and Down, Spinning Reserve (Spin) and Non-spinning Reserves (Non-spin). When optimizing the schedules, PG&E makes sure that the A/S schedules are within the operating ranges provided and that there is enough energy and storage capacity available. For valuation purposes, PG&E will assume that the value from providing Non-spin in addition to the Spin is negligible because the price for Non-spin is never higher than price for a similar Spin product. PG&E may include future CAISO A/S products such as flexible ramping product in an optimization to estimate their value if PG&E anticipates that there could be significant incremental value.

PG&E understands that the life and cost of the storage component depend on how it is operated. Sellers must identify in its Offer any constraints on storage operations to ensure that the storage

component will continue to meet its operating requirements throughout the term of the proposed contract. For example, if an energy storage component may degrade due to deep discharging, a bidder can specify the minimum State-of-Charge that PG&E should maintain when operating the component. As another example, if an energy storage component may degrade due to frequent switching between charging and discharging, a bidder can specify the number of switching constraints. PG&E will include such constraints in the optimization determining the operating schedules in order to derive the energy and A/S value of an Offer.

Dispatchable storage components that can follow CAISO's day-ahead and real-time dispatch instructions and thus allow PG&E to provide economic bids are expected to count towards meeting PG&E's requirement for flexible RA. Due to the uncertainty about the counting rules that will govern co-located storage components, PG&E will estimate Effective Flexible Capacity (EFC) for renewable offers with storage as a function of MW size and discharge duration of the energy storage component. The calculation of capacity benefit may evolve as more information is known about market rules. The flexible RA Value will be included in the Capacity Value of the Net Market Value.

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2. Portfolio Adjusted Value

Portfolio Adjusted Value (PAV) adjustments include the following components: Location, RPS Portfolio Need, Energy Firmness, and Curtailment.

a. Location

PG&E has a preference for projects in its service territory. This preference is influenced by constraints (either in the marketplace or imposed on PG&E by regulatory agencies) that may limit the amount of capacity from south of Path 26 (SP15) and from imports that PG&E can count toward its RA requirement. Capacity located closer to PG&E's load is likely to deliver energy that has more value for PG&E's bundled electric portfolio, even when market forward prices indicate that energy delivered farther away has greater Market Value. The long-term risk for PG&E's customers is less when resources are located within PG&E's service territory rather than outside of PG&E's service territory. The calculation of PAV effectuates this by adjusting the value of energy and capacity for offers from resources in SP15 or outside of the CAISO footprint.

For offers from resources not in NP26, the Energy Value component in Net Market Value is adjusted so that the PAV Energy Benefit is not more than the Energy Value component calculated using NP15 energy prices, for each period the value of energy is calculated. This adjustment is not intended to adjust for congestion—that is accounted for in the calculation of Net Market Value in the Congestion Multipliers. This adjustment is intended to account for the relative value, to PG&E's portfolio, of energy that may be used to serve PG&E's bundled customer load. This adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's calculation of Energy Value in Net Market Value represents an offer's

value of energy to any wholesale market participant, including investor-owned utilities in southern California and purely financial traders, the locational adjustment described here is specific to PG&E's portfolio and would not be made by investor-owned utilities in southern California, financial traders, and wholesale market participants in general (although the locational adjustment described here might be made by other load-serving entities with load heavily concentrated in northern and central California).

The PAV Capacity Benefit in SP15 or outside CAISO is calculated using capacity prices that are no higher than the capacity prices used for offers from resources in NP15. The PAV Capacity Benefit for offers from resources in SP15 will be based on capacity prices that are no higher than the short-run cost of capacity. This adjustment is intended to account for the relative value, to PG&E's portfolio, of capacity that may be used to meet future resource adequacy requirements to serve PG&E's bundled electric customers. The adjustment reflects the fact there are constraints on how much SP15 and import capacity may be counted toward PG&E's RA requirements. This adjustment is not duplicative of the Capacity Value component of Net Market Value. Whereas PG&E's calculation of Capacity Value in Net Market Value represents an offer's value of capacity to any wholesale market participant, including investor-owned utilities in southern California and purely financial traders, the locational adjustment described here is specific to PG&E's portfolio and would not be made by investor-owned utilities in southern California, financial traders, and wholesale market participants in general (although the locational adjustment described here might be made by other load-serving entities with load heavily concentrated in northern and central California).

As a consequence of these adjustments to the value of energy and capacity, offers from resources in NP15 will tend to have higher PAV and rank better than equivalent offers from resources in SP15 and outside of the CAISO footprint.

b. RPS Portfolio Need

PG&E will consider how an Offer contributes to PG&E's overall portfolio need for RPS energy. For each delivery year in which PG&E's portfolio (augmented by the offer) is projected to be short RPS-eligible energy, the PAV Adjustment for the Offer's RPS-eligible energy will be higher.

This RPS Portfolio Need adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's Net Market Value calculation reflects the value of generic energy in the marketplace, the RPS portfolio need adjustment described here reflects the incremental value of RPS-eligible energy to PG&E's portfolio in meeting the portfolio's RPS requirement.

Thus, Offers that deliver RPS energy only in periods when PG&E's portfolio needs RPS energy will have higher PAV and rank better than equivalent offers that deliver RPS energy in periods when PG&E's portfolio does not need RPS energy.

c. Energy Firmness

PG&E's Net Market Value calculation of Energy Value uses energy forward price curves that are associated with firm energy. Offers in the RPS RFO are typically not for firm energy. To value the energy benefit for an offer from a resource that has uncertainty in the minute-by-minute production of energy, a risk-adjusted multiplier is used in calculating PAV. PAV is calculated as the product of an offer's Energy Benefit (as calculated in the Energy Value component of Net Market Value and then adjusted by the locational adjustment and RPS portfolio need adjustment described above) and the PAV risk-adjusted multiplier for that offer. The PAV risk-adjusted multiplier takes on values between 0.8 and 1.0. A multiplier of 1.0 represents an offer's Energy Benefit is the same as if the offer were to provide firm energy. A multiplier of 0.8 represents substantial reduction in an offer's Energy Benefit because of the offer's significant uncertainty in energy production from its resource. The multiplier for an offer from a solar thermal resource will typically be higher than the multiplier for an offer from a wind resource or a solar PV resource. The multiplier for an offer that includes storage will have a higher multiplier than the alternative offer without storage. The particular PAV risk-adjusted multiplier applied to an offer will be a function of the relative firmness of the offer's energy and not simply a function of the renewable technology being offered.

The energy firmness adjustment itself will not result in any PAV increase or better ranking for offers providing dispatchability. For offers providing dispatchability, PG&E will either: (1) use option-based approaches to calculate the Energy Value component of Net Market Value, and/or (2) calculate PAV using the curtailment adjustment described below. Nonetheless, offers providing dispatchability will have higher PAV and rank better than equivalent offers that do not provide dispatchability.

The energy firmness adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's Net Market Value calculation reflects the value of firm energy in the marketplace, the energy firmness adjustment described here reflects PG&E's assessment of the reduction in offer value that results from measuring and managing a position with uncertainty in energy production. For the same particular offer, other wholesale market participants might assess lower or higher reductions in offer value, resulting from each wholesale market participant's different portfolio positions and different capabilities, opportunities, and constraints for wholesale market activities.

The energy firmness adjustment is also not a proxy or substitute for a nonzero integration cost adder. The energy firmness adjustment is strictly in the context of PG&E's portfolio. In contrast, an integration cost adder is in the context of the system. The PG&E portfolio perspective and the physical transmission system perspective are two distinct and separate perspectives.

Thus, offers that deliver RPS energy with greater firmness will have higher PAV and rank better than equivalent offers that deliver RPS energy with less firmness.

d. Curtailment Hours

PG&E prefers a Seller to offer its energy as able to be bid economically into the CAISO markets. These economic bids may result in Buyer Curtailment of a resource, for which the Seller will be compensated. PG&E's Net Market Value calculation of Energy Value includes the option value of the difference between the (presumably negative) wholesale market spot price avoided when Buyer Curtailment occurs and the Buyer's cost of Curtailment. This expected value is anticipated to be realized by any wholesale market participant and is not specific to the particular composition or positions of PG&E's portfolio or PG&E's particular capabilities, opportunities, and constraints for wholesale market activities.

When an offer does not conform to PG&E's preference for an ability to economically bid the resource by limiting the number of Buyer Curtailment hours, PG&E may not be able to curtail in the hours that are more valuable to PG&E and its customers. Recognizing increasing operational challenges that additional inflexible resources are placing on the system, PG&E will adjust the PAV of such offers to account for the costs and operational challenges that are induced to PG&E's portfolio. The operational challenges include the operational complexity caused by the limits on curtailment hours. The energy that PG&E cannot curtail when needed may increase the portfolio's costs for energy, imbalance energy charges from the CAISO, cause the CAISO to issue involuntary curtailment orders to PG&E that can be costly, cause extreme price volatility in spot market prices for energy and ancillary services and as a result increase the cost of ancillary services, and add similar costs associated with managing the portfolio. The PAV adjustment for limited curtailment hours represents these decremental values to PG&E's portfolio, not to the energy value of the individual offer. The PAV curtailment adjustment is therefore not duplicative of PG&E's calculation of Net Market Value.

The PAV curtailment adjustment will be calculated separately for each resource type. For each resource type, the hourly generation that cannot be curtailed in the over-generation hours will be multiplied by the magnitude of the negative hourly price. This quantity will be summed over the year and divided by the total annual generation from that resource type. Non-curtailable resources which generate a *higher* proportion of energy in the overgeneration hours will have a more negative PAV curtailment adjustment than non-curtailable resources which produce a *lower* proportion of energy in the overgeneration hours. Fully curtailable resources will have zero PAV curtailment Adjustment.

The PAV curtailment adjustment is not duplicative of any integration cost adder. The curtailment adjustment is strictly in the context of PG&E's portfolio. In contrast, an integration cost adder is in the context of the system. The PG&E portfolio perspective and the physical transmission system perspective are two distinct and separate perspectives.

The PAV curtailment adjustment is also not duplicative of the PAV energy firmness adjustment. The curtailment adjustment reflects a flexibility or dispatchability (emanating from hours of Buyer Curtailment) that is a quality superior to must-take firm energy, whereas the energy firmness adjustment reflects uncertain generation that is typically inferior to must-take firm energy and at best is the same quality as must-take firm energy.

Thus, offers that provide less than full curtailment will have lower PAV and rank worse than equivalent offers that provide full operational flexibility.

3. Project Viability

The CPUC developed a Project Viability Calculator (PVC) with stakeholder participation from utilities, renewable project developers and ratepayer advocates. The CPUC's PVC, along with background on its development, instructions for use, and criteria scoring guidelines can be found on http://www.cpuc.ca.gov/PUC/energy/Renewables/procurement.htm and in the PVC itself.

PG&E will evaluate the project viability of each offer using the June 2, 2011 CPUC PVC. Participants are requested to self-score each of their offers using the PVC in Attachment D and provide supporting documentation for each score. PG&E will review all submissions and adjust self-scores as appropriate.

For background, a project's viability score is based on weighted scores in three categories: (1) Company/Development Team, (2) Technology, and (3) Development Milestones. The Project Viability assessment results in a score ranging from 0 to 100 points with 100 being the highest possible score. Offer information required by PG&E for evaluation of project viability is described in this 2014 Solicitation Protocol Section VI. The Participant's claims in all three categories are verified to the extent possible using publicly available data and/or PG&E data.

4. RPS Goals

PG&E assesses the Offer's consistency with and contribution to California's goals for the RPS program (collectively "RPS Goals"). Determination of the extent to which the proposed development supports RPS Goals is based on the information provided in the Offer as well as PG&E's assessment of the project (see RPS Solicitation Protocol Section VI). The RPS Goals assessment considers the factors described below.

      i.   Legislative direction implemented in 399.13(a)(7):

"In soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."

      ii.   Consistency with the CPUC's Water Action Plan adopted on December 15, 2005 and updated October 2010.

To the extent a project uses water on site, its impact on California's water quality and consistency with the CPUC's recommended water conservation practices and goals is reviewed.

iii.   Executive Order S-06-06, signed on April 25, 2006.

In this executive order, Governor Schwarzenegger described the benefits of biomass resources in electricity production and established a goal that the state would meet 20% of its renewable energy needs with electricity produced from biomass. The Participant is encouraged to describe in its Offer how its ERR facility, if applicable, can support the 20% goal.

5. Supplier Diversity

In support of PG&E's supplier diversity goals, the good faith efforts of Participants to subcontract with Diverse Business Enterprised ("DBE") such as Women-, Minority-, and Service Disabled Veteran-owned Business Enterprises ("WMDVBE") and Lesbian, Gay, Bisexual, and Transgender-owned Business Enterprises ("LGBT") if a Participant is a DBE are factors that are considered in the bid evaluation process.

6. Contract Tenor

Longer-term transactions may pose greater project risk because of uncertainty in market conditions. PG&E therefore has a preference for offers with delivery periods of 10 to 15 years rather than delivery periods lasting 20 years or more.

7. Counterparty Concentration

PG&E may qualitatively consider the volume of energy already under contract from a particular counterparty, as well as offers received in this RFO.

8. Resource Diversity

Per Decision 04-07-029, a utility can use resource diversity as a qualitative attribute in its bid evaluation. PG&E may consider an offer's impact on its portfolio from a resource diversity perspective. Specifically, PG&E may qualitatively consider the contribution a bid may make to the energy production profile diversity of PG&E's portfolio.

9. Modifications

PG&E will qualitatively assess the materiality and cost impact of any of Participant's proposed modifications to Solicitation requirements and the applicable Agreement or term sheet.

10. Energy Storage Procurement Targets

PG&E will qualitatively consider the contribution to the storage procurement targets from an Offer with storage.

11. Other Qualitative Criteria

In addition to the criteria specifically listed above, PG&E may consider other qualitative factors that could impact the value or viability of bids, including, but not limited to: safety issues that affect performance; PG&E's past commercial experiences with a counterparty; project size; and the location of a generation resource.