Conservation & Renewable Energy Potential Study For Smith River Rancheria

Final Report

Period covered: August 1, 2005 through December 31, 2006

Date of Report: July 2007

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1 Executive Summary

1.1 Purpose

In January 2006 the Smith River Rancheria (SRR), located in Smith River, California, contracted with the team of Strategic Energy Solutions (SES) and Evergreen NRG to conduct a study for the community. The objective of the study was to identify renewable generation opportunities that would facilitate Rancheria energy independence through SRR owned and operated power projects. These generation facilities were to be located either on or near the reservation. Specifically, the Rancheria was interested in the viability of generating electric power using biomass and wind fuel resources.

Initial research identified that a very small portion of the community's energy could be offset by renewable energy generation due to the low solar resource in this area, and the lack of significant wind or biomass resources on or near reservation land. Some larger projects were identified which offered little or no benefit to the Rancheria. As a result, the scope of this study was changed in October 2006 to focus on energy efficiency opportunities for key reservation facilities, with a continued analysis of smaller renewable energy opportunities within reservation boundaries.

1.2 Project Location & Beneficiaries

The Smith River Rancheria is a coastal community about 20 miles north of Crescent City, California, and 2 miles south of the Oregon border. It is a modestly sized community of approximately 600 people with many other members living outside the reservation's borders, including some at Oregon locations.

1.3 Project Objectives

The Rancheria has developed an energy statement and guiding principles as part of their Comprehensive Economic Development Strategy. Some of the objectives outlined in these documents include achieving energy self –sufficiency, reducing energy costs, promoting renewable energy, obtaining more control over the Tribe's energy source, and creating employment opportunities. The overall objective of this project is to determine whether developing a power generation project (and which options) will support the tribal energy objectives and economic development objectives, and be economically viable.

Specifically, the Rancheria requested that the consultants focus their efforts on energy options that could be implemented on tribal properties. The objective of the study was to focus on solar, wind and conservation options that would have near term benefits. The study also looked into utility options that could lead to improved reliability and/or cost.

1.4 Description of Activities Performed

The consulting team initially performed a resource analysis for biomass and solar generation opportunities in the region of the Rancheria. It was quickly concluded that none of these options would yield renewable power for the Rancheria at costs competitive with current utility sources, and that any larger installations would require substantial funding that may not be available.

Having made these conclusions early on, the study effort was redirected and the team investigated each of the major Rancheria buildings to look for solar, wind and conservation opportunities. The buildings were audited for energy use and the roof areas were examined for exposure of solar radiation. Wind resources were also investigated to determine if smaller wind turbines would offer power generation at a reasonable cost.

1.4.1 Energy Efficiency Measure Identification & Energy Savings Analysis

Walk-through audits were performed at each building noting specifics on items such as the types of HVAC equipment and controls, interior and exterior lighting installed, building and duct insulation levels, window type (double or single pain) and wind coverings, and water heater insulation. Based on the efficiency level of the equipment currently installed, the engineering team was able to make specific recommendations on upgrades that could save additional energy, and the estimated costs and payback of the recommended equipment. Estimated savings were also compared to actual energy billing to determine reasonableness and identify areas of concern in the assumptions.

The energy savings measures recommended for each building are those that have a pay-back period of seven years or less. The payback period is the amount of time it will take for the cost of a particular measure to be recouped from the energy it saves (kWh/yr or kBtu/yr) over the current technology, based on today's utility rates. Higher future utility rates would result in lower payback periods than those shown below.

Filtering the list of possible efficiency measures for each building by the seven year payback criterion resulted in the following recommended measures by building (See Tables 1 – 5).

For the Guschu Administration Building, eight electric efficiency measures were identified that have a payback period of seven years or less for a total project cost of $9,802 and an energy savings of 56,675 kWh/yr or approximately 59% of the current annual consumption. Note the exterior door weather stripping was included in this list, in spite of the payback being longer, since the cost was so low. There is no gas load at the Guschu Administration Building.

Table 1 Guschu Administration Building Recommended Measures[1]

Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	48,331	$ 7,456	1.7
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	2,811	116	0.5
· Replace 13 incandescent lighting with CFLs	1,546	114	0.8
· Replace current exit signs with LED exit signs	1,226	204	1.8
· Insulate heating ducts under the building	1,076	1,215	13
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	948	480	5.6
· Insulate water heater	605	74	1.4
· Weather stripping exterior doors	132	143	12
Total	**56,675**	**$ 9,802**	

For the Howonquet Community Center, all six electric efficiency measures identified that have a payback period of seven years or less for a total electric project cost of $1,921 and an energy savings of 13,447 kWh/yr or approximately 15% of the current annual consumption. Note the exterior door weather stripping was included in this list, in spite of the payback being longer, since the cost was so low. The one gas efficiency measure identified has a payback period of seven years or less for a total gas project cost of $148 and an energy savings of 8,523 kBtu/yr or approximately 5% of the current annual consumption.

1 Energy efficiency measures shown in this table are only those that are recommended. A complete list of the energy efficiency measures identified for the Guschu Administration Building are contained in Section 4.0, Table 10.

Table 2 Howonquet Community Center Recommended Measures

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	10,156	$ 1,335	1.3
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	1,205	50	0.4
· Replace 13 incandescent lighting with CFLs	891	53	0.6
· Replace current exit signs with LED exit signs	613	100	1.6
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	356	240	6.7
· Weather stripping exterior doors	227	143	6.3
Total	**13,447**	**$ 1,921**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heaters	8,523	$ 148	0.80
Total	**8,523**	**$ 148**	

The Lucky 7 Casino already has very efficient lighting, heating and cooling systems installed; however, three electric efficiency measures were identified that have a payback period of seven years or less for a total electric project cost of $10,734 and an energy savings of 346,882 kWh/yr or approximately 18% of the current annual consumption. One gas efficiency measure was identified that has a payback period of seven years or less for a total gas project cost of $74 and energy savings of 16,819 kBtu/yr. While this gas measure (water heater insulation) is less than 2% of the total gas load, the water heater is in need of replacement and it would take very little effort to insulate it at the same time.

It was noted that many of the gaming machines remain lit and operable through the entire 24 hour day. It is believed that by turning off a portion of the machines during the 1:00 AM to 9:00 AM hours may offer significant energy use reductions. The impact of this measure may prove unappealing to guests, and imply that the casino is half closed. A study is recommended to determine the revenue impact of temporarily turning off (or placing in sleep mode) a portion of the gaming machines during low usage periods.

Table 3 Lucky 7 Casino Recommended Measures[2,3]

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· Manage gaming machine load by automatically or manually turning off a portion of the units (assume 25% of machines for 8 hours a day)	196,370	$ 7,868	0.5
· Replace selected interior incandescent lighting with CFLs	149,849	2,566	0.2
· Replace current exit signs with LED exit signs	663	300	4.5
Total	**346,882**	**$ 10,734**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Replace and insulate gas water heaters	16,819	$ 74	0.2
Total	**16,819**	**$ 74**	

For the Lucky 7 Fuel Mart, all five electric efficiency measures identified have a payback period of seven years or less for a total electric project cost of $5,135 and an energy savings of 39,759 kWh/yr or approximately 17% of the current annual consumption. One of the gas efficiency measures identified, water heater insulation, has a payback period of seven years or less for a total gas project cost of $74 and an energy savings of 1,373 kBtu/yr or approximately 1% of the current annual consumption.

Table 4 Lucky 7 Fuel Mart Recommended Measures[4]

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· Replace canopy lights with high pressure sodium bulbs	21,024	$ 2,860	1.7
· Replace interior flood lamps in visitor resource center with CFLs	10,652	207	0.2
· Replacement of refrigeration evaporator fans, condensor fans to higher efficiency units	7,227	2,000	3.5
· Replace 2 incandescent lights in restrooms with CFLs	549	18	0.4
· Replace current exit signs with LED exit signs	307	50	2.0
Total	**39,759**	**$ 5,135**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heater	1373	$ 74	2.5
Total	**1,373**	**$ 74**	

For the Howonquet Head Start & Day Care Center, all five electric efficiency measures identified have a payback period

2 Energy efficiency measures shown in this table are only those that are recommended. A complete list of the energy efficiency measures identified for the Lucky 7 Casino are contained in Section 6.0, Table 18.
3 A study should be conducted to determine the revenue impact of temporarily turning off (or placing in sleep mode) a portion of the gaming machines during low usage periods.
4 Energy efficiency measures shown in this table are only those that are recommended. A complete list of the energy efficiency measures identified for the Lucky 7 Fuel Mart are contained in Section 7.0, Table 22.

of seven years or less for a total electric project cost of $3,035 and an energy savings of 22,320 kWh/yr or approximately 75% of the current annual consumption. This savings percentage is very high due to the fact that the primary electric load for this building is lighting, nearly all of which can be upgraded to higher efficiencies. The one gas efficiency measure identified has a payback period of seven years or less for a total gas project cost of $148 and an energy savings of 19,786 kBtu/yr or approximately 8% of the current annual consumption.

Table 5 Howonquet Head Start & Day Care Recommended Measures

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	10,156	$ 1,335	1.5
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	8,432	347	0.5
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	2,371	1,199	5.6
· Replace 6 interior incandescent lights with CFLs	748	53	1.0
· Replace current exit signs with LED exit signs	613	100	1.8
Total	**22,320**	**$ 3,035**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heaters, optimize water tank timers to reduce consumption during start up periods.	19,786	$ 148	0.2
Total	**19,786**	**$ 148**	

1.4.2 Solar Energy Generation Assessment

Opportunities for solar power generation were considered by evaluating the solar exposure of the roof areas of each major building. The net power production estimate was reduced to reflect the impact of obstructions to the south (e.g. trees) that may cause shading of the solar system. Shading significantly decreases the electricity output of a system and is often the reason solar systems are found to be uneconomical.

The maximum solar generation capacity for each facility was determined by estimating the available south facing roof area and determining the portion of this area which is useable. The system sizes specified for each building are summarized in Table 6, along with the estimated electricity output of each system once the solar radiation for local weather conditions was determined.

Table 6 Estimated Solar System Size & Generation for each Building

Solar	Available Southern Facing Roof Area (sqft)	System Size (kW DC)	Estimated Generation (kWh/yr)	Total System Cost @ $7/Watt	Annual Net Metering Savings @ $/kWh	Tribal System Payback (years)
Gusehu Administration Building	2000	15	18000	$ 105,000	$ 1,620	65
Howonquet Community Center	2600	20	24000	$ 140,000	$ 2,400	58
Lucky 7 Fuel Mart	1800	15	18000	$ 105,000	$ 1,440	73
Howonquet Head Start & Day Care Center	1600	10	12000	$ 70,000	$ 1,080	65
Lucky 7 Casino	12,000	100	120000	$ 700,000	$ 8,400	83

* System sizes are smaller than the maximum allowed for the given roof area's to compensate for unknown roof obstructions

1.4.3 Wind Energy Generation

Site audits were performed at each of the Rancheria buildings to identify any visual indicators (deformed trees) that high winds were present. To avoid visual impacts to travelers passing through, however, only sites off the main highway were chosen for wind turbines. This decision excluded the Lucky 7 Fuel Mart and Lucky 7 Casino from the recommended turbine installation locations.

The American Wind Energy Association and California Department of Energy web sites were consulted to roughly estimate the wind energy available at different Rancheria locations. These resources indicate the average annual wind speed is 7-8 mph, which is considered a low to fair (Class 1 to Class 3, 100-400 W/m^2) wind regime. Given the visible tree flagging at the Howonquet Community Center site, the average wind speed for this site is assumed to be slightly higher, around 9 mph.

Turbines used for these lower wind resources are specifically designed for this application. After a review of available turbine options, a 10 kW turbine was selected. The estimated wind energy generation for each facility was determined as summarized in Table 7:

Table 7 Estimated Wind Energy System Size & Generation for each Building

Wind	Ave Windspeed (mph)	Estimated Annual Generation (kWh)	Annual Net Metering Credit ($/kWh)	Total System Cost Bergey 10kW System ($)	Tribal System Payback (years)
Gusehu Administration Building	8	5,880	$ 529	$ 38,000	72
Howonquet Community Center	9	8,400	$ 840	$ 38,000	45
Howonquet Head Start & Day Care Center	8	5,880	$ 529	$ 38,000	72

Installation of the renewable energy systems could reduce overall electricity demand and use. In one case (the Howonquet Head Start & Day Care Center) it could result in excess annual generation. It is recommended that the wind or solar electric systems should be installed if substantial financial subsidies or grants can be obtained.

1.5 Project Benefits

The energy efficiency and renewable generation measures proposed in the study will benefit the Rancheria in numerous ways. From a cultural standpoint, any reduction in energy supplied by fossil fueled power plants directly lowers the net environmental impact. This benefit fits well with SRR's long held commitment to earth stewardship.

The cultural commitment to reduced energy demand has social benefits as well, instilling a sense of pride in the community for their commitment and investments towards long-term energy sustainability. Given that energy measures are proposed for five different buildings of varying function, the entire community will have the opportunity to witness and/or participate in the project installations and benefits.

More directly, perhaps one of the most important benefits of the project will be the additional education and employment opportunities created for those asked to monitor, operate and maintain the new technologies after installation.

1.6 Environmental Assessment

There are virtually no foreseen environmental impacts associated with the proposed conservation or renewable generation measures. Both the energy efficiency and renewable generation measures proposed are environmentally beneficial due to the resultant decrease in electricity demand from the utilities.

If all of the renewable generation and electric energy efficiency measures are implemented, the result would be a reduction of power purchases from the utility of approximately 660,000 kWh/yr. This is equivalent to offsetting 660 tons of carbon dioxide emissions, which has the environmental benefit of taking 113 cars off the road for a year or planting 260 acres of trees.[5]

1.7 Interconnected Utilities, Transmission & Distribution (T&D) Options

All of the buildings owned by the Rancheria are served by Pacific Power & Light (PP&L). Monthly utility bills were reviewed for the buildings identified to determine if each building service is on the optimum tariff (rate schedule). Discussions were then held with the local Pacific Power & Light service manager to determine if any options exist to reduce costs. The discussions focused on the Rancheria's desire to minimize utility costs through options such as service

5 Environmental benefits per kWh obtained from the PP&L website for their Blue Sky program. http://www.pacificpower.net/bluesky/ Accessed 1/25/07.

and meter consolidation or formation of a separate Rancheria utility cooperative.

No changes are recommended as a result of this review. One situation is recommended for additional review; the Howonquet Community Center is served by two service meters at different tariffs, outdoor lighting service contract and a line extension contract requiring a monthly charge in addition to the normal tariff charge. With modifications to the building power panels, the line charge may be eliminated and the multiple meters may be combined to a single service. (See Appendix XIV for PP&L information on the different Rancheria tariffs.)

Power outages at the Tribal buildings continue to cause disruptions. A total of 32 interruptions totaling 317 minutes were experienced during 2006. Discussions were held with both PP&L and the Coos Curry Electric Cooperative to determine if arrangements could be made to improve system reliability by replacing the system interconnection between the utilities that was removed several years ago. PP&L is evaluating a series of system improvements but believes that such an interconnection would not be feasible. PP&L is addressing the concerns of the Tribe.

The impact of system interruptions has been minimized by the installation of Rancheria stand-by power generation facilities. These generators provide emergency at the Lucky 7 Casino, the Lucky 7 Fuel Mart and the Guschu Community Center. In addition, the Rancheria owns another stand-by generator that could be installed if necessary at another Rancheria facility

The State of California, through it’s state legislature and the California Energy Commission have implemented new rules preventing utilities from new purchases of power from or constructing coal generating facilities. The effect of this rule making will result in higher cost power over the long run. The scope of this analysis was limited to the Rancheria and it’s facilities, and does not include the effect of regional or state wide energy policy.

2 Definitions for Abbreviations & Acronyms

Abbreviation	Description
A	Amps, measure of electrical current
AC	Alternating Current
Btu	British Thermal Unit
CEC	California Energy Commission, state agency overseeing california renewable programs such as CSI
CFL	Compact flourescent lamp
CO2	Carbon dioxide
CPUC	California Public Utilities Commission
CSI	California Solar Initiative, solar electric system installation incentive program offered by California utilities, excludes PP&L
DC	Direct Current
DOE	United States Department of Energy, also referred to as USDOE
EIA	Energy Information Association, part of the USDOE
EPA2005	National Energy Policy Act of 2005
ERP	Emerging Renewables Program
EUI	Energy Use Index, energy intensity per square foot of building footprint (kWh/sqft-yr; kBtu/sqft-yr)
FITC	Federal Income Tax Credit
ft	Feet
gal	Gallon
HVAC	Heating ventilation and air conditioning
kBtu	Kilo-Btu (1000 Btu), measure of energy content of a fuel or heat production capacity of a gas HVAC unit
kBtu/hr	Kilo-Btu per hour, measure of heat output of a gas unit over time. Also depicted as kBtuh
kBtu/sqft-yr	Kilo-Btu (1000 Btu) per square foot per year, a measure of the gas energy use index of a building
kVA	Kilo-volt-amps (1000 volt-amps), unit of power rating for a piece of equipment
kW	Kilowatt, 1,000 watts unit of energy demand
kWh	Kilowatt-hour, 1000 watts/hour, unit of energy consumption
kWh/sqft-yr	Kilowatt hours per square foot per year, a measure of the electricity energy use index of a building
kWh/yr	Kilowatt-hour per year, annual energy consumption unit
LBNL	Lawrence Berkeley National Laboritories
LED	Light emitting diode
MACRS	Modified accelerated cost recovery system, a federal tax cost recovery formula allowing depreciation of renewable energy equipment over a period of 6 years
mph	Miles per hour
MW	Megawatt, 1,000,000 watts
NREL	National Renewable Energy Laboratory
O&M	Operations & Maintenance
PG&E	Pacific Gas & Electric, California utility participating in the state renewable energy system rebate programs such as CSI
PP&L	Pacific Power & Electric, utility serving the Rancheria
PV	Photovoltaic, solar electric generation panels
rpm	Revolutions per minute, used to describe motor speeds
SDG&E	San Diego Gas & Electric, California utility participating in the state renewable energy system rebate programs such as CSI
SEER	Seasonal energy efficiency rating, efficiency rating used for HVAC equipment
sqft	Square Feet , unit of building area
SRR	Smith River Rancheria
T&D	Transmission and distribution
therm	A gas measure, 10,000 Btu
USDOE	United States Department of Energy, also referred to as DOE
V12	Twelve valve engine, refers to one of the standby generators
W	Watt
W/m^2	Watts per meter squared, unit used to describe expected energy production from a square foot of wind turbine rotor swept area

3 Introduction

The Smith River Rancheria (SRR) has a strong commitment to becoming energy self-sufficient, reducing its energy costs, and stimulating economic development in the community. SRR, recognizing the energy needs of the Tribe and Tribal members, set the goal of becoming energy self-sufficient within five years with the full intention of utilizing its own natural recourses to realize this goal. To determine the best methods towards achieving this goal, the Rancheria commissioned this study with funding from the Federal Tribal Energy Program.

3.1 Project Purpose and Objectives

In January 2006 the Smith River Rancheria, located in Smith River, California, contracted with the team of Strategic Energy Solutions (SES) and Evergreen Energy to conduct a study concerning how the community can potentially become partially energy independent by generating some or all of the electric power needed by the Rancheria, either on or near the reservation.

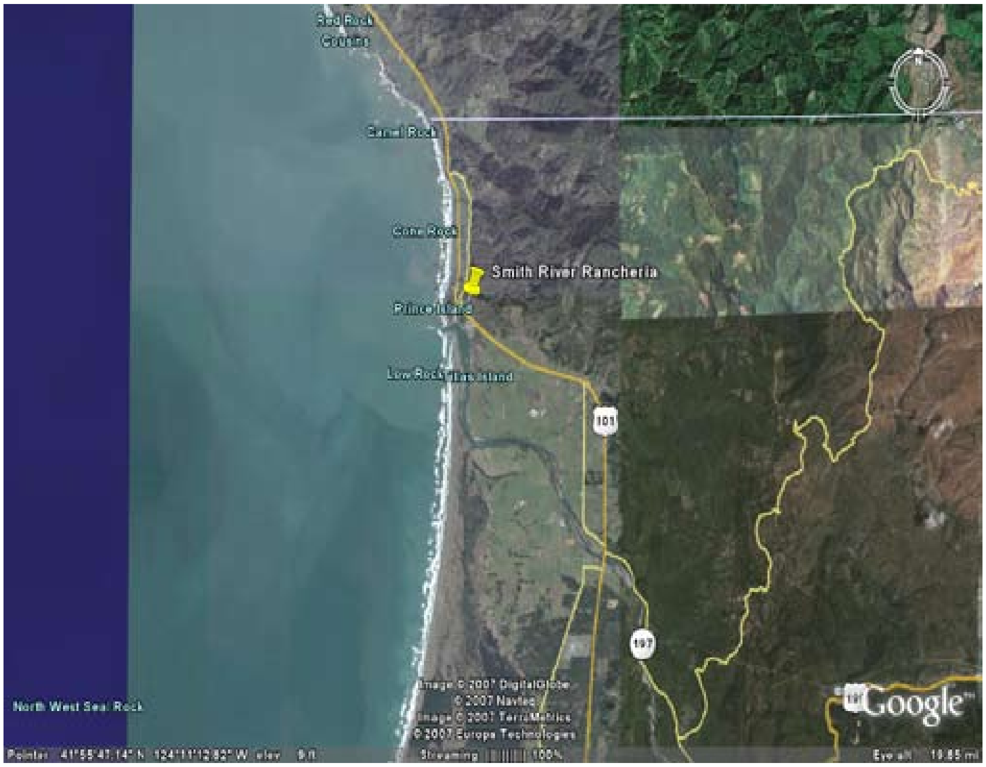
Initial research identified that a very small portion of the community's energy could be offset by renewable energy generation due to the low solar resource in this area, and the lack of significant wind resources on or near reservation land. As a result, the scope of this study was changed in October 2006 to focus on energy efficiency opportunities for key reservation facilities, with a continued analysis of smaller renewable energy opportunities within reservation boundaries.

This report summarizes the engineering team's evaluation of energy efficiency opportunities for the Guschu Administration Building, Lucky 7 Casino, Howonquet Community Center, Howonquet Day Care Center and Head Start, and the Lucky 7 Fuel Mart. Also included in the study are renewable energy potential studies for solar electric installations on reservation facilities and small wind energy generation with interconnection capabilities to the reservation's electric grid. Additional effort was spent identifying all federal, state and utility opportunities for tax incentives, equipment rebates, power purchase agreements (for renewable generation only), and financing mechanisms that could benefit the project and lower the cost to SRR.

3.2 Project Background

The Smith River Rancheria is a coastal community about 20 miles north of Crescent City, California, and 2 miles south of the Oregon border. It is a modestly sized community of approximately 600 people with many other members living outside the reservation's borders, including some at Oregon locations.

Figure 1 Smith River Rancheria Location

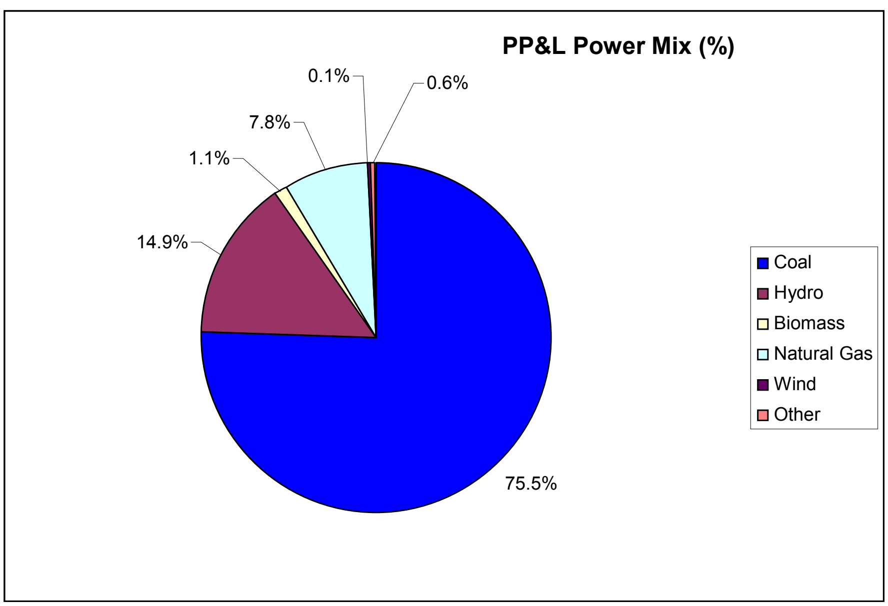


3.3 Environmental Assessment

There are virtually no foreseen environmental impacts associated with the proposed conservation or renewable generation measures. Both the energy efficiency and renewable generation measures proposed are environmentally beneficial due to the resultant decrease in electricity demand from the utilities.

The current power mix supplied by PP&L is shown in Figure 2 below[6]:

Figure 2 PP&L Power Mix by Fuel Type



6 Fuel mix obtained from PP&L website. http://www.pacificorp.com/Press_Release/Press_Release30283.html. Accessed 3/16/07.

The power mix is needed to determine the average emissions per kWh of electricity supplied by PP&L to the Rancheria. Calculating the emissions of the different generation sources, at the percentages shown, results in an offset of 120 tons of carbon for every 10,000 kWh saved annually. This is equivalent to an environmental benefit of taking 20 cars off the road for a year or planting 47 acres of trees.[7]

7 Environmental benefit equivalents obtained from PP&L website. http://www.pacificpower.net/Press_Release/Press_Release52280.html. Accessed 3/16/07.

4 Description of Activities Performed

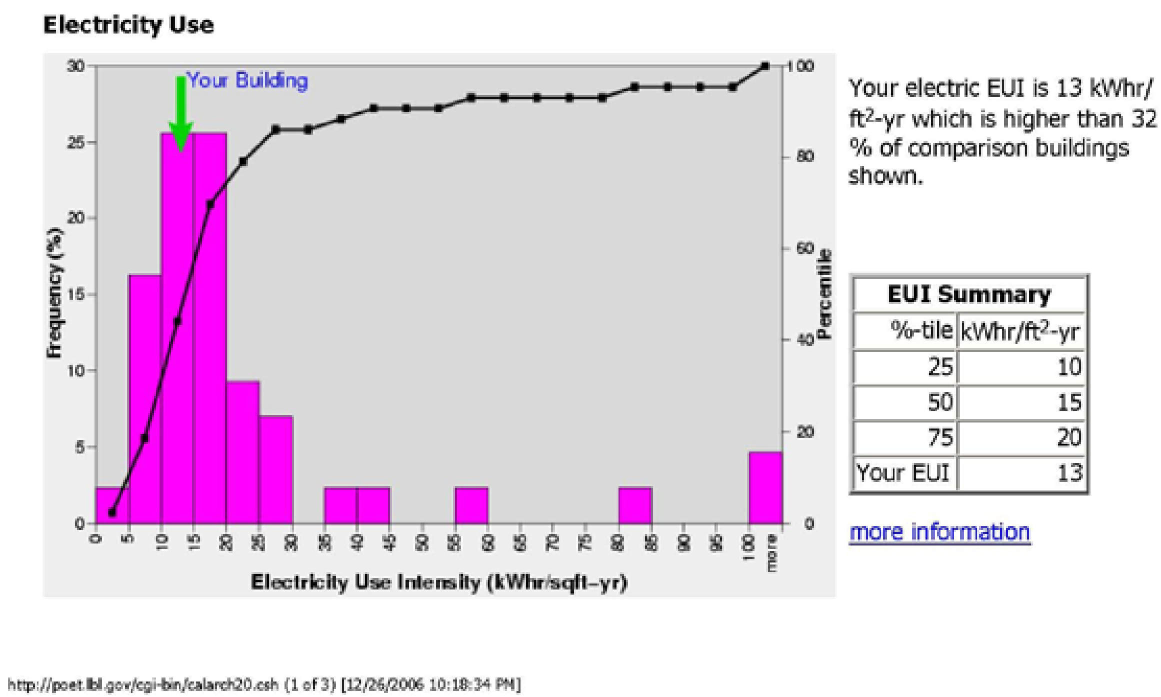
4.1 Building Energy Use

To compare energy use for Smith River Rancheria facilities to that of similar building types requires the calculation of a factor called the Energy Use Index (EUI).[8] The U.S. Department of Energy's Energy Information Association (EIA) has collected building energy use information for commercial buildings for years and makes this information available to the public.[9] This data is grouped in numerous categories according to variables including, but not limited to, building size, building use, year constructed, number of stories, climate zone.

Fortunately, California's Lawrence Berkeley National Laboratories (LBNL) has created a simple web-enabled tool that can be used for a quick and easy EUI comparison using California specific commercial building energy information.[10] The tool, named Cal-Arch, requires a minimum number of inputs (building type, zip code, floor area and annual energy consumption). This tool was used to calculate EUI's for each facility included in this report. These values and the comparative results to similar buildings in California are referenced in the energy consumption summary discussion for each building.
A graphical representation of the EUI comparison is also shown in the results. An example of the graphical summary is shown below in Figure 3. The bars use the left y-axis and represent the percent of all the buildings in the comparative database that had an EUI value in the range shown on the X-axis. For example the left most bar indicates that 2.5% of the comparative buildings have an energy use index (EUI) of 0 – 5 kWh/ft^2-yr. The building used for comparison had an EUI that fell within the range of comparable buildings, as shown by the green arrow.

The point-plot line uses the right y-axis and represents the cumulative percent of all buildings used in the comparison, moving from left to right. Referring again to the chart, the green arrow locates the comparative building in the third bar from the left. The buildings with EUI values lower than the comparative building are contained in the first two bars. The right side of the second bar bisects the line at about 32%, indicating that 32% of the buildings in the comparative database have the same or lower EUI values than the example building.

Figure 3 Example Energy Use Index Comparative Analysis Chart



8 An overview of energy use benchmarking and current tools available can be found on the Western Area Power Administrations website at http://www.wapa.gov/es/techhelp/powerline/03Apr.htm
9 EIA tables for commercial building energy use can be found at http://www.eia.doe.gov/emeu/cbecs/pdf/set8.pdf.
10 California commercial building EUI comparison tool (Cal-Arch) created by LBNL can be accessed at http:/poet.lbl.gov/cal-arch/compare.html.

4.2 Solar Energy Generation

Solar energy generation capacity for each facility was determined by estimating the available south facing roof area for each building. Using a 208 Watt panel (65" x 39") for area calculations equates to 18 sqft of roof area required per panel. Five panels are required for 1000W (1kW). Rounding this number off equates to approximately 100 sqft required for a 1kW PV system. South facing roof areas were estimated and then divided by 100sqft to determine the maximum PV system size that could be accommodated on each building. Note that smaller system sizes are recommended in all cases to adjust for unknown roof obstructions that would prevent system panel installation on 100% of the roof area.

The National Renewable energy Laboratory (NREL) has developed a tool that estimates AC energy production (kWh) for a given PV system.[11] This tool calculates solar radiation potential (W/m^2) based on the location longitude and latitude, and the orientation of the solar system from due south. One can also consult a statewide solar resource map for a rough estimate (see Appendix II).

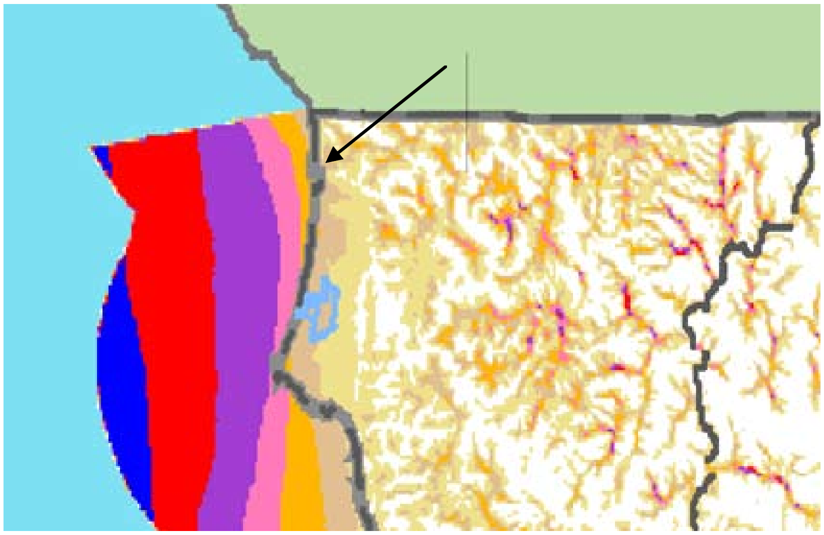
For the Smith River Rancheria coordinates of latitude 41 degrees north and longitude 124 degrees west was used. The array was assumed to be tilted up 41 degrees from horizontal facing due south. This tilt and orientation is optimum for this location. Lower tilt angles can be accommodated if the panels are to be placed flat on the roof lines, but lower tilt angles will result in slightly lower energy production. Using the above assumptions for a 1kW PV system results in an estimated electricity output of 1200 kWh/yr per kW of installed generation.

4.3 Wind Energy Generation

Wind energy is calculated based on the average wind speed at a particular height above the ground, or the height at which the wind turbine rotor will be mounted on a pole or support tower. Average annual wind speeds can be used for a particular location to make rough estimates of potential energy generation, and to assist in selecting the appropriate turbine for that wind regime. For instance, smaller wind turbines (e.g. 10 kW) can operate in slower wind speeds than the utility scale turbines (e.g. 1MW).

The American Wind Energy Association and California Department of Energy web sites enable us to estimate the wind energy available at different Rancheria locations. A full copy of the state wind power density map is shown in Appendix I. Figure 2 below is a snapshot of the Rancheria area (shown by arrow, the entire map and wind classifications are contained in Appendix I)[12]. This more granular map was funded by the California Energy Commission (CEC) and validated by the National Renewable Energy Laboratory (NREL) and consulting meteorologists.

Figure 4 Wind Power Density in the SRR Region



According to these two references the Rancheria is in a low to fair (Class 1 to Class 3, 100-400 W/m^2) wind regime. This was confirmed by looking up historical weather data at the Western Regional Climate Center for the nearest weather

11 The PV Watts calculator tool is publicly available and can be accessed at the NREL website http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/US/code/pvwatts1.cgi.

12 Wind power density map from Truewind can be found at http://www.awstruewind.com/inner/windmaps/California.htm .

station (Eureka) which indicates there is an average annual wind speed of approximately 7 mph. Given that Eureka is only in a Class 2 wind regime, the estimated average wind speed for the Tribal Headquarters and Head Start locations is around 8 mph. The Howonquet Community Center site, however, is right on the cliff edge with visible tree flagging. The average wind speed for this site is predicted to be slightly higher, around 9 mph. Only sites off the main highway were chosen for wind turbines, thus excluding the Lucky 7 Fuel Mart and Lucky 7 Casino. All annual wind speed assumptions would need to be verified by installing wind monitoring devices at each location (known as an anemometer) for a period of at least six months, if wind energy is to be considered.

To size the wind turbine one needs to know the swept area of the wind turbine blades and the wind resource in W/m^2. The Bergey Windpower Excel-S 10 kW turbine was selected. This turbine has a rotor diameter of seven meters (See Appendix VII for detailed specifications), which equates to $38.48m^2$. Multiplying the swept area times the average wind resource in this area (350 W/m^2) results in 13,470 Watts. Thus the 10 kW turbine is correctly sized for this wind regime. A list of small wind turbines that are eligible for state production incentives can be found on the California Energy Commissions website at http://www.consumerenergycenter.org/cgi-bin/eligible_smallwind.cgi (See Appendix VIII for a copy of the eligible turbines at the time of this report publication.)

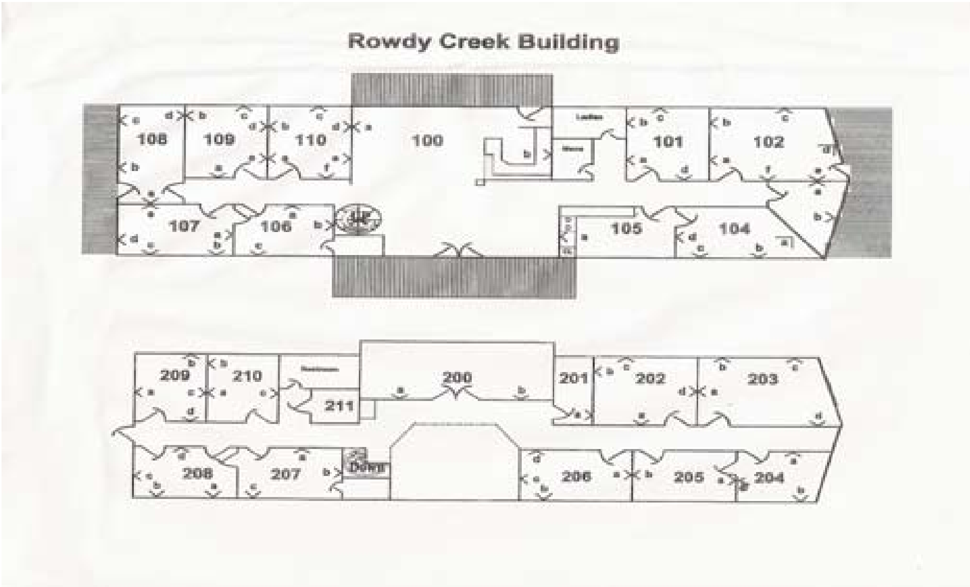
5 Guschu Administration Building

5.1 Site Description

The Guschu Administration Building is primarily an office building and meeting center. The office is a two story wood frame construction with a composition shake roof. The building size is approximately 7592 square feet, 3918 square feet on the first floor and 3674 square feet on the second floor (See Figure 5). Operating hours are M-F, 7:30am – 6:00pm.

The general layout of the building is shown in Figure 5 below. On the south side of the upper floor are five offices, one large meeting room, one restroom, and the computer server room. The north side of the upper floor contains three offices, an office space used as storage, and a computer room with nine connected personal computers.

Figure 5 Guschu Administration Building Floor Plan



On the lower floor, facing north, are eight offices, the kitchen and the library. The south side of the lower floor contains five offices, two restrooms, the building electrical panel, a utility room containing the water heaters, a lounge area used as an office by administrative staff and a reception area for visitors. (See Table 8 below for a more detailed description of the building and components.)

Table 8 Guschu Administration Building Property Details

Property Information	
Address	140 Rowdy Creek Road, Smith River, CA 95567-9446 (0.2 mile west on Rowdy Creek Road, east of Highway 101)
Building Rough Dimensions	7592 sqft, approx.
Building Orientation	Southern facing roof, main entrance faces north
Building Construction	Wood frame construction with a composition roof (4x12 pitch), vaulted ceiling running north-south in center of building. Large two-story entry way open to both floors.
Windows	Windows on all sides of building were recently replaced. There are no shades or blinds. All windows are energy efficient vinyl framed, double paned.
Ceiling Insulation	The ceiling was recently insulated with spray in cellulose type material.
Wall Insulation	Wall insulation levels are assumed to be adequate given when the building as completed.
Floor Insulation	The building is open to the weather in several crawlspace areas with insulation on the underside of the floor. The HVAC ducting is not insulated under floor.
Door Weather Stripping	The front door is not weather-stripped.
Interior Lighting	138 (2 or 4 tube, F40 DLX Universal, 40 watt) fluorescent ceiling fixtures in all rooms. Main foyer has a large ceiling fixture, wattage and bulbs assumed to remain unchanged. A total of thirteen incandescent bulbs are installed in the three bathrooms (two downstairs and one upstairs).
Exit Lighting	Four standard emergency exit signs, one located on each end of the central hallway on both floors of building.
Exterior Lighting	A total of seven floods light all sides of the building, some staying operational during the daytime. The parking area is illuminated by three pole mounted sodium flood lights. Two flood lamps light the decking on the first floor, south side of the building.
Heating and Cooling System	The building is divided into four HVAC zones, each supplied by newer Trane resistance heating and cooling units on the south side of building. Each zone is controlled by a separate thermostat. One Mitsubishi (R410A) cooling unit supplies the computer room. Venting for HVAC is at the ceiling level for the upper floor and at floor level for the bottom floor.
Thermostats	Five programmable thermostats total, four to control the four quadrants of the building (set at 69 degrees F), one to control the temperature in the computer room (set at 68 degrees F). One thermostat is used to control each Heat/AC unit. Building thermostats control east and west halves of building, two for each floor. The result is that the north and south portion of each zone are on the same thermostat.
Back-up Power	None
Cooking	No stove, just lunchroom with minor appliances
Water Heating	One 30 gallon electric water heater in crawl space. The water heater is uninsulated.
Electrical Panels	Two 225A panels
Other	Kitchenette appliances and refrigerators. Computer room with approximately 9 CPU's. Estimate approximately 20 more computers throughout offices. There is an old oil filled transformer located on the south side of the building, partially below ground. This utility type transformer previously served the building but is no longer in operation.
Annual Energy Consumption	96,720 kWh/yr (EUI = 13 kWh/sqft-yr)

General specifications for the building include new vinyl framed, double paned windows without coverings, overhead fluorescent lighting in all rooms contained within suspended ceilings (with the exception of the large entry light), with flood lighting on all sides of the exterior building. The building is entirely electric with electric resistance heating and air conditioning (AC) units for each of the four heating, ventilation and air conditioning (HVAC) control zones. One small electric water heater is located in the crawl space under the building. Each HVAC control zone has its own thermostat, located in the main hallways on each floor. Both the ceiling and floor are insulated, but the furnace ducts and the water heater under the building are not insulated.

5.2 Energy Consumption Analysis

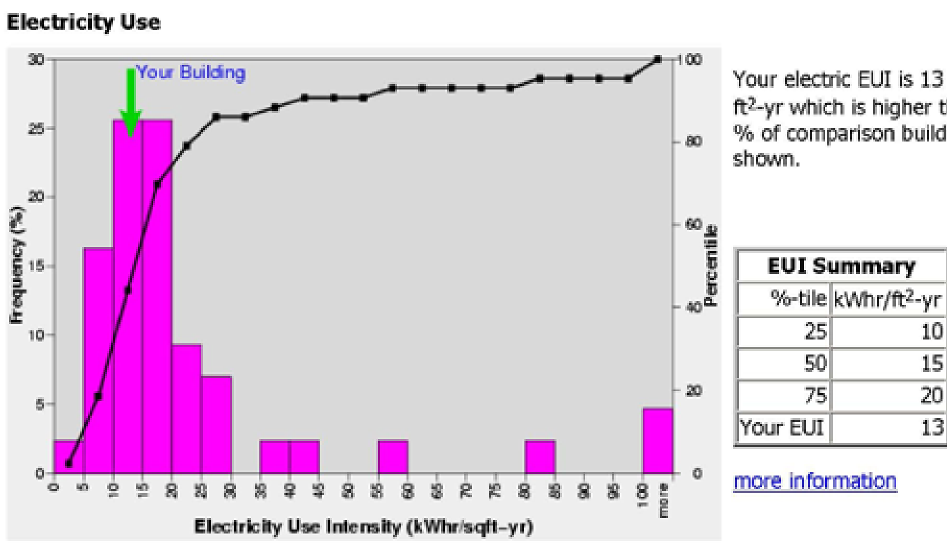
A monthly utility payment summary was provided for January through December 2006, showing an average energy cost of $0.09/kWh. (See Figure 6)

Figure 6 Guschu Administration Building Annual Energy Consumption

Electricity Consumption Data	Nov-06	Dec-06	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Annual Total
Gusehu Administration Building													
kWh	9,280	9,640	9,400	7,280	8,600	7,120	7,280	7,200	7,520	7,920	7,400	8,080	96,720
kW	39	40	32	32	38	34	27	29	29	29	30	34	393
Cost	$ 799	$ 828	$ 794	$ 639	$ 747	$ 635	$ 639	$ 635	$ 659	$ 698	$ 651	$ 705	$ 8,427
$/kWh	$ 0.09	$ 0.09	$ 0.08	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09

Using the annual kWh consumption value along with general building and climate specifications resulted in a calculated Energy Use Index (EUI) of 13 kWh/sqft-yr for the Administration Building. This EUI is higher than 32% of the comparable buildings in California, which had EUI values from 10 – 20 kWh/sqft-yr (Figure 7)[13], indicating that the Administration Building has a comparably low energy intensity for a building of this type.

Figure 7 Guschu Administration Building Energy Use Index (EUI) Comparison



http://poet.lbl.gov/cgi-bin/calarch20.csh (1 of 3) [12/26/2006 10:18:34 PM]

The estimated building energy use is comparable to the actual annual consumption as billed by the utility. This supports the above EUI findings that the Administration Building is currently at the low end of the expected energy use range.

Table 9 Guschu Administration Building Actual vs. Calculated Energy Consumption

Billing vs. Calculated Energy Consumption (No Gas)

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	96,720	89,437	92%

5.3 Opportunities for Energy Optimization

5.3.1 Energy Efficiency & Efficiency Measure Economics

The largest energy savings potential for the Administration Building would result from replacement of the standard 4-lamp 40W fluorescent overhead lighting with high efficiency 2-lamp 32W fixtures and ballasts. Estimated energy savings for this energy efficiency measure would be approximately 48,331 kWh/yr.

13 LBNL Cal-Arch tool.

Costs, energy savings and estimated payback periods for all energy efficiency measures identified for this building are summarized below:

Table 10 Guschu Administration Building Efficiency Savings Measures

Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	48,331	$ 7,456	1.7
· Replace current electric cooling/heating systems with SEER 18 heat pumps	6,585	16,278	27
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	2,811	116	0.5
· Replace 13 incandescent lighting with CFLs	1,546	114	0.8
· Install plug load occupancy sensors for 10 computers and task lighting (office computers only, not server room)	1,430	1,170	9.1
· Solar shades for south facing windows to reduce HVAC load and alleviate summer temperature issues in south facing rooms	1,362	5,760	47
· Replace current exit signs with LED exit signs	1,226	204	1.8
· Insulate heating ducts under the building	1,076	1,215	13
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	948	480	5.6
· Insulate water heater	605	74	1.4
· Weather stripping exterior doors	132	143	12
· Confirm that the old distribution transformer unit is disconnected to eliminate potential standby losses	0	N/A	N/A
Total	**66,052**	**$ 33,010**	

Total estimated savings from current consumption levels, if all measures are installed, is 66,052 kWh per year or approximately a 59% reduction in energy use. This equates to a total energy efficiency project cost for the Administration Building of $33,010. Using an estimated $5,945/year in energy savings equates to a 5.6 year payback on the project. (Referring to Figure 29 in Appendix III for further detail)

5.3.2 Renewable Generation & Economics

If a transaction with a taxable partner could be reached, certain tax benefits would improve the financial performance and payback. For taxable corporations, an investment in solar systems would result in the following benefits:

- 30% investment tax credit (wind); 10% investment tax credit (solar)
- 6 year MACRS depreciations schedule
- $0.019/kWh production tax credit (wind only)

In addition, the California Public Utility Commission (CPUC) administers a solar incentive program that is not currently available to the Rancheria. These incentives are summarized in Section 10.4.

5.3.2.1 Solar Energy Generation

There is approximately 2000 square feet (sqft) of south facing roof area on the Guschu Administration building. A Photovoltaic (PV) system requires approximately 100 sqft for each kilowatt (kW) of installed capacity, thus the roof area could safely accommodate about a 15 kW system, allowing room for roof obstructions. The 15 kW PV system will produce 30 kW of DC power on bright sunny days. This must be converted to AC power to be paralleled with the building energy system, resulting in losses of approximately 25%.[14]

In this region, PV units can be expected to produce 1200 kWh/yr per kW of installed capacity. Annual PV generation potential for this location is estimated to be 18,000 kWh/yr. At an average power cost of $0.09/kWh, this would result

14 Energy Trust of Oregon. Solar Electric Program Systems Requirement Document. April, 2003.

in an annual savings of $1,620. Assuming a capital cost of $7/watt installed, this equates to a system installation cost of approximately $105,000 to the Rancheria. Refer to Table 11 below for the solar system economics:

Table 11 Guschu Solar System Economics

		Gusehu Administration Building
Total System Size (kW)		15
System Cost (@ $7/kW)	$	105,000
Annual Energy Savings ($/yr)	$	1,620
Payback (years)		65

While the Guschu Administration Building is ideally orientated favorably for southern exposure, there are trees near the south side of the building that would cause limited shading of the solar array during the winter and thus reduce the generation potential (5-10%). An installation by the tribe, without the benefit of incentives available to many other Californians, yields a simple payback of 65 years. An investment in solar generation appears unattractive unless grants can be found to offset a substantial portion of the cost.

The federal government and the California Public Utility Commission (CPUC) offer significant incentives for solar power generation to customers of PG&E, SCE and SDG&E; however, none appear to be available or applicable for this site. There is a potential for USDOE grant funding for an installation under the same program that funded this study. Please refer to Section 10 for a detailed review of these incentives and options.

5.3.2.2 Wind Energy Generation

While there are no visible indicators (directional growth of trees due to strong winds) at this location, it has been determined that the average wind potential is approximately 8 mph (300-400 W/m^2) as indicated in the California Wind Resource Map in Appendix I. A 10 kW Bergey wind turbine, costing approximately $38,000 would generate about 5,880 kWh per year valued $529. This is an inferior location for a wind turbine installation.

California's net metering law requires investor owned utilities to compensate site generated electricity at retail rates. As detailed earlier in this report, a wind turbine located where an average wind speed of 8 mph at a rotor hub height of 30 meters (100ft) will result in estimated monthly wind energy production of 490 kWh, or annual wind energy production total of 5,880 kWh. At an average power cost of $0.09/kWh, this would result in an annual net metering credit of $529 and a lifetime (15 years) credit of $7,938. The Rancheria would be left with a balance of $30,062 at the end of the useful life of the turbine. The cost of the turbine would take a total of 72 years to pay back at current utility rates. Clearly, the turbine will need to be replaced much sooner than it can pay back the cost to the Rancheria in energy savings and is therefore not economical, unless grants can be found to cover most of the cost. Figure 8 summarizes the wind system economics for this site:

Figure 8 Guschu Administration Building Wind System Economics

		Gusehu Administration Building
Total System Size (kW)		10
System Cost	$	38,000
Energy Savings over 15 yr Useful Life ($)	$	7,938
Net System Cost	$	30,062
Payback (years)		72

As outlined in Section 10, a partnership with a taxable partner may improve the financial results, but not enough to justify a wind unit at this location.

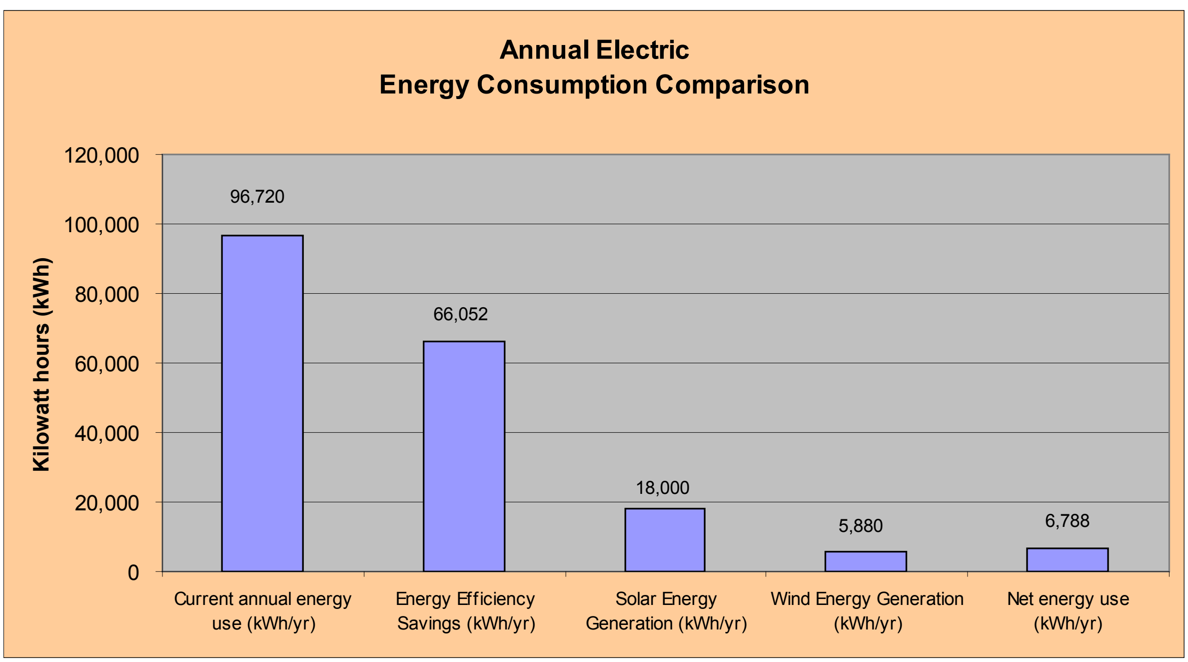
5.4 Guschu Administration Building Summary

The Guschu Administration Building electric energy efficiency measures combined equate to a total energy savings of 66,052 kWh/yr or an annual savings of $5,945/yr in energy costs.

The Guschu Administration Building solar and wind systems combined equate to a net installed capacity of 25 kW, well below the 1MW net metering cutoff. Total estimated generation from these two systems amounts to 23,880 kWh/yr or an annual savings of $2,149/yr in energy costs.

Combining both electric energy efficiency measures and potential renewable energy generation results in an estimated net decrease in utility energy demand of 89,932 kWh/yr or 93% (See Figure 9).

Figure 9 Guschu Administration Building Energy Summary



6 Howonquet Community Center

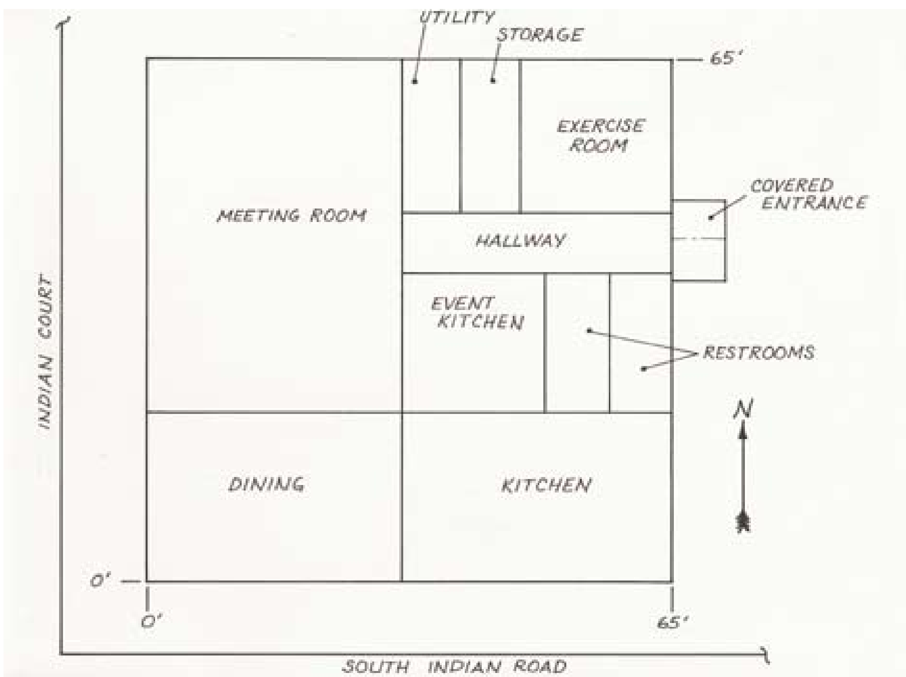
6.1 Site Description

Howonquet Community Center was constructed in 2003 to serve as the community social center and to provide a nutritional luncheon program for seniors. The Community Center is a single level wood frame construction building with a concrete slab on grade floor and a metal roof. Building size is approximately 4,225 sqft.

Operating hours are M-F, 7:30am – 6:00 pm. Twice a week the Community Center stays open until 10pm for Tribal meetings. Community events are also held at the hall, taking advantage of the fully equipped kitchen for any catering needs.

The general layout of the building is shown in Figure 10 below. The main entrance to the building faces east towards Highway 101 with the large meeting and dining hall on the west side of the building, having a commanding view of the Pacific Ocean. Off the foyer on the north side of the building is an exercise room and two utility closets. The restrooms and event kitchen are located on the south side of the building, just off the foyer.

Figure 10 Howonquet Community Center Floor Plan



Across Indian Court towards the ocean is a small park with traditional roasting pits used in celebrations. This park area will be discussed later in this section as a possible location for wind energy generation (see Figure 14).
General specifications for the building include new vinyl framed, double paned windows without coverings, overhead fluorescent lighting in all rooms (with the exception of the foyer), with flood lighting on three sides of the exterior building. The building has been constructed to meet current codes, including insulation and air circulation requirements. The ceiling is insulated but the water heaters in the utility closet are not.

The building is heated and cooled with four high-efficiency electric heat pumps (with resistance heat for extreme conditions), one for the exercise room, two for the large meeting room, and one for the dining and kitchen area. Each

HVAC control zone has its own thermostat located near the entrance doorways of each area. Propane is used for water heating, cooking, and to run the emergency power generator. (See Table 12 below for a more detailed description of the building and components.)

Table 12 Howonquet Community Center Property Details

Property Information	
Address	101 Indian Court, Smith River, CA 95567 (Between Highway 101 and Indian Court on South Indian Road)
Building Rough Dimensions	65' x 65' (4,225 sqft, approx.)
Building Orientation	Southern facing roof, main entrance faces east
Building Construction	Wood frame construction with a metal roof (4x12 pitch)
Windows	Largest window area is west facing towards the Pacific Ocean though a few windows also exist on the other three sides. There are no shades or blinds. All windows are vinyl framed, double pane.
Ceiling Insulation	Ceiling insulation levels should be checked, though the engineering team expects that they will be adequate given when the building was completed.
Wall Insulation	Wall insulation levels should be checked, though the engineering team expects that they will be adequate given when the building was completed.
Floor Insulation	The building is constructed on a single concrete slab
Weather Stripping	The front door is a solid commercial unit but is not weather stripped
Interior Lighting	29 (4 tube, 40 watt) fluorescent ceiling fixtures in all rooms except foyer and main meeting hall; 24 (2-tube, 32W) fluorescent fixtures in meeting room); four incandescent overhead lights in foyer and two incandescent lamps in bathrooms.
Exit Lighting	Two standard emergency exit signs, one located on each end of the building.
Exterior Lighting	A total of three flood lights illuminate the north, east and south sides of the building. The parking area is illuminated by three pool mounted sodium flood lights.
Heating and Cooling System	Four electric heat pump units are located on the north side of the building near the east corner. Three have a capacity of 9 tons and one has a capacity of 7 tons. One supports the exercise room at the northeast corner of the building, two support the large meeting room, and one supports the small dining room and kitchen area. Ducting is located at ceiling level. Filters are changed monthly.
Thermostats	One thermostat is used to control each heat pump. Two are located in the main meeting room, one on each side of the entrance door. One thermostat is located in the dining room near the kitchen door. One thermostat is located in the exercise room near the door to the foyer.
Air Sensors/Alarms	Two CO2 sensors in the main meeting room, one next to each thermostat
Back-up Power	A propane fired generator (size?) is located on the north side of the building to provide power in emergencies or when the electric supply is temporarily interrupted.
Cooking Fuel	All stoves in the kitchen are fueled by propane tanks located on the north side of the building.
Water Heating	Hot water is provided by two propane fired 55 gallon water heaters located in a utility closet midway on the north side of the building, with an entrance from the central foyer. Water heaters are not insulated
Other	Kitchen appliances, stoves, refrigerators
Estimated Annual Energy Consumption	105,996 kWh/yr (EUI = 24 kWh/sqft-yr); 11,817 gallons of propane (EUI = 44 kBtu/sqft/yr)

6.2 Energy Consumption Summary

A monthly utility payment summary was provided for December 2005 through November 2006, showing an average energy cost of \$0.09/kWh. This analysis resulted in an estimated annual electrical energy consumption of 88,640 kWh/yr and an annual propane consumption of 2007 gallons. (See Figure 11)

Figure 11 Howonquet Community Center Annual Energy Consumption

Electricity Consumption Data	Nov-06	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Annual Total
Howonquet Community Center													
kWh Schedule 109 (no load)	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost	$ 49	$ 39	$ 54	$ 62	$ 50	$ 57	$ 64	$ 63	$ 54	$ 64	$ 75	$ 42	$ 673
kWh Schedule A32	7,560	8,160	7,200	6,680	7,520	6,960	6,440	6,560	7,200	6,520	5,800	8,040	84,640
kW	31	34	32	31	30	32	33	30	28	28	28	29	366
Cost	$ 656	$ 702	$ 630	$ 591	$ 651	$ 613	$ 576	$ 581	$ 626	$ 585	$ 524	$ 689	$ 7,422
kWh Schedule A25	428	453	380	316	336	267	228	229	243	246	260	605	3,991
Cost	$ 51	$ 53	$ 46	$ 40	$ 42	$ 36	$ 32	$ 32	$ 33	$ 34	$ 35	$ 68	$ 502
Total kWh	7,988	8,613	7,580	6,996	7,856	7,227	6,668	6,789	7,443	6,766	6,060	8,645	88,631
kW	31	34	32	31	30	32	33	30	28	28	28	29	366
Total Cost	$ 755	$ 795	$ 730	$ 692	$ 742	$ 705	$ 672	$ 677	$ 714	$ 683	$ 633	$ 799	$ 8,598
$/kWh (Sched A32 & A25 only)	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.10

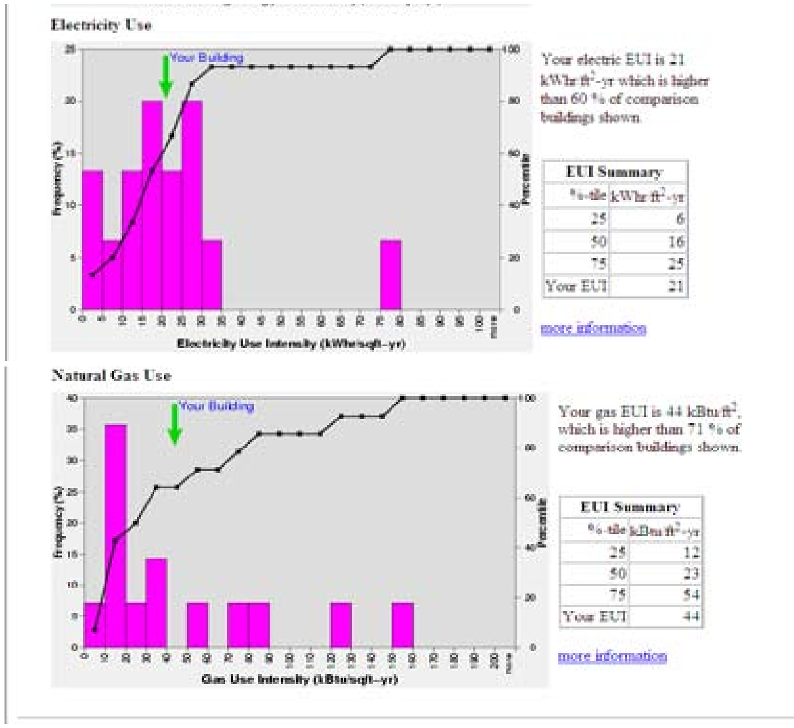
Notes:
= Schedule 109 Rates (there are no demand charges for this schedule)
= Schedule A32 Rates
= Schedule A25 Rates (there are no demand charges for this schedule)

Propane Consumption Data	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Annual Total (gal)
Howonquet Community Center													
Gallon	0	0	497	0	530	341	0	274	0	0	0	364	2,007
Cost			$ 977	$ -	$ 1,041	$ 706		$ 568				$ 742	$ 4,034
$/Gallon	$ -	$ -	$ 1.97	$ -	$ 1.97	$ 2.07	$ -	$ 2.07	$ -	$ -	$ -	$ 2.04	$ 2.01

Using the estimated annual kWh consumption value along with general building and climate specifications resulted in a calculated EUI's of 21 kWh/sqft-yr and 44 kBtu/sqft-yr for electricity and gas respectively. The electric EUI is at the higher range of all comparative buildings in California, which had EUI values from 6 - 25 kWh/sqft-yr (Figure 12).[15] The gas EUI is also at the higher range of all comparable buildings in California, which had EUI values from 12 - 54 kBtu/sqft-yr. These high values are due to the fact that the Howonquet Community Center, while fairly energy efficient, is affected significantly by the dual use of senior meals and community events involving food preparation.

15 LBNL Cal-Arch tool.

Figure 12 Howonquet Community Center EUI Comparisons



The estimated building energy use is approximately 25% lower than the actual annual consumption as billed by the utilities as shown below. This difference is attributed to the lack of detailed information on the kitchen appliance energy consumption.

Table 13 Howonquet Community Center Actual vs. Calculated Energy Consumption

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	88,631	62,691	71%
Gas (kBtu)	183,814	146,026	79%

6.3 Opportunities for Energy Optimization

6.3.1 Energy Efficiency & Efficiency Measure Economics

The largest energy savings potential for the Howonquet Community Center would result from replacement of the standard 4-lamp 40W fluorescent overhead lighting with high efficiency 2-lamp 32W fixtures and ballasts, with no noticeable decrease in illumination. Estimated energy savings for this energy efficiency measure would be approximately 10,156 kWh/yr.

Costs, energy savings and estimated payback periods for all energy efficiency measures identified for this building are summarized below:

Table 14 Howonquet Community Center Efficiency Savings Measures

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	10,156	$ 1,335	1.3
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	1,205	50	0.4
· Replace 13 incandescent lighting with CFLs	891	53	0.6
· Replace current exit signs with LED exit signs	613	100	1.6
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	356	240	6.7
· Weather stripping exterior doors	227	143	6.3
Total	**13,447**	**$ 1,921**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heaters	8,523	$ 148	0.80
Total	**8,523**	**$ 148**	

Total electric estimated savings from current consumption levels, if all measures are installed, is 13,447 kWh per year or approximately a 21% reduction in energy use. This equates to a total electric energy efficiency project cost for the Howonquet Community Center of $1,921. Using an estimated $1,345/year in energy savings equates to a 1.4 year payback on the electric efficiency portion of the project.

Total propane estimated savings from current consumption levels is 8,523 kBtu/yr. This equates to a total gas energy efficiency project cost of $148. Using an estimated $186/yr in energy savings equates to a 0.8 year payback on the gas efficiency portion of the project. (Referring to Figure 30 in Appendix III for further detail)

6.3.2 Renewable Generation & Economics

If a transaction with a taxable partner could be reached, certain tax benefits would improve the financial performance and payback. For taxable corporations, an investment in solar systems would result in the following benefits:

- 30% investment tax credit (wind); 10% investment tax credit (solar)
- 6 year MACRS depreciations schedule
- $0.019/kWh production tax credit (wind only)

In addition, the California Public Utility Commission (CPUC) administers a solar incentive program that is not currently available to the Rancheria. These incentives are summarized in Section 10.4.

6.3.2.1 Solar Energy Generation

There is approximately 2600 square feet (sqft) of south facing roof area on the Howonquet Community Center building. A Photovoltaic (PV) system requires approximately 100 sqft for each kilowatt (kW) of installed capacity, thus the roof area could safely accommodate about a 20 kW system, allowing room for roof obstructions. The 20 kW PV system will produce 20 kW of DC power on bright sunny days. This must be converted to AC power to be paralleled with the building energy system, resulting in losses of approximately 25%.[16]

In this region, PV units can be expected to produce 1200 kWh/yr per kW of installed capacity. Annual PV generation potential for this location is estimated to be 24,000 kWh/yr. At an average power cost of $0.10/kWh, this would result in an annual savings of $2,400. Assuming a capital cost of $7/watt installed, this equates to a system installation cost of approximately $140,000 to the Rancheria. Refer to Table 15 below for the solar system economics:

16 Energy Trust of Oregon. Solar Electric Program Systems Requirement Document. April, 2003.

Table 15 Howonquet Community Center Solar System Economics

		Howonquet Community Center
Total System Size (kW)		20
System Cost (@ $7/kW)	$	140,000
Annual Energy Savings ($/yr)	$	2,400
Payback (years)		58

While the Howonquet Community Center is ideally orientated favorably for southern exposure, an installation by the tribe, without the benefit of incentives available to many other Californians, yields a simple payback of 58 years. An investment in solar generation appears unattractive unless grants can be found to offset a substantial portion of the cost.

The federal government and the California Public Utility Commission (CPUC) offer significant incentives for solar power generation to customers of PG&E, SCE and SDG&E; however, none appear to be available or applicable for this site. There is a potential for USDOE grant funding for an installation under the same program that funded this study. Please refer to Section 10 for a detailed review of these incentives and options..

6.3.2.2 Wind Energy Generation

There is visible flagging of trees on the property to the west is shown in the picture below. These trees are located on the western edge of the parcel just west of the community center, on the edge of the embankment that leads down to the Pacific Ocean (see Figure 14).

It has been determined that the average wind potential is approximately 9 mph (300-400 W/m^2) as indicated in the California Wind Resource Map in Appendix I. A 10 kW Bergey wind turbine, costing approximately $38,000 would generate about 5,880 kWh per year valued $529. This is an inferior location for a wind turbine installation.

California's has net metering law requires investor owned utilities to compensate site generated electricity at retail rates. As detailed earlier in this report, a wind turbine located where an average wind speed of 8 mph at a rotor hub height of 30 meters (100ft) will result in estimated monthly wind energy production of 700 kWh, or annual wind energy production total of 8,400 kWh. At an average power cost of $0.10/kWh, this would result in an annual net metering credit of $840 and a lifetime (15 years) credit of $16,800. The Rancheria would be left with a balance of $21,200 at the end of the useful life of the turbine. The cost of the turbine would take a total of 45 years to pay back at current utility rates. Clearly, the turbine will need replaced much sooner than it can pay back the cost to the Rancheria in energy savings and is therefore not economical, unless grants can be found to cover most of the cost. Figure 13 summarizes the wind system economics for this site:

Figure 13 Howonquet Community Center Wind System Economics

		Howonquet Community Center
Total System Size (kW)		10
System Cost	$	38,000
Energy Savings over 15 yr Useful Life ($)	$	16,800
Net System Cost	$	21,200
Payback (years)		45

As outlined in Section 10, a partnership with a taxable partner may improve the financial results, but not enough to justify a wind unit at this location.

Figure 14 Topographic View of Proposed Wind Turbine Location

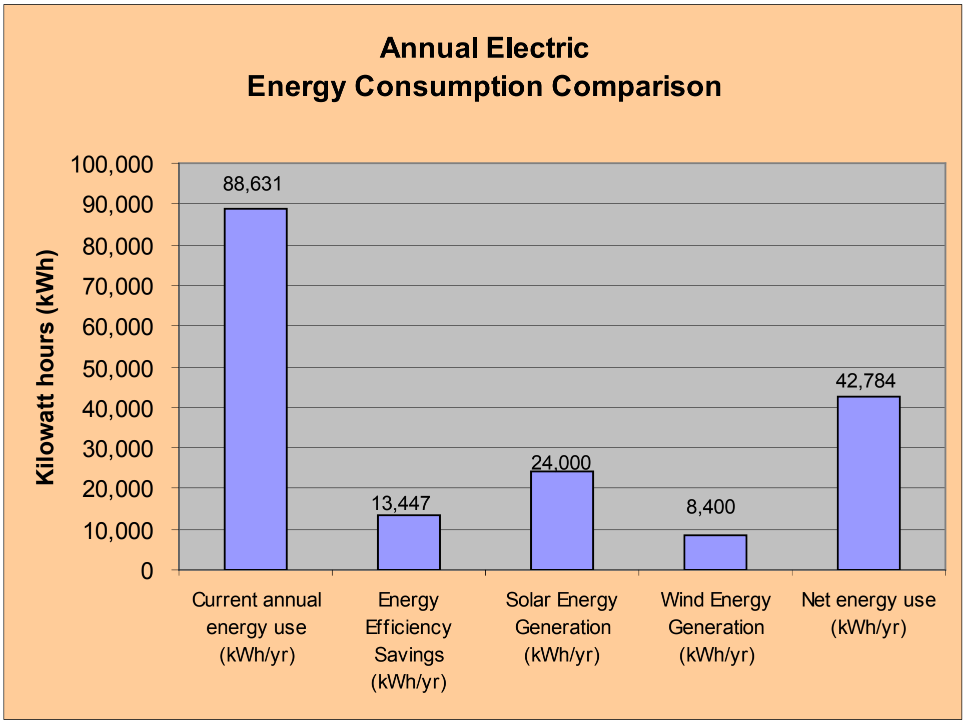
6.4 Howonquet Community Center Summary

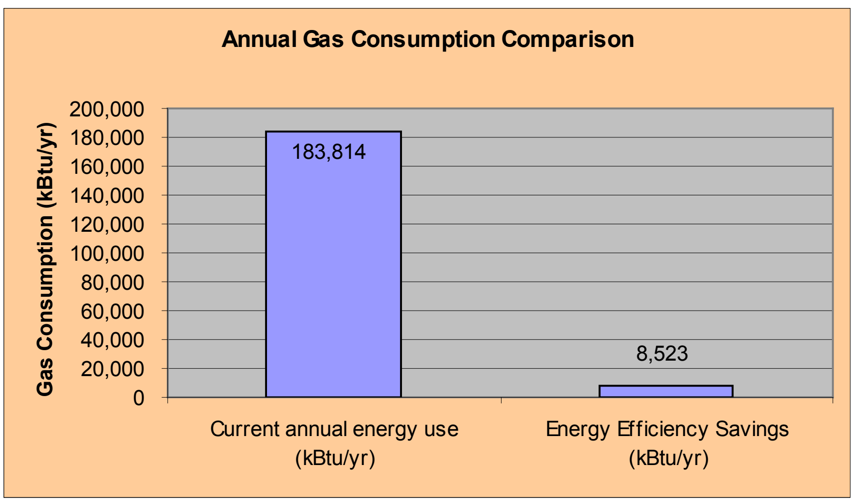
The Howonquet Community Center electric energy efficiency measures combined equate to a total energy savings of 13,447 kWh/yr or an annual savings of $1,345/yr in energy costs.

The Howonquet Community Center solar and wind systems combined equate to a net installed capacity of 30 kW, well below the 1MW net metering cutoff. Total estimated generation from these two systems amounts to 32,400 kWh/yr or an annual savings of $3,240/yr in energy costs.

Combining both electric energy efficiency measures and potential renewable energy generation results in an estimated net decrease in utility energy demand of 45,847 kWh/yr or 52% (See Figure 15). Gas energy efficiency measures result in an estimated net decrease in utility demand of 8,523 kBtu/yr or 5%.

Figure 15 Howonquet Community Center Energy Summary





7 Lucky 7 Casino & Howonquet Restaurant

7.1 Site Description

The Lucky 7 Casino & Howonquet Restaurant building (Lucky 7 Casino) was built in 1999 to serve as the primary revenue source and employment opportunity for the reservation.

The Casino and Restaurant building is a single level steel frame construction with a concrete slab on grade floor and a metal roof. Building size is approximately 21,400 sqft. Operating hours are 7 days a week, 24 hours a day.

The general layout of the building is shown in Figure 16 below. The main entrance to the building faces north towards the Lucky 7 Fuel Mart, on the east side of Highway 101. The Casino has 269 slot machines, 150 bingo seats, and much more in casino entertainment. In the northeast corner of the Casino is the Howonquet Restaurant. The southeast corner contains a large meeting room used for conferences or parties. Table 16 summarizes some of the property specifics.

Figure 16 Lucky 7 Casino & Howonquet Restaurant Floor Plan

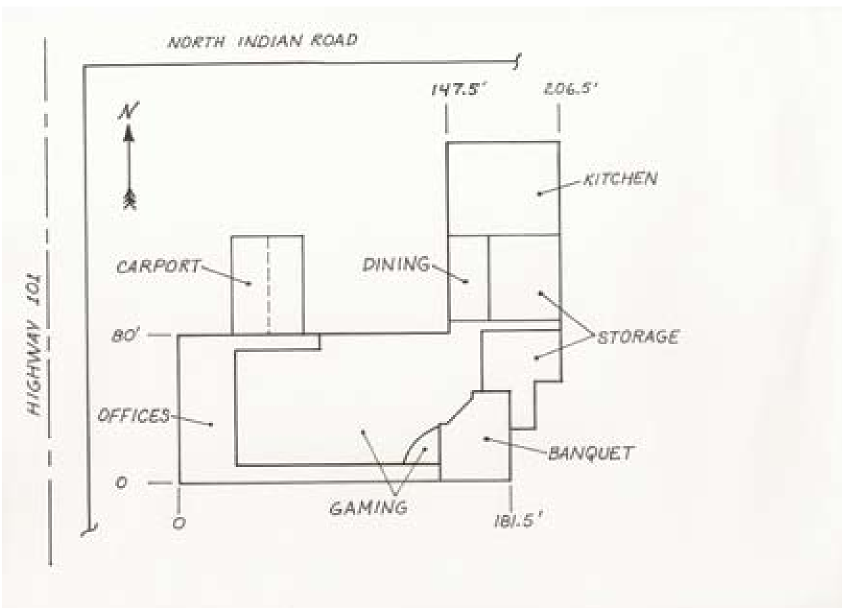


Table 16 Lucky 7 Casino & Howonquet Restaurant Property Details

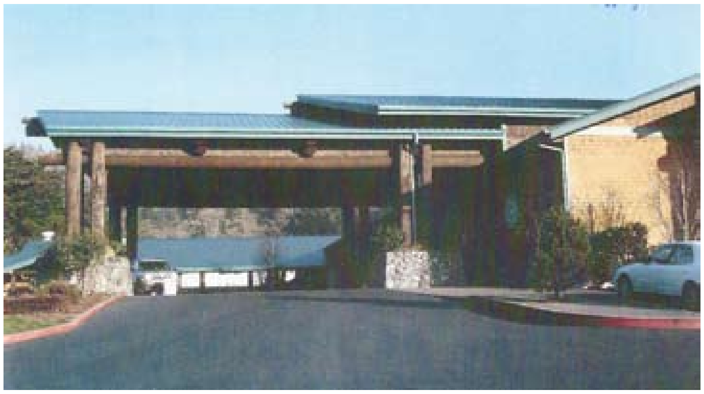
Property Information	
Address	350 N Indian Road, Smith River, CA 95567-9474 (On the SE corner of North Indian Road and Highway 101, directly south of the Convenience Store)
Building Rough Dimensions	21,400 sqft, approx.
Building Orientation	Southern facing roof, main entrance faces north
Building Construction	Wood frame construction with a metal roof (4x12 pitch), open indoor vaulted ceiling in gaming area.
Windows	Very few windows exist, primarily on the west side of the restaurant, facing 101, with a few around the perimeter in the office area. Windows appear to be vinyl framed single paned. Due to the high number of air exchanges, window upgrades are not cost-effective.
Ceiling Insulation	Ceiling area is open from inside the casino and the insulation level is unknown. Due to the temperature level maintained in the gaming area, and the high number of air exchanges, insulation upgrades are not cost effective.
Wall Insulation	Wall insulation levels should be checked, though the engineering team expects that they will be adequate given when the building as completed.
Floor Insulation	The building is constructed on a single concrete slab
Door Weather Stripping	There is one large main entrance to the gaming area and another smaller entrance into the restaurant. The large main entrance opens into a small foyer with another set of doors entering into the casino. Weather proofing should not be an issue given the entry buffer areas provided by the double door sets in each location.
Interior Lighting	(See Figure 32 for a detailed listing of the lighting equipment)
Exit Lighting	Six standard emergency exit signs are located around the perimeter of the building.
Exterior Lighting	A total of 22 flood lights illuminate all sides of the building. The large parking area is illuminated by three pool mounted sodium flood lights
Heating and Cooling System	60% fresh area mix is maintained within the gaming area. Three rooftop exhausts. There are five (5) AC units for a total capacity of 8 tons and eight (8) electric heat pump units for a total capacity of 17.5 tons located around the east and south sides of the building (See Figure 33 for a detailed listing of the equipment).
Thermostats	Did not record how HVAC is controlled and which outdoor units supply which areas of the building.
Back-up Power	A diesel power generator (V12, 570kW, 713 kVA, 978A, 1800 rpm) is located in a storage building near the southeast corner of the Casino.
Cooking Fuel	All stoves in the kitchen are fueled by propane tanks located on the north side of the building.
Water Heating	Propane water heat (A.O. Smith 306.6 Liter) needs replaced.
Electric Panel	Five 225A, One 400A panels. Main coming in was 120/208 3000A.
Propane	The two propane tanks are located on the northeast corner of the building.
Other	Kitchen appliances, stoves, refrigerators, large walk-in cooler, 269 slot machines
Estimated Annual Energy Consumption	1,971,000 kWh/yr (EUI = 92 kWh/sqft-yr); 11,817 gallons of propane (EUI = 51 kBtu/sqft-yr)

7.2 Energy Consumption Summary

A monthly utility payment summary was provided for November 2005 through October 2006, showing an average energy cost of $0.07/kWh. (See Figure 17)

Figure 17 Lucky 7 Casino & Howonquet Restaurant Annual Energy Consumption

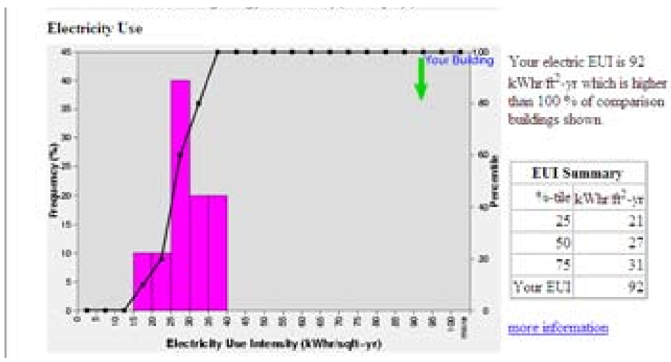
Electricity Consumption Data *Lucky 7 Casino*	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Annual Total
kWh	156,300	211,200	165,000	178,200	214,800	174,000	148,500	150,000	143,100	132,000	130,200	167,700	1,971,000
kW	290	343	329	361	359	350	345	308	225	239	244	310	3,703
Cost	$10,590	$ 13,817	$ 11,068	$12,092	$ 14,046	$11,739	$ 10,283	$ 10,235	$ 9,610	$ 8,947	$ 9,050	$ 11,248	$ 132,724
$/kWh	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07

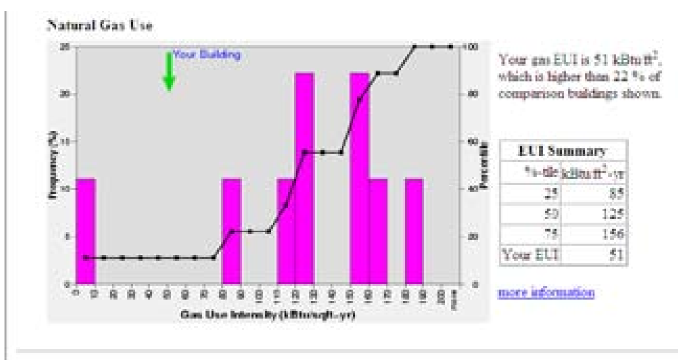


Using the annual kWh consumption value along with general building and climate specifications resulted in a calculated Electric Energy Use Index (EUI) of 92 kWh/sqft-yr and a Gas Energy Use Index of 51 kBtu/sqft-yr for the Lucky 7 Casino.

The electric EUI is significantly higher than 100% of the comparable buildings (hospitals) and the gas EUI is significantly lower than comparable buildings in California. The comparative building EUI value ranges are 21 - 31 kWh/sqft-yr and 85 156 kBtu/sqft-yr (Figure 18)[17], respectively, indicating that the Casino can not really be compared to a building of this type. As casino's were not listed as a building type in the database, this building was compared to that of hospitals which operation 24X7 every day of the year.

Figure 18 Lucky 7 Casino & Howonquet Restaurant EUI Comparisons





The estimated building energy use is comparable to the actual annual consumption as billed by the utilities (see Table 17 below).

Table 17 Lucky 7 Casino Actual vs. Calculated Energy Consumption

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	1,971,000	1,948,589	99%
Gas (kBtu)	1,082,465	980,320	91%

17 LBNL Cal-Arch tool.

7.3 Opportunities for Energy Optimization

7.3.1 Energy Efficiency & Efficiency Measure Economics

The largest energy savings potential for the Lucky 7 Casino would result from load management of a portion of the gaming machines. This could be done by automatically or manually turning off a portion of the units (assumed 25% of the machines for 8 hours a day). Estimated energy savings for this energy efficiency measure would be approximately 196,370 kWh/yr.

This proposed measure is not an established or standard practice for gaming facilities. The potential risk may be a loss of revenue when clients perceive some of the machines to be inoperable. A study should be conducted to determine the revenue impact to the casino of turning off (or placing in a sleep mode) a portion of the gaming machines during low usage periods such as early morning hours.

Costs, energy savings and estimated payback periods for all energy efficiency measures identified for this building are summarized below:

Table 18 Lucky 7 Casino & Howonquet Restaurant Efficiency Savings Measures

Electric Energy Efficiency Measure Description	**Energy Savings (kWh/yr)**	**Estimated Cost ($)**	**Estimated Payback (years)**
· Manage gaming machine load by automatically or manually turning off a portion of the units (assume 25% of machines for 8 hours a day)	196,370	$ 7,868	0.5
· Replace selected interior incandescent lighting with CFLs	149,849	2,566	0.2
· Replace current electric cooling/heating systems with SEER 18 heat pumps	2,376	29,164	175
· Replace current exit signs with LED exit signs	663	300	4.5
Total	**349,258**	**$ 39,898**	

Gas Energy Efficiency Measure Description	**Energy Savings (kBtu/yr)**	**Estimated Cost ($)**	**Estimated Payback (years)**
· Replace and insulate gas water heaters	16,819	$74	0.2
Total	**16,819**	**$ 74**	

Total electric estimated savings from current consumption levels, if all measures are installed, is 349,258 kWh per year or approximately a 18% reduction in energy use. This equates to a total electric energy efficiency project cost for the Lucky 7 Casino of $39,898. Using an estimated $27,930/year in energy savings equates to a 1.4 year payback on the electric efficiency portion of the project.

Total propane estimated savings from current consumption levels is 16,819 kBtu/yr. This equates to a total gas energy efficiency project cost of $74. Using an estimated $367/yr in energy savings equates to a 0.2 year payback on the gas efficiency portion of the project. (Referring to 31 in Appendix III for further detail)

7.3.2 Renewable Generation & Economics

If a transaction with a taxable partner could be reached, certain tax benefits would improve the financial performance and payback. For taxable corporations, an investment in solar systems would result in the following benefits:

- 30% investment tax credit (wind); 10% investment tax credit (solar)
- 6 year MACRS depreciations schedule
- $0.019/kWh production tax credit (wind only)

In addition, the California Public Utility Commission (CPUC) administers a solar incentive program that is not currently available to the Rancheria. These incentives are summarized in Section 10.4.

7.3.2.1 Solar Energy Generation

There is approximately 12,000 square feet (sqft) of south facing roof area on the Lucky 7 Casino. A Photovoltaic (PV) system requires approximately 100 sqft for each kilowatt (kW) of installed capacity, thus the roof area could safely accommodate about a 100 kW system, allowing room for roof obstructions. The 100 kW PV system will produce 100 kW of DC power on bright sunny days. This must be converted to AC power to be paralleled with the building energy system, resulting in losses of approximately 25%.[18]

In this region, PV units can be expected to produce 1200 kWh/yr per kW of installed capacity. Annual PV generation potential for this location is estimated to be 120,000 kWh/yr. At an average power cost of $0.07/kWh, this would result in an annual savings of $8,400. Assuming a capital cost of $7/watt installed, this equates to a system installation cost of approximately $700,000 to the Rancheria. Refer to Table 19 below for the solar system economics:

Table 19 Lucky 7 Casino Solar System Economics

	Lucky 7 Casino
Total System Size (kW)	100
System Cost (@ $7/kW)	$ 700,000
Annual Energy Savings ($/yr)	$ 8,400
Payback (years)	83

While the Lucky 7 Casino is favorably orientated for southern exposure, there are plans to build a 3-story hotel building to the south which is expected to completely shade the solar system. An installation by the tribe, without the benefit of incentives available to many other Californians, yields a simple payback of 83 years. An investment in solar generation appears unattractive unless grants can be found to offset a substantial portion of the cost.

The federal government and the California Public Utility Commission (CPUC) offer significant incentives for solar power generation to customers of PG&E, SCE and SDG&E; however, none appear to be available or applicable for this site. There is a potential for USDOE grant funding for an installation under the same program that funded this study. Please refer to Section 10 for a detailed review of these incentives and options.

7.4 Lucky 7 Casino Summary

The Lucky 7 Casino electric energy efficiency measures combined equate to a total energy savings of 349,258 kWh/yr or an annual savings of $39,898/yr in energy costs.

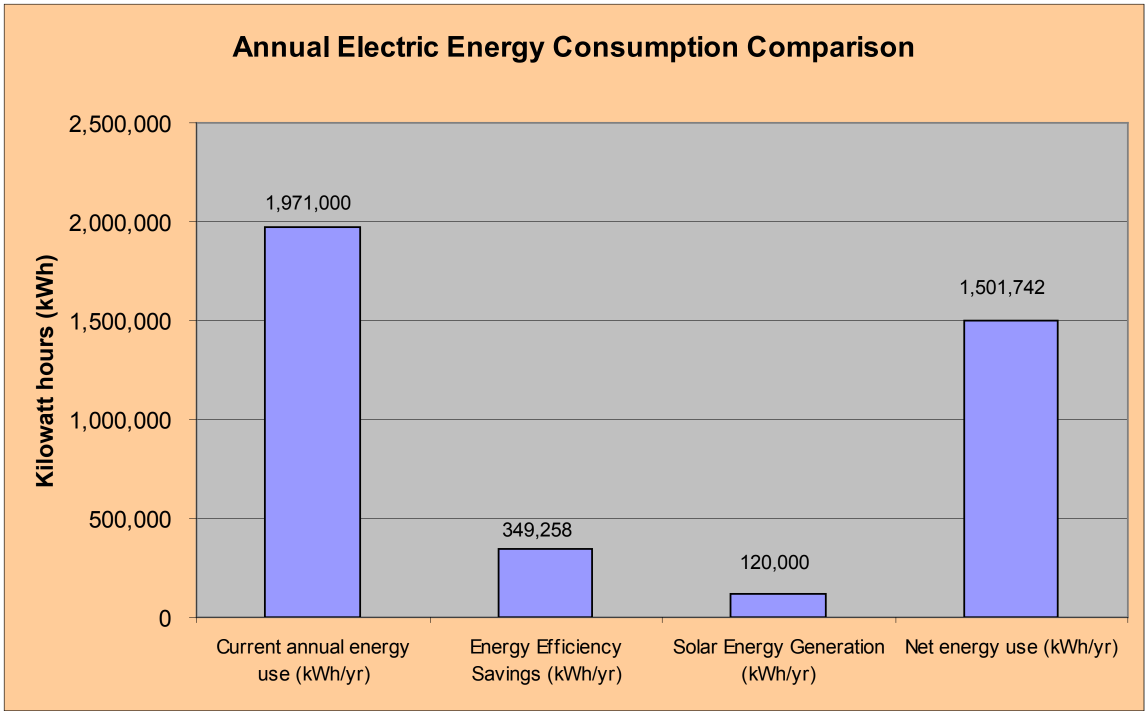
The Lucky 7 Casino solar system has an installed capacity of 100 kW, well below the 1MW net metering cutoff. Total estimated generation from this system amounts to 120,000 kWh/yr or an annual savings of $8,400/yr in energy costs.

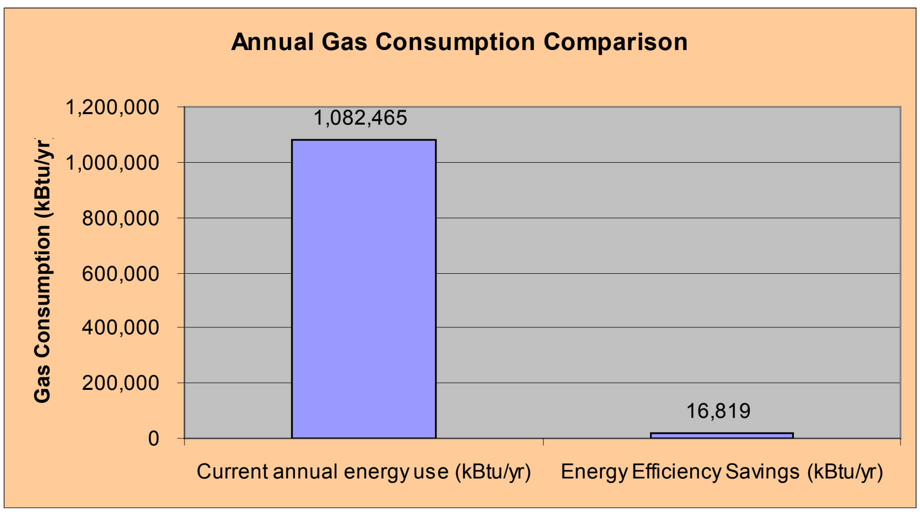
Combining both electric energy efficiency measures and potential renewable energy generation results in an estimated net decrease in utility energy demand of 469,258 kWh/yr or 24% (See Figure 19)

There is only one suggested gas efficiency measure, insulation of the water heating units, which results in a net decrease in utility propane demand of 16,819 kBtu/yr or 2%. While the water heater needs to be replaced, only the cost of the insulation installation is included in the economic analysis.

18 Energy Trust of Oregon. Solar Electric Program Systems Requirement Document. April, 2003.

Figure 19 Lucky 7 Casino & Howonquet Restaurant Energy Summary





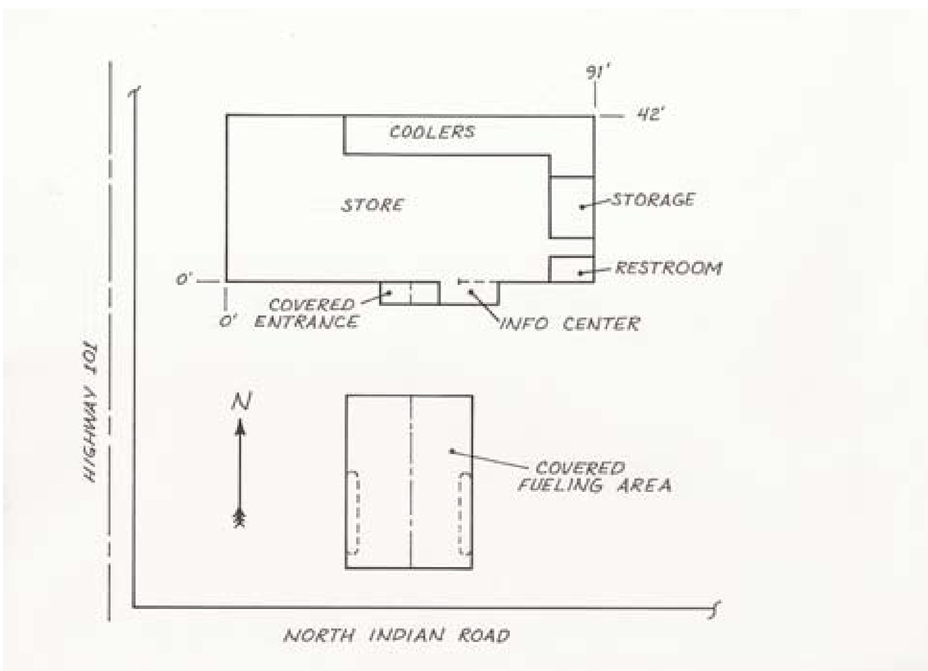
8 Lucky 7 Fuel Mart

8.1 Site Description

The Lucky 7 Fuel Mart was constructed in 2003 to serve as a revenue source for the community, and as a service stop for tourists visiting the casino or traveling through the area. The Fuel Mart building is a single level wood frame construction building with a concrete slab on grade floor and a metal roof. Building size is approximately 3,800 sqft. Operating hours are 6:00am – 10:00 pm, 7 days a week.

The general layout of the building is shown in Figure 20 below. The facility is located directly east of Highway 101, with the main entrance of the store facing directly towards the front of the Lucky 7 Casino to the south. The majority of the store is an open shopping area. Refrigerated reach-in coolers line the north and east sides of the building. Restrooms are located in the southeast corner of the main store. A small information center was recently added, protruding from the south side of the building, near the entrance, which contains information on local areas of interest.

Figure 20 Lucky 7 Fuel Mart Floor Plan



General specifications for the building include new vinyl framed, double paned windows without coverings, overhead fluorescent lighting in all rooms contained within suspended ceilings, with the exception of the refrigerated spaces. Flood lighting is installed on the under side of the covered fueling area. The building has been constructed to meet current codes, including insulation and air circulation requirements. The water heater in the utility closet requires insulation. The building is heated and cooled with an gas HVAC unit. Propane is used for water and space heating, and to fuel the emergency back up generator on the east side of the building. (See Table 20 below for a more detailed description of the building and components.)

Table 20 Lucky 7 Fuel Mart Property Details

Property Information	
Address	250 N Indian Road, Smith River, CA 95567 (On the NE corner of North Indian Road and Highway 101 just north of the casino)
Building Rough Dimensions	91'5" x 41'9" (3,800 sqft, approx.)
Building Orientation	Fueling station covered area has good solar access though roof faces east/west. Convenience store is south facing but has a lower roofline than the fuel station covered area
Building Construction	Wood frame construction with a metal roof (4x12 pitch)
Windows	Windows are on the front of the store only, south facing. There are no shades or blinds. All windows are vinyl framed, double pane.
Ceiling Insulation	Ceiling insulation levels should be checked, though the engineering team expects that they will be adequate given when the building was completed.
Wall Insulation	Wall insulation levels should be checked, though the engineering team expects that they will be adequate given when the building as completed.
Floor Insulation	The building is constructed on a single concrete slab
Door Weather Stripping	The front doors are newer metal and glass store front with adequate weather stripping
Interior Lighting	25 (4 tube , 40 watt) fluorescent ceiling fixtures; two incandescent lamps in bathrooms; 16 flood lights in new front room display area
Exit Lighting	One standard emergency exit sign at side exit from inside the store.
Exterior Lighting	18 mercury vapor flood lights in fueling station area
Heating and Cooling System	Lenox heat pump, 130,000 Btu/hr. Filters changed monthly
Thermostats	Location??
Back-up Power	A propane fired generator (Caterpillar Olympian 4100E, 75kW, 93.1 kVA) is located on the north side of the building to provide power in emergencies or when the electric supply is temporarily interrupted. The battery for the unit not on a Styrofoam pad
Water Heating	Hot water heat is provided by a propane water heater
Electrical Panel	Two 200A panels
Propane	Propane tank located at northeast corner of building. Used for water heat, cooling equipment, and power generation.
Other	Refreshment equipment (soda, coffee, etc…), 17 reach-in coolers with new looking doors and cooling equipment (Russell High Sierra Cooling Unit). Battery for back up generator is setting on the ground and should be placed on a foam insulator.
Estimated Annual Energy Consumption	238,760 kWh/yr (EUI = 63 kWh/sqft-yr); 2340 gallons (2144 therms) of propane per year (EUI = 56 kBtu/sqft-yr)

8.2 Energy Consumption Summary

A monthly utility payment summary was provided for November 2005 through October 2006, showing an average energy cost of \$0.08/kWh. (See Figure 21)

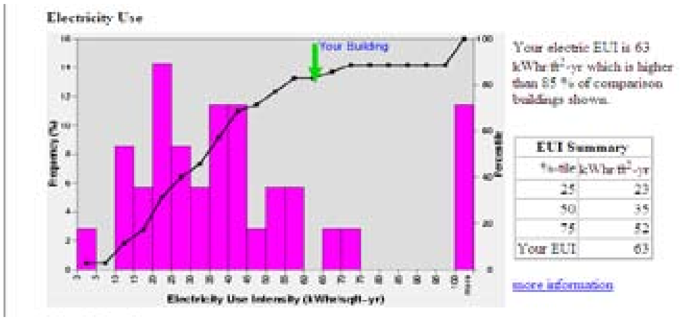
Figure 21 Lucky 7 Fuel Mart Building Annual Energy Consumption

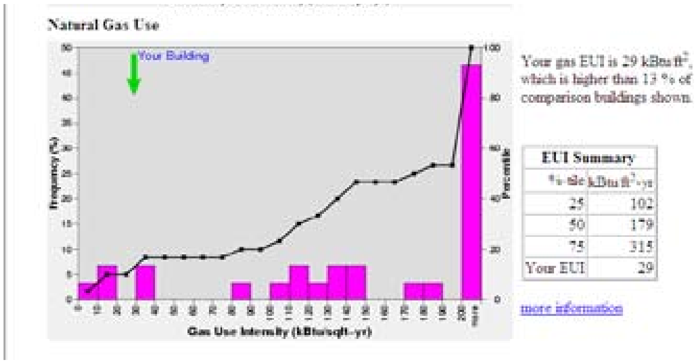
Electricity Consumption Data	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Annual Total
Lucky 7 Fuel Mart													
kWh	21,680	23,640	20,400	18,000	20,680	18,800	17,680	18,960	21,360	18,960	17,360	21,240	238,760
kW	37	39	38	40	39	39	40	42	43	41	38	39	475
Cost	\$ 1,623	\$ 1,926	\$ 1,609	\$ 1,438	\$ 1,632	\$ 1,497	\$ 1,416	\$ 1,514	\$ 1,694	\$ 1,516	\$ 1,395	\$ 1,681	\$ 18,941
\$/kWh	\$ 0.07	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08	\$ 0.08

Using the estimated annual kWh consumption value along with general building and climate specifications resulted in calculated EUI's of 63 kWh/sqft-yr and 29 kBtu/sqft-yr for electric and gas respectively. The electric EUI is at the higher range of all comparative buildings in California, which had EUI values from 23 - 52 kWh/sqft-yr (see Figure 22).[19] The gas EUI is at the lower range of all comparable buildings in California, which had EUI values from 102 - 315 kBtu/sqft-yr. Note, however, that the EUI values for gas ranged from 0 – 200+ kBtu/sqft-yr and thus there really does not seem to be a tight range of gas use that is indicative of these grocery buildings.

19 LBNL Cal-Arch tool.

Figure 22 Lucky 7 Fuel Mart EUI Comparisons





The estimated building energy use is comparable to the actual annual consumption as billed by the utility, though the calculated consumption was unable to account for approximately 25% of both the electric and propane consumption. This discrepancy is due to a lack of detail on the numerous food service equipment within the Fuel Mart.

Table 21 Lucky 7 Fuel Mart Actual vs. Calculated Energy Consumption

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	88,631	62,691	71%
Gas (kBtu)	183,814	146,026	79%

8.3 Opportunities for Energy Optimization

8.3.1 Energy Efficiency & Efficiency Measure Economics

The largest energy savings potential for the Lucky 7 Fuel Mart would result from replacement of the fueling area canopy lights with high pressure sodium lamps. Estimated energy savings for this energy efficiency measure would be approximately 21,024 kWh/yr.

Costs, energy savings and estimated payback periods for all energy efficiency measures identified for this building are summarized below:

Table 22 Lucky 7 Fuel Mart Efficiency Savings Measures

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· Replace canopy lights with high pressure sodium bulbs	21,024	$ 2,860	1.7
· Replace interior flood lamps in visitor resource center with CFLs	10,652	207	0.2
· Replacement of refrigeration evaporator fans, condensor fans to higher efficiency units	7,227	2,000	3.5
· Replace 2 incandescent lights in restrooms with CFLs	549	18	0.4
· Replace current exit signs with LED exit signs	307	50	2.0
Total	**39,759**	**$ 5,135**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Replace current Lennox gas HVAC system with higher efficiency unit	11,232	$ 4,044	16
· Insulate water heater	1373	74	2.5
Total	**12,605**	**$ 4,118**	

Total electric estimated savings from current consumption levels, if all measures are installed, is 39,759 kWh per year or approximately a 17% reduction in energy use. This equates to a total electric energy efficiency project cost for the Lucky 7 Fuel Mart of $5,135. Using an estimated $3,181/year in energy savings equates to a 1.6 year payback on the electric efficiency portion of the project.

Total propane estimated savings from current consumption levels is 12,605 kBtu/yr. This equates to a total gas energy efficiency project cost of $4,118. Using an estimated $275/yr in energy savings equates to a 15 year payback on the gas efficiency portion of the project. (Referring to 34 in Appendix III for further detail)

8.3.2 Renewable Generation & Economics

If a transaction with a taxable partner could be reached, certain tax benefits would improve the financial performance and payback. For taxable corporations, an investment in solar systems would result in the following benefits:

- 30% investment tax credit (wind); 10% investment tax credit (solar)
- 6 year MACRS depreciations schedule
- $0.019/kWh production tax credit (wind only)

In addition, the California Public Utility Commission (CPUC) administers a solar incentive program that is not currently available to the Rancheria. These incentives are summarized in Section 10.4.

8.3.2.1 Solar Energy Generation

There is approximately 1,800 square feet (sqft) of south facing roof area on the Lucky 7 Fuel Mart building. A Photovoltaic (PV) system requires approximately 100 sqft for each kilowatt (kW) of installed capacity, thus the roof area could safely accommodate about a 15 kW system, allowing room for roof obstructions. The 15 kW PV system will produce 15 kW of DC power on bright sunny days. This must be converted to AC power to be paralleled with the building energy system, resulting in losses of approximately 25%.[20]

In this region, PV units can be expected to produce 1200 kWh/yr per kW of installed capacity. Annual PV generation potential for this location is estimated to be 18,000 kWh/yr. At an average power cost of $0.08/kWh, this would result

20 Energy Trust of Oregon. Solar Electric Program Systems Requirement Document. April, 2003.

in an annual savings of $1,440. Assuming a capital cost of $7/watt installed, this equates to a system installation cost of approximately $105,000 to the Rancheria. Refer to Table 23 below for the solar system economics:

Table 23 Lucky 7 Fuel Mart Solar System Economics

		Lucky 7 Fuel Mart
Total System Size (kW)		15
System Cost (@ $7/kW)	$	105,000
Annual Energy Savings ($/yr)	$	1,440
Payback (years)		73

The Lucky 7 Fuel Mart is favorably orientated for southern exposure, with no obstructions that would cause shading of the solar system and a reduction in system performance. An installation by the tribe, without the benefit of incentives available to many other Californians, yields a simple payback of 73 years. An investment in solar generation appears unattractive unless grants can be found to offset a substantial portion of the cost.

The federal government and the California Public Utility Commission (CPUC) offer significant incentives for solar power generation to customers of PG&E, SCE and SDG&E; however, none appear to be available or applicable for this site. There is a potential for USDOE grant funding for an installation under the same program that funded this study. Please refer to Section 10 for a detailed review of these incentives and options.

8.4 Lucky 7 Fuel Mart Summary

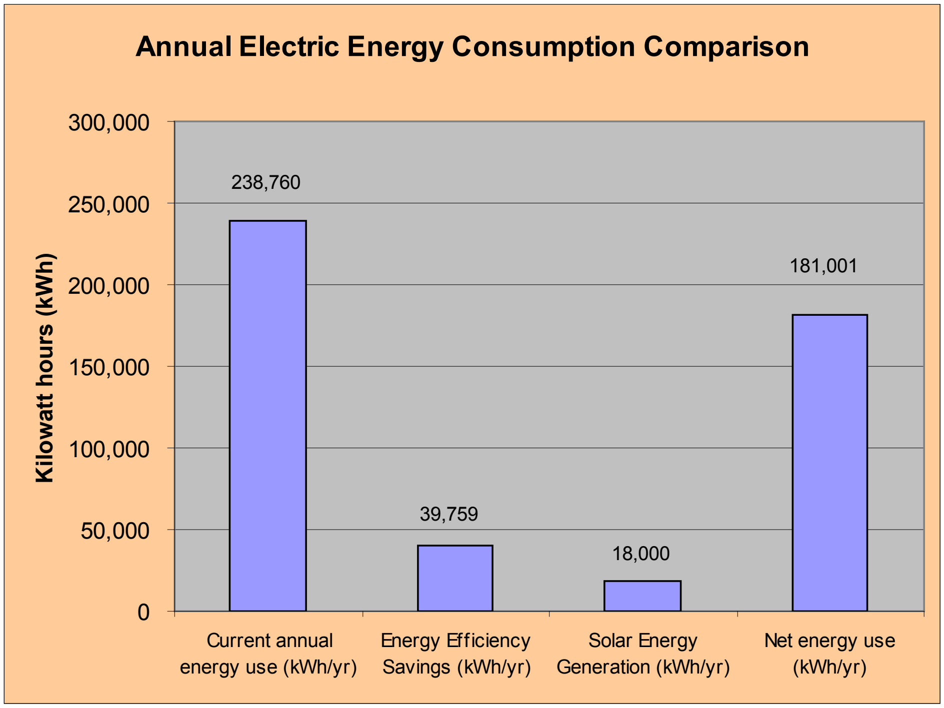
The Lucky 7 Fuel Mart electric energy efficiency measures combined equate to a total energy savings of 39,759 kWh/yr or an annual savings of $3,181/yr in energy costs.

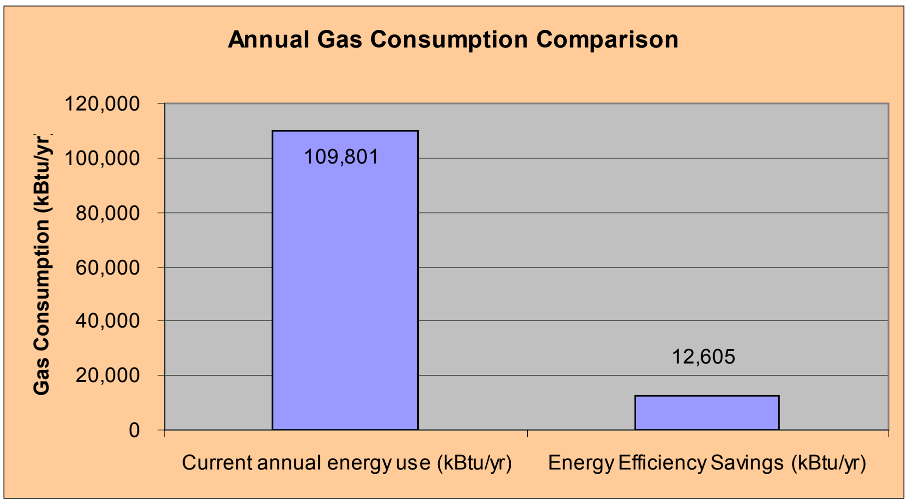
The Lucky 7 Fuel Mart solar system equates to an installed generation capacity of 15 kW, well below the 1MW net metering cutoff. Total estimated generation from this system amounts to 18,000 kWh/yr or an annual savings of $1,440/yr in energy costs.

Combining the electric energy efficiency measures and potential renewable energy generation results in an estimated net decrease in utility energy demand of 57,759 kWh/yr or 24% (See Figure 23)

In addition, the gas efficiency measures result in a net decrease in utility propane demand of 12,605 kBtu/yr or 11%.

Figure 23 Lucky 7 Fuel Mart Energy Summary





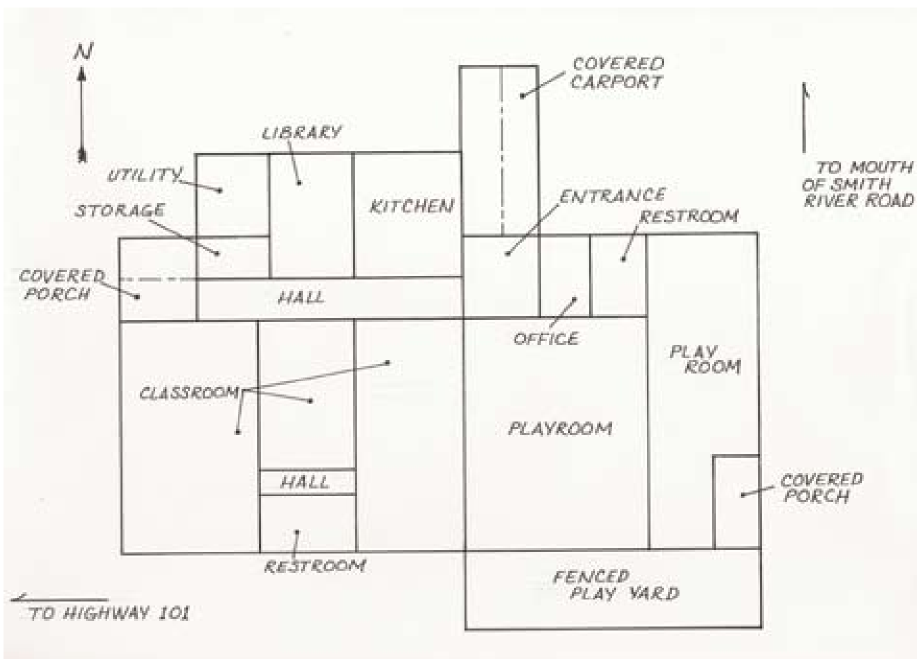
9 Howonquet Head Start & Day Care Center

9.1 Site Description

The Howonquet Head Start & Day Care Center (Head Start Building) was constructed in the last few years to serve as the community day care and educational head start center for children of the community. The building is a single level wood frame constructed building with a concrete slab on grade floor and a composition roof. Building size is approximately 6,500 sqft. Operating hours are M-F, 7:00am – 6:00pm.

The general layout of the building is shown in Figure 24 below. The main entrance to the building faces north on Mouth of the Smith River Road, east of Highway 101.

Figure 24 Howonquet Head Start & Day Care Center Floor Plan



On the north side of the building are a reading room, the kitchen, a utility room and the main entrance foyer. The south side of the building contains four student areas, two in the head start section and two in the day care section. The day care rooms are on the east side of the building and the head start rooms are located on the west side of the building. One restroom is located in each sections. A fenced play area is located on the south side of the facility.

Table 24 Howonquet Head Start &Day Care Center Property Details

Property Information	
Location	Located at 12840 Mouth of Smith River Road, east of Highway 101
Building Rough Dimensions	6,500 sqft, approx.
Building Orientation	Southern facing roof, main entrance faces north
Building Construction	Wood frame construction with a composite roof (4x12 pitch)
Windows	Windows exist on all four sides of the building. All windows are vinyl framed, double paned.
Ceiling Insulation	Ceiling insulation levels are sufficient.
Wall Insulation	Wall insulation levels should be checked, though the engineering team expects that they will be adequate given when the building as completed.
Floor Insulation	The building is sitting on a single concrete slab which is heating by radiant hot water heating.
Weather Proofing	The front door is a series of two doors, and thus should not require weather stripping due to the buffer zone between the two sets of doors
Interior Lighting	29 (4 tube, 40 watt) fluorescent ceiling fixtures; two incandescent lamps in bathrooms; 10 flood lights in the play room. Two 20' and three 24' high efficiency ceiling fixtures in the southwest room do not require replacement.
Exit Lighting	Two standard emergency exit signs, one located on each end of the building.
Exterior Lighting	The building is lit by nine flood lamps located on all sides of the building. Two additional flood lamps are located on east side of building in covered play area. Ten can flood lamps are located in the covered drive-up entry.
Heating and Cooling System	Radiant hot water floor heating. Rheem heat pump for cooling and backup heating.
Thermostats	Five different thermostat zones: west play room, center room on Head Start side, (did not note location of other three). Some thermostats do not appear to be working.
Back-up Power	None
Cooking Fuel	All stoves in the kitchen are fueled by propane tanks located on the north side of the building.
Water Heating	Hot water is provided by a 100 gallon propane fired water heater (A.O. Smith, 250 kBtu/hr, on timers with circulating pumps) located in a utility closet midway on the north side of the building, just to the west of the small reading room. Water heaters are not insulated. Buildings are supposed to have air handlers but the units would not turn on when the thermostats were adjusted.
Electrical Panel	Two 200 A panels
Propane	The propane tank is located on the east side of the building.
Other	Kitchenette appliances and refrigerators. There are two maintenance issues that need attended too: (1) There is currently a plumbing issue for the hot water system such that hot water can come out the outside cold water spigots; (2) The two gas pack HVAC units (A.S. Freedom 80 Gas Pack) in the attic space would not turn on when thermostats were adjusted. Both of the items will affect energy demand/use, though the magnitude is unknown given currently available consumption data.
Estimated Annual Energy Consumption	29,833 kWh/yr (EUI = 5 kWh/sqft-yr); 2,585 gallons (2,368 therms) of propane per year (EUI = 36 kBtu/sqft-yr)

9.2 Energy Consumption Summary

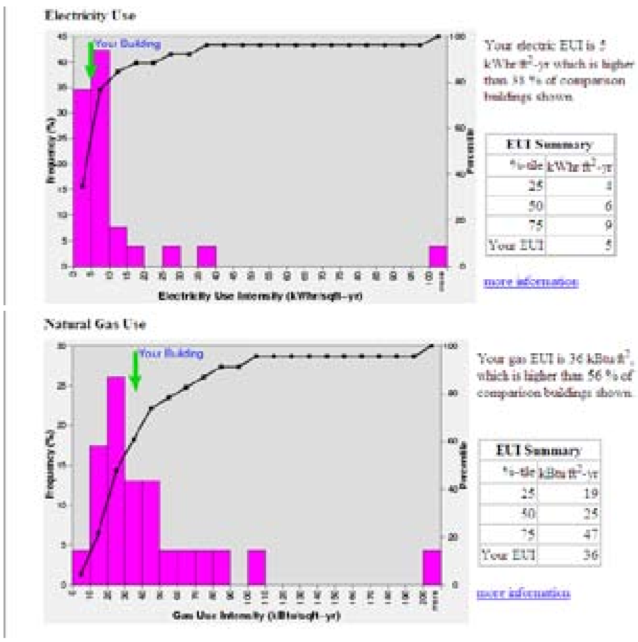
A monthly utility payment summary was provided for January through December 2006, showing an average energy cost of $0.09/kWh. (See Figure 25)

Figure 25 Howonquet Head Start & Day Care Center Annual Energy Consumption

Electricity Consumption Data *Howonquet Head Start & Day Care Center*	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Annual Total
kWh	2,725	2,905	2,460	2,474	2,727	2,327	2,275	2,124	2,050	2,327	2,782	2,657	29,833
kW	(unknown as actual bills were not supplied)												0
Cost (Estimated)	$ 245	$ 261	$ 221	$ 223	$ 245	$ 209	$ 205	$ 191	$ 185	$ 209	$ 250	$ 239	$ 2,685
$/kWh	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09

Using the estimated annual kWh consumption value along with general building and climate specifications resulted in a calculated EUI's of 5 kWh/sqft-yr and 36 kBtu/sqft-yr. The electric EUI is at the lower range of all comparative buildings in California, which had EUI values from 4 - 9 kWh/sqft-yr (see Figure 26).[21] The gas EUI is right at the middle of comparable buildings in California, which had EUI values from 19 - 47 kBtu/sqft-yr. The low value are electric EUI is primarily due to the fact that the Howonquet Head Start & Day Care Center is heated using radiant hot water in the slab flooring. The gas EUI value is right near the average for comparable buildings.

Figure 26 Howonquet Head Start & Day Care Center Energy Use Index (EUI) Comparison



The estimated building energy use is comparable to the actual annual consumption as billed by the utilities (see Table 25 below).

Table 25 Howonquet Head Start & Day Care Center Actual vs. Calculated Energy Consumption

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	29,833	31,034	104%
Gas (kBtu)	236,795	214,882	91%

9.3 Opportunities for Energy Optimization

9.3.1 Energy Efficiency & Efficiency Measure Economics

The largest energy savings potential for the Howonquet Head Start & Day Care Center would result from replacement of the standard 4-lamp 40W fluorescent overhead lighting with high efficiency 2-lamp 32W fixtures and ballasts with no noticeable decrease in illumination. Estimated energy savings for this energy efficiency measure would be approximately 10,156 kWh/yr.

21 LBNL Cal-Arch tool.

Costs, energy savings and estimated payback periods for all energy efficiency measures identified for this building are summarized below:

Table 26 Howonquet Head Start & Day Care Center Efficiency Savings Measures

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	10,156	$ 1,335	1.5
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	8,432	347	0.5
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	2,371	1,199	5.6
· Replace 6 interior incandescent lights with CFLs	748	53	1.0
· Replace current exit signs with LED exit signs	613	100	1.8
Total	**22,320**	**$ 3,035**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heaters, optimize water tank timers to reduce consumption during start up periods.	19,786	$ 148	0.2
Total	**19,786**	**$ 148**	

Total electric estimated savings from current consumption levels, if all measures are installed, is 22,320 kWh per year or approximately a 75% reduction in energy use. This equates to a total electric energy efficiency project cost for the Howonquet Community Center of $3,035. Using an estimated $1,994/year in energy savings equates to a 1.5 year payback on the electric efficiency portion of the project.

Total propane estimated savings from current consumption levels is 19,786 kBtu/yr. This equates to a total gas energy efficiency project cost of $148. Using an estimated $864/yr in energy savings equates to a 0.2 year payback on the gas efficiency portion of the project. (Referring to Figure 35 in Appendix III for further detail)

9.3.2 Renewable Generation & Economics

If a transaction with a taxable partner could be reached, certain tax benefits would improve the financial performance and payback. For taxable corporations, an investment in solar systems would result in the following benefits:

- 30% investment tax credit (wind); 10% investment tax credit (solar)
- 6 year MACRS depreciations schedule
- $0.019/kWh production tax credit (wind only)

In addition, the California Public Utility Commission (CPUC) administers a solar incentive program that is not currently available to the Rancheria. These incentives are summarized in Section 10.4.

9.3.2.1 Solar Energy Generation

There is approximately 1,600 square feet (sqft) of south facing roof area on the Howonquet Head Start & Day Care Center. A Photovoltaic (PV) system requires approximately 100 sqft for each kilowatt (kW) of installed capacity, thus the roof area could safely accommodate about a 10 kW system, allowing room for roof obstructions. The 10 kW PV system will produce 10 kW of DC power on bright sunny days. This must be converted to AC power to be paralleled with the building energy system, resulting in losses of approximately 25%.[22]

In this region, PV units can be expected to produce 1200 kWh/yr per kW of installed capacity. Annual PV generation potential for this location is estimated to be 12,000 kWh/yr. At an average power cost of $0.09/kWh, this would result

22 Energy Trust of Oregon. Solar Electric Program Systems Requirement Document. April, 2003.

in an annual savings of $1,080. Assuming a capital cost of $7/watt installed, this equates to a system installation cost of approximately $70,000 to the Rancheria. Refer to Table 27 below for the solar system economics:

Table 27 Howonquet Head Start & Day Care Center Solar System Economics

		Howonquet Head Start & Day Care Center
Total System Size (kW)		20
System Cost (@ $7/kW)	$	70,000
Annual Energy Savings ($/yr)	$	1,080
Payback (years)		65

The Howonquet Head Start & Day Care Center is favorably orientated for southern exposure, with no obstructions that would cause shading of the solar system and a decrease in system performance. An installation by the tribe, without the benefit of incentives available to many other Californians, yields a simple payback of 65 years. An investment in solar generation appears unattractive unless grants can be found to offset a substantial portion of the cost.

The federal government and the California Public Utility Commission (CPUC) offer significant incentives for solar power generation to customers of PG&E, SCE and SDG&E; however, none appear to be available or applicable for this site. There is a potential for USDOE grant funding for an installation under the same program that funded this study. Please refer to Section 10 for a detailed review of these incentives and options.

9.3.2.2 Wind Energy Generation

While there are no visible indicators (directional growth of trees due to strong winds) at this location, it has been determined that the average wind potential is approximately 8 mph (300-400 W/sq meter) as indicated in the California Wind Resource Map in Appendix I. A 10 kW Bergey wind turbine, costing approximately $38,000 would generate about 5,880 kWh per year valued $529. This is an inferior location for a wind turbine installation.

California's has net metering law requires investor owned utilities to compensate site generated electricity at retail rates. As detailed earlier in this report, a wind turbine located where an average wind speed of 8 mph at a rotor hub height of 30 meters (100ft) will result in estimated monthly wind energy production of 490 kWh, or annual wind energy production total of 5,880 kWh. At an average power cost of $0.09/kWh, this would result in an annual net metering credit of $529 and a lifetime (15 years) credit of $7,938. The Rancheria would be left with a balance of $30,062 at the end of the useful life of the turbine. The cost of the turbine would take a total of 72 years to pay back at current utility rates. Clearly, the turbine will need replaced much sooner than it can pay back the cost to the Rancheria in energy savings and is therefore not economical, unless grants can be found to cover most of the cost. Figure 27 summarizes the wind system economics for this site:

Figure 27 Howonquet Head Start & Day Care Center Wind System Economics

		Howonquet Head Start & Day Care Center
Total System Size (kW)		10
System Cost	$	38,000
Energy Savings over 15 yr Useful Life ($)	$	7,938
Net System Cost	$	30,062
Payback (years)		72

As outlined in Section 10, a partnership with a taxable partner may improve the financial results, but not enough to justify a wing unit at this location.

9.4 Howonquet Head Start & Day Care Center Summary

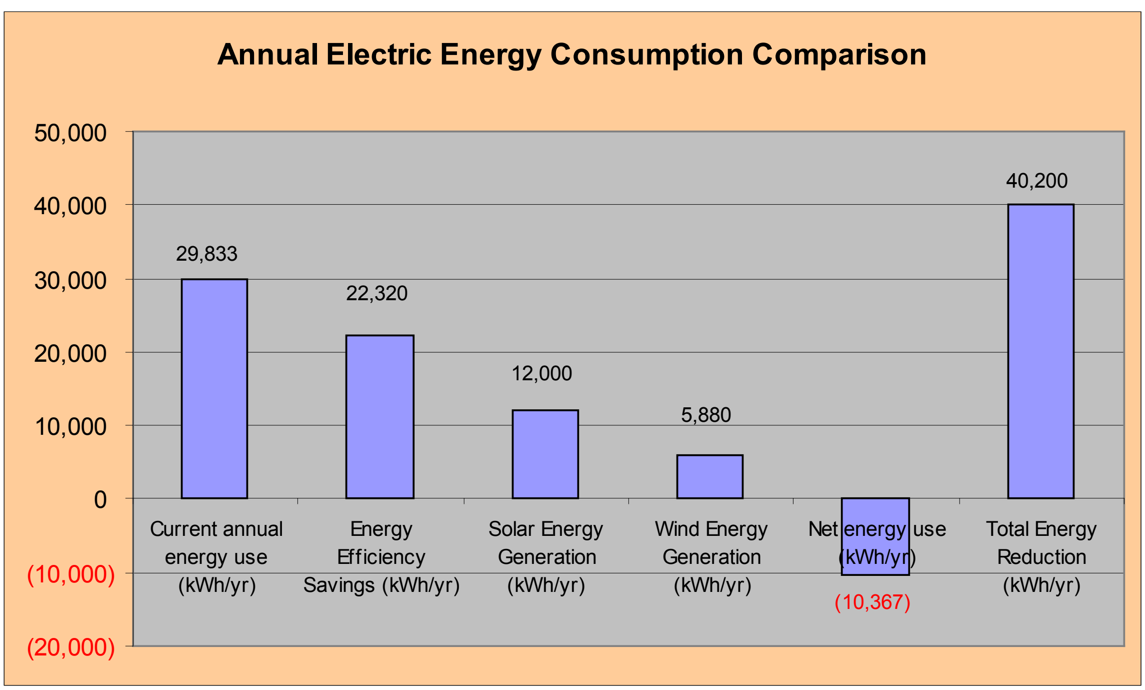
The Howonquet Head Start & Day Care Center electric energy efficiency measures combined equate to a total energy savings of 22,320 kWh/yr or an annual savings of $1,994/yr in energy costs.

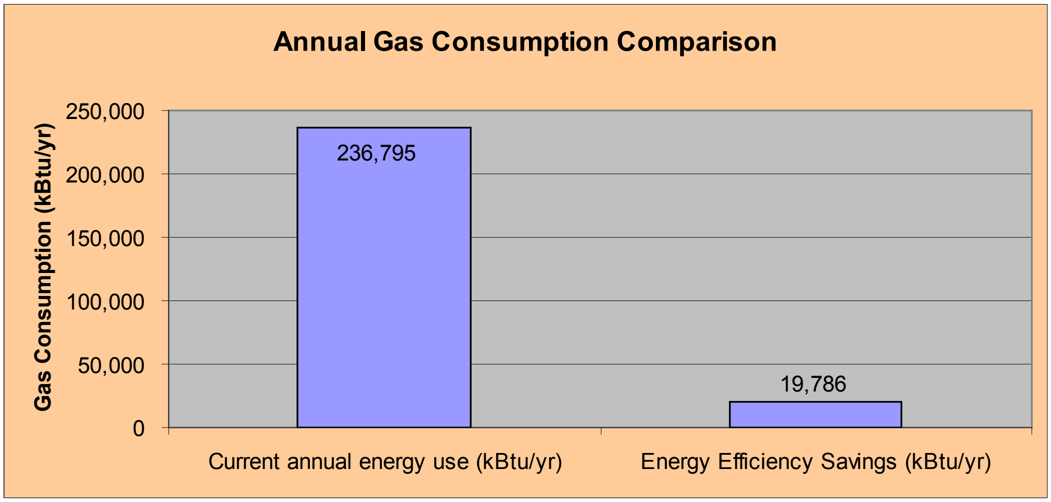
The Howonquet Head Start & Day Care Center solar and wind systems combined equate to a net installed capacity of 20 kW, well below the 1MW net metering cutoff. Total estimated generation from these two systems amounts to 17,880 kWh/yr or an annual savings of $1,609/yr in energy costs.

Combining both electric energy efficiency measures and potential renewable energy generation results in an estimated net decrease in utility energy demand of 40,200 kWh/yr or 135% (See Figure 28).

There is only one suggested gas efficiency measure, insulation of the water heating units, which results in a net decrease in utility propane demand of 19,786 kBtu/yr or 8%.

Figure 28 Howonquet Head Start & Day Care Center Energy Summary




Annual Gas Consumption Comparison
Gas Consumption (kBtu/yr)
250,000
200,000
150,000
100,000
50,000
0
236,795
19,786
Current annual energy use (kBtu/yr)
Energy Efficiency Savings (kBtu/yr)

10 Transmission & Interconnect Considerations

The goal of the Rancheria is to become as energy independent as possible through a combination of energy efficiency, on-site generation, and possibly establishing their own utility. The feasibility of establishing a separate utility infrastructure was investigated through discussions with Pacific Power & Light (PP&L), the Rancheria's current provider. This analysis included investigation as to whether 1) Pacific Power would cooperate in a sale of the transmission and distribution (T&D) system serving SRR to the reservation; 2) gain information concerning outages seen in the past year that might further justify Rancheria investments in site generation for outage periods; and, 3) determine the savings that may be gained by consolidating the Lucky 7 Casino, Lucky 7 Fuel Mart, and Howonquet Community Center on one meter, which would then qualify for wholesale power rates.

PP&L was recently purchased by MidAmerican Energy. The local PP&L representative indicated that MidAmerican has plans to update the T&D system that serves the Rancheria by rebuilding the substation within the next year, and to investigate reinstalling the transmission line between California and Oregon to improve system reliability. PP&L will not discuss the potential sale of utility assets to the Rancheria.[23]

PP&L supplied the outage information for the past year. According to the PP&L representative responsible for this area, the circuit from Simonson Substation serving the Rancheria sustained 32 outages in 2006 for an average customer outage time of 317 minutes for the calendar year 2006.[24] The impact of system interruptions has been minimized by the installation of Rancheria stand-by power generation facilities. Howonquet Community Center and the Lucky 7 Casino have back up generators that can supply their entire load. These generators are capable of adequately supplying power for that level of interruption. This data further supports SRR remaining a part of the PP&L system as the cost to purchase the assets would not justify the small risks associated with future outages, and if the California/Oregon transmission systems are reconnected, the outage risks would decrease.

There is a possibility to reduce monthly utility charges by consolidating two or all three of the Rancheria service facilities on a single primary voltage meter. These include the Lucky 7 Casino, the Howonquet Community Center and the Lucky 7 Fuel Mart. These buildings are in close proximity to each other, minimizing the costs of this option. The investment required would include running separate high voltage lines from the primary voltage meter to each of the three buildings, and owning the primary voltage system and transformers. This would involve the purchase of the current electric service facilities from PP&L and the installation of some new circuits. The construction work could be completed by PP&L, and is estimated to be between $1M - $2M.

An estimate of the savings that would result from consolidating on a primary voltage service (Schedule 47M) was completed. The annual energy demand and usage was summarized for the three buildings and multiplied by the Schedule 47M rate ($0.033/kWh and $1.835/kW fully loaded). Annual usage for the three buildings totals 2,298,391 kWh and the demand is 3,771 kW for a total estimated cost of $82,767/yr at the Schedule 47M rate and $160,263/yr at the current rates for an annual savings of approximately $77,496. The savings available from implementing this measure appears small compared to the cost to change to Schedule 47M. Further analysis and pricing of this option may be pursued with PP&L; however, a more detailed transmission and distribution study is beyond the scope of the current project.

The State of California, through it's state legislature and the California Energy Commission have implemented new rules preventing utilities from new purchases of power from or constructing coal generating facilities. The effect of this rule making will result in higher cost power over the long run. The scope of this analysis was limited to the Rancheria and it's facilities, and does not include the effect of regional or state wide energy policy.

10.1 Utility Rate Schedules

There are a variety of utility rate schedules used for billing at the Rancheria (See Table 28 below for details on the different utility schedule rates). There may be an opportunity for further savings through billing consolidation using a single primary voltage rate schedule for the four buildings in the Casino area. The advantages of primary voltage service are lower utility rates and possibly lower overall demand charges (e.g. peak for each of the three buildings would not occur simultaneously). However, this tariff requires that the Rancheria own all distribution equipment and transformers

23 Phone discussion with Mr. Monte Mendenhall, PP&L Area Service Manager.
24 Email from Mr. Monte Mendenhall, PP&L Area Service Manager, dated 1/30/2007.

serving the loads beyond the meter.

The following table summarizes the rate schedules for the Rancheria currently published by PP&L:

Table 28 Utility Rate Schedules by Building

Buildings On This Rate Schedule	Schedule	Cost ($/kWh)	Monthly Demand Charge ($/kW)	Annual Costs ($)
Howonquet Community Center	109	$ -	$ -	$ 673.29
	A25	$ 0.094	$ -	$ 502
	A32	$ 0.072	$ 2.70	$ 7,422
Gusehu Administration Building	A32	$ 0.072	$ 2.70	$ 8,427
Lucky 7 Fuel Mart	A32	$ 0.072	$ 2.70	$ 18,941
Lucky 7 Casino	A36	$ 0.053	$ 5.30	$ 132,724
Howonquet Head Start & Day Care Center		Not supplied		$ 2,685
			Total	***$ 171,374***

The PP&L representative, Monte Mendenhall, indicated that it would be cost prohibitive to consolidate services on opposite sides of the highway for the limited savings that may be available. A primary voltage tariff requires that the Rancheria own the distribution lines and transformers from the meter connection point with PP&L to the respective Rancheria buildings. A follow on study could be done to estimate the costs in more detail to determine the payback before a recommendation could be made on whether this option should be pursued.

11 Financial Subsidies & Opportunities

11.1 California Solar Initiative Incentives[25]

In January 2006, the California Public Utilities Commission (CPUC) adopted a program—the California Solar Initiative (CSI)—to provide incentives for solar projects with the objective of providing 3,000 MW of solar capacity by 2017. Beginning in 2007, the CPUC will manage the solar program for non-residential and existing residential customers. Because PP&L serves so few California customers, the CSI Program is not available to PP&L customers; however, it may be extended in the future. A description of the program is described as follows:

Among the elements of the CSI is the transition to performance-based and expected performance-based incentives in 2007 (rather than continue with purely capacity-based buy-downs) with the aim of promoting effective system design and installation. CSI incentive levels for 2007 are as follows:

Performance-Based Buy down for Systems less than 100 kW

- $2.50/Watt AC (Alternating Current) for residential and commercial systems, adjusted based on expected performance.
- $3.23/Watt AC for government entities and nonprofits, adjusted based on expected performance

Performance-Based Incentives for Systems 100 kW and larger

- $0.39/kWh for first 5 years for taxable entities
- $0.50/kWh for first 5 years for government entities and nonprofits

These incentives for systems over 100 kW will be paid monthly based on the actual energy produced for a period of five years. Residential and small commercial projects (<100 kW) can also choose to opt-in to this monthly performance-based incentive payment approach. Performance incentives are scheduled to decrease over time as the total solar capacity installed in the state increases.

At this time, however, the program is only offered to electric utility service areas of Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Bear Valley Electric Service (BVE). With California's strong commitment to renewable energy, however, it may be possible that PP&L customers will become eligible for incentives in the future. A copy of the California Solar Initiative Handbook is included in Appendix X for reference and future contact information.

11.2 Net Metering Credits[26]

The state of California offers financial assistance for solar and wind energy systems installed on non-residential buildings through the state's net metering rules. Net metering involves crediting the customer for all site generated electricity that is not consumed. This credit is determined by allowing the utility meter to run backward whenever site generation exceeds site energy demand. All customers with systems up to 1 megawatt (MW) in size qualify for net metering. A credit will be given on the monthly billing statement at the rate agreed to by the utility. Note that net metering rates may be lower than the commercial rates charged to the Rancheria. For the purposes of this report it was assumed that net metering rates were equivalent to retail rates charged to the Rancheria.
Appendix XIII contains an initial response letter from PP&L to our inquiries about Rancheria site generation. Included in this Appendix are the utility procedures and qualification requirements for small generation interconnection.

11.3 California Emerging Renewables Buy-Down Program Incentives

The California Energy Commission's (CEC) Emerging Renewables Program (ERP) provides incentives for the purchase of four types of grid-connected renewable energy generating systems—photovoltaic, solar thermal electric systems, fuel cells using renewable fuels, and small wind turbines (50 kW or less). Beginning January 1, 2005, the rebate amounts for wind are $1.70 for the first 7.5 kW and $0.70 for increments >7.5 kW up to 30 kW.

25 The California Solar Initiative is managed by the California Public Utilities Commission. Detailed incentive structure information can be found at the Go Solar California website, http://www.gosolarcalifornia.ca.gov/csi/performance_based.html , Accessed 12/19/06.
26 Information obtained from the Database of State Initiatives for Renewable Energy (DSIRE), http://www.dsireusa.org, Accessed 12/19/06.

At this time, however, the program is only offered to electric utility service areas of Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Bear Valley Electric Service (BVE). With California's strong commitment to renewable energy, however, it may be possible that PP&L customers may become eligible for incentives in future. A copy of the CEC Emerging Renewables Program Guidebook is included in Appendix IX for reference and future contact information.

11.4 PP&L California Energy FinAnswer Program[27]

PP&L offers the Energy FinAnswer program to help commercial customers upgrade their facilities to become more energy-efficient. The program provides advice on energy-efficient lighting, compressed air systems, refrigeration systems, heating and cooling systems, pumping systems and more, and can help finance the upgrades if the customer decides to implement any of the recommendations.

If the customer elects to use the financing option, an energy service charge will appear as a separate line item on the monthly utility bill upon project completion. To ensure that the upgrades actually achieve the savings predicted, PP&L will also perform a post-installation inspection. For larger, complex upgrades, commissioning support is available to ensure maximum performance. All of this is available to the customer at no cost.

Current Interest Rates for PP&L Financing are as follows:

Loan Term	Interest Rate	
	Resource	Supplemental
5 years or less	6.34%	8.84%
6-8 years	6.36%	8.86%
Over 8 years	7.89%	8.89%

To inquire about this program the Rancheria may initiate contact in one of the following methods before starting the energy efficiency project:

E-mail PP&L at energy.expert@pacificorp.com
Call the PP&L Energy Services Hotline at 1-800-222-4335
Contact the Rancheria account manager

More information is also available by reviewing the approved program tariffs—Schedule 120 and Schedule 122. (Copies of these tariff schedules are included in Appendix XIV.)

The steps required to use the Energy FinAnswer are as follows:

11.4.1 Existing Facilities

1. Signing a Letter of Intent—PP&L works with the customer to develop a project scope. The scope will be used to select an energy consultant for the energy analysis. After selection is made, this professional team will go on-site and conduct a thorough technical analysis and quantify the energy savings potential.

2. If design assistance is appropriate the customer will then be asked to sign an interim agreement — a design agreement — enabling PP&L to move forward to the design phase.

3. If the customer chooses to take advantage of PP&L financing they will be asked to sign an Energy Services Agreement. Payments may be made on a progress basis or as a lump sum upon the installation of the energy efficiency measures and project completion.

11.4.2 New Facilities

In future, if the Rancheria is planning on building a new facility or starting a major renovation, the procedure is different. To establish a baseline for energy savings, PP&L will work with the customers existing engineering firm during the initial design stages. PP&L conducts a high-quality study to identify energy efficiency measures that will improve the energy efficiency of the design. PP&L will pay for the cost of the study.

27 Data obtained from the Pacific Power & Light website for California incentives. http://www.pacificpower.net/Navigation/Navigation1855.html . Accessed 7/6/07.

After a comparison is made and if there is a redesign of existing plans (if required), PP&L can provide funding for the incremental costs of the measures to the customer. The customer remains in control, choosing the final technologies and equipment suppliers and contractors for installation of the energy efficient equipment.

11.5 Tax Incentives for Investment Partners—State & Federal Tax Credits

11.5.1 State Tax Credit & Deductions

With the introduction of the National Energy Policy Act of 2005 (EPA2005), California phased out the state tax credits and deductions allowed for solar and wind energy system installations.[28]

11.5.2 Federal Investment Tax Credit

EPA2005 qualifies solar and wind energy systems for the Federal Investment Tax Credit (FITC) for Commercial and Business owned systems. If the Rancheria utilizes tax partners (perhaps through a capital lease agreement) for the proposed solar and wind energy systems, these tax incentives can be used to reduce the net capital costs of the installations. However, the Rancheria may not benefit from the energy savings until the costs of the solar systems are fully paid for.

The FITC is 30 percent of the net system costs, with no cap on the amount that can be claimed. This applies for systems that are installed in 2006 and 2007. The tax credit is equal to the total installed system cost, less any and all other incentives, multiplied by 30 percent. After 2007, if not extended, the tax credit will revert to the permanent level of 10%. In the past this credit could be carried forward fifteen or back 3 years. It is not clear if this has changed. An example FITC calculation for a solar system installed cost of $100,000 that does not qualify for other cash incentives is as follows:

Tax Credit = [(Total Installed System Cost) – (All Cash Incentives)] X 0.30
= ($100,000 - $0) X 0.30
= $30,000

If the energy project is financed in whole or in part by subsidized energy financing or by tax-exempt, private-activity bonds, the credit may be taken only on the portion of the investment or purchase that is not subsidized. In addition, tax credits can not exceed the amount of tax owned by the business partner in any one year.

11.5.3 Federal Modified Accelerated Cost Recovery System (MACRS)

Systems owned by a taxable business partner may also be eligible for the federal 6-year Modified Accelerated Cost Recovery System (MACRS).[29] The MACRS depreciation schedule uses a declining balance method at the business partner's tax bracket.

Basis for Depreciation = [(Total Installed system Cost) – (Tax Credits & Other Cash Incentives)]

28 State tax credit announcement found on the CEC website, http://wwwconsumerenergycenter.org/erprebate/tax_credit.html, Accessed 1/2/07
29 California Solar Energy Industries Association. "Fact Sheet on Federal Tax Incentives for Solar Energy." http://www.powerhousesolar.com/images/pdf/federal%20Tax%20Credits%20For%20PV.pdf Accessed 1/2/07.

An example of the total tax savings from depreciation is shown below:

Example: Solar System Install Cost After Tax Credits & Cash Incentives = $70,000

Year 1 Tax Savings: [$70,000 X 0.20 X 0.34] = $4,760

MACRS Table

Year	Percent Depreciation	Tax Bracket	Tax Savings
1	20.00%	34%	$ 4,760
2	32.00%	34%	$ 7,616
3	19.20%	34%	$ 4,570
4	11.52%	34%	$ 2,742
5	11.52%	34%	$ 2,742
6	5.76%	34%	$ 1,371
Total	100%	34%	$ 23,800

The following illustrates total savings related with the same $100,000 project in which the federal incentives are combined:

Total Project Size	15 kilowatts AC
Total Installed Cost	$100,000
Federal 30% ITC	($30,000)
	$70,000
Net Tax Savings Due to MACRS	$ (23,800)
Final cost in year 6 after final depreciation	***$46,200***

It is important to consult with a tax advisor, if a business partner is obtained to make use of the federal tax credits and accelerated depreciation, as there are cases when the full 30% credit can not be taken of the amount to be used in the MACRS schedule varies.

11.5.4 USDA Renewable Energy & Energy Efficiency Program

The Farm Security and Rural Investment Act of 2002 (the Farm Bill) established the **Renewable Energy Systems and Energy Efficiency Improvements Program** under Title IX, Section 9006. This program currently funds grants and loan guarantees to agricultural producers and rural small business for assistance with purchasing renewable energy systems and making energy efficiency improvements. Unfortunately, the application deadline for 2007 was May 18th; however, if a favorable project is identified, the Rancheria should investigate the availability of grant funds early in 2008, and determine whether this project would qualify for such funding.

11.5.5 White House Interagency Native eDGE Program[30]

Native eDGE is a White House Interagency initiative to facilitate sustainable economic development within American Indian and Alaska Native communities. Coordinated by HUD's Office of Native American Programs, Native eDGE links over twelve Federal agencies, including Business and Cooperative Programs, through a single economic development access center so that tribes, Native Americans, lending institutions, non-profits, foundations and private businesses can collaborate to promote economic growth in Indian Country. The Call Center is accessible via a toll-free telephone number 1-877-807-9013, the staff provides information on Federal and non-Federal resources that are appropriate for the caller as well as basic advice on requirements of the economic development process. Additional funding or partnership opportunities may be identified for the Rancheria projects by consulting this organization.

30 Information obtained from HUD website http://www.fcc.gov/indians/internetresources/hud.html. Accessed 7/6/07.

11.6 Investment Partner Summary

Financial projects with taxable investment partners do not always lead to a complete financial solution. These partners expect to earn a profit on their investment. While the savings seem substantial using an investment partner, the net system cost remaining after the six years of depreciation is still quite large without additional state or utility program buy-downs. More importantly, there does not seem to be any advantage to the Rancheria with an investment partner, as investors typically want a reasonable rate of return on the entire investment (system cost). If this were the case, the renewable energy systems would have to be completely paid for by the Tribe (through utility rate payments or other subsidies) until the system could be sold to the Tribe. The economics have been calculated for both cases (with and without an investment partner) and are shown in Appendix XII.

11.7 Commercial Financing Options for Renewable Energy Systems

The California Energy Commission has compiled a list of lenders and investors, by loan type, to assist in the purchase and financing of renewable energy systems. A copy of this list is contained in Appendix XI. It would seem likely that federal grants available through the U.S. Department of Energy's Tribal Energy Program would be an attractive approach to pursue.

12 Project Operation and Maintenance Planning

Until the Rancheria determines which recommendations or changes will be made to each building, specific changes to current operations and maintenance procedures can not be suggested. In general, however, no changes should be required as a result of any of the energy efficiency measures, with the exception of measures that involved control systems or sensors, which facilitate equipment standby mode or shut down periods to conserve energy. Any new control system technology would need to be monitored initially to be sure settings were adjusted properly to obtain optimum energy conservation while not affecting Rancheria operation efficiencies or productivity. Specifics can be recommended by equipment manufacturers or technical consultants once the specific efficiency measures to be installed are determined.

Renewable generation projects would require new operation and maintenance procedures that included periodic preventive maintenance processes such as turbine service checkups and safety inspections to be sure generation systems are properly connected and grounded. Each manufacturer will have specific instructions on the recommended maintenance and operation procedures required for their equipment.

12.1 Training Requirements

Once the Rancheria determines which of the identified energy efficiency or renewable generation technologies will be installed at each facility, contracting will be required to ensure technology is properly installed and that local personnel are properly trained on the operations and maintenance procedures. It is recommended that contractors be required to include a training and technology transfer component in their bids which provide hands on training for Rancheria personnel on the specific operating characteristics and maintenance requirements for each component or system, or that a general contractor/consultant overseeing the entire project provide such training once the projects are completed. This is especially important for any renewable generation systems installed as there are added safety issues with a generation facility that must be well understood.

13 Summary

13.1 Conclusions & Recommendations

13.1.1 Energy Efficiency Measure Recommendations

The energy savings measures recommended for each building are those that have a pay-back period of seven years or less. This criterion was selected as a reasonable amount of time, in the consulting team's opinion, and was calculated based on current utility rates. Rising utility rates would result in lower payback periods than those shown below.

Filtering the list of possible efficiency measures for each building by the seven year payback criteria resulted in the recommended measures summarized in Tables 29 through 33.

For the Guschu Administration Building, eight electric efficiency measures were identified that have a payback period of seven years or less for a total project cost of $9,802 and an energy savings of 56,675 kWh/yr or approximately 59% of the current annual consumption. Note the exterior door weather stripping was included in this list, in spite of the payback being longer, since the cost was so low. There is no gas load at the Guschu Administration Building.

Table 29 Guschu Administration Building Recommended Measures[31]

Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	48,331	$ 7,456	1.7
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	2,811	116	0.5
· Replace 13 incandescent lighting with CFLs	1,546	114	0.8
· Replace current exit signs with LED exit signs	1,226	204	1.8
· Insulate heating ducts under the building	1,076	1,215	13
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	948	480	5.6
· Insulate water heater	605	74	1.4
· Weather stripping exterior doors	132	143	12
Total	**56,675**	**$ 9,802**	

For the Howonquet Community Center, all six electric efficiency measures identified that have a payback period of seven years or less for a total electric project cost of $1,921 and an energy savings of 13,447 kWh/yr or approximately 15% of the current annual consumption. Note the exterior door weather stripping was included in this list, in spite of the payback being longer, since the cost was so low. The one gas efficiency measure identified has a payback period of seven years or less for a total gas project cost of $148 and an energy savings of 8,523 kBtu/yr or approximately 5% of the current annual consumption.

31 Energy efficiency measures shown in this table are only those that are recommended. A complete list of the energy efficiency measures identified for the Guschu Administration Building are contained in Section 4.0, Table 10.

Table 30 Howonquet Community Center Recommended Measures

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	10,156	$ 1,335	1.3
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	1,205	50	0.4
· Replace 13 incandescent lighting with CFLs	891	53	0.6
· Replace current exit signs with LED exit signs	613	100	1.6
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	356	240	6.7
· Weather stripping exterior doors	227	143	6.3
Total	**13,447**	**$ 1,921**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heaters	8,523	$ 148	0.80
Total	**8,523**	**$ 148**	

The Lucky 7 Casino already has very efficient equipment installed; however, three electric efficiency measures were identified that have a payback period of seven years or less for a total electric project cost of $10,734 and an energy savings of 346,882 kWh/yr or approximately 18% of the current annual consumption. One gas efficiency measure was identified that has a payback period of seven years or less for a total gas project cost of $74 and energy savings of 16,819 kBtu/yr. While this gas measure (water heater insulation) is less than 2% of the total gas load, the water heater is in need of replacement and it would take very little effort to insulate it at the same time.

Table 31 Lucky 7 Casino Recommended Measures[32]

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· Manage gaming machine load by automatically or manually turning off a portion of the units (assume 25% of machines for 8 hours a day)	196,370	$ 7,868	0.5
· Replace selected interior incandescent lighting with CFLs	149,849	2,566	0.2
· Replace current exit signs with LED exit signs	663	300	4.5
Total	**346,882**	**$ 10,734**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Replace and insulate gas water heaters	16,819	$ 74	0.2
Total	**16,819**	**$ 74**	

For the Lucky 7 Fuel Mart, all five electric efficiency measures identified have a payback period of seven years or less for a total electric project cost of $5,135 and an energy savings of 39,759 kWh/yr or approximately 17% of the current annual consumption. One of the gas efficiency measures identified, water heater insulation, has a payback period of seven years or less for a total gas project cost of $74 and an energy savings of 1,373 kBtu/yr or approximately 1% of the current annual consumption.

32 Energy efficiency measures shown in this table are only those that are recommended. A complete list of the energy efficiency measures identified for the Lucky 7 Casino are contained in Section 6.0, Table 18.

Table 32 Lucky 7 Fuel Mart Recommended Measures[33]

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· Replace canopy lights with high pressure sodium bulbs	21,024	$ 2,860	1.7
· Replace interior flood lamps in visitor resource center with CFLs	10,652	207	0.2
· Replacement of refrigeration evaporator fans, condensor fans to higher efficiency units	7,227	2,000	3.5
· Replace 2 incandescent lights in restrooms with CFLs	549	18	0.4
· Replace current exit signs with LED exit signs	307	50	2.0
Total	**39,759**	**$ 5,135**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heater	1373	$ 74	2.5
Total	**1,373**	**$ 74**	

For the Howonquet Head Start & Day Care Center, all five electric efficiency measures identified have a payback period of seven years or less for a total electric project cost of $3,035 and an energy savings of 22,320 kWh/yr or approximately 75% of the current annual consumption. This savings percentage is very high due to the fact that the primary electric load for this building is lighting, nearly all of which can be upgraded to higher efficiencies. The one gas efficiency measure identified has a payback period of seven years or less for a total gas project cost of $148 and an energy savings of 19,786 kBtu/yr or approximately 8% of the current annual consumption.

Table 33 Howonquet Head Start & Day Care Recommended Measures

Electric Energy Efficiency Measure Description	Energy Savings (kWh/yr)	Estimated Cost ($)	Estimated Payback (years)
· High efficiency fluorescent overhead lighting F32T8	10,156	$ 1,335	1.5
· Replace exterior incandescent flood lamps with high efficiency outdoor CFL lamps	8,432	347	0.5
· Photo-sensitive controls for exterior flood lighting (move, repair or convert to time clocks)	2,371	1,199	5.6
· Replace 6 interior incandescent lights with CFLs	748	53	1.0
· Replace current exit signs with LED exit signs	613	100	1.8
Total	**22,320**	**$ 3,035**	

Gas Energy Efficiency Measure Description	Energy Savings (kBtu/yr)	Estimated Cost ($)	Estimated Payback (years)
· Insulate water heaters, optimize water tank timers to reduce consumption during start up periods.	19,786	$ 148	0.2
Total	**19,786**	**$ 148**	

13.1.2 Solar Energy Generation Assessment

Opportunities for solar power generation were considered by evaluating the solar exposure of the roof areas of each major building. The net power production estimate was reduced to reflect the impact of obstructions to the south (e.g. trees) that

33 Energy efficiency measures shown in this table are only those that are recommended. A complete list of the energy efficiency measures identified for the Lucky 7 Fuel Mart are contained in Section 7.0, Table 22.

may cause shading of the solar system. Shading significantly decreases the electricity output of a system and is often the reason solar systems are found to be uneconomical.

The maximum solar generation capacity for each facility was determined by estimating the available south facing roof area and determining the portion of this area which is useable. The system sizes specified for each building are summarized in Table 34, along with the estimated electricity output of each system once the solar radiation for local weather conditions was determined.

Table 34 Estimated Solar System Size & Generation for each Building

Solar	Available Southern Facing Roof Area (sqft)	System Size (kW DC)	Estimated Generation (kWh/yr)	Total System Cost @ $7/Watt	Annual Net Metering Savings @ $/kWh	Tribal System Payback (years)
Gusehu Administration Building	2000	15	18000	$ 105,000	$ 1,620	65
Howonquet Community Center	2600	20	24000	$ 140,000	$ 2,400	58
Lucky 7 Fuel Mart	1800	15	18000	$ 105,000	$ 1,440	73
Howonquet Head Start & Day Care Center	1600	10	12000	$ 70,000	$ 1,080	65
Lucky 7 Casino	12,000	100	120000	$ 700,000	$ 8,400	83

* System sizes are smaller than the maximum allowed for the given roof area's to compensate for unknown roof obstructions

13.1.3 Wind Energy Generation

Site audits were performed at each of the Rancheria buildings to identify any visual indicators (deformed trees) that high winds were present. To avoid visual impacts to travelers passing through, however, only sites off the main highway were chosen for wind turbines. This decision excluded the Lucky 7 Fuel Mart and Lucky 7 Casino from the recommended turbine installation locations.
The American Wind Energy Association and California Department of Energy web sites were consulted to roughly estimate the wind energy available at different Rancheria locations. These resources indicate the average annual wind speed is 7-8 mph, which is considered a low to fair (Class 1 to Class 3, 100-400 W/m^2) wind regime. Given the visible tree flagging at the Howonquet Community Center site, the average wind speed for this site is assumed to be slightly higher, around 9 mph.

Turbines used for these lower wind resources are specifically designed for this application. After a review of available turbine options, a 10 kW turbine was selected. The estimated wind energy generation for each facility was determined as summarized in Table 35:

Table 35 Estimated Wind Energy System Size & Generation for each Building

Wind	Ave Windspeed (mph)	Estimated Annual Generation (kWh)	Annual Net Metering Credit ($/kWh)	Total System Cost Bergey 10kW System ($)	Tribal System Payback (years)
Gusehu Administration Building	8	5,880	$ 529	$ 38,000	72
Howonquet Community Center	9	8,400	$ 840	$ 38,000	45
Howonquet Head Start & Day Care Center	8	5,880	$ 529	$ 38,000	72

Installation of the renewable energy systems could reduce overall electricity demand and use. In one case (the Howonquet Head Start & Day Care Center) it could result in excess annual generation. It is recommended that the wind or solar electric systems should be installed if substantial financial subsidies or grants can be obtained.

13.2 Lessons Learned

This energy study resulted in a number of interesting findings:

1. The potential for renewable energy generation development on the Smith River Rancheria is limited due to the small wind resource in the area, few biomass resources on Tribal properties, limited solar access and inability to take advantage of tax incentives. While solar, and in some cases wind energy systems, were sized for the different facilities, there does not appear to be any renewable generation project that can be developed economically solely on the basis of energy sales without substantial subsidization. This discovery led to the Rancheria's decision to modify the scope of the study to include energy efficiency opportunities along with any smaller scale renewable generation potential.

2. A number of attractive building energy efficiency measures were identified. The economic performance was verified by reviewing monthly utility statements and industry accepted savings associated with these measures. The team was surprised and pleased with the relatively favorable paybacks associated with lighting improvements available today.

3. The rate comparison analysis identified several differences in billing rates and rate schedules among the buildings. There may be an opportunity for further savings by consolidating electric services and receiving power for multiple buildings from a single meter. A favorable payback was anticipated but not found to be available.

4. The energy efficiency analysis for larger buildings may be facilitated by having access to building design drawings. Those available for the Lucky 7 Casino enabled the team to more expeditiously complete the analysis. For a building with this size and complexity, it was helpful to have access to the billing statements, physical inspection notes, and building drawings.

Conservation & Renewable Energy Potential Study For Smith River Rancheria

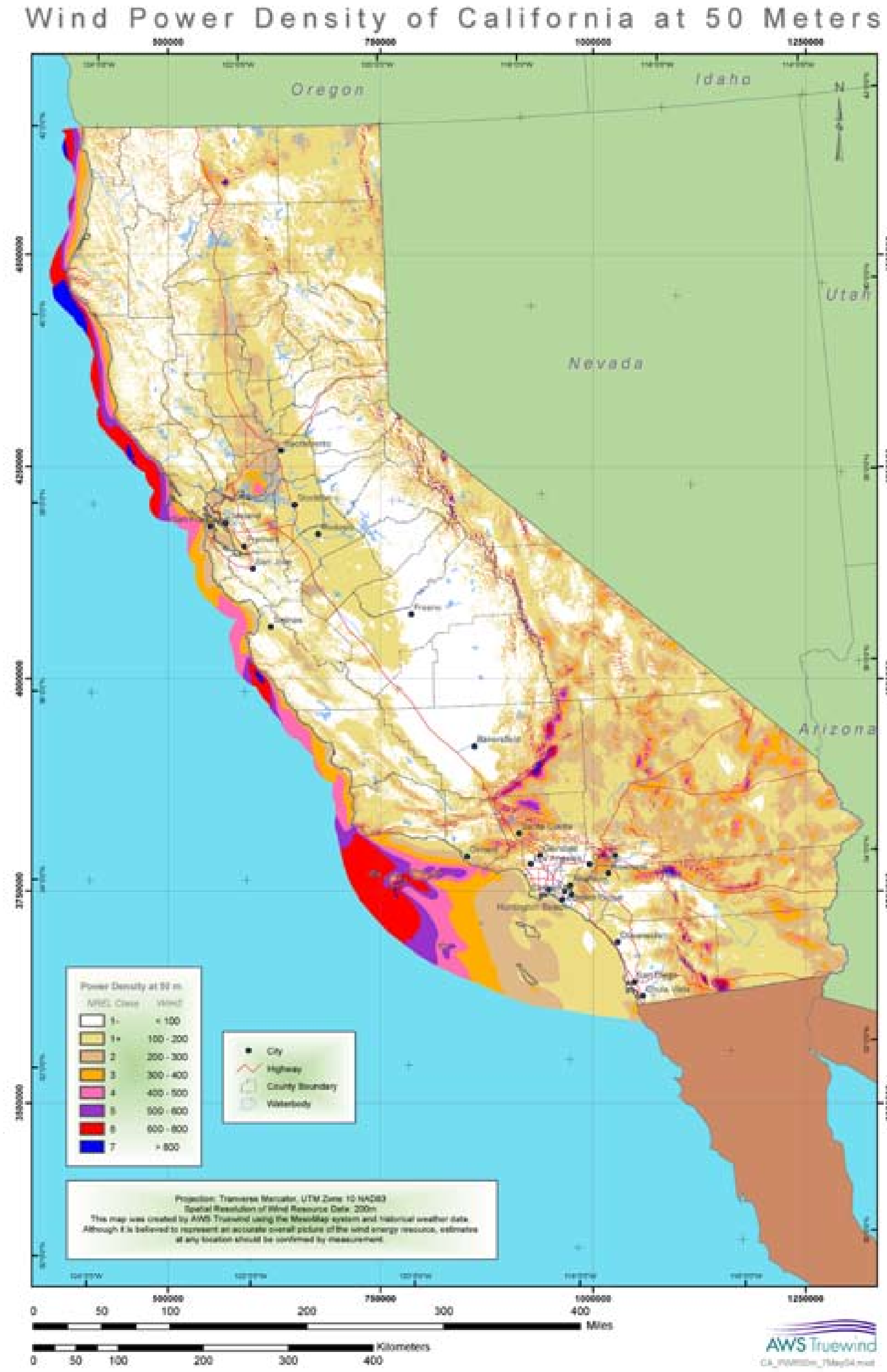
Draft Final Report

Period covered: August 1, 2005 through December 31, 2006

Date of Report: April 6th, 2007

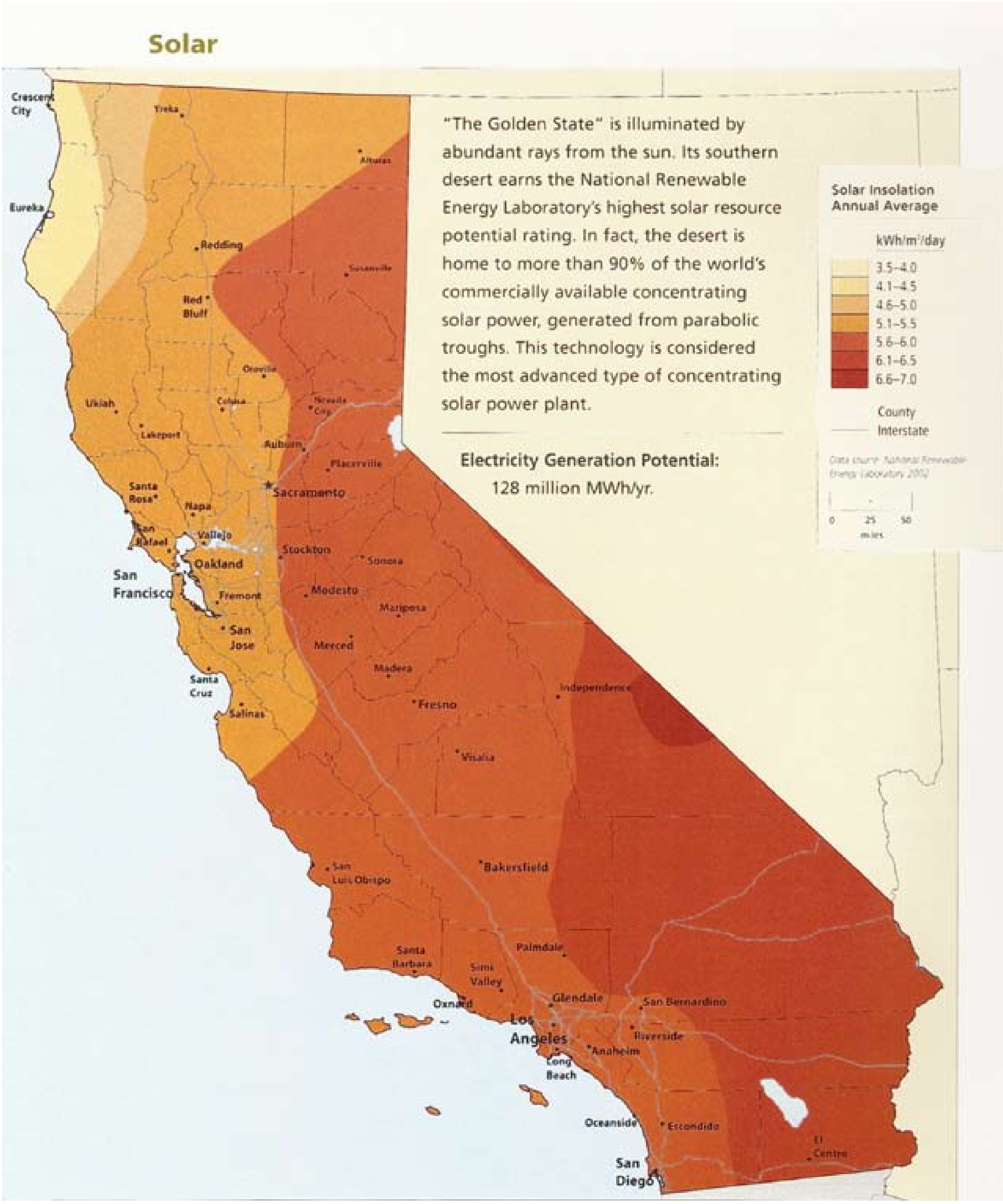
Appendices

Appendix I California Wind Resource Maps[1]



1 This California wind map was funded by the California Energy Commission and validated by NREL and consulting meteorologists. Map found at the AWS Truewind site http://www.awstruewind.com/inner/windmaps/California.htm

Appendix II California Solar Resource Map[2]



2 Nielsen, 32.

Appendix III Electricity Consumption Summaries[3]

Electricity Consumption Data	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Annual Total
Lucky 7 Fuel Mart													
kWh	21,680	23,640	20,400	18,000	20,680	18,800	17,680	18,960	21,360	18,960	17,360	21,240	238,760
kW	37	39	38	40	39	39	40	42	43	41	38	39	475
Cost	$ 1,623	$ 1,926	$ 1,609	$ 1,438	$ 1,632	$ 1,497	$ 1,416	$ 1,514	$ 1,694	$ 1,516	$ 1,395	$ 1,681	$ 18,941
$/kWh	$ 0.07	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Lucky 7 Casino													
kWh	156,300	211,200	165,000	178,200	214,800	174,000	148,500	150,000	143,100	132,000	130,200	167,700	1,971,000
kW	290	343	329	361	359	350	345	308	225	239	244	310	3,703
Cost	$10,590	$ 13,817	$11,068	$12,092	$ 14,046	$11,739	$ 10,283	$ 10,235	$ 9,610	$ 8,947	$ 9,050	$ 11,248	$ 132,724
$/kWh	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07
Howonquet Head Start & Day Care Center													
kWh	2,725	2,905	2,460	2,474	2,727	2,327	2,275	2,124	2,050	2,327	2,782	2,657	29,833
kW	(unknown as actual bills were not supplied)												0
Cost (Estimated)	$ 245	$ 261	$ 221	$ 223	$ 245	$ 209	$ 205	$ 191	$ 185	$ 209	$ 250	$ 239	$ 2,685
$/kWh	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09
	Nov-06												
Howonquet Community Center													
kWh Schedule 109 (no load)	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost	$ 49	$ 39	$ 54	$ 62	$ 50	$ 57	$ 64	$ 63	$ 54	$ 64	$ 75	$ 42	$ 673
kWh Schedule A32	7,560	8,160	7,200	6,680	7,520	6,960	6,440	6,560	7,200	6,520	5,800	8,040	84,640
kW	31	34	32	31	30	32	33	30	28	28	28	29	366
Cost	$ 656	$ 702	$ 630	$ 591	$ 651	$ 613	$ 576	$ 581	$ 626	$ 585	$ 524	$ 689	$ 7,422
kWh Schedule A25	428	453	380	316	336	267	228	229	243	246	260	605	3,991
Cost	$ 51	$ 53	$ 46	$ 40	$ 42	$ 36	$ 32	$ 32	$ 33	$ 34	$ 35	$ 68	$ 502
Total kWh	7,988	8,613	7,580	6,996	7,856	7,227	6,668	6,789	7,443	6,766	6,060	8,645	88,631
kW	31	34	32	31	30	32	33	30	28	28	28	29	366
Total Cost	$ 755	$ 795	$ 730	$ 692	$ 742	$ 705	$ 672	$ 677	$ 714	$ 683	$ 633	$ 799	$ 8,598
$/kWh (Sched A32 & A25 only)	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.10
	Nov-06	**Dec-06**											
Gusehu Administration Building													
kWh	9,280	9,640	9,400	7,280	8,600	7,120	7,280	7,200	7,520	7,920	7,400	8,080	96,720
kW	39	40	32	32	38	34	27	29	29	29	30	34	393
Cost	$ 799	$ 828	$ 794	$ 639	$ 747	$ 635	$ 639	$ 635	$ 659	$ 698	$ 651	$ 705	$ 8,427
$/kWh	$ 0.09	$ 0.09	$ 0.08	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09

Notes:
- = Schedule 109 Rates (there are no demand charges for this schedule)
- = Assumed rates based on kWh usage, no actual bills received
- = Schedule A32 Rates
- = Schedule A25 Rates (there are no demand charges for this schedule)
- = Schedule A36 Rates

3 See Appendix XIV for PP&L details on the different Rancheria tariffs.

Appendix IV Propane Consumption Summary

Propane Consumption Data	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06
Lucky 7 Fuel Mart							
Gallon	133	0	0	245	180	208	217
Cost	$ 230			$ 420	$ 310	$ 357	$ 379
$/Gallon	$ 1.73	$ -	$ -	$ 1.71	$ 1.72	$ 1.72	$ 1.75
Lucky 7 Casino							
Gallon		935	1,031	946	1,058	1,212	970
Cost		$ 1,820	$ 2,019	$ 1,862	$ 2,082	$ 2,387	$ 1,972
$/Gallon	$ -	$ 1.95	$ 1.96	$ 1.97	$ 1.97	$ 1.97	$ 2.03
Howonquet Head Start & Day Care Center							
Gallon		313	246	236	342	341	206
Cost		$ 614	$ 483	$ 464	$ 670	$ 669	$ 410
$/Gallon	$ -	$ 1.96	$ 1.96	$ 1.96	$ 1.96	$ 1.96	$ 2.00
Howonquet Community Center							
Gallon		0	0	497	0	530	341
Cost				$ 977	$ -	$ 1,041	$ 706
$/Gallon	$ -	$ -	$ -	$ 1.97	$ -	$ 1.97	$ 2.07

Propane Consumption Data	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Annual Total (gal)
Lucky 7 Fuel Mart								
Gallon	161	0	0	0	0	188		1,199
Cost	$ 284					$ 325		$ 2,074
$/Gallon	$ 1.76	$ -	$ -	$ -	$ -	$ 1.73	$ -	$ 1.73
Lucky 7 Casino								
Gallon	916	913	860	958	1,365	655	457	11,817
Cost	$ 1,895	$ 1,889	$ 1,777	$ 1,980	$ 2,806	$ 1,334	$ 929	$ 23,823
$/Gallon	$ 2.07	$ 2.07	$ 2.07	$ 2.07	$ 2.06	$ 2.04	$ 2.03	$ 2.02
Howonquet Head Start & Day Care Center								
Gallon	245	0	0	284	0	180	193	2,585
Cost	$ 488	$ -	$ -	$ 569	$ -	$ 356	$ 380	$ 5,103
$/Gallon	$ 1.99	$ -	$ -	$ 2.00	$ -	$ 1.98	$ 1.97	$ 1.97
Howonquet Community Center								
Gallon	0	274	0	0	0	364		2,007
Cost		$ 568				$ 742		$ 4,034
$/Gallon	$ -	$ 2.07	$ -	$ -	$ -	$ 2.04	$ -	$ 2.01

Appendix V Cal-Arch EUI Input Page

California Building Energy Reference Tool

CALARCH
CALIFORNIA BUILDING ENERGY REFERENCE TOOL

HOME | BENCHMARK | ABOUT CalARCH | MORE INFORMATION
Back - Getting Started Compare Interpret Results

1 Select the **principal activity** of your building:

Office/Professional

2 Enter the building's **floor area** 7592 (gross square feet)
If both **floor area** and energy use are entered, an EUI will be calculated for your building and displayed on the graph.

☐ Check here to display only buildings with comparable floor area.

3 Enter the **annual energy consumption** for your building for each fuel used:

Fuel	Energy Consumption
Electricity	100112 kWh/year
Natural Gas	0 therms/year
Other	0 Million Btu/year

☐ Check here if the data entered represents whole building energy use.

4 Enter the **zipcode** your building is located in. 95567

If a zip code is entered, only buildings within the same **climate zone** will be displayed. Use this field only if your building is within PG&E or SCE service territory.

5 Select how **energy use** should be reported: ◉ Site ○ Source

http://poet.lbl.gov/cal-arch/compare.html (1 of 2) [12/26/2006 10:05:57 PM]

Appendix VI Smith River Facilities-Energy Efficiency Measures

Figure 29 Guschu Administration Building Potential Energy Efficiency Measures

Energy Efficiency Measures--Gusehu Administration Building (open 2531 hrs/yr)

Measure	Est Elect Baseline (kWh/yr)	Possible Measures	Measure Quantity	Est Elect Savings (kWh/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $0.09/kWh)	EUL (useful life, yr)	Payback Period	Notes
Interior flourescent lighting (1)	68,445	Replace current overhead lighting with higher efficiency T8 lighting	138	48,331	$ 4,333	$ 3,123	$ 7,456	$ 4,350	11	1.7	138-4 tube 40 watt F40 bulbs replaced by 138-2 tube 32W bulbs. Labor taken from "delamp" sheet
Heat Pump (8)	10,760	Replace current electric resistance heating and air conditioning with heat pumps	4	6,585	$ 13,446	$ 2,831	$ 16,278	$ 593	15	27.5	Replaces 4 (3 ton) split electric AC/resistance heating units; Base load for building determined by lowest energy month X12 = 7,120 kWh/yr X 12 = 85,440 kWh/yr. Heating load is delta above base for Oct - Mar = 9,560 kWh/yr. Assume save 2/3 moving from electric resistance to a heatpump = 6,450 kWh/yr. Cooling load is delta above base for Jul - Aug = 1,200 kWh/yr. Assume save 15% moving from 10 to 13 SEER unit = 180 kWh/yr.
High Efficiency exterior flood lamps	3,833	Repalce existing outdoor lighting with outdoor CFLs	7	2,811	$ 89	$ 26	$ 116	$ 253	7.1	0.5	Assumed went from 150W incandescent to 40W CFL Outdoor bulbs
Water Heater Insulation (2)	3,024	Insulate water heater	1	605	$ 29	$ 45	$ 74	$ 54	10	1.4	Used 1kW X 720 hrs X 35% X 12mo = 3300 (steve), Savings = 20% of baseline. Pricing from DEER.
CFL's in place of incandescents in bathrooms (2)	1,974	Replace incandescents with CFLs	13	1,546	$ 65	$ 49	$ 114	$ 139	3.2	0.8	assume 60W Incandescent replaced by 13W CFL
LED Exit Signs (2), (10)	1,402	Replace current incandescent exit signs with LED signs	4	1,226	$ 68	$ 136	$ 204	$ 110	16	1.8	EPA Energy Star website indicates standard exit signs are 40 W as compared to the new 5W LED exit signs. Assume 24X7 operation. Costs & EUL from DEER.
Weather strip exterior doors (11), (12)	0	Weather stripping of exterior doors to reduce heating/cooling losses	3	132	$ 68	$ 75	$ 143	$ 12	10	12.1	Assume 2% savings of baseline heating cooling load.
Solar shades for south facing windows (4), (6), (7)	0	Treat south facing windows with solar shading film to reduce temperatures in summer.	800 sqft	1,362	$ 5,760	$ -	$ 5,760	$ 123	20	47.0	Used 1.3% energy savings during cooling per BASE article; Estimated solar chade cost at $7.20/sqft (includes labor) per The Shade Store quote (assumed 800 sqft window area on south side of building)
Plug Load Occupancy Sensor (2)	0	Occupancy sensors for personnel PC's allows units to conserve energy when not in use.	10	1,430	$ 820	$ 350	$ 1,170	$ 129	10	9.1	Assume one per PC w/ task lighting for only 1/2 (10) of the PC's.
Heating Duct Insulation (2) (13)	0	Insulate HVAC ducting exposed under the building	1	1,076	$ 1,215		$ 1,215	$ 97	20	12.5	Cost estimated from DEER includes labor. Savings from EPA website, assumed to be 10% of heating/cooling load.
Photo-sensitive flood lighting controls or timer	0	Savings on outdoor lighting when personnel are not in the vacinity to require the lighting.	2	948	$ 246	$ 234	$ 480	$ 85	8	5.6	Savings based on 4-70W (95W w/ ballast) HPS fixtures. One timer for each 4 bulbs.
Totals	89,437			66,052	$ 26,140	$ 6,870	$ 33,010	$ 5,945		5.6	

Billing vs. Calculated Energy Consumption (No Gas)

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	96,720	89,437	92%

Operating Hours	$/kWh	Hrs/day	Days/yr	Hours/yr	Notes
Gusehu Administration Building	$ 0.09	10.5	241	2,531	Assumes 124 days that office is closed per year, including weekends

Notes

(1) Full Spectrum Solutions, http://fullspectrumsolutions.com/electronic_ballasts_36_ctg.htm, Accessed 1/1/07
(2) California Database of Energy Efficient Resources (DEER), http://eega.cpuc.ca.gov/deer/, Accessed 12/27/06
(3) Energy Information Administration 1999 Commercial Buildings Energy Consumption Survey: Table C3
(4) Base Energy Inc., "Energy Savings for a Commercial Building", http://www.baseco.com, Accessed 1/1/2007
Cooling with a Heat Pump",
(5) http://oee.nrcan.gc.ca/publications/infosour
(6) The Shade Store, http://www.theshadestore.com, Accessed 1/1/2007
(7) California Title 24 Commercial Building Fact Sheet, http://www.iid.com/Media/title_24_fact_sheet.pdf, Accessed 1/1/07
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(8) http://www.eere.energy.gov/consumer/your
Heating Piping Air Conditioning (HPAC) Engineering, "The Energy Use Characteristics of Small Commercial Buildings",
(9) http://www.hpac.com/member/archive/0205data.htm, Accessed 1/1/2007
(10) Environmental Protection Agency (EPA) Energy Star Website, http://www.energystar.gov/index.cfm?c=exit_signs.pr_exit.signs
Weather stripping savings % estimates
(11) from Ames City, Iowa website,
(12) Weatherization cost estimates from Preservation Resources, Inc., http://www.ic-fhp.org/Yapp/WINDOW~1.DOC, Accessed 1/2/2007
(13) EPA website information on heating/cooling duct sealing. Http://www.energystar.gov/index.cfm?c=heat_cool.pr_hvac. Accessed 3/29/07

Figure 30 Howonquet Community Center Potential Energy Efficiency Measures

Energy Efficiency Measures--Howonquet Community Center (open 3158 hrs/yr)

Measure	Est Elect Baseline (kWh/yr)	Possible Measures	Measure Quantity	Est Elect Savings (kWh/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $0.10/kWh)	EUL (useful life, yr)	Payback Period	Notes
Miscellaneous Kitchen Appliances	30,000	Further identification of loads is needed to suggest any efficiency improvements									Refrigerators, etc.
High efficiency flourescent lighting F32T8 (1)	14,383	Replace current overhad lighting in all rooms except the meeting room with higher efficiency T8 lighting	29	10,156	$ 679	$ 656	$ 1,335	$ 1,016	11	1.3	29-4 tube 40 watt F40 bulbs replaced by 29-2 tube 32W bulbs. Labor taken from "delamp" sheet
Heat Pump (8)	11,330	Heat pumps are already high efficiency. No change is recommended	1								Three Trane #2TWX4060A1000AA = 5 ton, 12 SEER split cooling unit. Assume 4th smaller unit is the same efficiency for a 3 ton size. 13 SEER Hp data from DEER entered for all 4 units (18 tons total) as baseline to calculate weatherization measures. No efficiency improvements planned for HVAC units.
Existing high efficiency T8 fixtures not requiring replacement	3,498	Meeting hall lighting is already high efficiency. No change recommended	24								Energy demand included only for energy totals
High Efficiency exterior flood lamps (2)	1,643	Replace existing outdoor lighting with outdoor CFLs	3	1,205	$ 38	$ 11	$ 50	$ 120	7.1	0.4	Assumed went from 150W incandescent to 40W CFL Outdoor bulbs
CFL's in place of incandescents in bathrooms & foyer (2)	1,137	Replace incandescents with CFLs	6	891	$ 30	$ 23	$ 53	$ 89	3.2	0.6	assume 60W Incandescent replaced by 13W CFL
LED Exit Signs (2), (10)	701	Replace current incandescent exit signs with LED signs	2	613	$ 34	$ 66	$ 100	$ 61	16	1.6	EPA Energy Star website indicates standard exit signs are 40 W as compared to the new 5W LED exit signs. Assume 24X7 operation. Costs from DEER.
Perimeter photo-sensitive flood lighting controls or timer (2)	0	Savings on outdoor lighting when personnel are not in the vacinity to require lighting	1	356	$ 123	$ 117	$ 240	$ 36	8	6.7	Savings based on 4-70W (95W w/ ballast) HPS fixtures. One timer for each 4 bulbs.
Weather strip exterior doors (13), (12)	0	Weather stripping of exterior doors to reduce heating/cooling losses	3	227	$ 68	$ 75	$ 143	$ 23	10	6.3	Assume 2% savings of baseline heating cooling load.
Totals	62,691			13,447 21%	$ 973	$ 948	$ 1,921	$ 1,345		1.4	

Gas Energy Efficiency Measures

Load (Energy Efficiency Measure If Possible)	Est Gas Baseline (kBtu/yr)	Possible Measures	Quantity	Est Gas Savings (kBtu/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $2.00/gallon)	EUL (useful life, yr)	Payback Period	Notes
Miscellaneous Kitchen Appliances	75,000	Further identification of loads is needed to suggest any efficiency improvements	N/A								Ovens, stoves, warmers, etc…
Gas Water Insulation (2)	71,026	Insulate water heaters	2	8,523	$ 58	$ 91	$ 148	$ 186	10	0.8	Wrapping of water heater assumed to save approximately 12% of water heating bill lost to standby
Totals	146,026			8,523	$ 58	$ 91	$ 148	$ 186		0.8	

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	88,631	62,691	71%
Gas (kBtu)	183,814	146,026	79%

Operating Hours		$/kWh	Hrs/day	Days/yr	Hours/yr	Notes
Howonquet Community Center		$ 0.10	varies	365	3,158	Assumes open 10.5 hours 252 days plus an extra 4 hours a day, twice a week, plus one event a month on the weekend at 8 hours each

Notes

(1) Full Spectrum Solutions, http://fullspectrumsolutions.com/electronic_ballasts_36_ctg.htm, Accessed 1/1/07
(2) California Database of Energy Efficient Resources (DEER), http://eega.cpuc.ca.gov/deer/, Accessed 12/27/06
(3) Energy Information Administration 1999 Commercial Buildings Energy Consumption Survey: Table C3
(4) Base Energy Inc., "Energy Savings for a Commercial Building", http://www.baseco.com, Accessed 1/1/2007
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(5) Canada,
(6) The Shade Store, http://www.theshadestore.com, Accessed 1/1/2007
(7) California Title 24 Commercial Building Fact Sheet, http://www.iid.com/Media/title_24_fact_sheet.pdf, Accessed 1/1/07
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(8) Efficiency and
Air
(9) Conditioning
(10) Environmental Protection Agency (EPA) Energy Star Website, http://www.energystar.gov/index.cfm?c=exit_signs.pr_exit.signs
University,
(11) "Comparing
(12) Weather
(13) Weatherization cost estimates from Preservation Resources, Inc., http://www.ic-fhp.org/Yapp/WINDOW~1.DOC, Accessed 1/2/2007

Figure 31 Lucky 7 Casino Potential Energy Efficiency Measures

Electric Energy Efficiency Measures--Lucky 7 Casino (open 8760 hrs/yr)

Load (Energy Efficiency Measure If Possible)	Est Elect Baseline (kWh/yr)	Possible Measures	Quantity	Est Elect Savings (kWh/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $0.07/kWh)	EUL (useful life, yr)	Payback Period	Notes
Gaming Machines	1,060,398	Unknown, possible timeclocks in low use hours or sleep mode occupancy sensors similar to PC's	269	196,370	$ 5,515	$ 2,354	$ 7,868	$ 15,710	10	0.5	Estimate 400 W per machine, operating 8760 hrs. Savings from shut down of 25% of the units, 8hrs per day. Cost estimated to be the same as the plug load occupancy sensors for PC's from DEER
Lighting (See Casino Lighting Sheet for Detail) (14)	605,912	Some fixture & lamp replacement	N/A	149,849	$ 1,717	$ 849	$ 2,566	$ 11,988	8	0.2	Savings based on 4-70W (95W w/ ballast) HPS fixtures. One timer for each 4 bulbs.
Air Exchange Exhaust Fans	153,000	Reduce hours of operation/ timeclocks	24								Approx 21,8 kW of exhaust fans, 24 total units. Operating 80% of time.
Air Conditioning & Heat Pump units Note: (8) (15)	67,014	Replace 23.5 tons of SEER 10 Hp/AC equipment with SEER 18 and/or timeclocks. Save energy through exhaust heat recovery heat exchanger.	13	2,376	$ 24,091	$ 5,073	$ 29,164	$ 166	15	175	26 total tons of AC & Heat Pumps, 39 kW, operating at a 20% capacity factor. Assumed 1.5 kW each operating for 24X7 operations. Most units are at SEER 10, with two units at SEER 13 efficiency or higher. Exhause Heat recovery heat exchangers would cost $20,000 to install and would be of nominal value since the building operates in a cooling mode most of the time.
Miscellaneous Kitchen & Office Equipment	55,000	None Identified	N/A								Delta between actual billing and calculated consumption assumed to be due to miscellaneous operation expences.
Radiant wall heaters	6,507	Control use.	4								13.5 kW each. Assume office staff occupy rooms 241 days a year and run the heaters an average of 2 hours a day. No savings planned for electric resistance wall heaters.
Exit Signs (2), (10)	758	Replace with LED units	6	663	$ 102	$ 198	$ 300	$ 66	16	5	EPA Energy Star website indicates standard exit signs are 40 W as compared to the new 5W LED exit signs. Assume 24X7 operation. Costs from DEER.
Totals	1,948,589			349,258 18%	$ 31,425	$ 8,474	$ 39,898	$ 27,930		1.4	

Gas Energy Efficiency Measures

Load (Energy Efficiency Measure If Possible)	Est Gas Baseline (kBtu/yr)	Possible Measures	Quantity	Est Gas Savings (kBtu/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $2.00/gallon)	EUL (useful life, yr)	Payback Period	Notes
Miscellaneous Kitchen Appliances	700,000	Further identification of loads is needed to suggest any efficiency improvements	N/A								Ovens, stoves, warmers, etc…
Gas Water Heater Replacement (2)	280,320	Replace older unit with higher efficiency unit and insulate.	1	16,819	$ 29	$ 45	$ 74	$ 367	13	0.2	Wrapping of water heater assumed to save approximately 6% of water heating bill lost to standby
Totals	980,320			16,819	$ 29	$ 45	$ 74	$ 367		0	

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	1,971,000	1,948,589	99%
Gas (kBtu)	1,082,465	980,320	91%

Operating Hours		$/kWh	Hrs/day	Days/yr	Hours/yr	Notes
Lucky 7 Casino		$ 0.07	24	365	8,760	Assumes open 24hrs a day, 365 days per year

Notes

(1)	Full Spectrum Solutions, http://fullspectrumsolutions.com/electronic_ballasts_36_ctg.htm, Accessed 1/1/07
(2)	California Database of Energy Efficient Resources (DEER), http://eega.cpuc.ca.gov/deer/, Accessed 12/27/06
(3)	Energy Information Administration 1999 Commercial Buildings Energy Consumption Survey: Table C3
(4)	Base Energy Inc., "Energy Savings for a Commercial Building", http://www.baseco.com, Accessed 1/1/2007
(5)	Natural Resources Canada, "Heating and Cooling with a Heat Pump",
(6)	The Shade Store, http://www.theshadestore.com, Accessed 1/1/2007
(7)	California Title 24 Commercial Building Fact Sheet, http://www.iid.com/Media/title_24_fact_sheet.pdf, Accessed 1/1/07
(8)	US DOE Energy Efficiency and Renewable Energy, "Electric Resistance Heating",
(9)	Heating Piping Air Conditioning (HPAC) Engineering, "The Energy Use Characteristics of Small Commercial Buildings",
(10)	Environmental Protection Agency (EPA) Energy Star Website, http://www.energystar.gov/index.cfm?c=exit_signs.pr_exit.signs
(11)	Cornell University, "Comparing Values of Various Heating Fuels", http://housing.cce.cornell.edu/f-sht-pdf%20libraries/EE-F-
(12)	Weather stripping savings % estimates from Ames City, Iowa website,
(13)	Weatherization cost estimates from Preservation Resources, Inc., http://www.ic-fhp.org/Yapp/WINDOW~1.DOC, Accessed
(14)	Details of lighting breakdown and savings summarized in separate table.
(15)	Details of HVAC cost and savings are summarized in a separate table

Figure 32 Lucky 7 Casino Lighting Summary

Building Plan ID	Mfgr.	Lamp Model No.	Lithonia Catalog Page No.	Watt/ Lamp	Lamps/ fixture	Total Wattage	Annual Cost to Operate per Fixture	Higher Efficiency Lamp Watts	New Total Wattage	kWh savings/ fixture	#Fixtures	Total kWh/ yr	Total Cost/ yr	Total kWh Savings/ yr	Total Cost Savings/ yr	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)
A&A2	Lithonia	2SPG432A12 (32W T8)	50	32	4	128	$ 76	N/A	N/A	0	121	135,675	$ 9,136	0	$ -	N/A	N/A	N/A
B&B2	Lithonia	LB432A12 (32W T8)	58	32	4	128	$ 76	N/A	N/A	0	39	43,730	$ 2,945	0	$ -	N/A	N/A	N/A
C&C2	Lithonia	LB232A12 (32W T8)	58	32	2	64	$ 38	N/A	N/A	0	8	4,485	$ 302	0	$ -	N/A	N/A	N/A
D	Lithonia	AF2A3TT6AR (13W Twin Tube)	212	13	2	26	$ 15	N/A	N/A	0	50	11,388	$ 767	0	$ -	N/A	N/A	N/A
E	Lithonia	AF232TRT8AR (32W Triple Tube)	210	32	1	32	$ 19	N/A	N/A	0	27	7,569	$ 510	0	$ -	N/A	N/A	N/A
F	Eureka	E3008HB (100W T3)	N/A	100	1	100	$ 59	23	23	675	15	13,140	$ 885	10,118	$ 681	$ 100	$ 57	$ 156
Sav	Lithonia	WS217	69	17	2	34	$ 20	N/A	N/A	0	2	596	$ 40	0	$ -	N/A	N/A	N/A
H	Eureka	E4702PUP (40W Incand)	N/A	40	1	40	$ 24	13	13	237	17	5,957	$ 401	4,021	$ 271	$ 85	$ 64	$ 149
K	Not Spec'd	500W Chandelier	N/A	500	1	500	$ 295	N/A	N/A	0	3	13,140	$ 885	0	$ -	N/A	N/A	N/A
L	CSL	SC502BU (75W Halogen)	N/A	75	1	75	$ 44	N/A	N/A	0	4	2,628	$ 177	0	$ -	N/A	N/A	N/A
M	Lithonia	T-Series 10' Track w/5 120 PAR TEGR Heads	324	120	5	600	$ 354	36	180	3,679	1	5,256	$ 354	3,679	$ 248	$ 46	$ 19	$ 65
N	Lithonia	T-Series 10' Track w/4 120 PAR TEGR Heads	324	120	4	480	$ 283	36	144	2,943	5	21,024	$ 1,416	14,717	$ 991	$ 184	$ 75	$ 259
P	Lithonia	T-Series 8' Track w/4 120 PAR TEGR Heads	324	120	4	480	$ 283	36	144	2,943	22	92,506	$ 6,229	64,754	$ 4,360	$ 809	$ 332	$ 1,141
Q	Lithonia	T-Series 44' Track w/16 120 PAR TEGR Heads	324	120	16	1,920	$ 1,133	36	576	11,773	1	16,819	$ 1,133	11,773	$ 793	$ 147	$ 60	$ 207
R	Lithonia	T-Series 50' Track w/10 120 PAR TEGR Heads	324	120	10	1,200	$ 708	36	360	7,358	1	10,512	$ 708	7,358	$ 496	$ 92	$ 38	$ 130
S	Lithonia	T-Series 10' Track W/6 q250W TEGR Heads	324	250	6	1,500	$ 885	75	450	9,198	3	39,420	$ 2,654	27,594	$ 1,858	$ 165	$ 136	$ 301
T	Lithonia	T-Series 12' Track w/6 50W MR16FL TEGR Heads	324	50	6	300	$ 177	13	78	1,945	3	7,884	$ 531	5,834	$ 393	$ 90	$ 68	$ 158
V	Not Spec'd	300W Chandelier	N/A	300	1	300	$ 177	N/A	N/A	0	1	2,628	$ 177	0	$ -	N/A	N/A	N/A
W	Visa	CB4062	N/A	13	2	26	$ 15	N/A	N/A	0	2	456	$ 31	0	$ -	N/A	N/A	N/A
SA	Lithonia	KAD250SR3120SPD04	Not Found	250	1	250	$ 147	N/A	N/A	0	43	94,170	$ 6,341	0	$ -	N/A	N/A	N/A
SB	Lithonia	KAD250SR3120SPD04	Not Found	250	2	500	$ 295	N/A	N/A	0	8	35,040	$ 2,360	0	$ -	N/A	N/A	N/A
SC	Stonco	G5W18HFL2-9WPL	N/A	9	2	18	$ 11	N/A	N/A	0	9	1,419	$ 96	0	$ -	N/A	N/A	N/A
SD	Stonco	RMS3-100HLXL (100W HPS)	N/A	100	1	100	$ 59	N/A	N/A	0	8	7,008	$ 472	0	$ -	N/A	N/A	N/A
SE	Hydrel	9000BMR-05 (Assume specialized bulb, no change)	614	75	1	75	$ 44	N/A	N/A	0	6	3,942	$ 265	0	$ -	N/A	N/A	N/A
SF	Lithonia	CEW10-50S (50W HPS)	Not Found	50	1	50	$ 29	N/A	N/A	0	28	12,264	$ 826	0	$ -	N/A	N/A	N/A
SG	Lithonia	CEW10-100S (100W HPS)	Not Found	100	1	100	$ 59	N/A	N/A	0	16	14,016	$ 944	0	$ -	N/A	N/A	N/A
SH	Lithonia	VWC217CW (17W T8)	414	17	2	34	$ 20	N/A	N/A	0	5	1,489	$ 100	0	$ -	N/A	N/A	N/A
SJ	Night shading	GV0510-1LO25WFL	N/A	Not Spec'd	Not Spec'd	100	$ 59	N/A	N/A	0	1	876	$ 59	0	$ -	N/A	N/A	N/A
SK	Stonco	TFL50WHLXL (50W HPS)	N/A	50	1	50	$ 29	N/A	N/A	0	2	876	$ 59	0	$ -	N/A	N/A	N/A
					Totals		5433			40,752	451	605,912	$ 40,801	149,849	$ 10,091	$ 1,717	$ 849	$ 2,566

Note: Actual kWh per fixture will vary slightly due to adjustments needed for ballast factors.

Assumptions

F	Cost data from DEER for a 100W incandescent changed to a 23W CFL, $6.66/bulb + $3.77 labor/bulb
H, T	Cost data from DEER for a 40W incandescent changed to a 13W CFL, $4.99/bulb + $3.77 labor/bulb
M, N, P, Q, R	Cost data from DEER for a 150W incandescent changed to a 36W CFL, $9.19/bulb + $3.77 labor/bulb
S	Assumed more efficienct bulb size of 75W, used same equipment price ($9.19/bulb) as 150W replacement and twice the labor ($7.56 per bulb) since the lights may have harder access.

Figure 33 Lucky 7 Casino HVAC Summary

Mfgr.	Model Number	Unit Type	Btuh	Tons	SEER	kWh rate	Measure Quantity	Total Tons	Est Elect Baseline (kWh/yr)	Est Elect Savings (kWh/yr)	Est Gas Baseline (kBtu/yr)	Est Gas Savings (kBtu/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)
American Standard	6H3024A100A4	Heat Pump	24,000	2	13	$ 0.07	1	2	1,259	13	N/A	N/A	N/A	N/A	N/A
American Standard	6C0036A300A2	Heat Pump	36,000	3	10	$ 0.07	2	6	2,197	328	N/A	N/A	$ 3,362	$ 708	$ 4,069
American Standard	6C0042A300A2	Heat Pump	42,000	3.5	10	$ 0.07	1	4	2,563	383	N/A	N/A	$ 3,922	$ 826	$ 4,748
American Standard	6C0048A300A3	Heat Pump	48,000	4	10	$ 0.07	1	4	2,929	437	N/A	N/A	$ 4,482	$ 944	$ 5,426
American Standard	6C0060A300A2	Heat Pump	60,000	5	10	$ 0.07	2	10	3,662	547	N/A	N/A	$ 5,603	$ 1,180	$ 6,782
ComfortMaker	H2H360GHA100	AC	36,000	3	10	$ 0.07	1	3	2,197	328	N/A	N/A	$ 3,362	$ 708	$ 4,069
Goodman	HDC241AB	AC	24,000	2	14	$ 0.07	1	2	1,259	13	N/A	N/A	N/A	N/A	N/A
Trane	TTB018C100A2	AC	18,000	1.5	10	$ 0.07	1	2	1,098	164	N/A	N/A	$ 1,681	$ 354	$ 2,035
TWA	TWA180B300BD	AC	18,000	1.5	10	$ 0.07	6	9	1,098	164	N/A	N/A	$ 1,681	$ 354	$ 2,035
						Totals	Heat Pump	26	12,610	1,707			$ 17,368	$ 3,657	$ 21,025
							AC	16	5,653	669			$ 6,723	$ 1,416	$ 8,139
						Grand Totals		41	18,263	2,376			$ 24,091	$ 5,073	$ 29,164

Assumptions

American Standard, ComfortMaker & Goodman	Data obtained from Air Conditioning & Refrigeration Institute (ARI) website at http://www.aridirectory.org/ari/hp.php. Accessed 3/25/07
Trane	Equipment specifications obtained at the Trane website at http://www.trane.com/commercial/LiteratureSearch.aspx?i=931. Accessed 3/25/07
TWA	Specifications could not be found either on the web or on the ARI certification website. Assumptions were made based on the model number format, 18,000 Btuh, SEER 10
Heat Pumps & AC Calculations	Assume only units with SEER values below 13 will be upgraded to SEER 18. Cost and savings estimates from DEER.

Figure 34 Lucky 7 Fuel Mart Potential Energy Efficiency Measures

Energy Efficiency Measures--Lucky 7 Fuel Mart (open 5840 hrs/yr)

Measure	Est Elect Baseline (kWh/yr)	Possible Measures	Measure Quantity	Est Elect Savings (kWh/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $0.08/kWh)	EUL (useful life, yr)	Payback Period	Notes
Miscellaneous Food Server & Office Equipment	58,400										Estimate 10 kW, operating 16 hours a day, 365 days a year.
Canapy outdoor flood lamps (2)	42,048	Timeclock and/or replacement with HPS	18	21,024	$ 1,639	$ 1,221	$ 2,860	$ 1,682	7.1	1.7	Assumed went from 400W Mercury Vapor (Metal Halide) to 250W High Pressure Sodium Outdoor bulbs. DEER used for pricing and EUL.
Walk In Cooler Refrigeration Unit (2) (7)	32,850	Replacement or tuning of evaporator fans, condensor fans and the compressor to higher efficiencies	1	7,227	$ 1,000	$ 1,000	$ 2,000	$ 578	15	3.5	DIH5H22-E, 5-ton, R22 refrigerant, electric defrost. 5 tons X 1.5 kW/ton X 8750 X 50% operation. Savings estimated based on 7% (evap fans), 3% (cond fans), & 12% (compressor). Costs assumed at $200/ton for labor and $200/ton for equipment to upgrade components.
Fluorescent Interior Lighting	21,280		25								Assumed 32W 3-tube operating 16 hours a day, 365 days a year.
High Efficiency indoor flood lamps (2)	14,016	Replace incandescent lighting with CFLs	16	10,652	$ 147	$ 60	$ 207	$ 852	11	0.2	Assume 150W Incandescent replaced by 36W CFL
Fuel Pumps	14,016										Assumed 12 1kW pumps, 1.5 Hp, operating 20% of the time
CFL's in place of incandescents in bathrooms (2)	701	Replace incandescent lighting with CFLs	2	549	$ 10	$ 8	$ 18	$ 44	3.2	0.4	Assume 60W Incandescent replaced by 13W CFL
LED Exit Signs (2), (5)	350	Replace with LED units	1	307	$ 17	$ 33	$ 50	$ 25	16	2.0	EPA Energy Star website indicates standard exit signs are 40 W as compared to the new 5W LED exit signs. Assume 24X7 operation. Costs from DEER.
Totals	183,662			39,759 22%	$ 2,813	$ 2,322	$ 5,135	$ 3,181		1.6	

Gas Energy Efficiency Measures

Load (Energy Efficiency Measure If Possible)	Est Gas Baseline (kBtu/yr)	Possible Measures	Quantity	Est Gas Savings (kBtu/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $2.00/gallon)	EUL (useful life, yr)	Payback Period	Notes
Lennox Gas HVAC System	93600	Replace current gas furnace with higher efficiency furnace	1	11232	$2,222.39	$ 1,821.87	$ 4,044.26	$ 245	18	16.5	Lennox gas HVAC system LGC102S2BS1Y, 130,000 Btu. Savings assumed to be 12% of gas load per DEER. Costs DEER valies X10
Water Heater Insulation (2), (6), (10)	5,490	Lower thermostat setting & insulate water heater. Convert to electric due to high prices of gas.	1	1373	$ 29	$ 45	$ 74	$ 30	10	2.5	Assume water heating is approximately 5% of the gas bill. Wrapping of water heater assumed to save approximately 25% of water heating bill lost to standby
Totals	99,090			12,605 13%	$ 2,251	$ 1,867	$ 4,118	$ 275		15.0	

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	238,760	183,662	77%
Gas (kBtu)	109,801	99,090	90%

Operating Hours	$/kWh	Hrs/day	Days/yr	Hours/yr	Notes
Lucky 7 Fuel Mart	$ 0.08	16	365	5,840	Assumes open 7 days a week, 6am - 10pm

Notes

(1) Full Spectrum Solutions, http://fullspectrumsolutions.com/electronic_ballasts_36_ctg.htm, Accessed 1/1/07
(2) California Database of Energy Efficient Resources (DEER), http://eega.cpuc.ca.gov/deer/, Accessed 12/27/06
(3) US DOE Energy Efficiency and Renewable Energy, "Electric Resistance Heating", http://www.eere.energy.gov/consumer/your_home/space_heating_cooling/index.cfm/mytopic=12520, Accessed 1/1/2007
(4) Heating Piping Air Conditioning (HPAC) Engineering, "The Energy Use Characteristics of Small Commercial Buildings", http://www.hpac.com/member/archive/0205data.htm, Accessed 1/1/2007
(5) Environmental Protection Agency (EPA) Energy Star Website, http://www.energystar.gov/index.cfm?c=exit_signs.pr_exit.signs
(6) Cornell University, "Comparing Values of Various Heating Fuels", http://housing.cce.cornell.edu/f-sht-pdf%20libraries/EE-F-SHTS/comparing%20heat%20fuels.pdf, Accessed 1/2/2007
(7) Arizona Public Service study of energy use in commercial buildings.
(8) PP&L 2006 power bills total 238,760 kWh
(9) Propane bills for 2006 total
(10) Gas Water Heating Insulation Savings, Department of Energy Energy Efficiency and Renewable Energy website.

Figure 35 Howonquet Head Start & Day Care Center Potential Energy Efficiency Measures

Energy Efficiency Measures--Howonquet Head Start & Day Care Center (open 2651 hrs/yr)

Measure	Est Elect Baseline (kWh/yr)	Possible Measures	Measure Quantity	Est Elect Savings (kWh/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $0.09/kWh)	EUL (useful life, yr)	Payback Period	Notes
Interior flourescent lighting	14,383	Replace current overhead lighting with higher efficiency T8 lighting	29	10,156	$ 679	$ 656	$ 1,335	$ 914	11	1.5	24-4 tube 40 watt F40 bulbs replaced by 24 2-tube 32W bulbs. Labor taken from "delamp" sheet.
High Efficiency exterior porch flood lights	11,498	Replace existing outdoor lighting with outdoor CFLs	21	8,432	$ 268	$ 79	$ 347	$ 759	7.1	0.5	Assumed went from 150W incandescent to 40W CFL Outdoor bulbs
Existing interior high efficiency T8 fixtures not requiring replacement	3,498		24								Energy demand included only for energy totals
CFL's in place of incandescents in bathrooms & foyer (2)	954	Replace incandescents with CFLs	6	748	$ 30	$ 23	$ 53	$ 52	3.2	1.0	Assume 60W Incandescent replaced by 13W CFL
LED Exit Signs (2), (10)	701	Replace current incandescent exit signs with LED signs	2	613	$ 34	$ 66	$ 100	$ 55	16	1.8	EPA Energy Star website indicates standard exit signs are 40 W as compared to the new 5W LED exit signs. Assume 24X7 operation. Costs from DEER.
Perimeter photo-sensitive flood lighting controls or timer (2)	0	Savings on outdoor lighting when personnel are not in the vacinity to require the lighting	5	2,371	$ 615	$ 584	$ 1,199	$ 213	8	5.6	Savings based on 4-70W (95W w/ ballast) HPS fixtures. One timer for each 4 bulbs.
Attic space gas HVAC unit maintenance or repair											No data is available on the possible energy demand impact of the two gas HVAC units in the attic space. They do not appear to be working, or the thermostat connection to the units is defective. Not included in energy savings or cost estimates.
Hot water plumbing repair (14)											No data is available on the amount of energy loss when hot water is released through the outside pipes. Replumbing needed to fix the problem. Not included in energy savings or cost estimates.
Totals	31,034			22,320 72%	$ 1,626	$ 1,409	$ 3,035	$ 1,994		1.5	

Gas Energy Efficiency Measures

Load (Energy Efficiency Measure If Possible)	Est Gas Baseline (kBtu/yr)	Possible Measures	Quantity	Est Gas Savings (kBtu/yr)	Equip Cost ($)	Labor Cost ($)	Installed Cost ($)	Est $/yr Savings (@ $2.00/gallon)	EUL (useful life, yr)	Payback Period	Notes
Water Heater Insulation (2), (11)	164,882	Replace older unit with higher efficiency unit and insulate.	2	19786	$ 58	$ 91	$ 148	$ 864	10	0.2	Wrapping of water heater assumed to save approximately 12% of water heating bill lost to standby
Miscellaneous Kitchen Appliances	50,000	Further identification of loads is needed to suggest any efficiency improvements	N/A								Ovens, stoves, warmers, etc…
Totals	214,882			19,786 9%	$ 58	$ 91	$ 148	$ 864		0.2	

Billing vs. Calculated Energy Consumption

Fuel Type	Billing	Calculated	% Calculated of Billing
Electric (kWh)	29,833	31,034	104%
Gas (kBtu)	236,795	214,882	91%

Operating Hours		$/kWh	Hrs/day	Days/yr	Hours/yr	Notes
Howonquet Head Start & Day Care Center		$ 0.09	11	241	2,651	Assumes closed 124 days per year, open 7am to 6pm

Notes

(1) Full Spectrum Solutions, http://fullspectrumsolutions.com/electronic_ballasts_36_ctg.htm, Accessed 1/1/07
(2) California Database of Energy Efficient Resources (DEER), http://eega.cpuc.ca.gov/deer/, Accessed 12/27/06
(3) Energy Information Administration 1999 Commercial Buildings Energy Consumption Survey: Table C3
(4) Base Energy Inc., "Energy Savings for a Commercial Building", http://www.baseco.com, Accessed 1/1/2007
(5) Natural Resources Canada, "Heating and Cooling with a Heat Pump", http://oee.nrcan.gc.ca/publications/infosource/pub/home/heating-heat-pump/asheatpumps.cfm, Accessed 1/1/2007
(6) The Shade Store, http://www.theshadestore.com, Accessed 1/1/2007
(7) California Title 24 Commercial Building Fact Sheet, http://www.iid.com/Media/title_24_fact_sheet.pdf, Accessed 1/1/07
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(9) Heating Piping Air Conditioning (HPAC) Engineering, "The Energy Use Characteristics of Small Commercial Buildings", http://www.hpac.com/member/archive/0205data.htm, Accessed 1/1/2007
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(11) Cornell University, "Comparing Values of Various Heating Fuels", http://housing.cce.cornell.edu/f-sht-pdf%20libraries/EE-F-SHTS/comparing%20heat%20fuels.pdf, Accessed 1/2/2007
(12) Weather stripping savings % estimates from Ames City, Iowa website, http://www.city.ames.ia.us/ElectricWeb/Energy%20Savings%20Cost%20Estimate.htm
(13) Weatherization cost estimates from Preservation Resources, Inc., http://www.ic-fhp.org/Yapp/WINDOW~1.DOC, Accessed 1/2/2007
(14) Staff reports hot water coming out of the exterior faucets. Assume plumbing problem that needs fixed. Undetermined amount of savings that may result given lack of leaking water volume information.

Appendix VII Bergey Windpower BWC EXCEL-S 10kW Specification

Bergey Turbines are Tornado-Tuff
Designed, Built, and Proven in America's Tornado Alley

Exclusive 5 Year Warranty

BWC EXCEL
10KW CLASS WIND TURBINE

- 5-YEAR WARRANTY
- AMERICA'S BEST SELLING RESIDENTIAL SYSTEM
- CERTIFIED BY CALIFORNIA ENERGY COMMISSION
- SIMPLE DESIGN - 3 MOVING PARTS
- PATENTED POWERFLEX® ROTOR SYSTEM
- AUTOFURL® AUTOMATIC STORM PROTECTION
- DIRECT-DRIVE PM ALTERNATOR
- NO SCHEDULED MAINTENANCE REQUIRED
- HEAVY-DUTY CONSTRUCTION
- DESIGNED FOR 30+ YEARS
- POLYURETHANE AIRCRAFT-QUALITY PAINT
- PROVEN, OVER 50 MILLION OPERATIONAL HOURS

The Bergey BWC Excel is a rugged and reliable small wind turbine that has been proven in hundreds of installations around the world. It comes from the world's leading manufacturer of small wind turbines and is backed by the longest warranty in the industry. Whether you want to reduce the electric bills at your home or power a critical load far from the power grid, the BWC Excel will deliver years of "worry-free" power.

Excel–S: Grid-Intertie Applications (10kW)
Excel–R: Battery Charging Applications (7.5kW)
Excel–PD: Pumping Applications (10kW)

Excel–S GridTek 10 Power Processor (AC output)

Excel–R OptiCharge Voltage Regulator (DC output)

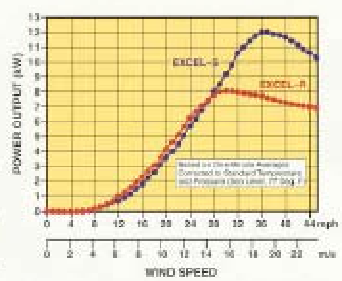
Net Weight: 1,050 lbs
Shipping Weight: 1,200 lbs

THE ONLY MOVING PARTS ARE THE PARTS YOU SEE MOVING

PERFORMANCE

Start-up Wind Speed...7.5 mph
Cut-In Wind Speed...8 mph
Rated Wind Speed...31 mph
Rated Rotor Speed...310 RPM
Furling Wind Speed...36 mph
Max. Design Wind Speed...125 mph
(with Extra-Stiff Blades...150 mph)

POINT, CLICK, LEARN, ANALYZE & BUY WISELY: WWW.BERGEY.COM



Predicted Monthly Energy Production

Wind Speeds Taken at Top of Tower

Average Wind Speed	8 mph	9 mph	10 mph	11 mph	12 mph	13 mph	14 mph
Excel–S (AC kWh)	240	370	520	700	900	1,130	1,370
Excel–R (DC kWh)	340	530	680	880	1,090	1,320	1,550

Wind Speeds Taken at 10 meters (per standard wind resource maps)

Average Wind Speed		8 mph	9 mph	10 mph	11 mph	12 mph	13 mph	14 mph
60 ft. Tower	Excel–S	330	480	670	870	1,110	1,360	1,610
	Excel–R	440	620	830	1,050	1,280	1,510	1,740
80 ft. Tower	Excel–S	430	620	840	1,100	1,370	1,675	1,960
	Excel–R	560	780	1,030	1,290	1,550	1,820	2,060
100 ft. Tower	Excel–S	490	700	960	1,220	1,510	1,820	2,130
	Excel–R	630	870	1,140	1,410	1,690	1,960	2,230
120 ft. Tower	Excel–S	550	780	1,050	1,340	1,650	1,970	2,290
	Excel–R	700	960	1,240	1,530	1,800	2,070	2,320

Assumptions: Inland Site, Rayleigh Distribution, Shear Exponent = 0.18, Altitude = 1,000 ft.
Note: Battery charge regulation (batteries full) will reduce actual Excel–R performance.
Your Performance May Vary.

BERGEY WINDPOWER

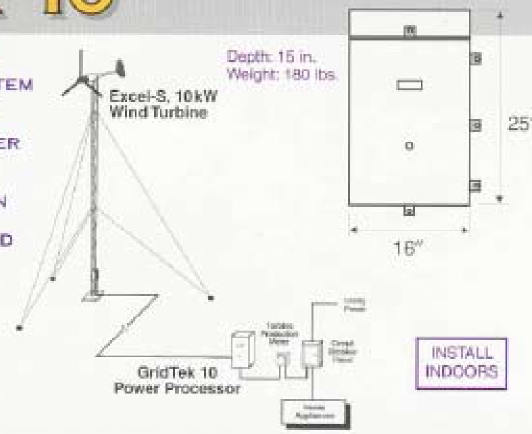
SIMPLICITY•RELIABILITY•PERFORMANCE

2001 PRIESTLEY AVE.
NORMAN, OK 73069
T: 405-364-4212
F: 405-364-2078
SALES@BERGEY.COM
WWW.BERGEY.COM

ELECTRONICS FOR THE BWC EXCEL WIND TURBINE

GRIDTEK 10

- POWER PROCESSOR FOR THE EXCEL-S GRID-INTERTIE SYSTEM
- 240 VAC OUTPUT, 60 HZ OR 50 HZ, 220 VAC
- NO BATTERIES, EXCESS POWER IS SOLD TO THE POWER COMPANY
- FULLY AUTOMATIC OPERATION
- ADVANCED DIGITAL DESIGN
- DISPLAYS OUTPUT POWER AND TURBINE SPEED
- 5-YEAR WARRANTY
- UL LISTED
- CEC CERTIFIED

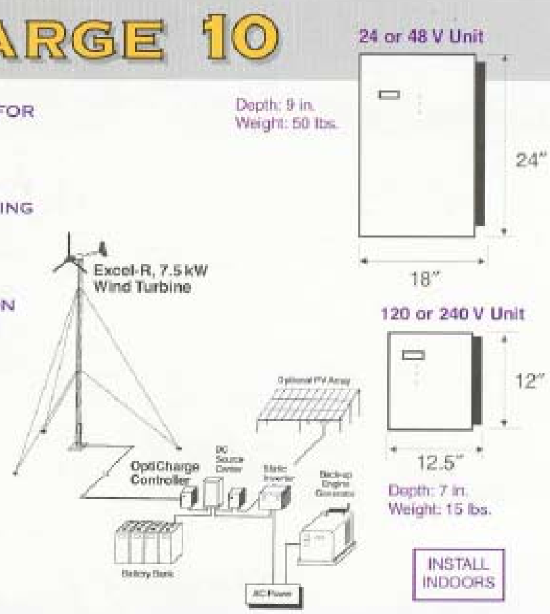


48 V unit, with optional E-Meter

240 V unit

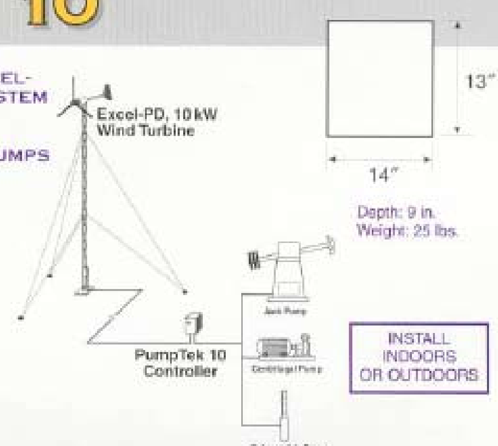
OPTICHARGE 10

- RECTIFIER AND REGULATOR FOR THE EXCEL-R BATTERY CHARGING SYSTEM
- 24, 48, 120, OR 240 VDC OUTPUTS
- SOLID-STATE, PASSIVE COOLING (EXCEPT 24 V UNIT)
- OPTICHARGE, CONSTANT VOLTAGE CHARGING, FOR LONGER BATTERY LIFE
- FULLY AUTOMATIC OPERATION
- DISPLAYS BATTERY VOLTAGE AND CHARGING STATUS
- OPTIONAL INTEGRATED DC POWER CENTER
- 5-YEAR WARRANTY



PUMPTEK 10

- PUMP CONTROLLER FOR THE EXCEL-PD WIND-ELECTRIC PUMPING SYSTEM
- NEW IMPROVED DESIGN
- SOLID-STATE, NO BATTERY
- FOR STANDARD 240 VAC 3-PH PUMPS
- FULLY AUTOMATIC OPERATION
- DRY PUMP SHUTDOWN
- OUTDOOR RATED ENCLOSURE
- 5-YEAR WARRANTY



Dealer

Appendix VIII CEC List of Eligible Small Wind Turbines

Manufacturer Name	Model Number	Description	Power Output (Watts)	Notes
Atlantic Orient Canada	AOC 15/50	50,000W Wind Turbine	50,000	Rated at 35.8
Bergey Windpower	BWC 1500	1,500W Wind Turbine	1,500	N/A
Bergey Windpower	BWC EXCEL	10,000W Wind Turbine	10,000	Rated at 31 mph.
Bergey Windpower	BWC XL.1	1,000W Wind Turbine	1,200	Rated at 25 mph.
Cygnus Wind Systems	Wind Eagle 30	30,000W Wind Turbine	30,000	Rated at 26 mph.
Entegrity Wind Systems	EW15	50,000W Wind Turbine	50,000	Formerly Atlantic Orient Canada, AOC 15/50 - Rated at 25.3 mph
Fortis	Alize	12,000W Wind Turbine	10,000	Rated at 24 mph.
Fortis	Montana	5,800W Wind Turbine	5,000	Rated at 31 mph.
Fortis	Espada	800W Wind Turbine	750	Rated at 36 mph.
Iskra Wind Turbine Manufacturers Ltd	AT5-1	Iskra AT5-1	5000	Rated at 11 m/s, 200 rpm
Point Power Systems	5.8 kW	5,800W Wind Turbine	5,000	Rated at 31 mph.
Point Power Systems	0.8 kW	800W Wind Turbine	750	Rated at 36 mph.
Point Power Systems	12 kW	12,000W Wind Turbine	10,000	Rated at 24 mph.
Southwest Windpower	Skystream 3.7	1,800W Direct Grid Connect Wind Turbine	1,800 Continuous 2,400 Peak	Rated at 20 mph
Southwest Windpower	500	Whisper 500 Wind Turbine	3,000	Formerly model 175 (3,000W Whisper 3000 Wind Turbine)
Southwest Windpower	200	Whisper 200 Wind Turbine	1,000	Formerly model H80
Southwest Windpower	100	Whisper 100 Wind Turbine	900	Formerly model H40
Southwest Windpower	503	500W Windseeker Wind Turbine	500	N/A
Southwest Windpower	502	500W Windseeker Wind Turbine	500	N/A
Southwest Windpower	AIR403	400W Wind Turbine	472	N/A
Synergy Power Corporation	SLG/S300	Survivor 30,000W Wind Turbine	30,000	N/A
Wind Turbine Industries	23-10	10,000W Jacobs 23-10 Wind Turbine	10,000	Rated at 26 mph.
Wind Turbine Industries	31-20	20,000W Jacobs 31-20 Wind Turbine	20,000	Rated at 26 mph.

Appendix IX CEC Emerging Renewables Program Guidebook

CALIFORNIA ENERGY COMMISSION

RENEWABLE ENERGY PROGRAM

OVERALL PROGRAM GUIDEBOOK

APRIL 2006

CEC-300-2006-008-F

STATE OF CALIFORNIA ENERGY COMMISSION

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Joseph Desmond
Chairman

Jackalyne Pfannenstiel
Vice Chair

Commissioners:
Arthur H. Rosenfeld
James D. Boyd
John L. Geesman

B.B Blevins
Executive Director

Heather Raitt
Technical Director
Renewable Energy Program

Drake Johnson
Office Manager
RENEWABLE ENERGY OFFICE

Valerie Hall
Deputy Director
EFFICIENCY, RENEWABLES, AND DEMAND ANALYSIS DIVISION

These guidelines were formally adopted by the California Energy Commission on February 19, 2003, pursuant to Public Utilities Code Section 383.5, Subdivision (h), and subsequently revised pursuant to this authority and Public Resources Code Section 25747 (a) on April 21, 2004, May 19, 2004, and April 26, 2006.

Table of Contents

I. Introduction

The California Energy Commission (Commission) has developed these *Guidelines* to implement and administer its Renewable Energy Program under Senate Bill 1038 (Sher), Chapter 515, Statutes of 2002[1]. This law in conjunction with the Reliable Electric Service Investments Act[2] extends the collection of a non-bypassable system benefit charge initiated in 1998 under Assembly Bill 1890 (Brulte), Chapter 854, Statutes of 1996 and authorizes the expenditure of funds collected to support existing, new, and emerging renewable resources. The goal of SB 1038 is to establish a competitive, self-sustaining renewable energy supply for California while increasing the near-term quantity of renewable energy generated in-state.

These *Guidelines* also address aspects of the Renewable Energy Program related to the state's Renewables Portfolio Standard (RPS) under Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002).[3] This law requires certain retail sellers of electricity to increase the amount of renewable energy they procure each year by 1 percent until the renewable energy content of their electricity portfolios equal 20 percent. Retail sellers of electricity must meet this 20 percent level by December 31, 2017. Under SB 1078, the Energy Commission is charged with certifying eligible renewable energy resources that may be used by retail sellers of electricity to satisfy their RPS procurement requirements and for developing an accounting system to verify a retail seller's compliance with the RPS. Many of these eligible renewable energy resources may qualify for funding under the Renewable Energy Program.

These *Guidelines* were adopted to govern the Renewable Energy Program and its various program elements under SB 1038 and SB 1078, to assist interested applicants in applying for Program funds and RPS certification, and for verifying RPS compliance. The *Guidelines* are divided into six parts and available in six separate documents:

- *Overall Program Guidebook*
- *Existing Renewable Facilities Program Guidebook*
- *Emerging Renewable Program Guidebook*
- *Renewable Resource Consumer Education Guidebook*
- *New Renewable Facilities Program Guidebook*
- *Renewables Portfolio Standard Eligibility Guidebook*

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[1] The pertinent provisions of SB 1038 were formerly codified in Public Utilities Code Sections 383.5 and 445 but are now codified in Public Resources Code Sections 25740 through 25751 as a result of Senate Bill 183 (Sher), Chapter 666, Statutes of 2003.
[2] Public Utilities Code Section 399, et seq., as enacted by Assembly Bill 995 (Wright), Chapter 1051, Statutes of 2000 and Senate Bill 1194 (Sher), Chapter 1050, Statutes of 2000.
[3] The pertinent provisions of SB 1078 are codified in Public Utilities Code Section 399.11 through 399.15. This law was subsequently amended to add Sections 399.16 and 399.17 pursuant to Senate Bill 67 (Bowen), Chapter 731, Statutes of 2003; and Assembly Bill 200 (Leslie), Chapter 5, Statutes of 2005; respectively.

To qualify for funding under the Renewable Energy Program or RPS certification, individuals and entities must satisfy the requirements and specifications contained in both this *Overall Program Guidebook* and the applicable program element guidebook. If after reading these *Guidelines* you require additional information about the Renewable Energy Program or its various program elements, please visit the Commission's Web site or contact the Commission's Call Center.

Web site:	<http:/www.energy.ca.gov/renewables/>
Call Center E-mail:	Renewable@energy.state.ca.us
Call Center Phone:	(800) 555-7794

II. General Provisions

1. Guidelines

These *Guidelines* shall be known as the *Renewable Energy Program Guidelines* and may be referred to herein as the *Guidelines*. As noted above, the *Guidelines* comprise six separate documents, referred to as guidebooks. These guidebooks are as follows:

- *Overall Program Guidebook.* This guidebook describes how the Renewable Energy Program will be administered. It includes information and requirements that apply overall to the Renewable Energy Program and program elements.

- *Existing Renewable Facilities Program Guidebook.* This guidebook describes the eligibility requirements specific to the Existing Renewable Facilities Program element and identifies eligible renewable generating facilities, eligible generation, the funding available, and specific administrative procedures for receiving funding under this program element.

- *Emerging Renewables Program Guidebook.* This guidebook describes the eligibility requirements specific to the Emerging Renewable Program and identifies eligible applicants, eligible renewable energy systems, the funding available, and specific administrative procedures for receiving funding under this program element.

- *Renewable Resource Consumer Education Guidebook.* This guidebook describes the eligibility requirements specific to the Consumer Education element of the Renewable Energy Program and identifies eligible applicants and projects and specific administrative procedures for receiving funding under this program element.

- *New Renewable Facilities Program Guidebook.* This guidebook describes the eligibility requirements specific to the New Renewable Facilities Program element and identifies eligible renewable generating facilities, eligible generation, the funding available, and specific administrative procedures for receiving funding under this program element.

- *Renewables Portfolio Standard Eligibility Guidebook*. This guidebook describes the eligibility requirements and process for certifying renewable energy resources as eligible for the RPS. This guidebook also describes the interim process the Commission will use to track and verify compliance with the RPS.

A seventh guidebook may be adopted in the future to address a Customer Credit Program element should the Commission choose to implement this program element. The Commission does not anticipate implementing a Customer Credit Program element at this time. Pursuant to SB 1038, the Commission prepared a report for the Governor and the Legislature recommending that a Customer Credit Program element not be implemented and that any funds allocated for this purpose be reallocated for use in the Emerging Renewable Program, New Renewable Facilities Program, and Consumer Education program elements. This report, titled *Customer Credit Renewable Resources Account: Report to the Governor and the Legislature*, was published in April 2003.

2. Authority

These *Guidelines* are adopted pursuant to Public Resources Code Section 25747, Subdivision (a), which directs the Commission to adopt guidelines governing the funding programs authorized by Public Resources Code Section 25740 through 25751, and portions of the RPS under Public Utilities Code Section 399.13. The guidelines adopted pursuant to this authority are exempt from the rulemaking requirements of the Administrative Procedures Act, as specified in Chapter 3.5 (commencing with Section 11340) of Division 3 of Title 2 of the Government Code. These *Guidelines* may be revised pursuant to Public Resources Code Section 25747, Subdivision (a).[4]

3. Application

These *Guidelines* govern any funding available under the Renewable Energy Program or any of the program elements starting January 1, 2003. Any funding awarded prior to this date from the Renewable Energy Program — including any funding from the Existing Renewable Resources Account, New Renewable Resources Account, Emerging Renewable Resources Account, or Customer-side Renewable Resource Purchases Account — shall be subject to the adopted guidelines applicable at that time.

These *Guidelines* also govern the certification of renewable energy resources eligible for the RPS.

[4] The *Guidelines* were initially adopted pursuant to Public Utilities Code Section 383.5, Subdivision (h), which was subsequently amended and recast as Public Resources Code Section 25747, Subdivision (a), pursuant to Senate Bill 183.

4. Interpretation

Nothing in these *Guidelines* shall be construed to abridge the powers or authority of the Commission or any Commission-designated Committee as specified in Division 15 of the Public Resources Code, commencing with Section 25000, or Division 2 of Title 20 of the California Code of Regulations, commencing with Section 1001.

5. Effective Date

These *Guidelines* shall take effect once adopted by the Commission at a publicly noticed Business Meeting with no less than 30 days public notice.

6. Substantive Changes

Substantive changes to these *Guidelines* may be made upon the recommendation of the assigned Committee with the approval of the Commission. Substantive changes shall take effect once adopted by the Commission at a publicly noticed Business Meeting with no less than 10 days public notice. Substantive changes include, but are not limited to, the following:

a. Changes in the eligibility or evaluation criteria.

b. Changes to funding or incentives levels.

c. Reallocation of funds between program elements.

7. Non-Substantive Changes

Non-substantive changes to these *Guidelines* may be made upon the recommendation and approval of the assigned Committee. Non-substantive changes shall take effect 10 days after the assigned Committee has approved and publicly noticed the non-substantive changes. Non-substantive changes include, but are not limited to, the following:

a. Changes to the formatting of any application form, invoice, or report required under these *Guidelines* and

b. Changes to information required in any application form, invoice, or report required under these *Guidelines.*

8. Definitions

The terms defined below are used repeatedly throughout this *Overall Program Guidebook.* A glossary of pertinent terms used in the program element guidebooks is appended for reference purposes.

a. "Awardee" - An individual or entity awarded or reserved grant funding or certified as RPS eligible, or both, pursuant to these *Guidelines.*

b. "Billing Month" - The period of time coinciding with a calendar month in which an awardee is entitled to receive a payment pursuant to the awardee's funding award.

c. "Commission" - State Energy Resources Conservation and Development Commission. Also referred to as the California Energy Commission.

d. "Committee" – A Committee of the California Energy Commission charged with overseeing implementation of the Renewable Energy Program. At the time these *Guidelines* were adopted, the Renewables Committee was charged with this responsibility.

e. "Funding Award" - An award or reservation of grant funding under the Renewable Energy Program pursuant to these *Guideline*s.

f. "Guidelines" – The guidelines governing the Renewable Energy Program, including aspects related to RPS eligibility. These guidelines include the following:

- *Overall Program Guidebook.*
- *Existing Renewable Facilities Program Guidebook.*
- *Emerging Renewables Program Guidebook.*
- *Renewable Resources Consumer Education Guidebook.*
- *New Renewable Facilities Program Guidebook.*
- *Renewables Portfolio Standard Eligibility Guidebook.*

g. “Registrant” - Any individual or entity that applies for and is granted registration as a renewable supplier pursuant to these *Guidelines*.

h. "Renewable Resource Trust Fund" - The fund created in the State Treasury pursuant to Public Resources Code Section 25751, and comprising the following accounts:

- Existing Renewable Resources Account.
- New Renewable Resources Account.
- Emerging Renewable Resources Account.
- Customer Credit Renewable Resource Purchases Account.
- Renewable Resources Consumer Education Account.

i. “RPS Certification” – Certified by the Commission as eligible for purposes of the meeting the state’s Renewables Portfolio Standard under SB 1078, or eligible for meeting both the state’s Renewables Portfolio Standard and for receiving supplemental energy payment from the New Renewable Facilities Program element under SB 1078 and SB 1038.

j. "Substantive Changes" - Changes to these *Guidelines* that affect an individual's or an entity's ability to qualify for awards made pursuant to these *Guidelines*, or affect the award amount of any awardee.

III. Program Funding

1. Existing Renewable Facilities Program

Twenty percent (20%) of the funds deposited into the Renewable Resource Trust Fund pursuant to SB 1038, approximately $135,000,000 over five years, are available for the Existing Renewable Facilities Program element.

2. Emerging Renewables Program

Seventeen and one-half percent (17.5%) of the funds deposited into the Renewable Resource Trust Fund pursuant to SB 1038, approximately $118,125,000 over five years, are available for the Emerging Renewables Program element.

3. Consumer Education

One percent (1%) of the funds deposited into the Renewable Resource Trust Fund pursuant to SB 1038, approximately $6,750,000 over five years, is available for the Consumer Education Program element of the Renewable Energy Program.

4. New Renewable Facilities Program

Fifty-one and one-half percent (51.5%) of the funds deposited into the Renewable Resource Trust Fund pursuant to SB 1038, approximately $347,625,000 over five years, are available for the New Renewable Facilities Program element.

5. Customer Credit Program

Ten percent (10%) of the funds deposited into the Renewable Resource Trust Fund pursuant to SB 1038, approximately $67,500,000 over five years, are available for the Customer Credit Program element.

In accordance with the Commission's recommendations as stated in its report titled *Customer Credit Renewable Resources Account: Report to the Governor and the Legislature*, published in April 2003, the funds available for a Customer Credit Program element are reallocated as follows:

- 10 percent (approximately $6,750,000 over five years) to the Consumer Education program element
- 90 percent (approximately $60,750,000 over five years) to the Emerging Renewables Program element

(The Commission had previously recommended in the above noted report that 30 percent of these funds (approximately $30,375,000) be reallocated to the New Renewable Facilities Program. However, an increase in demand in the Emerging Renewables Program dictates that the Commission reallocate these funds for this program element.)

6. Reallocation of Program Funds

Funds available for a particular program element may be reallocated to another program element at the Commission's discretion. Any reallocation of funds shall comport with the following requirements and shall be recommended by the Committee.

a. The reallocation shall be consistent with the Commission's legislative reports, as required by Public Resources Code Section 25748, Subdivision (a), and Public Utilities Code Section 399.6.

b. Pursuant to Public Resources Code Section 25748, Subdivision (b), the reallocation may not increase the funds available to the Existing Renewable Facilities Program as provided in Subsection 1 of this section.

c. Pursuant to Public Resources Code Section 25748, Subdivision (b), the reallocation may not decrease the funds available to the New Renewable Facilities Program as provided in Subsection 4 of this section.

7. Transfers of Program Funds

Funds may be transferred between program elements for cash flow purposes, provided the balance due each program element is restored and the transfer does not adversely affect the program element as determined by the Commission.

8. Administrative Expenses

The Commission may use funds deposited into the Renewable Resource Trust Fund pursuant to SB 1038 to administer the Renewable Energy Program to the extent appropriated by the Legislature and authorized by the California Department of Finance.

9. Interest on Program Funds

Interest earned on the funds deposited in the Renewable Resource Trust Fund pursuant to SB 1038 may be used to augment funds for a particular program element at the Commission's discretion, as recommended by the Committee. Such interest may be used for the Commission's administration of the Renewable Energy Program to the extent appropriated by the Legislature and authorized by the California Department of Finance.

IV. Application for Program Funds and RPS Certification

1. Applicant Eligibility

Individuals and entities are eligible for program funding and RPS certification if they satisfy the eligibility requirements specified in the program element guidebooks.

2. Applications for Program Funding and RPS Certification

To qualify for funding or RPS certification, eligible individuals and entities must apply to the Commission as specified in the applicable program element guidebook.

3. Approvals of Funding Awards and RPS Certification

Funding shall be awarded to eligible applicants as specified in the program element guidebooks. Formal Commission approval of each funding award shall not be required unless stated otherwise in the program element guidebooks.

RPS certification shall be approved for eligible applicants as specified in the *Renewables Portfolio Standard Eligibility Guidebook*. Formal Commission approval of each application for RPS certification shall not be required unless stated otherwise in the *Renewables Portfolio Standard Eligibility Guidebook*.

4. Cancellation of Funding Awards and RPS Certification

The Committee may cancel the funding award or RPS certification of any awardee that changes or otherwise modifies its basis for funding or RPS certification eligibility under these *Guidelines* and no longer satisfies the requisite eligibility criteria. The Committee shall notify the awardee in writing of the basis for canceling the awardee's funding award or RPS certification, the effective date of the cancellation, and the terms and conditions for the repayment of any portion of the funding award the awardee was not otherwise entitled to receive. The written notice required herein shall be given at least 15 days in advance of the effective date of the cancellation to provide the awardee an opportunity to file a petition for reconsideration pursuant to Section V of these *Guidelines*.

5. Funding Award Invoicing

Awardees shall submit the necessary invoices and supporting documentation as specified in the program element guidebooks to receive funding award payments.

6. Funding Award Payments

Funding award payment shall be made to awardees as specified in the program element guidebooks. However, funding award payments shall not be made under any of the following conditions.

a. The Committee determines, pursuant to Subsection 4 of this section, that the awardee is no longer eligible to receive a funding award.

b. The awardee fails to properly invoice the Commission's Accounting Office as specified in Subsection 5 of this section.

c. An audit conducted pursuant to Subsection 8 of this section reveals an awardee's invoice, submitted pursuant to Subsection 5 of this section, is overstated, inaccurate or unsupported.

d. The awardee fails to repay the Commission for any overpayment the awardee received as specified in the written notice issued pursuant to Subsection 8 of this section.

e. Based on an investigation conducted pursuant to Section VII, Subsection 2, the Committee determines that the awardee has misstated, falsified, or misrepresented information in applying to register as a renewable supplier, in applying for a funding award or RPS certification, in invoicing for a funding award payment, or in reporting any information required by these *Guidelines*.

7. Assignment of Funding Award Payments

Awardees may assign their right to receive a funding award payment to a third party by completing the appropriate assignment form and submitting it to the Commission's Accounting Office, along with the necessary invoices and supporting documentation as specified in the program element guidebooks.

8. Audits

The Commission's Accounting Office or its authorized agents, in conjunction with Commission technical staff, may audit any awardee to verify the accuracy of any information included as part of an application for funding, RPS certification, or registration, invoice for funding award payment, or report required under these *Guidelines*. As part of an audit, an awardee may be required to provide the Accounting Office or its authorized agents with any and all information and records necessary to verify the accuracy of any information included in the awardee's applications, invoices, or reports. An awardee may also be required to open its business records for on-site inspection and audit by the Accounting Office or its authorized agents for purposes of verifying the accuracy of any information included in the awardee's applications, invoices, and reports.

If an audit finds that an awardee has incorrectly stated or falsified information included on the awardee's applications, invoices, or reports, the Accounting Office will notify the awardee of its findings in writing within 30 days of completing the audit. Based on the audit results, an awardee may be required to refund all or a portion of the funding award payments it has received. In addition, the awardee's funding award or RPS certification may be cancelled pursuant to Subsection 4 of this section and enforcement actions initiated pursuant to Section VII.

9. Record Retention

Awardees shall keep all records relating to and verifying the accuracy of any information included in an application for funding, RPS certification, or registration, invoice for funding award payment, or report submitted pursuant to these *Guidelines*. These records shall be kept for no less than three years after the end of the calendar year in which the awardee's RPS certification is approved or the awardee's final funding award payment is made, whichever is longer. These records shall be made available to the Commission or its authorized agents as part of any audit conducted pursuant to these *Guidelines*.

10. Use and Disclosure of Information and Records

The Commission or its authorized agents may use any information or records submitted to the Commission or obtained as part of any audit pursuant to these *Guidelines* to determine eligibility and compliance with the *Guidelines*, evaluate the Renewable Energy Program, the RPS, or related Commission program, and prepare necessary reports as required by law. The information and records include, but are not limited to, applications for registration, funding, and RPS certification, invoices for funding award payments, and any documentation submitted in support of said applications or invoices.

Information and records submitted pursuant to these *Guidelines* will be disclosed to other governmental entities and policing authorities for civil and criminal investigation and enforcement purposes. This information and records may also be disclosed to members of the public pursuant to the California Public Records Act (Government Code Sections 6250 et sequentia). Personal information, such as taxpayer identification or social security numbers, will not be disclosed to members of the public.

Information concerning the identity of awardees and the amount or payment of funding awards is public information and will be disclosed pursuant to the California Public Records Act. This information, along with other public information describing program participants, may be disclosed to members of the public to educate them and encourage further program participation. The information may be disclosed through the Commission's Web site or other means, as the Commission deems appropriate.

If, as part of any audit, the Commission requires the awardee to provide copies of records that the awardee believes contain proprietary information entitled to protection under the California Public Records Act or other law, the awardee may request that such records be designated as confidential pursuant to the Commission's regulations for confidential designation, Title 20, California Code of Regulations, Section 2505.

11. Tax Consequences

Awardees are responsible for any federal and state tax consequences associated with the receipt of funding award payments. The Commission will report funding award payments to the Internal Revenue Service and issue the awardee an informational form (e.g., 1099-Misc) when required to do so by law. To process funding award payments for tax purposes, awardees must complete a Vendor Record Data Record form to provide the Commission taxpayer information. The taxpayer identified in this form must be the awardee as identified in the funding award application. Copies of this form and instructions for completing it are included in the program element guidebooks. Awardees who assign their funding award payments to third parties pursuant to Subsection 7 will be reported as the recipient of said payment and issued the informational form when required by law. Applicants should carefully consider the tax consequences of receiving funding award payments when applying for funding awards under any of the program elements.

V. Reconsideration of Funding Awards, Funding Award Cancellations, and Registration

1. Committee Reconsideration

Any individual or entity may petition the Committee for reconsideration if the application for funding or RPS certification was denied, their funding award reduced or cancelled, their RPS certification cancelled, their application to register as a renewable supplier denied, or their registration as a renewable supplier revoked. The petition for reconsideration shall be in writing and shall be submitted, together with any supporting documentation, to the Committee at the following address within 15 days of receiving the notice of funding award or RPS certification denial, cancellation, or reduction, or registration denial or revocation.

Address: California Energy Commission
Renewables Committee
1516 9th Street, MS-31
Sacramento, CA 95814-5512

The petition shall specify the basis for the appeal, state why the petitioner believes the funding award or RPS certification denial, cancellation, or reduction, or registration denial or revocation is improper given the eligibility criteria for the funding award, RPS certification, or registration, explain any supporting documentation filed with the petition, identify any legal authority or other basis supporting the petitioner's position, and identify the remedy sought.

Within 45 days of receiving a complete petition, the Committee, at its discretion, shall either issue a decision based on its consideration of the petition and the written response of Commission staff or schedule a hearing to consider the petition. If a hearing is scheduled, the petitioner shall be notified of the hearing date and any additional information the petitioner is directed to submit. This notice shall be given at least 15 days in advance of the Committee hearing date. The Committee may direct the petitioner and Commission staff to attend the Committee hearing to offer pertinent testimony.

The Committee shall provide the petitioner with a written decision on the petition within 45 days of holding the hearing. Should the petitioner disagree with the Committee's decision, the petitioner may appeal the decision to the Commission pursuant to Subsection 2 of this section.

2. Commission Appeals

Within 15 days of receiving the Committee's decision, the appealing party shall file a letter of appeal stating why the Committee's decision is unacceptable. The letter of appeal — along with a copy of the petition for reconsideration, supporting documentation, and the Committee's written decision — shall be sent to the Commission's Public Adviser at the following address.

California Energy Commission
Public Adviser's Office
1516 9th Street, MS-12
Sacramento, CA 95814-5512

Within 30 days of receiving the letter of appeal, the Public Adviser shall arrange for the appeal to be presented to the Commission at a regularly scheduled Business Meeting. The Public Adviser shall inform the appealing party in writing of the Business Meeting date and the procedures for participating in the Business Meeting. The appealing party shall be responsible for presenting the appeal to the Commission during the Business Meeting. Unless otherwise determined during the course of the Business Meeting, the Commission shall determine the appeal during the Business Meeting.

VI. Disputes of Funding Award Payments

1. Accounting Office Review

Awardees may dispute the amount of a funding award payment by filing a written claim with the Commission's Accounting Office. The claim shall be filed within 15 days of receipt of the payment, the amount of which is disputed, or a notice from the

Commission's Accounting Office indicating no payment will be made. The claim must be filed, together with any evidence supporting the awardee's position, with the Commission's Accounting Office at the following address.

California Energy Commission
Accounting Office
1516 9th Street, MS-2
Sacramento, CA 95814-5512

The claim shall identify the payment in dispute, the date on which payment was received or expected, an explanation of the evidence supporting the awardee's position, any legal authority or other basis supporting the awardee's position, and the amount of repayment sought. The Accounting Office will review the claim within 30 days of its receipt, determine its validity, and provide the awardee with a written decision supported by reasons. The written decision shall specify that portion of the claim, if any, determined to be valid and the amount and date when payment will be made. Should the awardee disagree with the determination of the Accounting Office, the awardee may seek reconsideration pursuant to Subsection 2 of this section.

2. Executive Office Review

Within 15 days of receiving a written decision from the Accounting Office, the awardee shall file a letter of reconsideration stating why the written decision is unacceptable. The letter shall be filed with the Commission’s Executive Director, along with a copy of the original dispute claim, supporting documents, and the Accounting Office's written decision, at the following address:

California Energy Commission
Office of the Executive Director
1516 9th Street, MS-39
Sacramento, CA 95814-5512

The Executive Director, or his or her designee, will review the letter of reconsideration within 30 days of its receipt, assess the Accounting Office's written decision, and provide the awardee with a written decision. The written decision shall specify whether the Accounting Office's determination shall be upheld, whether any portion of the awardee's original dispute claim is deemed valid, and the amount and date that any repayment will be made. Should the awardee disagree with the Executive Director’s determination, the awardee may appeal the determination to the Commission pursuant to Subsection 3 of this section.

3. Commission Appeal

Within 15 days of receiving the Executive Director's written determination, the awardee shall file a letter of appeal stating why the Executive Director's written decision is unacceptable. The letter of appeal shall be sent to the Commission's Public Adviser, along with a copy of the original dispute claim, supporting documents, and the Accounting Office and Executive Director decisions. The letter shall be sent to the following address:

California Energy Commission
Public Adviser's Office
1516 9th Street, MS-12
Sacramento, CA 95814-5512

Within 30 days of receiving the written appeal, the Public Adviser shall arrange for the appeal to be presented to the Commission at a regularly scheduled Business Meeting. The Public Adviser shall inform the awardee in writing of the Business Meeting date and the procedures for participating in the Business Meeting. The awardee shall be responsible for presenting the appeal to the Commission during the Business Meeting. Unless otherwise decided during the course of the Business Meeting, the Commission shall determine the awardee's appeal during the Business Meeting.

VII. Enforcement Action

1. Recovery of Overpayment

The Committee, with the concurrence of the Commission, may direct the Commission's Office of Chief Counsel to commence formal legal action against any awardee or former awardee to recover any portion of a funding award that the Committee determines the awardee or former awardee was not otherwise entitled to receive.

2. Fraud and Misrepresentation

The Committee may initiate an investigation of any registrant or awardee who the Committee has reason to believe may have misstated, falsified, or misrepresented information in applying for registration, funding, or RPS certification, invoicing for a funding award payment, or reporting any information required by these *Guidelines*. Based on the results of the investigation, the Committee may take any action it deems appropriate, including, but not limited to, revocation of the registration, cancellation of the funding award or RPS certification, recovery of any overpayment, and, with the concurrence of the Commission, recommending the Attorney General initiate an investigation and prosecution pursuant to Government Code Sections 12650, et seq., or other provisions of law.

VIII. Arbitration

If an awardee's dispute of funding award payment is not resolved to the satisfaction of the awardee through the Commission Appeal process specified in Chapter VI of these Guidelines, the awardee and the Commission may mutually agree to have the dispute resolved through binding arbitration. The arbitration proceeding shall take place in Sacramento County, California, and shall be governed by the commercial arbitration rules of the American Arbitration Association (AAA) in effect on the date the arbitration is initiated. One arbitrator who is an expert in the particular field of the dispute shall resolve the dispute. The arbitrator shall be selected in accordance with the aforementioned commercial arbitration rules. The decision rendered by the arbitrator shall be final, and judgment may be entered upon it in accordance with the applicable law in any court having jurisdiction thereof. The demand for arbitration shall be made no later than six months after the date the Commission renders a decision through the Commission Appeal process specified in Chapter VI, irrespective of when the dispute arose, and irrespective of the applicable statute of limitations for a suit based on the dispute. If the awardee and the Commission do not mutually agree to arbitration, the sole forum to resolve the dispute is State court.

The cost of arbitration shall be borne by the awardee and Commission as follows:

a. The AAA's administrative fees shall be borne equally by the parties.

b. The expense of a stenographer shall be borne by the party requesting a stenographic record.

c. Witness expenses for either side shall be paid by the party producing the witness.

d. Each party shall bear the cost of its own travel expenses.

e. All other expenses shall be borne equally by the parties, unless the arbitrator apportions or assesses the expenses otherwise as part of his or her award.

Glossary of Terms

Aggregator — an entity responsible for planning, scheduling, accounting, billing, and settlement for energy deliveries for portfolios of sellers and/or buyers.

Appropriation — consistent with Water Code Section 1201, the right to use a specified quantity of water from any surface streams or other surface bodies of water, or from any subterranean streams flowing through known and definite channels.

Annual procurement target — the quantity of eligible renewable resources that a retail seller must procure within a particular year to reach the target of 20 percent of its retail sales procured from eligible energy resources no later than December 31, 2017.

Baseline — refers to the quantity of eligible renewable resources procured in 2001. For purposes of the baseline, "procurement" includes power sold to an investor-owned utility's customers by the Department of Water Resources and power from a facility owned or contracted for by the investor-owned utility in accordance with Public Utilities Code Section 399.15 (a) (3) and (b)(2).

Billing month — the period of time coinciding with a calendar month in which a Registered Renewable Supplier is entitled to receive an incentive payment pursuant to these *Guidelines*.

Biomass — any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, sludge derived from organic matter, and wood and wood waste from timbering operations.

Capacity — the maximum amount of electricity that a generating unit, power facility, or utility can produce under specified conditions. Capacity is measured in kilowatts or megawatts.

Collaborative Staff — the staff at the Energy Commission and the California Public Utilities Commission who have been designated as having special status to work collaboratively and participate in confidential deliberations concerning decision-making on the implementation of the RPS.

Commercial operation — the date on which a renewable energy facility first generates power for use by the facility or any customer or for sale to any procuring retail seller. (In the event power is sold to a retail seller, this definition shall be consistent with the facility's initial power purchase contract with a retailer seller.)

Commercially available — for purposes of the Emerging Renewables Program, any complete generating system that is based on a designated emerging technology and is available for immediate purchase under typical business terms and deliverable within a reasonable period of time.

Community choice aggregator — as defined in Public Utilities Code Section 331.1 refers to any of the following entities, if that entity is not within the jurisdiction of a local publicly owned electric utility that provided electrical service as of January 1, 2003: any city, county, or city and

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county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a communitywide electricity buyers' program or any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency established under Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code.

Competitive transition charge (CTC) — a charge authorized by the California Public Utilities Commission that is imposed on investor-owned utility (IOU) ratepayers (or customers that receive electricity distribution services from the IOU) to recover the costs of utility investments made on behalf of their former customers. The CTC is to be collected in a competitively neutral manner that does not increase rates for any customer class solely due to the existence of transition costs. [Public Utilities Code Section 367]

Conventional power source — Public Utilities Code Section 2805 defines a "conventional power source" as power derived from nuclear energy, the operation of a hydropower facility greater than 30 megawatts, or the combustion of fossil fuels with the exception of cogeneration.

Digester gas — gas from the anaerobic digestion of organic wastes.

Distributed generation — small-scale electricity generation facilities sited in or close to a load center or at a customer's site.

Diversion — consistent with Water Code Section 5100(b), the taking of water by gravity or pumping from a surface stream or subterranean stream flowing through a known and definite channel, or other body of surface water, into a canal, pipeline or other conduit, and includes impoundment of water in a reservoir.

Electric service provider — as defined in Public Utilities Code Section 218.3 refers an entity that offers electrical service to customers within the service territory of an electrical corporation but does not include an entity that offers electrical service solely to service customer load consistent with Public Utilities Code Section 218, Subdivision (b) and does not include an electrical corporation or a public agency that offers electrical service to residential and small commercial customers within its jurisdiction, or within the service territory of a local publicly owned electric utility. Electric service providers include the unregulated affiliates and subsidiaries of an electrical corporation.

Electrical corporations — Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison Company, PacifiCorp, Sierra Pacific Power, Southern California Water Company (doing business as Bear Valley Electric Service), or other electrical corporations as defined by Public Utilities Code Section 218. Also referred to as "investor-owned utilities."

Emerging renewable technology — technology that uses a renewable power source, such as solar or wind energy, to generate electricity, and that has emerged beyond the research and development phase, is commercially available, and has significant commercial potential as determined by the Energy Commission. Emerging renewable technologies include photovoltaic, solar thermal electric, fuel cells using a renewable fuel, and small wind turbine technology no greater than 50 kilowatts in size.

End-use customer (end-user) — a residential, commercial, agricultural, or industrial electric customer who buys electricity to be consumed as a final product (not for resale).

Existing long-term contract — a power purchase contract entered into with an IOU prior to September 26, 1996, that provides long-term fixed energy and/or capacity payments.

Facility — see “project.”

Fixed energy payments — payments to a generator for energy delivered under a power purchase contract, which are based on a price per unit measure of electricity that was known or ascertainable at the time the contract was entered into. (Fixed energy payments cannot be based on market conditions, such as short-run avoided costs, since these conditions were not known or ascertainable at the time the power purchase contract was entered into).

Fossil fuel — fuel comprised of hydrocarbon constituents, including coal, petroleum, or natural gas, occurring in and extracted from underground deposits, and mixtures or byproducts of these hydrocarbon constituents.

Fuel cell — an advanced energy conversion device that combines hydrogen-bearing fuels with airborne oxygen in an electrochemical reaction to produce electricity very efficiently and with minimal environmental impact.

Full-scale — for purposes of the Emerging Renewable Program, refers to scale or size equal or comparable to the scale at which commercially available generating systems are being sold or are expected to be sold.

Geothermal — natural heat from within the earth, captured for production of electric power, space heating, or industrial steam.

Grid — the electrical transmission and distribution system linking power plants to customers through high power transmission line service.

Hydroelectric — a technology that produces electricity by using falling water to turn a turbine generator, referred to as hydro. See also “small hydro.”

Incremental geothermal — pursuant to Public Utilities Code Section 399.12 (a)(2), incremental geothermal refers to the electricity that can be produced from existing geothermal resource and is eligible to be counted toward an utility’s required additional procurement rather than its baseline.

In-state renewable electricity generation facility — as defined in Public Resources Code Section 25741(a).

Investor-Owned Utility (IOU) — synonymous with “electrical corporations” as defined herein. For purposes of the *Existing Renewable Facilities Program Guidebook* and the *Emerging Renewables Program Guidebook*, refers collectively to Pacific Gas & Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Water Company (doing business as Bear Valley Electric Service); the four electrical corporations whose ratepayers are subject to a surcharge for the purpose of funding various public goods programs, including the Energy Commission’s Renewable Energy Program.

For purposes of the *New Renewable Facilities Program Guidebook* and the *Renewables Portfolio Standard Eligibility Guidebook*, refers collectively to Pacific Gas & Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, PacifiCorp, and Sierra Pacific Power.

Kilowatt (kW) — one thousand watts. A unit of measure for the amount of electricity needed to operate given equipment. A typical home using central air conditioning and other equipment might have a demand of 4-6 kW on a hot summer afternoon.

Kilowatt hour (kWh) — the most commonly-used unit of measure telling the amount of electricity consumed over time. It means one kilowatt of electricity supplied for one hour. A typical California household consumes about 500 kWh in an average month.

Landfill gas (LFG) — gas produced by the breakdown of organic matter in a landfill (composed primarily of methane and carbon dioxide) or the technology that uses this gas to produce power.

Local publicly owned electric utility — as defined in Public Utilities Code Section 9604, Subdivision (d), and which includes a municipal utility district, a public utility district, an irrigation district, or a joint powers authority made up of one or more of these entities.

Market price referent — refers to the cost of a non-renewable product used as a comparison to renewable products that are needed to satisfy a retail seller's RPS obligation pursuant to Public Utilities Code Section 399.15 (c). Further, pursuant to Section 399.14 (f), procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable resources, at or below the market price determined by the California Public Utilities Commission pursuant to Subdivision (c) of Section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates.

Marketer — an agent for generation projects who markets power on behalf of the generator. The marketer may also arrange transmission, firming, or other ancillary services as needed. Though a marketer may perform many of the same functions as a broker, a marketer represents the generator while a broker acts as a middleman.

Megawatt (MW) — one thousand kilowatts. One megawatt is about the amount of power to meet the peak demand of a large hotel.

Megawatt hour (mWh) — a unit of measure describing the amount of electricity consumed over time. It means one megawatt of electricity supplied for one hour. Two typical California households consume about a combined total of 1 mWh in an average month, one household consumes about 0.5 mWh.

Metered — the independent measurement with a standard meter of the electricity generated by a project or facility.

Municipal solid waste (MSW) —solid waste as defined in Public Resources Code Section 40191.

Municipal utility — a local publicly owned (customer-owned) electric utility that owns or operates electric facilities subject to the jurisdiction of a municipality, as opposed to the California Public Utilities Commission.

Ocean thermal — refers to experimental technology that uses the temperature differences between deep and surface ocean water to produce electricity.

Ocean wave — refers to an experimental technology that uses ocean waves to produce electricity.

On-site generation — any electricity that is generated and used to serve load on that same site.

Owned by electrical corporations or local publicly owned electric utilities — for purposes of the Emerging Renewable Program, any generating systems purchased, owned, and operated by electrical corporations or local publicly owned electric utilities and, if installed on a customer's premises, the power produced by such systems does not offset the power consumed by the customer or otherwise directly benefit the customer. Systems purchased by electrical corporations or local publicly owned electric utilities and that, in turn, are leased or sold to customers or, if installed on a customer's premises, offset the customer's electricity consumption and are operated to the benefit of the customer as if owned by the customer are not considered to be owned by such electrical corporations or local publicly owned electric utilities for the purposes of the Emerging Renewables Program.

PG&E — Pacific Gas & Electric Company

Photovoltaic (PV) — a technology that uses a semiconductor to convert sunlight directly into electricity.

Placed in service — for purposes of the Emerging Renewables Program, refers to a generating system that has been installed, is operational, and capable of producing electricity.

Power purchase contract — an agreement for the purchase of electrical energy and/or capacity, and that may be structured to provide payments based on both fixed and/or variable factors.

Procurement — for the purposes of Public Utilities Code Section 399.14 (g), refers to a utility acquiring the renewable output of electric generation facilities that the utility owns or for which it has contracted.

Project — for purposes of the New Renewable Facilities Program, refers to a group of one or more pieces of generating equipment, and ancillary equipment necessary to attach to the transmission grid that is unequivocally separable from any other generating equipment or components. Two or more sets of generating equipment that are contiguous or that share common control or maintenance facilities and schedules and are located within a one-mile radius shall constitute a single project.

For purposes of the Emerging Renewables Program, "project" refers to all otherwise eligible generating systems installed during the term of this program at one physical location and serving the electrical needs of all real and personal property at this location, as evidenced by the electric utility meter for this location.

For purposes of the Existing Renewable Facilities Program, "project" refers to a group of one or more pieces of electrical generating equipment, and ancillary equipment necessary to attach to the transmission grid, that is unequivocally separable from any other electrical generating equipment or components. Two or more sets of electrical generating equipment that are contiguous or that share common control or maintenance facilities and schedules and are located within a one-mile radius shall constitute a single project.

PTC — PVUSA Test Conditions (PTC), 1,000 watts/square meter plane of array (POA) irradiance for flat-plate photovoltaic modules or 850 watts/ square meter direct normal irradiance for concentrating photovoltaic or solar thermal systems with 20 degrees Centigrade ambient air temperature and 1 meter/second wind speed.

Public Goods Charge (PGC) — a surcharge applied to the electric bills of IOU ratepayers used to support energy efficiency, public interest research, development and demonstration, and low-income and renewable energy programs and collected pursuant to Public Utilities Code Section 399.

Public information — any information in the Commission's possession that is not subject to a request or determination of confidential designation pursuant to Title 20 of the California Code of Regulations, Sections 2505, et seq., and may be disclosed pursuant to the California Public Records Act (Government Code Sections 6250, et seq.) and the Information Practices Act (Civil Code Section 1798, et seq.).

Pumped hydro — an energy storage technology consisting of two water reservoirs separated vertically; during off-peak hours, water is pumped from the lower reservoir to the upper reservoir, allowing the off-peak electrical energy to be stored indefinitely as gravitational energy in the upper reservoir. During peak hours, water from the upper reservoir may be released and passed through hydraulic turbines to generate electricity as needed.

Qualifying facility — a qualifying small power production facility eligible for certification pursuant to Section 292.207 of Title 18 of the Code of Federal Regulations.

Renewable — a power source other than a conventional power source within the meaning of Section 2805 of the Public Utilities Code. Section 2805 states: " 'Conventional power source' means power derived from nuclear energy or the operation of a hydropower facility greater than 30 megawatts or the combustion of fossil fuels, unless cogeneration technology, as defined in Section 25134 of the Public Resources Code, is employed in the production of such power."

Renewable energy credits (RECs) — generally represent the non-energy attributes (such as environmental, economic, and social impacts) associated with the generation of renewable electricity; the attributes of a given unit of renewable generation, separated from the underlying electrical energy. Green tag, green ticket, and tradable renewable certificate (TRC) are often used synonymously with REC. The CPUC adopted an initial definition for RECs as part of its decision outlining RPS standard contract terms and conditions. For more information, please refer to Decision 04-06-014, Opinion Adopting Standard Contract Terms and Conditions, dated June 9, 2004, Rulemaking 04-04-026.

Renewables Portfolio Standard (RPS) — for the purposes of this document, the term refers to California's Renewables Portfolio Standard pursuant to SB 1078. Public Utilities Code Section 399.12, Subdivision (d) provides that, "'renewables portfolio standard' means the specified percentage of electricity generated by eligible renewable energy resources that a retail seller is required to procure….". Under the RPS, an electrical corporation must increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible energy resources no later than December 31, 2017.

Repower(ed) — generically refers to replacing a significant portion of the generating equipment at an existing facility.

Retail seller — an entity engaged in the retail sale of electricity to end-use customers as defined in Public Utilities Code Section 399.12, Subdivision (c). Retail sellers include electrical corporations, community choice aggregators, and electric service providers. Retail sellers do not include local publicly owned electric utilities (commonly referred to as municipal utilities), entities employing cogeneration technology or producing power consistent with Public Utilities Code Section 218(b), or the Department of Water Resources acting within it capacity pursuant to Division 27 of Water Code (commencing with Section 80000).

RPS Collaborative Workplan — a written description of how the Energy Commission and the California Public Utilities Commission will work together to implement the RPS, including laying out a three-phased schedule to categorize and sequentially address issues as appropriate. The designated collaborative staff of the Energy Commission and the California Public Utilities Commission developed the RPS Collaborative Workplan.

SB 90 funding award — funding awarded under the New Renewable Resources Account under Notice of Auction 500-97-506, Notice of Auction 500-00-504, or Notice of Auction 6-01-3.

SCE — Southern California Edison Company

SDG&E — San Diego Gas & Electric Company

Self-generation — generation of electricity used on-site and not sold into the main power grid.

Sewer gas — gas produced by the anaerobic decomposition of sewage.

Small hydro — a facility employing one or more hydroelectric turbine generators, the sum capacity of which does not exceed 30 megawatts. Pursuant to Public Utilities Code Section 399.12, procurement from a small hydro facility as of January 1, 2003, is eligible only for purposes of establishing the baseline of an electrical corporation. A new small hydro facility is not eligible for the RPS if it will require a new or increased appropriation or diversion of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code. Pursuant to Public Utilities Code Section 383.5 (d) (2) (C) (iv) as amended by Public Resources Code Section 25743(b)(3)(D), a new small hydro facility must not require a new or increased appropriation of water under Part 2 (commencing with Section 1200) of Division 2 of the Water Code to be eligible for supplemental energy payments.

Solar thermal electric — the conversion of sunlight to heat and its concentration and use to power a generator to produce electricity.

Solid-fuel biomass — a biomass technology that uses solid fuel, such wood, agricultural waste, and other organic material that may be burned to produce electricity.

Supplemental Energy Payments (SEP) — incentive payments from the Energy Commission to eligible renewable generators for the costs above the market referent of energy procured to meet the RPS, pursuant to Public Utilities Code Section 399.15 (a) (2). Any indirect costs from procuring eligible renewable resources – such as imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades – are not eligible for SEP. The cost of the contract bids for renewable resources that are selected by the utilities to meet their RPS obligation will be compared to the cost of a comparable nonrenewable product, the market price referent. Costs for renewable products that exceed the referent, excluding indirect costs noted above, will be covered by the SEP, subject to availability of Public Goods Charge (PGC) funds, pursuant to Public Utilities Code Section 399.15 (a) (4). The Energy Commission will distribute the SEP directly to the renewable generator through its New Renewable Facilities Program.

Tidal current power — energy obtained by using the motion of the tides to run water turbines that drive electric generators.

Transmission system — an interconnected group of electric transmission lines and associated equipment to move or transfer electric energy in bulk between points of supply and consumption.

WECC interconnection — the substation where radial lines from a given power plant interconnect to the WECC-controlled transmission system.

Western Electricity Coordinating Council (WECC) — formed on April 18, 2002, by the merger of the Western Systems Coordinating Council (WSCC), Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). WECC is responsible for coordinating and promoting electric system reliability, assuring open and non-discriminatory transmission access among members, and providing a forum for resolving transmission access disputes.

Wind power— energy from wind converted into mechanical energy and then electricity.

RENEWABLE
ENERGY
PROGRAM

**CALIFORNIA
ENERGY
COMMISSION**

RENEWABLES PORTFOLIO STANDARD ELIGIBILITY GUIDEBOOK

APRIL 2006
CEC-300-2006-007-F

Arnold Schwarzenegger, *Governor*

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This guidebook was formally adopted by the Energy Commission on April 21, 2004, pursuant to Public Utilities Code Section (PUC) 383.5, Subdivision (h), and subsequently revised pursuant to this authority and Public Resources Code Section 25747, Subdivision (a), on May 19, 2004, August 11, 2004, May 21, 2005, and April 26, 2006 pursuant to PUC Section 383.5 Subdivision (h), paragraph (1) and Public Resources Code (PRC) Section 25747 Subdivision (a), which authorize the Energy Commission to adopt guidelines to govern its funding programs and portions of the Renewables Portfolio Standard under Senate Bill 1038 and Senate Bill 1078. These guidelines are exempt from the formal rulemaking requirements of the Administrative Procedures Act.

The requirements in this guidebook are based on applicable law, the *Renewables Portfolio Standard Decision on Phase 1 Implementation Issues* (publication number 500-03-023F), the *Renewables Portfolio Standard Decision on Phase 2 Implementation Issues* (publication number 500-03-049F), staff analysis, advice from the Energy Commission's technical support contractor, and public input.

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Introduction

On April 21, 2004, the California Energy Commission (Energy Commission) adopted this *Renewable Portfolio Standard Eligibility Guidebook (Guidebook)*, pursuant to Senate Bill 1038 (Sher) Chapter 515, Statutes of 2002, Senate Bill 1078 (Sher) Chapter 516, Statutes of 2002, Senate Bill 67 (Bowen), Chapter 731, Statutes of 2003, and Senate Bill 183 (Sher)Chapter 666, Statutes of 2003. The pertinent provisions of these laws are codified in Public Utilities Code Sections 381 and 399.11 through 399.16, and Public Resources Code (PRC) Sections 25740 through 25751.[1]

This *Guidebook* describes the requirements and process for certifying eligible renewable energy resources for California's Renewables Portfolio Standard (RPS) and supplemental energy payments (SEP). This *Guidebook* also describes how the Energy Commission will track and verify compliance with the RPS using an interim generation tracking process.

This *Guidebook* establishes efficient and effective processes to encourage participation in California's RPS and assure program credibility to benefit stakeholders, regulators, and consumers. Although this *Guidebook* addresses the Energy Commission's role in implementing the RPS, the Energy Commission recognizes that the California Public Utilities Commission (CPUC) also has a key RPS implementation role.

SB 1078 establishes the RPS in California and sets a goal for California retail electric sellers to increase their sales of renewable electricity by at least 1 percent per year, until 20 percent of electricity retail sales will be served with renewable resources by 2017. Pursuant to the *Energy Action Plan*, *2003 Integrated Energy Policy Report*, the *2004 Integrated Energy Policy Report Update*, and the *2005 Integrated Energy Policy Report*, the state's energy agencies are working to accelerate the RPS to achieve the 20 percent target by 2010.

The law also establishes specific roles for the Energy Commission and the CPUC and directs the two agencies to work together to implement the RPS. Although the law assigns lead roles for specific implementation efforts to each agency, the roles of the two agencies are interrelated. The Energy Commission is responsible for certifying eligible renewable resources and tracking the procurement of such resources to ensure compliance with the RPS. The CPUC is responsible for establishing targets for the amount of eligible renewable resources the investor-owned utilities (IOUs) must procure to comply with the RPS and for verifying that the IOUs comply with the requirements.

In February 2003, the CPUC issued a ruling formalizing collaboration on RPS issues, and in March 2003 the Energy Commission adopted a reciprocal agreement. The Energy Commission subsequently developed this *Guidebook* collaboratively with the CPUC.

[1] The pertinent provisions of SB 1038 were formerly codified in Public Utilities Code sections 383.5 and 445, but are now codified in Public Resources Code sections 25740 through 25751 as a result of SB 183.

While this *Guidebook* reflects current requirements, the Energy Commission recognizes that it may need to periodically revise program guidelines to reflect market and regulatory developments as well as incorporate the lessons learned from experience implementing the RPS.

Related Reports

This *Guidebook* is one of several guidebooks the Energy Commission has adopted to implement and administer the various program elements of its Renewable Energy Program. The Energy Commission's *Overall Program Guidebook for the Renewable Energy Program (Overall Program Guidebook)* describes how the Renewable Energy Program will be administered and includes information on requirements that apply to all program elements. To qualify for certification as a renewable energy resource eligible for RPS and SEPs, an applicant must satisfy the requirements specified in this *Renewables Portfolio Standard Eligibility Guidebook* and the *Overall Program Guidebook*.

To receive SEPs, applicants must also satisfy the requirements specified in the Energy Commission's *New Renewable Facilities Program Guidebook*. Parties interested in receiving SEPs may refer to the *New Renewable Facilities Program Guidebook* for information on how to apply for and receive SEPs. Please note that the Energy Commission also provides production incentive payments to eligible existing renewable resources that are not eligible for SEPs but may be eligible for the RPS. For more information, refer to the *Existing Renewable Facilities Program Guidebook*.

For general information on the process of creating, appealing, and implementing RPS guidelines, please refer to the *Overall Program Guidebook*. Program guidebooks are available online at the Energy Commission's Web site at <www.energy.ca.gov>.

Outstanding Issues

This *Guidebook* addresses only RPS certification and verification requirements as they apply to Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), Southern California Edison Company (SCE), PacifiCorp and Sierra Pacific Power. It does not address these requirements as they apply to Electric Service Providers (ESPs) or Community Choice Aggregators (CCAs). The Energy Commission intends to collaborate with the CPUC to address RPS requirements for ESPs and CCAs.

There are several ongoing issues that could affect these guidelines. The Energy Commission will continue to address these issues collaboratively with the CPUC:

- Renewable Energy Credit/Certificate (REC) trading:

  RECs generally represent the non-energy attributes associated with energy production. The CPUC adopted an initial definition for RECs as part of its decision outlining RPS standard contract terms and conditions. For more information, please refer to Decision 04-06-014, *Opinion Adopting Standard Contract Terms and Conditions,* dated June 9, 2004, Rulemaking 04-04-026. Consistent with CPUC Decision 03-06-071 (June 19, 2003), generation currently must be bundled with the associated RECs to qualify for the RPS. Any action by the Energy Commission and CPUC to allow RPS eligibility for RECs that are traded separately from energy would require further deliberations and public input.

  RECs associated with electricity generation should be transferred to the utility when the utility procures the RECs and electricity. A REC procured by a utility and counted toward the utility's RPS obligation should be retired and not allowed to be resold.

- Determining how customer-side renewable distributed generation resources fit into the RPS:

  The law includes solar energy as an eligible resource for the RPS, but several issues need to be clarified to determine how best to include distributed photovoltaic resources, as well as other forms of customer-side renewable distributed generation. This *Guidebook* describes these issues in the section on eligibility requirements.

- Defining fuel specific issues:

  The Energy Commission anticipates that new issues may arise that will need to be addressed as implementation begins. The Energy Commission recognizes that some parties may be interested in using hydrogen fuel to generate electricity but recommends deferring the development of implementation guidelines for such facilities. The Energy Commission recommends, however, that only eligible RPS fuel stock may be used to produce hydrogen for use at an RPS-eligible facility.

- Hybrid technologies:

  For new and repowered facilities not certified as Qualifying Small Power Production Facilities under the federal Public Utilities Regulatory Policies Act that operate on co-fired fuels or a mix of fuels that includes fossil fuel, the Energy Commission will allow the renewable portion of the electricity production to qualify for the RPS once an appropriate tracking system for such electricity production is developed. Facilities that were operational before 2002 or that were or will be developed and awarded power purchase contracts as result of an Interim RPS solicitation approved by the CPUC pursuant to Decision 02-08-071 and Decision 02-10-062 may use up to 25 percent fossil fuel annually (on a total energy input basis) and count all the electricity generated as renewable. If a facility is a Qualifying Small Power Production Facility, then all of the electricity production can qualify for the RPS.

Guidebook Organization

This *Guidebook* is organized as follows:

1. Introduction
2. Eligibility Requirements
3. Certification Process
4. Generation Tracking System
5. Forms
6. List of Acronyms
7. Summary Table of Reporting Requirements

Section 2 covers eligibility requirements for generators interested in producing electricity that can be procured by retail sellers to comply with the RPS. For the purposes of this *Guidebook*, “retail sellers” refers to California’s three largest IOUs, PG&E, SCE, and SDG&E, and to PacifiCorp and Sierra Pacific Power (electrical corporations with 60,000 or fewer customer accounts in California that also serve retail end-use customers outside California pursuant to Public Utilities Code 399.17). These particular retail sellers are also referred to as “electrical corporations” as defined in the glossary in the *Overall Program Guidebook.*

Section 2 also addresses eligibility requirements for generators interested in producing electricity that can be procured to comply with the RPS and that is eligible to receive SEPs.

Section 3 discusses the Energy Commission’s certification process, including the following:

- Pre-certification application process for developers of renewable facilities that are not yet online but who are seeking a preliminary determination that their facility will be eligible for the RPS or SEPs.

- Certification application process for generators with renewable facilities that are online who are interested in serving energy to meet an RPS obligation or to serve energy that is eligible for SEPs.

- Registration application process for facilities whose owners are interested in registering with the Energy Commission that they are a renewable generator but are not eligible for the RPS or for SEPs.

Section 4 discusses the data submission requirements for a generation tracking system that will be used to verify retail sellers’ compliance with the RPS and to verify that generation is counted only once in California or any other state.

Eligibility Requirements

This section describes eligibility requirements for the RPS, for SEPs, and for out-of-state facilities that seek RPS or SEP eligibility. In general, a facility is eligible if it uses an eligible renewable resource or fuel, satisfies resource-specific criteria, and is either located within the state or satisfies applicable requirements for out-of-state facilities. If a retail seller owns a renewable facility, the facility may be RPS-eligible, but is not eligible for SEPs.

RPS Targets

The CPUC sets annual procurement targets (APTs) for the amount of RPS-eligible energy each retail seller must procure. Public Utilities Code Section 399.15 (b)(1) requires the retail sellers to annually increase their renewable procurement by at least 1 percent of retail sales per year to serve 20 percent of their retail sales with RPS-eligible energy. The CPUC sets an “incremental procurement target” (IPT) for this 1 percent or greater annual increase and sets the APT for total annual RPS-eligible procurement needed to meet the 20 percent goal. Procurement eligible towards the APT includes “baseline” procurement and “incremental” procurement as defined by the CPUC.[2]

When a retail seller procures energy and the associated RECs from a facility that is eligible for the RPS (or eligible for the RPS and SEPs), then the procurement may count towards the retail seller’s APT, assuming the transaction meets applicable delivery requirements and other eligibility criteria. The Energy Commission verifies RPS procurement, and the CPUC determines whether or not a retail seller is in compliance with its procurement targets, consistent with CPUC rules for flexible compliance.[3]

In accounting for RPS-eligible procurement, it is necessary to categorize specific purchases as incremental procurement or baseline procurement as discussed in the section on *Generation Tracking System*. To determine if procurement is baseline or may qualify towards the IPT depends on statutory restrictions and implementation of CPUC compliance rules.

1. Static information: The characteristics of the renewable energy facility determine if it may be accounted for as incremental procurement or if it is restricted to baseline and adjusting the baseline. The following resources are restricted by statute to count only towards baseline or adjusting the baseline; generation cannot count towards the incremental procurement target:
    a) Geothermal facilities that began commercial operations before September 26, 1996.

[2] The CPUC is refining its definitions and compliance rules through Rulemaking 06-02-012 and 04-06-026 and its successor.
[3] Public Utilities Code section 399.14 (a)(2)(C).

b) Small hydroelectric facilities that began commercial operations before September 12, 2002 and were owned, or whose generation was procured, by a utility as of this date.
c) Eligible municipal solid waste combustion facilities located in Stanislaus County that began commercial operations before September 26, 1996.

2. Dynamic information: The amount of time the retail seller has been procuring energy from the RPS-eligible facility may be the determining factor in accounting for procurement as baseline or incremental, as defined by CPUC compliance rules.

The Energy Commission's RPS certification identifies if a facility is RPS-eligible, or RPS and SEP-eligible. In the event that the generation from a facility is statutorily restricted to baseline, the Energy Commission will note this on the facility's RPS-certification notice.

Eligibility for the Renewables Portfolio Standard

The Energy Commission has determined that it is appropriate to define eligible renewable energy resources by renewable resource or fuel rather than by the specific technology used. For certain eligible renewable energy resources, however, the law contains specific requirements, and the Energy Commission must consider both the resource or fuel and the technology to determine RPS eligibility.

To qualify as eligible for California's RPS, a generation facility must use one or more of the following renewable resources or fuels (see the *Overall Program Guidebook* for full definitions):

- Biomass
- Biodiesel
- Fuel cells using renewable fuels
- Digester gas
- Geothermal
- Landfill gas
- Municipal solid waste
- Ocean wave, ocean thermal, and tidal current
- Photovoltaic
- Small hydroelectric (30 megawatts or less)
- Solar thermal
- Wind

Table 1 on the following page summarizes the requirements for a facility to qualify for the RPS and be eligible for SEPs. The table does not reflect any additional requirements that may apply to facilities located out-of-state.

Table 1: Renewables Portfolio Standard Eligibility Requirements for Renewable Electricity Facilities

Resource Used	RPS Eligibility	RPS and SEP Eligibility
Biomass	Yes	Yes, if New or Repowered AND IF meets fuel use specifications. See notes below. [1,2,3]
Biodiesel	Yes, subject to RESTRICTION [4]	Yes, if New or Repowered
Digester Gas	Yes	Yes, if New or Repowered
Fuel Cells	Yes, if a renewable fuel is used.	Yes, if New or Repowered
Geothermal	Yes, RESTRICTED to adjusting the baseline if the facility was originally operating before September 26, 1996.	Yes, if New or Repowered
Incremental Geothermal	Yes, regardless of original operation date, if certified as Incremental Geothermal Generation.[5]	Yes, if New or Repowered
Hydroelectric	Yes, RESTRICTED to facilities 30 MW or less. RESTRICTED if it was owned by an IOU as of September 12, 2002, or if the generation was procured by an IOU as of September 12, 2002, then the generation may be counted only towards adjusting an IOUs RPS baseline. Facilities originally operational AFTER September 12, 2002 must meet SEP requirements.	Yes, if 30 MW or less, New or Repowered AND IF it does NOT require a new or increased appropriation or diversion of water.
Landfill Gas	Yes	Yes, if New or Repowered
MSW Combustion	Yes, but generation from MSW combustion is RESTRICTED to adjusting the baseline AND is only eligible IF the electric generation facility is located wholly within Stanislaus County and began operating before September 26, 1996.	Combusted MSW is NOT SEP eligible.
MSW Conversion	Yes, if it meets SEP requirements.	Yes, if New or Repowered AND IF it meets the definition "solid waste conversion." [6]
Photovoltaic	Yes [7]	Yes, if New or Repowered
Solar Thermal	Yes	Yes, if New or Repowered
Tidal Current	Yes	Yes, if New or Repowered
Ocean Wave	Yes	Yes, if New or Repowered
Ocean Thermal	Yes	Yes, if New or Repowered
Wind	Yes	Yes, if New or Repowered

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Notes to Table 1

[1] **New:** Resources that first begin commercial operation or are repowered on or after January 1, 2002, and meet the other eligibility requirements of Public Resources Code Section 25743, including Subdivision (f), are eligible for SEPs.

[2] **Repowered:** Repowered generators will be eligible for SEPs if they replace their prime generating equipment and use tax records, or an acceptable alternative, to demonstrate that they have made capital investments in the facility equal to “at least 80 percent of the value of the repowered facility,” as required by Public Resources Code Section 25743, Subdivision (c). For generators with existing long-term contracts originally entered into before September 26, 1996, only generation above and beyond what is already under contract, as determined in accordance with Public Utilities Code Section 399.6, Subdivision (c), paragraph (1)(C), may compete to satisfy the RPS obligation of a retail seller and be eligible for SEPs.

[3] **New or Repowered Biomass:** New or repowered biomass facilities seeking SEP eligibility must certify to the satisfaction of the Energy Commission that fuel utilization is limited to the following pursuant to Public Resources Code Section 25743, Subdivision (f):

(A) Agricultural crops and agricultural wastes and residues.

(B) Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.

(C) Wood and wood wastes that meet all of the following requirements:

(i) Have been harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973, Chapter 8 (commencing with Section 4511 of Part 2 of Division 4 of the Public Resources Code).

(ii) Have been harvested for the purpose of forest fire fuel reduction or forest stand improvement.

(iii) Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by those agencies.

[4] **Biodiesel:** Electricity produced from biodiesel is eligible for the RPS IF the biodiesel is derived either from 1) a biomass feedstock such as "agricultural crops and agricultural wastes and residues” or as a result of an eligible "solid waste conversion" process (see Municipal Solid Waste Conversion) and 2) if it meets the requirements for hybrid technologies, as appropriate. Electricity generated from biodiesel derived from biomass fuel or as a result of a solid waste conversion process may also quality for SEPs if the SEP requirements for biomass or solid waste conversion are satisfied.

[5] **Incremental Geothermal:** Incremental Geothermal Generation is defined as resulting from eligible capital expenditures that reflect:

1) a substantial capital project, resulting in replacement of generating equipment or increase in steam converted to generation at a facility;
2) a sustainable impact on the underlying reservoir use; that is, a project does not cause an increase in the decline rate of the reservoir; and
3) a capital project completion date after September 26, 1996;
4) AND IF the incremental output was not sold to a retail seller under contract entered into prior to September 26, 1996.

[6] **Municipal Solid Waste Conversion:** A technology using a noncombustion thermal process to convert solid waste to a clean burning fuel for the purpose of generating electricity that meets all of the following criteria:

(i)The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.
(ii) The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code.
(iii) The technology produces no discharges to surface or groundwaters of the state.
(iv) The technology produces no hazardous wastes.
(v) To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream before the conversion process, and the owner or operator of the facility certifies that those materials will be recycled or composted.
(vi) The facility at which the technology is used complies with all applicable laws, regulations, and ordinances.
(vii) The technology meets any other conditions established by the Energy Commission.
(viii) The facility certifies that any local agency sending solid waste to the facility diverted at least 30 percent of all solid waste it collects through solid waste reduction, recycling and composting. To qualify for SEPs, the facility must certify that any local agency sending solid waste to the facility is in compliance with Division 30 of the Public Resources Code (commencing with Section 40000), and has reduced, recycled, or composted solid waste to the maximum extent feasible, and shall have been found by the California Integrated Waste Management Board to have diverted at least 30 percent of all solid waste through source reduction, recycling, and composting.

[7] **Photovoltaic**: The CPUC is currently deliberating how to achieve the RPS eligibility of distributed generation, particularly solar.

Please note that, in some cases, the criteria for RPS-eligibility depends on the date that commercial operations commence. If a facility shuts down and later recommences operations, it is subject to the eligibility requirements that apply to the original operation date. If a facility is repowered as provided in this *Guidebook*, its commercial operation date corresponds to its repowering date, and the facility may then qualify for SEPs.

Facilities using biomass, municipal solid waste, geothermal, hydropower, or biodiesel are subject to the additional resource or fuel-specific requirements described below. Also addressed below are requirements for photovoltaic facilities, as well as those for hybrid facilities that use a mix of fuels, including those that operate in part by using fossil fuels.

Resource or Fuel-Specific Eligibility Requirements

The following requirements apply to generators seeking RPS certification or RPS and SEP certification for a facility that operates on biodiesel, biomass, geothermal or incremental geothermal, hydropower, municipal solid waste (MSW), photovoltaics, or a mix of fuels in a “hybrid technology.”

Biodiesel: The electricity produced from combusting biodiesel is eligible for the RPS to the extent that the biodiesel is derived from the following:

1. A biomass feedstock such as “agricultural crops and agricultural wastes and residues,” consistent with the requirements for hybrid technologies (refer to the guidelines for biomass eligibility and for hybrid technologies below), or

2. An eligible “solid waste conversion” process using MSW (refer to the MSW eligibility guidelines below), consistent with applicable requirements for hybrid technologies.

In addition, the facility must be located in California or satisfy the out-of-state eligibility requirements discussed later in this *Guidebook*.

Biomass: The eligibility requirements for biomass facilities vary depending on the date the facility first commences “commercial operation” as defined in the *Overall Program Guidebook*.

Pre-January 1, 2002: The generation from a biomass facility that commenced commercial operations prior to January 1, 2002, is eligible for the California RPS if the facility is located in-state or satisfies the out-of-state eligibility requirements.

Post-January 1, 2002: The generation from a biomass facility that commences commercial operations or is repowered on or after January 1, 2002, is eligible for the RPS to the extent that the facility is located in-state or satisfies the out-of-state eligibility requirements. The generation is eligible for SEPs if the facility operator certifies to the satisfaction of the Energy Commission that the fuel used is limited to the following:

1. Agricultural crops and agricultural wastes and residues.

2. Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.

3. Wood and wood wastes that meet all of the following requirements:

   a. Have been harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Chapter 8 (commencing with Section 4511) of Part 2 of Division 4 of the Public Resources Code).

   b. Have been harvested for the purpose of forest fire fuel reduction or forest stand improvement.

   c. Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by these agencies.

When applying for pre-certification or certification, biomass facility operators that are repowering or commencing commercial operations on or after January 1, 2002, and are seeking SEP eligibility must state their intent in writing to (1) procure biomass fuel supplies that meet the applicable statutory requirements noted above, and (2) comply with annual reporting requirements. After receiving certification and commencing commercial operations, facility operators must submit an annual written attestation from the facility's fuel supplier(s) stating that the biomass fuel delivered to the facility meets the applicable statutory requirements.

This annual attestation must be submitted regardless of whether the facility operator intends to compete for SEPs. The attestation is due to the Energy Commission on February 15th of each year and should apply to fuel use for the previous calendar year. Biomass facility operators must also provide documentation upon request by the Energy Commission to verify ongoing compliance with these requirements between reporting dates.

Additional information is required annually for biomass facility operators receiving SEPs; that information is discussed in the *New Renewable Facilities Program Guidebook.*

Geothermal: The RPS eligibility of geothermal facilities varies depending on the date the facility first commences commercial operations.

- Pre-September 26, 1996: Generation from geothermal facilities that began commercial operations before September 26, 1996, is eligible for the RPS only to establish or adjust a retail seller's baseline of eligible renewable energy resources. The facility must also be located in-state or satisfy the out-of-state requirements. Generation from these facilities is not eligible for SEPs.

- September 26, 1996, to January 1, 2002: Generation from geothermal facilities that began commercial operations on or after September 26, 1996, and before January 1, 2002, is eligible for the RPS. The facility must also be located in-state or satisfy the out-of-state requirements. Generation from these facilities is not eligible for SEPs.

- Post-January 1, 2002: Generation from geothermal facilities that commence commercial operations or are repowered on or after January 1, 2002, is eligible for the RPS provided the facility is located in-state or satisfies the out-of-state requirements. Generation from these facilities is also eligible for SEPs provided it meets the eligibility requirements described in the *New Renewable Facilities Guidebook*.

Incremental Geothermal: Incremental generation from geothermal facilities is eligible for the RPS but is limited to generation resulting from eligible capital expenditures as described below. Incremental geothermal generation is eligible for SEPs to the extent that the generation meets the criteria for "new" or "repowered" in-state renewable electricity generation technology facilities described in SB 1038.

To be considered an "eligible capital expenditure," the expenditure must meet the following criteria:

1. is a substantial capital project that results in replaced generating equipment or increased steam converted to generation.

2. does not cause an increase in the decline rate of the reservoir.

3. is a capital project completed after September 26, 1996.

Examples of eligible capital expenditures at a facility are repowering or refurbishing generation equipment, or using the geothermal energy more effectively to increase generation, such as adding a binary bottoming cycle. An example of an eligible capital expenditure at a steamfield is increasing production from the steamfield through increased water injection.

Small Hydroelectric: The RPS eligibility of small hydroelectric facilities varies depending on the date the facility first commences commercial operations and whether the facility is owned, or its generation is procured by, an IOU.

- Pre-September 12, 2002: Except as noted, generation from a small hydroelectric facility that commenced commercial operations before September 12, 2002, is eligible for the RPS if the facility meets all of the following criteria:

1. The facility is 30 MW or less.

2. The facility is located in-state or satisfies the out-of-state requirements.

3. The facility was not owned by an IOU as of September 12, 2002, and its generation was not procured by an IOU as of September 12, 2002.

4. If the facility was owned by an IOU as of September 12, 2002, or its generation procured by an IOU as of September 12, 2002, its generation is eligible only for purposes of establishing or adjusting an IOU's RPS baseline. The facility's generation may not be used for meeting an IOU's incremental procurement target.

- Post-September 12, 2002: Generation from a small hydroelectric facility that commences commercial operations or is repowered on or after September 12, 2002, and is 30 MW or less is eligible for the California RPS and SEPs if the facility meets all of the following criteria:

    1. The facility is 30 MW or less.

    2. The facility is located in-state or satisfies the out-of-state requirements.

    3. The facility does not require a new or increased appropriation or diversion of water. For purposes of this limitation, the terms "appropriation" and "diversion" shall be defined as follows:

"Appropriation" shall be defined in a manner consistent with Water Code Section 1201 to mean the right to use a specified quantity of water from any surface streams or other surface bodies of water or from any subterranean streams flowing through known and definite channels.

"Diversion" shall be defined in a manner consistent with Water Code Section 5100(b) to mean the taking of water by gravity or pumping from a surface stream or subterranean stream flowing through a known and definite channel, or other body of surface water, into a canal, pipeline, or other conduit, and includes impoundment of water in a reservoir.

Hydroelectric Facilities Located within California

A new or repowered small hydroelectric facility located within California is NOT eligible for the RPS or RPS and SEPs if it requires any of the following:

1. A new or revised permit from the State Water Resources Control Board (SWRCB) for a new appropriation of water.

2. A new permit or license from the SWRCB for a new diversion of water.

3. An increase in the volume or rate of water diverted if the increase would require a new permit or license from the SWRCB.

4. An increase in the volume or rate of water diverted under an existing right, even if such an increase would not require a water right permit or license from the SWRCB.

If a new or repowered small hydroelectric project can demonstrate that it could operate without a new or increased appropriation or diversion of water, it may be eligible for the RPS and SEPs. For example, a small hydro facility that can operate by simply adding hydroelectric power generation as an authorized purpose of use to its existing SWRCB permit or license may be eligible for the RPS and SEPs if this change in use does not require a new appropriation or does not increase the volume or rate of water diverted beyond that which is allowed under that permit or license. Similarly, a water development project that has been granted a permit by the SWRCB but has not been built out and issued a license by the SWRCB may be able to use additional water as authorized under the permit to create electric energy so long as there is no change in water use relative to what the permittee would have used under the approved project.

A new or repowered small hydroelectric project located in California can qualify for the RPS and SEPs if it meets the following criteria:

1. The applicant has a permit or license to appropriate water from the SWRCB, which was issued on or before September 12, 2002.

2. The applicant can operate its proposed project under its existing SWRCB permit or license.

Hydroelectric Facilities Located Outside California

A new or repowered small hydroelectric facility located outside California is NOT eligible for the RPS or RPS and SEPs if it requires any of the following:

1. A new permit or license from any government body for a new appropriation of water.

2. A new permit or license from any government body for a new diversion of water.

3. An increase in the volume or rate of water diverted under an existing right, even if such an increase would not require a new permit or license from any government body.

If a new or repowered small hydroelectric project located outside California can demonstrate that it could operate without a new or increased appropriation or diversion of water, it may be eligible for the RPS and SEPs. For example, a small hydro facility that can operate by simply adding hydroelectric power generation as an authorized purpose of use to its existing government permit or license may be eligible for the RPS and SEPs if this change in use does not require a new appropriation or increased diversion and does not change the volume or rate of water withdrawn or released under that permit or license. A project located outside California would likely qualify for the RPS and SEPs if it meets the following criteria, as well as the out-of-state eligibility criteria specified earlier in this guidebook:

1. The applicant has a permit or license to appropriate water from the applicable governing body, which was issued on or before September 12, 2002.

2. The applicant can operate its proposed project under its existing government-issued permit or license.

The applicant is responsible for showing that its project qualifies for the RPS. Information required for small hydropower applicants is discussed in the section on certification.

The Energy Commission interprets the 30-MW size limit to apply to the total hydro project. Consequently, the facility must not exceed 30MW, including any incremental increases to the efficiency or size of the facility. For example, a 5-MW incremental addition to a 50-MW facility would not qualify for the RPS because the facility exceeds the 30-MW size limit.

Municipal Solid Waste: Applicants representing facilities using MSW fall into two categories:

1. Combustion Facilities: A facility that directly combusts MSW to produce electricity is only eligible for the RPS if it is located in Stanislaus County and was operational before September 26, 1996. Applicants for combustion facilities must submit documentation to the Energy Commission demonstrating that the facilities meet these requirements. The generation from such facilities is eligible for the RPS only to establish or adjust an IOU's baseline quantity of eligible renewable energy resources. Generation from these facilities does not qualify for SEPs.

2. Solid Waste Conversion Facilities: A facility that uses a non-combustion thermal process to convert MSW to a clean burning fuel that is then used to generate electricity is eligible for the RPS and may qualify for SEPs if it qualifies as new or repowered and is located in-state or satisfies the out-of-state requirements. Such facilities must meet all of the following criteria in accordance with Public Resources Code Section 25741(a)(3):

   a. The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.

b. The technology produces no discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code.

c. The technology produces no discharges to surface or groundwaters of the state.

d. The technology produces no hazardous wastes.

e. To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream before the conversion process, and the owner or operator of the facility certifies that those materials will be recycled or composted.

f. The facility at which the technology is used complies with all applicable laws, regulations, and ordinances.

g. The technology meets any other conditions established by the State Energy Resources Conservation and Development Commission (formal name of the Energy Commission).

h. The facility certifies that any local agency sending solid waste to the facility diverted at least 30 percent of all solid waste it collects through solid waste reduction, recycling, and composting. To qualify for SEPs, the facility must certify that any local agency sending solid waste to the facility is in compliance with Division 30 of the Public Resources Code (commencing with Section 40000), has reduced, recycled, or composted solid waste to the maximum extent feasible, and shall have been found by the California Integrated Waste Management Board to have diverted at least 30 percent of all solid waste through source reduction, recycling, and composting.

Solar Energy and Distributed Generation: Generation from facilities using solar energy is eligible for the RPS. Both central station and distributed generation facilities are eligible, but the Energy Commission has not yet determined how to include distributed generation into RPS compliance or guidelines.

Solar thermal electric central station facilities delivering electricity to the grid are relatively straightforward to integrate into RPS implementation because the generation can be readily measured and procured towards meeting RPS requirements. It is possible that a photovoltaic (PV) central station facility could also produce electricity that is eligible for the RPS with standard metering employed for central station facilities.

Distributed generation PV facilities and other distributed renewable energy technologies, however, have qualities that make them more difficult than central station facilities to integrate into RPS implementation. For example, distributed PV facilities are typically small-scale applications designed to meet on-site energy demands. In addition, generation from distributed generation PV may be metered differently than central station facilities or not metered at all. Also, as described in the *New Renewable Facilities Program Guidebook*, on-site generation is not eligible for SEPs.

Both the Energy Commission and the CPUC have roles in determining RPS implementation for distributed generation. However, the Energy Commission is deferring any decisions on how to integrate distributed generation PV and other forms of customer-sited renewable energy into the RPS until the CPUC has further addressed RPS implementation issues for distributed generation.

In May 2005, the CPUC issued the *Opinion Clarifying Participation of Renewable Distributed Generation in the Renewable Portfolio Standards Program* to clarify participation of renewable distributed generation in the RPS (Decision 05-05-011, Rulemaking 04-04-026). Among other things, the CPUC ruled that RECs from eligible renewable distributed generation facilities installed after October 24, 2002, may qualify for the RPS. However, the CPUC stated that renewable distributed generation facilities cannot be counted for the RPS until issues surrounding measurement, metering, and how to account for subsidies distributed generation may receive elsewhere (such as rebates from the Energy Commission's Emerging Renewables Program) are resolved. The CPUC referred the outstanding issues to its distributed generation Rulemaking (R. 04-03-017).

Hybrid Systems: In the past, the Energy Commission's Renewable Energy Program (REP) provided that renewable facilities using fossil fuels were eligible for funding as long as the percentage of fossil fuel used did not exceed 25 percent of the total energy input of the facility during a given calendar year. As long as a facility did not use more than 25 percent fossil fuel for its total generation, including the portion produced with fossil fuels then it was considered eligible for funding by the Energy Commission. The Energy Commission will provide the same treatment under the RPS for existing facilities that originally commenced commercial operations prior to January 1, 2002, and have not been repowered.

Further, any facility that is developed and awarded a power purchase contract as a result of an Interim RPS procurement solicitation approved by the CPUC pursuant to Decision 02-08-071 and Decision 02-10-062 may use up to 25 percent fossil fuel in its facility and count 100 percent of the electricity generated as RPS-eligible (assuming the electricity meets all other eligibility requirements).

The Energy Commission will allow two alternatives for eligibility of new and repowered facilities that operate on co-fired fuels or a mix of fuels that includes fossil fuel:

1. If the facility is certified as a Qualifying Small Power Production Facility (QF) under the federal Public Utilities Regulatory Policies Act (PURPA), then 100 percent of the electricity production from the facility may count as renewable provided the facility satisfies the fossil fuel use limitations specified in PURPA and the facility otherwise satisfies the applicable California RPS standards.

2. If the facility is NOT certified as a QF, then only the renewable portion of the electricity production can qualify for the RPS, and then only once an appropriate tracking system for such electricity production is developed.

Before new or repowered non-QF hybrid facilities can be certified as RPS eligible, the Energy Commission will need to develop a methodology as part of the tracking system to measure the renewable fraction of generation. This methodology could be based on the total heat input of the fuel, for example. As part of their application for certification from the Energy Commission, parties interested in certifying such facilities are invited to propose an appropriate tracking methodology for their facility.

Pumped storage hydro may qualify for the RPS to the extent that: 1) the facility meets the eligibility requirements for small hydro, and 2) the electricity used to pump the water qualifies as RPS-eligible. The amount of energy that may qualify for the RPS is the amount of electricity dispatched from the system.

The Energy Commission clarifies that pumped storage facilities qualify for the RPS on the basis of the renewable electricity used for pumping, and that electricity storage facilities will not be certified for the RPS as distinct or separate renewable facilities. A facility certified as RPS eligible may include an electricity storage device if it does not conflict with other RPS eligibility criteria, but the storage unit itself will not be separately certified.

Eligibility for Supplemental Energy Payments

A facility that is eligible for the RPS may also be eligible for SEPs. To qualify as eligible for SEPs, a facility must meet the RPS eligibility requirements above, as well as the additional requirements below.

1. The facility is either:

    a. “new,” meaning the facility first commences commercial operations on or after January 1, 2002, with the commercial operation date used to designate a facility as “new” to be periodically updated by the Energy Commission, or

    b. “repowered,” such that the prime generating equipment of the facility is replaced and the applicant demonstrates that the capital investments equal “at least 80 percent of the value of the repowered facility,” as required by Public Resources Code Section 25743 (c). A facility qualifies as “repowered” only if it re-enters commercial operations on or after the commercial operations date that distinguishes “new” facilities. Only investments made in the two years prior to re-entering commercial operations qualify toward the 80 percent investment threshold. More information about the requirements to qualify as a repowered facility is provided in the section on certification.

2. A small hydroelectric facility may qualify for SEPs if it commences commercial operations or is repowered on or after September 12, 2002.

3. If a facility has an existing long-term contract with a retail seller originally entered into before September 24, 1996, then only incremental new or repowered generation that is above and beyond what is already under contract, as determined in accordance with Public Utilities Code Section 399.6 (c)(1)(C), may qualify for SEPs.

For information about applying for and receiving SEPs, please refer to the *New Renewables Facilities Program Guidebook*).

Eligibility of Out-of-State Facilities

This section applies to renewable facilities that are located out-of-state and have their first point of interconnection to the Western Electricity Coordinating Council (WECC) transmission system outside the state, as defined in the *Overall Program Guidebook*. Facilities that have their first point of interconnection to the WECC transmission system within the state are considered to be in-state facilities and are not subject to the requirements of this section for purposes of RPS or SEP eligibility. Out-of-state facilities that are not or will not be interconnected to the WECC transmission system are not eligible for the RPS.

Generation from renewable facilities located out-of-state is potentially eligible for both the RPS and SEPs. To qualify only for the RPS, generation from an out-of-state facility must meet the RPS eligibility requirements described above and must satisfy all of the following criteria. Note that the criteria below do not apply to electric corporations that serve retail end-use customers outside California and have 60,000 or fewer customer accounts in California pursuant to Public Utilities Code Section 399.17, as enacted by Assembly Bill 200 (Leslie) AB 200, Chapter 50, Statutes of 2005. AB 200 modified the definition of eligible renewable resources to include out-of-state facilities for certain electric corporations, such as PacifiCorp and Sierra Pacific Power, which serve customers both in and outside California.

For PG&E, SCE and SDG&E, electricity procured from a facility located out-of-state must meet the following criteria to be eligible for the RPS.

1. The generation must be from a facility that:

   a) Is located so that it is or will be connected to the WECC transmission system.

   b) Has a guaranteed contract to sell its generation to a retail seller or the California Independent System Operator (CA ISO).

   c) Demonstrates delivery of its generation to an in-state market hub or in-state substation located within the CA ISO control area of the WECC transmission system (or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO).

d) Satisfies the "Delivery Requirements" set forth below.

e) Participates in an RPS tracking and verification system approved by the Energy Commission.

To qualify for both the RPS and SEPs, generation from an out-of-state facility must meet the RPS eligibility requirements described above and must satisfy all of the following criteria:

2. The generation must be from a facility that:

a) Is located so that it is or will be connected to the WECC transmission system.

b) Is developed with guaranteed contracts to sell its power to end-users subject to the funding requirements of Public Utilities Code Section 381 (end-use customers of PG&E, SCE, and SDG&E) during the period in which it receives SEPs.

c) Demonstrates delivery of its generation to an in-state market hub or in-state substation located within the CA ISO control area of the WECC transmission system (or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO).

d) Does not cause or contribute to any violation of a California environmental quality standard or requirement.

e) If located outside the United States, is developed and operated in a manner that is as protective of the environment as a similar facility located in California.

f) Participates in an RPS tracking and verification system approved by the Energy Commission.

g) Satisfies the "Delivery Requirements" set forth below.

For retail sellers that serve end-use customers outside California and have 60,000 or fewer customer accounts in California pursuant to Public Utilities Code Section 399.17, such as PacifiCorp and Sierra Pacific Power, electricity procured from a facility located out-of-state must meet the following criteria to be eligible for the RPS.

a) The generation must be procured by the retail seller on behalf of its California customers and is not used to fulfill its renewable energy procurement requirements in other states.

b) The facility and retail seller must participate in an RPS tracking and verification system approved by the Energy Commission.

Generation procured by retail sellers pursuant to Public Utilities Code Section 399.17 is not eligible for SEPs.

Delivery Requirements

To count generation from out-of-state facilities for purposes of RPS compliance, it must be delivered to an in-state market hub (also referred to as “zone”) or in-state substation (also referred to as “node) located within the CA ISO control area of the WECC transmission system (or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO). The retail seller and Seller may negotiate which party is responsible for securing transmission at any point along the delivery path as long as the energy is delivered into the CA ISO (or delivered into California if applicable CPUC rules allow delivery outside CA ISO). The delivery must be made consistent with North American Electricity Reliability Council (NERC) rules and documented with a NERC tag as described below.

The following deliverability requirements were developed in consultation with the CA ISO. These requirements must be satisfied for an out-of-state facility to qualify for the RPS or SEPs (with the exception noted above for retail sellers pursuant to Public Utilities Code Section 399.17). The delivery requirements do not apply to facilities located outside of California whose first point of interconnection to the WECC transmission system is located in California.

1. The facility must either (a) engage in an interchange transaction with the CA ISO to deliver the facility’s generation to the market hub or substation in the CA ISO control area or (b) engage in an interchange transaction with another control area operator to deliver the facility’s generation to an in-state location that satisfies applicable CPUC rules for delivery location. In accordance with the policies of the NERC, the interchange transaction must be tagged as what is commonly referred to as a “NERC tag,” which requires, among other things, that information be provided identifying the Generation Providing Entity, the “Source” or the “Point of Receipt”, the physical transmission path for delivery showing intermediary “Points of Delivery”, the contract or market path, the final Point of Delivery or load center, known as the “sink”, and the Load Serving Entity responsible for the consumption of electricity delivered.

2. The owner of the eligible facility shall register the facility as a unique Source with NERC. This Source shall be used on NERC transaction tags for all eligible energy deliveries.

3. The facility must provide the Energy Commission with its NERC identification (Source point name)[4] when it applies for RPS certification.

4. The facility must submit for and receive acceptance of a NERC tag between the CA ISO and the operator of the control area in which the facility is located.

5. The applicable parties (the Generation Providing Entity and Load Service Entities) must agree to make available upon request documentation of the NERC tag to the Energy Commission. On May 1 of each year, the retail seller must submit an annual report documenting compliance with this NERC tag requirement for the previous calendar year to the Energy Commission.

6. The facility, or the retail seller on the facility's behalf, must submit verification of its generation to the Energy Commission annually until the long-term tracking system is in place. Please refer to the section on the generation tracking system. The Energy Commission will use these data to verify the actual generation of power that was scheduled for delivery via NERC tags.

Certification Process

This section covers pre-certification and certification of renewable facilities eligible only for the RPS, eligible for both the RPS and SEPs, and for registration as renewable only (not RPS eligible). This section also describes required supplemental information for renewable facilities using technologies that must meet special eligibility requirements.

Electricity generation from a facility cannot be counted towards meeting a retail seller's RPS procurement requirement until the Energy Commission certifies the facility as a Renewable Supplier Eligible for the RPS or as a Renewable Supplier Eligible for the RPS and SEPs. Any facility operator interested in entering into a contract through an RPS solicitation to generate electricity that will count toward a retail seller's RPS obligation must certify the facility with the Energy Commission.

Procurement in 2001 and 2002 may count toward a retail seller's RPS obligation even though facilities were not RPS certified at the time of procurement. The electricity will not be considered eligible, however, and will not be counted toward meeting an RPS obligation until the facility is certified by the Energy Commission as being eligible for the RPS. This applies to all facilities regardless of whether they previously registered with the Energy Commission's Renewable Energy Program.

In applying for certification, the facility operator, or the IOU on the operator's behalf, agrees to participate in the Energy Commission's generation tracking system. For more

[4] The NERC identification is the Source point name, an alpha-numeric code the generator uses to identify itself when it registers with the Transmission Services Information Network (TSIN). Registration with TSIN is mandatory for participation in the NERC tagging system.

information about the tracking system, please refer to the section of this guidebook titled "Generation Tracking System."

The generation from facilities certified as eligible for the RPS may be claimed by the procuring retail seller for purposes of establishing the retail seller's baseline, adjusting its baseline, or meeting its annual procurement requirements, depending on the eligibility requirements established in this *Guidebook*. The generation from facilities certified as eligible for the RPS and SEPs may qualify for SEP funding under the Energy Commission's New Renewable Facilities Program. To receive SEPs, eligible facilities must satisfy the requirements specified in the Energy Commission's *New Renewable Facilities Program Guidebook*.

Applying for Certification and Pre-Certification

Facilities seeking certification as eligible for the RPS or RPS and SEPs consistent with the eligibility requirements noted above must submit a completed application, along with any necessary supporting documentation, to the Energy Commission at the address shown on the form. An application may be submitted for a facility by the facility operator (CEC-RPS-1A) or by the procuring retail seller on the operator's behalf (CEC-RPS-2) for facilities under contract with the retail seller prior to April 21, 2004, the initial adoption date of this *Guidebook*.

Except for CPUC-ordered extensions to existing QF power purchase contracts, retail seller certification on the operator's behalf becomes void in the event that the facility's contract with the retail seller expires, or is voluntarily extended, or is otherwise renegotiated by the retail seller and the facility operator. Once the contract expires or is voluntarily renegotiated, the facility operator must apply for certification from the Energy Commission on its own behalf, and the retail seller may not recertify the facility on the operator's behalf. For CPUC-ordered extensions, retail seller certification may continue until the extension expires.

The Energy Commission will review the application to determine eligibility as a Renewable Supplier Eligible for the RPS or as a Renewable Supplier Eligible for the RPS and SEPs and will notify applicants once a determination of eligibility is made. Facilities that are certified by a retail seller will only be granted certification for the generation procured under contract by that retail seller. The facility operator must separately certify any facility capacity that is not subject to the retail seller's procurement contract but is procured to satisfy the RPS targets of another retail seller.

Provisional or "pre" certification as an eligible renewable resource is available for applicants whose facilities are not yet online or do not have a contract in place to sell their generation to a retail seller at the time of application. Applicants seeking pre-certification must complete CEC-RPS-1B. The information submitted by these applicants will be subject to further verification once the pre-certified facility comes online or secures a contract with a retail seller. Applicants must indicate their desire to be pre-certified on their completed CEC-RPS-1B form and must submit all required supplemental information, as described below, to the extent available. If the required supplemental information is not available at the time of pre-certification application because of the facility's stage of development or contract negotiations, the applicant must explain this in its application and identify the missing information and the dates when this information is expected to be available. Facilities that are pre-certified must submit a complete and updated certification application (CEC-RPS-1A) with all required supplemental information and be certified as RPS or RPS and SEP eligible before any of its generation may be counted toward satisfying a retail seller's RPS procurement requirements.

The Energy Commission will make every effort to notify applicants of their facility's eligibility status as soon as possible. For facilities that are not required to submit supplemental information as described below, the Energy Commission expects to review and process applications for certification and pre-certification within ten business days of their receipt, unless questions or concerns arise regarding the applications. If questions arise, the applicant will be contacted and may be asked to submit additional information. The Energy Commission recognizes that it may receive a large volume of applications at the onset of this program and that the 10-day goal may not be met.

The Energy Commission will notify applicants in writing of its determination on the application for certification. If the application for certification or pre-certification is approved, the Energy Commission will issue a certificate stating that the facility is certified or pre-certified as eligible for the RPS, or eligible for the RPS and SEPs, as appropriate. The certificate will list the Energy Commission-issued certification number for the facility as well as the size, fuel type and percentage of annual fossil fuel usage (if any), name, location, and owner/operator of the facility. The certificate will also indicate whether the facility was certified by the facility owner/operator or a retail seller on the owner/operator's behalf.

In addition, the certificate will identify any limits on certification or pre-certification. For example, a certificate issued for a facility that has been certified by a retail seller will indicate certification by the retail seller, rather than the facility operator, and will limit certification to the generation procured under contract by the retail seller. A certificate issued for a facility that produces (or will produce) electricity that is eligible only for RPS baseline or baseline adjustment will indicate certification for this purpose only. A certificate issued for a facility that has certified a portion of its capacity as incremental geothermal, and the remainder as geothermal, will identify the amount of capacity that falls into each category.

The Energy Commission encourages local publicly owned electric utilities to meet their RPS obligations through procurement from RPS-certified facilities. However, to become RPS-certified an out-of-state facility must have a guaranteed contact to sell its generation to a retail seller or the CA ISO. By statute, the definition of a "retailer seller" excludes local publicly owned electric utilities. Consequently, an out-of-state facility selling its generation exclusively to a local publicly owned electric utility is not RPS-eligible and may not apply for RPS certification, but may apply for pre-certification. If the

Energy Commission determines that an out-of-state facility is eligible for pre-certification and is otherwise eligible for certification except that it does not have a guaranteed contract with a retail seller or the CA ISO, then it will note this determination in the pre-certification notification upon request by the applicant.

For applicants that must submit supplemental information, such as small hydroelectric, incremental geothermal, MSW/solid waste conversion, out-of-state, or repowered facilities, the Energy Commission must conduct an extensive review of the supplemental data. Review of these applications will require a minimum of 30 days from when the Energy Commission receives a complete application. The 30-day clock starts on the date a complete application is date-stamped by the Energy Commission as received. After completing its review, the Energy Commission will either notify the applicant of its proposed determination, or will request additional information from the applicant.

Applicants that disagree with the Energy Commission's determination on certification or pre-certification applications may petition the Renewables Committee and the Energy Commission for reconsideration as described in the *Overall Program Guidebook*. As described in the *Overall Program Guidebook,* the Energy Commission expects to issue decisions on petitions for reconsideration within 45 days of receipt of a complete petition. The 45-day clock starts on the date a complete petition is date-stamped by the Energy Commission as received.

Certification and pre-certification must be renewed every two years to confirm that all certified renewable energy resources remain eligible for the RPS. This provision also applies to facilities certified by a retail seller. All facilities certified in year 2004 will be subject to recertification in January 2007, with facilities certified in year 2005 recertifying in January 2008, and so on. In addition, if a certified or pre-certified facility does not respond to the Energy Commission's request for an information update in a timely manner, it will risk losing its certification status.

The Energy Commission will post information on its Web site listing those facilities that are certified or pre-certified as eligible for the RPS or for the SEPs. Any changes in a facility's certification status will also be posted on the Energy Commission's Web site.

Consistent with the *Overall Program Guidebook,* the Energy Commission may conduct periodic or random reviews to verify records submitted for certification or pre-certification as a Renewable Supplier eligible for the RPS or for the RPS and SEPs. Further, the Energy Commission may conduct on-site audits and facility inspections to verify compliance with the requirements for certification or pre-certification. The Energy Commission may request additional information it deems necessary to monitor compliance with the certification requirements specified in this *Guidebook*.

To the extent that a retail seller applies for certification on a facility's behalf, the retail seller must secure and have available for inspection records to verify the application for certification or pre-certification. In addition, the retail seller must possess documents to verify a facility's compliance with the requirements of certification and pre-certification. These documents must be available to the Energy Commission upon request for auditing purposes.

Amending Certification and Pre-Certification

Representatives of certified and pre-certified facilities must notify the Energy Commission promptly of any changes in information previously submitted in an application for certification or pre-certification. A facility failing to do so risks losing its certification status. Any changes to a certification or pre-certification application should be reported on an amended CEC-RPS-1 form (CEC-RPS-1A to amend certification and CEC-RPS-1B to amend pre-certification). For example, if a facility's annual fossil fuel use changes from the percentage identified in its previous application for certification, the facility must submit an amended application. The Energy Commission will review the amended application and notify the applicant of any modifications to their certification status.

Also, any changes to the status of a facility's certification will be posted on the Energy Commission's Web site and any affected retail seller contracting with that facility will be promptly notified.

Supplemental Information

The following supplemental instructions apply to applications for biomass, small hydroelectric, incremental geothermal, and MSW/solid waste conversion facilities. Supplemental instructions are also included for applicants seeking certification or pre-certification of repowered facilities and facilities located outside California. The information described below must be submitted as an attachment to the applicant's completed CEC-RPS-1A or CEC-RPS-1B form.

Supplemental Instructions for Biomass Facilities

Applicants for certification or pre-certification of biomass facilities that commenced commercial operations on or after January 1, 2002, must submit an attestation attached to the applicant's completed CEC-RPS-1A or CEC-RPS-1B that they comply or will comply, in the case of pre-certification, with the biomass fuel requirements described above.

Additionally, Public Resources Code 25748 requires the Energy Commission to "…identify the types and quantities of biomass fuels used by facilities receiving funds pursuant to [Public Resources Code] Section 25743 and their impacts on improving air quality." To meet this requirement, biomass facility operators receiving SEPs must submit an annual report to the Energy Commission describing fuel use as follows: tons of biomass by type of biomass, the air district from which the biomass originated if the fuel may have been open-field burned had it not been used for electricity production, and an attestation from the fuel supplier(s) that the biomass fuel continues to meet the

RPS eligibility standards. The report is due to the Energy Commission on February 15th of each year to report on the biomass supply consumed in the previous calendar year.

Supplemental Instructions for Small Hydropower Facilities

To demonstrate that a hydropower facility built or repowered on or after September 12, 2002, is eligible for the RPS and SEPs, the applicant must provide the following water-use data and documentation attached to its completed CEC-RPS-1A (for certification) or CEC-RPS-1B (for pre-certification) form to substantiate its self-certification. These requirements apply to facilities located within California as well as those located out-of-state. Applicants possessing a permit or license from the State Water Resources Control Board (SWRCB) – or from another governing body, if located out-of-state – must submit a copy of the permit or license as well as the application for the permit or license.

1. Name of the Facility

2. Ownership of the Facility

3. Source Water Description

   The application must identify the source of the water for the small hydro project. The source must be characterized as surface, groundwater, or other (for example, recycled water). For surface water sources, a map at a scale of 1:24,000 must be provided. The map should also identify the location of the diversion point and all other facilities. In addition, a written description of the location of the diversion should be provided (county and nearest city) as well as the name of the body of water at the point of diversion. For groundwater, the location of the well(s) and conveyance facilities shall be identified on a map of 1:24,000 scale. The applicant must also specify how much water is used for each of the identified beneficial uses.

4. Water Rights

   Both in-state and out-of-state applicants must clearly establish their right to divert water by submitting all necessary information as well as all appropriate licenses or permits. Within California, this information must establish the applicant's legal right to appropriate or divert water and identify the permitted volume and rate of water diversions, the place of diversion, and beneficial uses. This may be achieved through submittal of the appropriate SWRCB appropriation permit or license. Out-of-state facilities must provide similar documentation of an existing water right for the water diversion of the project.

5. Hydrologic Data

   The applicant must submit appropriation and/or diversion data for the last five years, or for the period of operation if the project has been operating less than five years.

Information contained in any legally required reports may be used to meet this requirement if sufficient information is included in the report. For other projects, the hydrologic data submitted must be accompanied by a description of how the data is collected. Flow data shall be provided at the frequency set forth in the applicable water appropriation permit; for example, if the permit specifies minimum and maximum flows on a monthly basis that is the level of information necessary to be submitted.

6. Other Permits

   The applicant must submit all other applicable permits, including those permits and exemptions issued by the Federal Energy Regulatory Commission.

7. Environmental Documentation

   The applicant must submit copies of any permits, agreements, contracts, or other requirements affecting the operation of the facility, especially those that affect the volume and rate of flows.

8. Capacity

   The applicant must demonstrate how the project will comply with the size limitations under the RPS. For repowering projects, the applicant must describe how capacity will be increased without an increase in the appropriation and/or diversion of water or in the change in the volume or rate of flows.

Supplemental Instructions for Incremental Geothermal Facilities

Applicants must provide the following information attached to the completed CEC-RPS-1A or CEC-RPS-1B form when applying for certification or pre-certification as an incremental geothermal facility. The following information must be presented for individual facilities and may not be aggregated for the entire steam field.

1. Evidence that the incremental generation from the facility resulted or will result from an eligible capital expenditure in a project completed after September 26, 1996. The capital investment must be in new or replaced capacity or steam production and must exclude monies that would have been spent on operation and maintenance in the normal course of doing business.

2. The expected production increase for each year in megawatt hours resulting from each capital improvement for as long as the increased production is expected to last.

3. All of the capital investments that pertain to each facility along with a brief description of each investment. The brief description must include the relationship

between the capital investment and the production increase from the facility, including a discussion of the nature of the capital investments and how they resulted in the incremental generation.

4. A graph and table for each facility that shows the historical generation for each facility in megawatt hours. The graph and table should include a forecast of future generation from each facility based on the capital investments along with a forecast of generation without the capital investments. This information should provide the Energy Commission with an estimate of future increased production based on the capital improvements.

5. A discussion of how and why capital improvements are assigned to a particular generating facility.

6. A discussion of the sustainability of increased production from the facility. The discussion should show how the capital investment is consistent with, and protective of, the long-term preservation of the geothermal resource and also demonstrate that increased production from the facility in the short-term is not overdrawing the resource and leading to overall diminished production in the long-term.

7. A discussion of the methodology used by the applicant to estimate, forecast, and measure increased generation from each capital improvement.

In substantiating a claim of incremental geothermal production, the burden of proof will be on the applicant for the geothermal facility to submit compelling evidence demonstrating the effect that capital expenditures have had on production. As applicable, applicants also have the responsibility of properly allocating any increase among different generating facilities in the same steamfield.

In addition, all data submitted to substantiate a claim are expected to be public, although the Energy Commission is interested only in data with a direct bearing on the claim. For example, although information on capital investments and the resulting production increases is expected to be submitted publicly, the Energy Commission has no interest in any proprietary underlying economic analyses that may have led to the decision to make such investment.

Supplemental Instructions for Municipal Solid Waste Conversion Facilities

Applicants for certification or pre-certification of solid waste conversion facilities must provide copies of permits issued by the California Integrated Waste Management Board (CIWMB) attached to the completed CEC-RPS-1A or CEC-RPS-1B form to verify compliance with the requirements specified above. The Energy Commission will verify compliance in consultation with the CIWMB and based on CIWMB's proposed regulations for solid waste conversion technologies as set forth in Title 14, California Code of Regulations, Division 7, Chapter 3, Article 6.0, commencing with Section 17400. These regulations are being adopted pursuant to Assembly Bill 2770 (Mathews, Chapter 704, Statutes of 2002), which establishes requirements for solid waste conversion technologies that mirror the requirements for these technologies found in Public Resources Code Section 25741(a)(3). The proposed regulations are part of CIWMB's Transfer/Processing Operations and Facilities Regulatory Requirements and will require facilities using solid waste conversion technologies to obtain a Conversion Technology Facility Permit. Pending the adoption of the proposed regulations, the CIWMB may permit facilities using solid waste conversion technologies on a case-by-case basis pursuant to its existing regulations for the Transfer/Processing Operations and Facilities Regulatory Requirements.

To become certified as a renewable energy resource eligible for RPS (and SEPs), an applicant for a solid waste conversion facility must submit to the Energy Commission a copy of its Conversion Technology Facility Permit approved by the CIWMB. In the event that CIWMB's regulations for solid waste conversion technologies are not adopted at the time the facility seeks RPS certification, the facility must request and obtain from CIWMB a Solid Waste Facility Permit under CIWMB's existing regulations for the Transfer/Processing Operations and Facilities Regulatory Requirements. The Energy Commission will confirm that the permit is approved, active, and applicable to the facility seeking RPS certification. These permits must demonstrate the following:

1. The facility is using only a "gasification" conversion technology, as defined in Public Resources Code Section 40117.

2. The facility accepts and processes "solid waste" as defined in Public Resources Code Section 40191 and is not limited to receiving and processing "source separated" waste as defined in Title 14, California Code of Regulations, Section 17402.5(b)(4).

3. The facility processes solid waste from which, to the maximum extent feasible, all recyclable materials and marketable green waste compostable materials have been removed prior to the solid waste conversion process.

In addition, an applicant must certify to the Energy Commission the following:

1. All recyclable materials and marketable green waste compostable materials that have been removed from solid waste delivered to the facility are recycled or composted.

2. Any local agency sending solid waste to the facility diverted at least 30 percent of all solid waste it collects through solid waste reduction, recycling, and composting. For purposes of this certification, "local agency" means any city, county, or special district, or subdivision thereof, that is authorized to provide solid waste handling services.

To become pre-certified as RPS and SEP eligible, the applicant must submit to the Energy Commission the information required to receive a Conversion Technology

Facility Permit from CIWMB. In the event CIWMB's regulations for solid waste conversion technologies have not been adopted at that time, then the applicant must submit to the Energy Commission the information required to receive a Solid Waste Facility Permit. This information is identified in Title 14, California Code of Regulations, Sections 18221.5 and 18221.6. The Energy Commission will review this information in consultation with the CIWMB to determine if the information is complete and satisfies the requirements specified in Public Resources Code Section 25741(a)(3).

If a pre-certified applicant does not obtain a Conversion Technology Facility Permit from CIWMB by the time the project commences commercial operation, or if it is denied approval for a permit, the Energy Commission will revoke the applicant's pre-certification.

Supplemental Instructions for Out-of-State Facilities

Out-of-state facilities seeking certification as RPS-eligible must provide their NERC identification (the Source point name) and the control area to which the facility is connected in a completed CEC-RPS-1 form. The NERC identification and control area is required to receive certification that a facility located outside California is eligible for California's RPS. This requirement does not apply, however, to a facility that is: 1) exclusively serving retail sellers subject to Public Utilities Code Section 399.17, or 2) seeking pre-certification and is not yet on-line.

Out-of-state facilities seeking certification as eligible for RPS and SEPs must submit the following additional information with a completed CEC-RPS-1 form.

1. Impact on California Environmental Quality Standards: The applicant must provide a) a comprehensive list and description of all California environmental quality laws, ordinances, regulations, and standards (collectively referred to as "LORS") that may be directly or indirectly impacted by the facility's development or operation, and b) an assessment as to whether the facility's development or operation will cause or contribute to a violation of any of these LORS.

   At a minimum, the LORS described shall address the following environmental areas consistent with Appendix B, Section (g), of the Energy Commission's regulations for power plant certification, Title 20, California Code of Regulations, Sections 1701, et seq:

   - Cultural Resources
   - Land Use
   - Traffic and Transportation
   - Visual Resources
   - Socioeconomics
   - Air Quality
   - Public Health
   - Hazardous Materials Handling

- Workers' Safety
- Waste Management
- Biological Resources
- Water Resources
- Agriculture and Soil
- Paleontologic Resources
- Geological Hazards and Resources
- Transmission System Safety and Nuisance

The applicable LORS for a given facility will vary depending on the facility's location, since the LORS across California vary. For example, the air quality standards in Southern California may differ from the air quality standards in Northern California.

2. Out-of-Country Facilities: In addition to the above information, an applicant for a facility located outside the United States must provide all of the following:

    a. A comprehensive list and description of all California environmental quality LORS that would apply to the facility if the facility were located within California.

    b. An assessment as to whether the facility's development or operation will cause or contribute to a violation of any of these LORS.

    c. An explanation as to how the facility's developer and/or operator will meet these LORS in developing or operating the facility, including whether the developer and/or operator will secure and put in place mitigation measures to ensure that these LORS are complied with.

Supplemental Instructions for Repowered Facilities

To apply for certification or pre-certification as a repowered facility, an applicant must submit a completed CEC-RPS-1A or CEC-RPS-1B form, along with documentation confirming the replacement of the facility's prime generating equipment and the capital investments made to repower the facility as well as the value of those investments.

1. Prime Generating Equipment: The applicant must document that the facility's prime generating equipment is new and that the repowered facility re-entered commercial operations on or after January 1, 2002.

    - The "prime generating equipment" for each renewable resource is defined as follows:

        - Wind: the entire wind turbine, including the generator, gearbox (if any), nacelle, and blades.

        - Biomass: the entire boiler. Stoker boilers may be replaced with boilers using improved stoker technology or fluidized bed technology.

- Geothermal: the entire steam generator, including the turbine rotors, shaft, stationary blades, and any gear assemblies.

- Small hydroelectric: the entire turbine and structures supporting the turbine.

- Solid waste conversion: the entire gasifier (gasifying equipment) and combustion turbine.

- Landfill gas: the entire internal combustion engine or combustion turbine as applicable.

- Digester gas: the entire digester unit and internal combustion engine or combustion turbine as applicable.

- Solar thermal: the entire steam turbine.

- All prime generating equipment at the facility must be replaced with new equipment for the facility to qualify as a repowered facility. For example, a 25-MW wind facility consisting of 50 separate wind turbines must at a minimum replace each of the 50 wind turbines with new turbines of like or greater capacity for the entire 25-MW facility to qualify as a repowered facility. The Energy Commission recognizes that a wind facility owner may want or need to repower only a portion of the turbines owned at a site and does not exclude that option. In the event that a generator is interested in repowering a portion of a site, then it will need to re-certify or re-register the remaining portion of the site that is not being repowered.

2. Capital Investments: The applicant must document that capital investments were made not more than two years prior to the date that the facility re-entered commercial operations. Expenses are only applicable on that portion of the facility that contributes directly to the production of electricity.

   - Electrical Generators and/or Fuel Processing and Delivery Equipment: It is generally not necessary for a facility to replace its existing electrical generators or fuel processing and delivery equipment because replacing this equipment will produce little or no improvement to the facility's efficiency and, therefore, does not warrant the additional expense. Exceptions are cases in which the electrical generator is an integral part of the prime generating equipment, such as for wind facilities, or where the fuel processing and delivery equipment is an integral part of the prime generating equipment via the fuel conversion process, such as for solid waste conversion facilities and digester gas facilities. The facility's environmental control equipment, such air pollution control equipment, would not be considered because such equipment does not contribute directly to the production of electricity.

- Any associated process control equipment and structures used for structural support of the prime generating equipment, electrical generators, fuel processing and delivery equipment, and associated process control equipment, as appropriate, would also fall into this category and are generally not necessary to replace.

The applicant must provide documentation, such as invoice receipts, verifying the replacement of the old equipment, as well as other components of the technology relevant to the repowering application. The Energy Commission will confirm that the equipment listed is appropriate for certification as a repowered facility.

The applicant must document the value of the capital investments made to the facility and the total value of the repowered facility. The value of the capital investments must equal at least 80 percent of the total value of the repowered facility.

The "repowered facility" is defined as all of the new and/or existing prime generating equipment, electrical generators, fuel processing and delivery equipment, and any associated process control equipment and structures at the facility. The land on which the facility sits will not be considered part of the repowered facility for purposes of determining the 80 percent threshold. Similarly, intangibles such as the value of a facility's power purchase contract or its goodwill will not be considered part of the repowered facility.

The applicant may show that it has met the 80 percent threshold by submitting either tax records or an assessment of the "replacement value" of the facility along with documentation of the cost of the new equipment. The applicant must notify the Energy Commission which method it is using and provide the appropriate information as described below.

a. Tax Records Methodology:

   The applicant must submit to the Energy Commission all relevant tax records needed to demonstrate that the capital investments made to repower the facility are equal to at least 80 percent of the value of the repowered facility.

   1) The applicant must document the value of the capital investments and the year the investments were made. In this case, the value of capital investments is the original tax "basis" declared to the Internal Revenue Service to calculate depreciation. The tax basis should reflect the value of the equipment the applicant has attested to purchasing. The tax basis is generally what a business pays for an item to be depreciated.

   2) The applicant must document the value of the repowered facility. In this case, the value of the repowered facility is based on the sum of the tax basis declared for all of the equipment and structures in the repowered facility as of

the year the facility is repowered. For new equipment and structures, the value of the repowered facility is the original tax basis; for existing equipment and structures, the value of the repowered facility is the tax basis as adjusted for depreciation. For facilities financed using a sale/lease-back or similar structure, the original tax basis of the equipment and structures for both the lessor and lessee will be considered.

3) The applicant must divide the total value of capital investments by the total value of the repowered facility. This calculation must show that the investment is equal to or greater than 80 percent of the total value of the facility for it to qualify as repowered.

b. Replacement Value Methodology:

This alternative approach may make it more difficult for a facility to meet the 80 percent repowering threshold but is a reasonable alternative for parties who are unable or unwilling to secure the necessary tax records to use the adjusted tax basis approach.

1) The applicant must document the value of the equipment replaced in the facility. The replacement cost of new equipment is based on the equipment's purchase price and, consequently, is the same value when compared to the adjusted tax basis approach.

2) The applicant must submit an independent evaluation of the replacement cost of existing, unreplaced equipment ("retained equipment"). The evaluation should be an estimate of the capital costs that would have to be incurred to replace the retained equipment. This estimate must be provided by an accountant in good standing with the American Institute of Certified Public Accountants or a member in good standing and certified as an Internal Auditor with the Institute of Internal Audits.

3) The applicant must divide the total value of capital investments by the sum of the replacement cost of the new equipment and the independent estimate of the replacement cost of the retained equipment. This calculation must show that the investment is equal to or greater than 80 percent of the total value of the facility for it to qualify as repowered.

Registration as Renewable Only (not RPS eligible)

Applicants representing facilities that do not meet the RPS or SEP eligibility requirements may apply to the Energy Commission for "registration" as a Renewable Supplier. To qualify for registration as a Renewable Supplier, a facility must satisfy the following requirements:

1. The facility must use one or more of the following energy sources, as defined in the *Overall Program Guidebook*, to generate electricity: biomass, biodiesel, fuel cells using renewable fuels, digester gas, geothermal, landfill gas, municipal solid waste, ocean wave, ocean thermal, tidal current, photovoltaic, small hydroelectric (30 megawatts or less), solar thermal, or wind.

2. The facility must specify the type and percentage of any fossil fuel used in the facility.

Applicants must submit a completed form CEC-1038E-1, Registration Form for Renewable Suppliers, to the Energy Commission.

The Energy Commission expects to review and process complete applications for registration within 15 business days of their receipt, unless questions or concerns arise regarding the applications. If questions arise, the Energy Commission will contact the applicant for additional information. Otherwise, the Energy Commission will notify applicants in writing once it determines registration eligibility.

Once the Energy Commission approves an application for registration, the Energy Commission will issue a certificate stating that the facility is a registered Renewable Supplier, along with a supplier number to be used in all subsequent transactions. The certificate will also specify the amount of fossil fuel, if any, used by the facility.

Registration as a Renewable Supplier does **NOT** imply Energy Commission endorsement or verification of renewable status. Registration as a Renewable Supplier merely indicates that the applicant has certified under penalty of perjury that its facility meets the registration requirements of a Renewable Supplier and has obtained an identification number from the Energy Commission.

Generation Tracking System

The Energy Commission is responsible for developing a tracking system to verify compliance with the RPS. Pursuant to SB 1078, the Energy Commission is required to:

> Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state. In establishing the guidelines governing this system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers, in accordance with the requirements of this article and the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of

the Government Code). In seeking data from electrical corporations, the Energy Commission shall request data from the CPUC.

The Energy Commission is developing an electronic tracking system to meet this requirement and will use an interim generation tracking system until the electronic system is operational. Once the long-term, electronic tracking system referred to as the "Western Renewable Energy Generation Information System" (WREGIS) is in place, the Energy Commission will require renewable suppliers and retail sellers to participate in the WREGIS as part of RPS compliance.

Reports to the Energy Commission

Retail sellers must report annually to the Energy Commission on the amount of RPS-eligible electricity they procure per facility, called a "specific purchase." Using the CEC-RPS-Track form, retail sellers must report the amount of energy they procured per month from each RPS-eligible facility, various identification numbers for each facility, and how the retail seller intends to count the procurement (i.e. whether to count it as incremental or baseline procurement). The CEC-RPS-Track form must be executed by an authorized agent of the retail seller who can attest that the specific purchases reported on the form were sold once and only once to retail consumers. This information is due to the Energy Commission on May 1 (or the next business day) of each year until WREGIS is operational. Once WREGIS is operational, this reporting requirement is expected to be satisfied with reports generated through WREGIS. The CEC-RPS-Track form and instructions are provided in Appendix A.

A facility that certifies as RPS or RPS and SEP eligible with the Energy Commission must annually submit data on its monthly generation, including any generation sold to an entity that does not qualify as a retail seller pursuant to Public Utilities Code Section 399.12, Subdivision (c). These data must be reported on the CEC-RPS-GEN by May 1 (or the next business day) of each year and indicate if the generation is restricted to counting towards the baseline/adjusting the baseline. To verify generation, the facility must submit monthly payment statements from the retail seller as an attachment to the form showing the amount of energy procured from the facility. If the facility is serving an entity that does not qualify as a retail seller pursuant to Public Utilities Code Section 399.12, Subdivision (c), and is participating in the Energy Commission's RPS-tracking system, then the verification may be from that entity. The Energy Commission intends to simplify program implementation by using the retail seller's payment statement to serve as the verification rather than allowing alternate sources of data. The facility should strike out any price or other data on the statement that it does not want to make publicly available. Once WREGIS is operational, this reporting requirement is expected to be satisfied with reports generated through WREGIS system. The CEC-RPS-Gen form and instructions are provided in Appendix A.

For cases in which the retail seller certifies a facility on the facility's behalf, the retail seller is responsible for reporting the generation data for the facilities it certifies. This reporting requirement will be satisfied through the CEC-RPS-Track form until WREGIS is operational, and retail sellers do not need to file separate CEC-RPS-GEN forms for the facilities they certify. Also, since the retail seller is providing the data, the retail seller does not need to separately provide third party verification of the generation.

In addition, a facility, or a retail seller on the facility's behalf, must submit documentation verifying compliance with the NERC tag requirements (described under "Delivery Requirements" in the "Eligibility of Out-of-State Facilities" section). This documentation is required annually beginning in 2005, and is due to the Energy Commission by May 1 (or the next business day) each year. The Energy Commission intends to work with industry to establish a standardized, annual summary report and a standardized format for supporting documentation.

If necessary, the Energy Commission will request that the CPUC direct the retail sellers to submit the CEC-RPS-Track form data and documentation showing compliance with the NERC tag requirement if the Energy Commission does not receive these data promptly.

Accounting for Incremental Geothermal Generation

In some cases, part of the capacity of a geothermal facility is certified as incremental geothermal, with the remainder certified as geothermal that is restricted to the baseline or adjusting the baseline. To determine the amount of energy from a facility that qualifies as incremental geothermal, the Energy Commission will calculate the percent of incremental capacity relative to operational capacity and apply it to the facility's total energy generation. For example, if 12 MW is certified as incremental geothermal from a facility with 100 MW of operational capacity, then 12 percent of the monthly and annual generation will qualify as incremental geothermal energy.

Energy Commission RPS Verification Report

The Energy Commission intends to prepare an annual RPS Verification Report specifying the quantity of RPS-eligible energy each retail seller procured in the previous calendar year. This report will be transmitted to the CPUC and is intended to help the CPUC determine RPS procurement targets and evaluating retail sellers' RPS compliance. The Energy Commission will account for procurement disaggregated by baseline and incremental procurement consistent with the requirements of this *Guidebook* and applicable CPUC decisions.

Although the first RPS Verification Report (February 2006) stated that the Energy Commission anticipated adopting subsequent Verification Reports by the end of each calendar year, the Energy Commission intends to accelerate the schedule by bifurcating the report.[5] By September of each year, the Energy Commission intends to adopt the

[5] California Energy Commission, February 2006, *Renewables Portfolio Standard Procurement Verification Report*, Commission Report, CEC-300-2006-002-CMF.

following findings: verification that delivery requirements were met, verification of RPS eligibility, verification that the procurement was counted only once, allocation of procurement as eligible for the APT and IPT, and calculation of incremental geothermal energy generated. By the end of each calendar year, the Energy Commission anticipates separately reporting its findings on reconciling procurement and generation to verify that procurement does not exceed generation. This bifurcation and schedule will be readdressed once WREGIS is operational.

Verification of Delivery

As part of the RPS Verification Report, the Energy Commission will also verify compliance with delivery requirements for out-of-state facilities. The Energy Commission will annually verify that the delivery requirements were satisfied on a monthly (not daily or hourly) basis. This level of verification is consistent with the interim accounting system for generation and the CA ISO Participating Intermittent Renewable Projects program.

To verify deliveries from out-of-state facilities, the Energy Commission intends to compare the monthly generation procured from an RPS-eligible facility with the monthly NERC tag data for that facility, with the lesser of the two considered to be eligible RPS procurement. For example, if the monthly energy delivery shown on the NERC tags for a facility exceeds the monthly amount of energy procured, then the Energy Commission will count the amount procured as RPS-eligible procurement. Conversely, if the amount procured exceeds the monthly amount that was delivered as demonstrated by the NERC tags, the Energy Commission will assume some of the generation was delivered elsewhere and will only count as RPS-eligible the amount of procurement supported by the NERC tag data.

Verification Methodology using the Interim Tracking System

As discussed above, the Energy Commission has developed an interim accounting system for use until WREGIS is operational. The Energy Commission will verify that the RPS procurement reported in the CEC-RPS-Track form is certified as RPS-eligible. Also, to the extent possible the Energy Commission will ensure that RPS-eligible energy procured by retail sellers is counted only once in California or any other state. In the interim until WREGIS is operational, the Energy Commission will conduct this verification by cross-checking RPS procurement with retail claims reported under the Energy Commission's Power Source Disclosure Program and other similar data.

The Energy Commission will apply statutory provisions and CPUC rules to report on the amount of procurement that is eligible toward the IPT and the APT. For incremental geothermal, the Energy Commission does not intend to allocate the amount of generation that is sold to separate parties if more than one retail seller procures from a facility (assuming the facility is part incremental and part baseline geothermal). The allocation of incremental geothermal and baseline geothermal procurement should be contractually determined and reported on the CEC-RPS-Track form. The Energy

Commission intends to verify that the specific purchases of incremental geothermal procurement do not exceed the eligible amount generated.

The Energy Commission will verify the energy generation to the extent possible, and will verify that the amount of RPS-eligible procurement did not exceed the facility's total generation. As part of the interim tracking system, the Energy Commission will check that if two or more retail sellers procured energy from the same facility, the cumulative amount of energy procured does not exceed the facility's total generation. If procurement exceeds generation, the Energy Commission will report the discrepancies.

Appendix A - Forms

Please note that current versions of the forms (downloadable) are available online at: <www.energy.ca.gov/portfolio/documents/index.html>

- CEC-RPS-Track, Interim data collection from retail sellers
- CEC-RPS-GEN, Interim data collection from RPS-eligible facilities
- CEC-RPS-1A, Application for Certification, California Renewable Portfolio Standard Program
- CEC-RPS-1B, Application for Pre-Certification, California Renewable Portfolio Standard Program
- CEC-RPS-2, Utility Application for Certification of Renewable Facility, California Renewable Portfolio Standard Program

CEC-RPS-TRACK

(TO BE COMPLETED BY RETAIL SELLERS)
REPORT to the CALIFORNIA ENERGY COMMISSION
Procurement of
Renewable Energy by Retail Sellers in 2005

GENERAL INSTRUCTIONS

Please enter your company's name, CPUC registration number as filed with the California Public Utilities Commission, or CEC identification number (if applicable).

Company Name	
CPUC Reg # (if applicable)	
CEC Reg # (if applicable)	

PLEASE ENABLE MACROS FOR THE FORMS TO WORK PROPERLY. Fill out Schedules 1 and 2 and e-mail the completed file to the address shown below. Then print out the file, sign the attestation as appropriate, and mail the package to the address shown below:

California Energy Commission
e-mail: RPSTrack@energy.state.ca.us
Jason Orta
Attn: Interim Tracking
California Energy Commission
1516 9th Street, MS-45
Sacramento, CA 95814-5512

Responses to this request are due by close of business May 1, 2006.

CEC-RPS-TRACK

Schedule 1: TO BE COMPLETED BY RETAIL SELLERS
Report to the California Energy Commission
Certified RPS Facilities from which Generation was Procured in_2005

INSTRUCTIONS: Please list the generating facilities from which procurement was claimed for 2005. Please enter the requested information for each generating unit. Do not enter information into the shaded cells. **To expedite the processing of this form, please list as many of the generating units' identification numbers as possible**. If you need additional rows, please click on the "Insert Row" button above.

RENEWABLE ENERGY FACILITIES														
Facility Name	Unit Number	Fuel Type	CEC RPS Certification Number[1]	EIA ID Number[2]	CEC ID Number[3]	GenReport Certificate Number[4]	CEC Plant ID Number[5]	ISO Meter ID Number[6]	ISO Resource ID Number[7]	QF ID Number[8]	NERC ID Number[9]	Other Facility Identifier[10]	Procurement Qualifies for Baseline or Incremental Procurement[11]	Annual Generation Procured (in kWh)
														0
														0
														0
														0
														0
														0
														0
														0
														0
														0
														0
														0
														0
														0

[1] Please enter the California Energy Commission RPS Certification number for the facility, **REQUIRED**.

[2] Please enter the Energy Information Administration identification number for the generating facility, if available.

[3] Please enter the Energy Commission Renewable Energy Program Registration number for the generating facility, if applicable.

[4] Please enter the California Energy Commission's assigned unique number for the Certificate of Specific Generation Program, if applicable.

[5] Please enter the California Energy Commission's Plant ID number, if applicable.

[6] Please enter the ISO Meter ID Number for the facility, if available.

[7] Please enter the ISO Resource ID Number for the facility, if available.

[8] Please enter the Qualifying Facility ID Number for the facility, if available.

[9] Please enter the NERC ID number if the facility is located out-of-state, **REQUIRED**. This requirement does not apply if the facility exclusively sells to retail sellers subject to 399.17 of the Public Utilities Code.

[10] Please enter an alternative facility identifier such as a FERC number or if the facility does not have any of the identification numbers in the previous columns. Please describe the "Other Facility Identifier" in footnote a below.

[11] If the procurement claim qualifies for the retailer seller's baseline RPS procurement, please type the word "Baseline". If the procurement claims qualifies as incremental procurement, for the seller's RPS Incremental Procurement Target, please type "IP" for incremental procurement. If a portion of procurement from one facility is claimed and a portion qualifies as IP and another qualifies for the Baseline, please use a separate row for each portion of the claim.

CEC-RPS-TRACK

SCHEDULE 2: TO BE COMPLETED BY RETAIL SELLERS
Report to the California Energy Commission
Procurement of Renewable Energy Generation in 2005

INSTRUCTIONS: Enter procurement by month made from **all** renewable facilities in 2005, regardless of their classification as an "eligible renewable energy resource" as defined in Public Utilities Code Section 399.12(a). If you need additional rows, please click on the "Insert Row" button on Schedule 1.
PLEASE COMPLETE the field labeled "Total Retail Sales in 2005 in kWh" to indicate the base of retail sales against which the renewable energy purchases will be compared.

SPECIFIC RENEWABLE ENERGY PURCHASES																	
Facility Name	Unit Number	Fuel Type	CEC RPS Certification Number	Procurement Qualifies for Baseline or IPT	Method of Accounting Line Losses[1]	January kWh Procured	February kWh Procured	March kWh Procured	April kWh Procured	May kWh Procured	June kWh Procured	July kWh Procured	August kWh Procured	September kWh Procured	October kWh Procured	November kWh Procured	December kWh Procured	Annual Procurement in kWh
																	0
																	0
																	0
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																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0
																	0

Total Retail Sales in 2005 in kWh[2]

Total Certified Renewables Procured
0

[1] Indicate whether a Generation Meter Multiplier (denote GMM), ISO settlement data (denote ISO), or another method (please indicate) was used to apply a line loss factor in computing kWh procured. If no line loss factor was used, denote "None".
[2] If this value differs from utility FERC Form 1 filing for this year, please detail the discrepency in a footnote.

CEC-RPS-TRACK

(TO BE COMPLETED BY RETAIL SELLERS)
Report to the California Energy Commission
Procurement of Renewable Energy By Retail Sellers in 2005
ATTESTATION FORM

I, (print name and title) ____, **declare under penalty of perjury that the statements contained in Schedules 1 and 2 are true and correct and that I, as an authorized agent of** (print name of company) ____________________, **have authority to submit this report on the company's behalf. I further declare that the kilowatt-hours claimed as specific purchases as shown in Schedule 2, are to the best of my knowledge, sold once and only once to retail consumers. The renewable electricity and associated Renewable Energy Certificates used for RPS compliance have not otherwise been, nor will be, sold, retired, claimed, or represented as part of electical energy output or sales, or used to satisfy obligations in jurisdictions other than California, and for no other reason than to comply with California's Renewables Portfolio Standard. I certify that the procurement claimed to meet baseline and Interim Procurement Target, respectively meets those criteria.**

Out-of-state facilities are subject to the same deliverability requirements as in-state facilities. Generation that will be counted for purposes of RPS compliance from out-of-state facilities must be delivered to an in-state market hub (also referred to as "zone") or in-state substation (also referred to as "node") located within the California ISO control area (or delivery point that meets applicable CPUC rules) of the WECC transmission system. The requirements of the two foregoing sentences do not apply to retail sellers subject to Public Utilities Code Section 399.17.

Signed: ____________________________________

Dated: ______________

Executed at: ________________________________

CONTACT INFORMATION	
Name	
Title	
Company Name	
Address	
City, State, Zip	
Phone	
Fax	
E-mail	

CEC-RPS-GEN

(TO BE COMPLETED BY GENERATORS)
REPORT to the CALIFORNIA ENERGY COMMISSION
Report of Generation for California RPS Certified Facilities
for Calendar Year 2005

GENERAL INSTRUCTIONS

Please enter the following information:

Name of Company Preparing Form	
Name of Individual Completing Form	

PLEASE ENABLE MACROS IN ORDER FOR THE FORMS TO WORK PROPERLY. Generating facilities that were certified by an Investor-Owned Utility on their behalf are not required to complete Schedules 3 and 4. However generators that certified on their own behalf are required to complete Schedules 3 and 4. This form may be used to enter information for any number of generating facilities. Complete Schedules 3 and 4 and e-mail the completed file to the address shown below. Then print out the file, sign the attestation as appropriate, and mail the package to the address shown below:

California Energy Commission
e-mail: RPSTrack@energy.state.ca.us
Jason J. Orta
Attn: Interim Tracking
California Energy Commission
1516 9th Street, MS-45
Sacramento, CA 95814-5512

These forms are due by close of business on May 1, 2006.

PLEASE NOTE: The Energy Commission reserves the right to ask for supplemental documentation to this filing including utility statements provided to the individual generators.

Schedule 3: TO BE COMPLETED BY GENERATORS
Report to the California Energy Commission
Certified RPS Facilities (20054)

INSTRUCTIONS: Please list the generating facilities for which certified RPS generation will be reported on this form. Please enter the requested information for each generating unit. Do not enter information into the shaded cells. **To expedite the processing of this form, please list as many of the generating units' identification numbers as possible**. If you need additional rows, click the "Insert Row" button above.

RENEWABLE ENERGY FACILITIES														
Facility Name	Unit Number	Fuel Type	CEC RPS Certification Number[1]	EIA ID Number[2]	CEC ID Number[3]	GenReport Certificate Number[4]	CEC Plant ID Number[5]	ISO Meter ID Number[6]	ISO Resource ID Number[7]	QF ID Number[8]	NERC ID Number[9]	Other Facility Identifier[10]	Generation Statutorily Restricted to Baseline[11]	Annual Generation (in kWh)

[1] Please enter the California Energy Commission RPS Certification number for the facility, REQUIRED.
[2] Please enter the Energy Information Administration identification number for the generating facility, if available.
[3] Please enter the Energy Commission Renewable Energy Program Registration number (i.e. the Existing and New Account Number) for the generating facility, if applicable.
[4] Please enter the California Energy Commission's assigned unique number for the Certificate of Specific Generation Program, if applicable.
[5] Please enter the California Energy Commission's Plant ID number, if applicable.
[6] Please enter the ISO Meter ID Number for the facility, if available.
[7] Please enter the ISO Resource ID Number for the facility, if available.
[8] Please enter the Qualifying Facility ID Number for the facility, if available.
[9] Please enter the NERC ID number if the facility is located out-of-state, **REQUIRED**. This requirement does not apply if the facility exclusively sells to retail sellers subject to Public Utilities Code Section 399.17.
[10] Please enter an alternative facility identifier such as a FERC number or if the facility does not have any of the identification numbers in the previous columns. Please describe the "Other Facility Identifier" in footnote a below.
[11] Generation from the following facilities is statutorily limited to a retail seller's baseline: Geothermal facilities originally operating prior to September 26, 1996, Hydroelectric facilities owned by an IOU as of September 12, 2002, or hydroelectric generation procured by an IOU as of September 12, 2002, and municipal solid waste combustion facilities located in Stanislaus County and operating prior to September 26, 1996. If the generation reported was generated by the aforementioned technologies, please write "Baseline." If a portion of procurement from one facility is claimed and a portion qualifies as IP and another qualifies for the baseline, please use a

CEC-RPS-GEN

Schedule 4: TO BE COMPLETED BY GENERATORS
Report to the California Energy Commission
Generation from Certified RPS Facilities (2005)

Please list the monthly IOU or third party verified meter reads of generation for each generating facility. If you need additional rows, please click the "Insert Row" button above.

GENERATION FROM RENEWABLE ENERGY FACILITIES																	
Facility Name	Unit Number	Fuel Type	CEC RPS Certification Number[1]	Generation Statutorily Restricted to Baseline[10]	January Generation (in kWh)	February Generation (in kWh)	March Generation (in kWh)	April Generation (in kWh)	May Generation (in kWh)	June Generation (in kWh)	July Generation (in kWh)	August Generation (in kWh)	September Generation (in kWh)	October Generation (in kWh)	November Generation (in kWh)	December Generation (in kWh)	Annual Generation (in kWh)

CEC-RPS-GEN

(TO BE COMPLETED BY GENERATORS)
REPORT to the CALIFORNIA ENERGY COMMISSION
Report of Generation for California RPS Certified Facilities for Calendar Year 2005
ATTESTATION FORM

I (print name and title) ___________________________ declare under penalty of perjury that the following is true and correct to the best of my knowledge:

1) I am an authorize agent of (print name of company) _________________ and have authority to submit this report on the company's behalf;
2) The information and data provided in this report, including information provided in Schedules 3 and 4, is correct and is submitted for use to verify generation and procurement requirements pursuant to the California Renewables Portfolio Standard;
3) The kilowatt-hours of electricity generation in Schedule 4 of this report have been sold once and only once by the generator signing this attestation;
4) To the best of my knowledge, none of the renewable electricity identified in Schedules 3 or 4 of this report, nor any of the Renewable Energy Certificates associated with this renewable electricity, has been or will be used, sold, retired, claimed, or represented as part of electrical energy output or sales to satisfy renewable procurement obligations in jurisdictions other than California;
5) Out-of-state facilities are subject to the same deliverability requirements as in-state facilities. Generation that will be counted for purposes of RPS compliance from out-of-state facilities must be delivered to an in-state market hub (also referred to as "zone") or in-state substation (also referred to as "node") located within the California ISO control area (or delivery point that meets applicable CPUC rules) of the WECC transmission system. The requirements of the two foregoing sentences do not apply to retail sellers subject to Public Utilities Code Section 399.17.

Signed: ____

Dated: _________________

CONTACT INFORMATION
(FOR PREPARER OF THIS REPORT)

Name	
Title	
Company Name	
Address	
City, State, Zip	
Phone	
Fax	
E-mail	

California Energy Commission

CEC-RPS-1A
Application for Certification
California Renewables Portfolio Standard Program

For certification, please fill out all applicable portions of application, sign, and submit completed form to:

California Energy Commission, Attn: RPS Certification
1516 Ninth Street, MS-45, Sacramento, CA 95814

Please also submit form electronically via e-mail to:
RPSTrack@energy.state.ca.us, subject line "RPS Certification"

To apply for pre-certification, use form CEC-RPS-1B

All data on this form is subject to public disclosure

Section I: Type of Certification Requested

*Choose **One***

☐ Eligible for California RPS

☐ Eligible for California RPS plus Supplemental Energy Payments (SEPs)

*Choose **One***

☐ Certification ☐ Amended certification ☐ Renewal

If this is an amendment or renewal, date of original certification (m/d/yyyy): ________________

If an amendment, note certification number, if applicable. ________________

Please note: Facility must be on line to qualify for certification. To register as Renewable Only (not eligible for RPS or SEP), please use form CEC-1038-E1, available on-line at: www.energy.ca.gov/renewables/documents

Section II: Applicant Contact Information

Name: ________________ Title: ________________

Company: ________________

Address: ________________

City: ________________ State: ________ ZIP: ________

Telephone: ________________ Fax: ________________ E-Mail: ________________

Person Completing Form (if different from Applicant Contact): ________________

Section III: Facility Information

Name of Facility: ________________

Location: City: ________________ County: ________________ State: ______

☐ Located within California ☐ Located outside of California

Telephone: ________________ Fax: ________________ E-Mail: ________________

Owner Name: ________________

Owner Address: ________________

City: ________________ State: ________ ZIP: ________

Owner Telephone: ________________ Fax: ________________ E-Mail: ________________

A-10

Please specify any additional names this facility is or has been known by, including names the facility has used in the past, if known: ____________________

For example, the facility may have changed names or may be part of a group of facilities collectively known by one name.

ID#'s (if known): CEC-REP ____________ CEC-RPS _____________ CEC-Other ____________

QFID ____________ EIA ____________ CA ISO ____________ SO ____________

Other (please explain) __________________

CEC-REP *refers to the CEC ID# under the Renewable Energy Program.*

CEC-RPS *refers to the CEC ID# issued under the Renewables Portfolio Standard, if this application is an amendment or renewal.*

CEC-Other *refers to any other CEC ID# issued.*

QFID *refers to a unique identifier assigned to a Qualifying Facility by the retail seller contracting for power from the facility.*

EIA *refers to the number assigned by the Energy Information Administration that is used to report monthly generation data to the EIA.*

CAISO *refers to the number assigned to the facility by the California Independent System Operator.*

SO *refers to number assigned to the facility by another system operator, not the CA ISO.*

Location of WECC interconnection: ____________________

The WECC interconnection is the substation where radial lines from the facility interconnect/will interconnect to the WECC controlled transmission system.

Control area operator for facility: ☐ CA ISO ☐ Other (provide name): ____________________

Nameplate capacity of facility (in megawatts): ____________________

Choose ***One***	☐ Facility commenced commercial operations prior to January 1, 2002 (specify date): ____________________
	☐ New facility, commenced commercial operation after January 1, 2002 (specify date): ____________________
	☐ Repowered facility, re-entered commercial operation after January 1, 2002 (specify date): ____________________

Section IV: Eligibility for Supplemental Energy Payments

1. Is the output from this facility being sold under a long-term contract entered into prior to January 1, 2002 with a California retail seller that includes fixed energy or capacity payments?

   ☐ Yes ☐ No

If yes: A. Date contract executed: ____________________

B. Retail seller contracted with: ____________________

C. Does the output from this facility meet the requirements in Public Utilities Code Section 399.6(c)(1)(C) as shown below? ☐ Yes ☐ No (*If yes, attach a detailed explanation. If no, facility is not eligible for SEPs)*

Public Utilities Code Section 399.6(c)(1)(C) – to be eligible for SEPs, all of the following must occur:

1) The facility's power purchase contract provides that all energy delivered and sold under the contract is paid at a price that does not exceed commission-approved short-run avoided cost of energy.

2) Either of the following:

a. The power purchase contract is amended to provide that the kWh used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kWh production, but no greater than the five-year average of the kWh delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive.

b. If a facility's installed capacity as of December 31, 1998, is less than 75 percent of the nameplate capacity as stated in *the power purchase contract, the power purchase contract is amended to provide that the kWh used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kWh production, but no greater than the product of the five-year average of the kWh delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive, and the ratio of installed capacity as of December 31 of the previous year, but not to exceed contract nameplate capacity, to the installed capacity as of December 31, 1998.*

3) *The Supplemental Energy Payments are payable only with respect to the kWh delivered in a particular month that exceeds the corresponding five-year average calculated pursuant to clause 2.*

2. Is the facility owned by a retail seller or local publicly-owned electric utility? ☐ Yes ☐ No
Retail seller-owned facilities are not eligible to receive SEPs, but may be eligible for the RPS.

3. Is the entire output of the facility intended to be used exclusively on-site (i.e. self generation)? ☐ Yes ☐ No
On-site generation is not eligible to receive SEPs.

4. Is the entire output of facility excluded from paying an applicable competitive transition charge? ☐Yes ☐No
If yes, facility is not eligible to receive SEPs.

Section V: Facility Fuel Type

5. Please indicate energy source used by the facility. For hybrid systems, indicate all energy sources used.

☐ Biodiesel *(complete Section VI, questions 7-11)*

☐ Biomass *(complete Section VI, questions 8-11)*

☐ Digester Gas *(skip to Section VII)*

☐ Fuel Cell *(skip to Section VII)*

☐ Geothermal *(complete Section VI, questions 12-15)*

☐ Hydropower *(complete Section VI, questions 16-20)*

☐ Landfill Gas *(skip to Section VII)*

☐ Municipal Solid Waste, combustion *(complete Section VI, question 21)*

☐ Municipal Solid Waste, conversion *(complete Section VI, questions 21-23)*

☐ Photovoltaic *(skip to Section VII)*

☐ Solar Thermal Electric *(skip to Section VII)*

☐ Tidal Current *(skip to Section VII)*

☐ Ocean Wave *(skip to Section VII)*

☐ Ocean Thermal *(skip to Section VII)*

☐ Wind *(skip to Section VII)*

☐ Hybrid System *(complete Section VI, questions 24-25)*

6. Does this facility use any fossil fuel for purposes of generating electricity? ☐ Yes ☐ No

If yes, please specify average annual percentage on a total heat input basis for the calendar year immediately prior to the date of application: ______________________________

Facilities that use fossil fuel must complete Section VI, questions 24-25 for hybrid systems.

Section VI: Additional Required Information for Specific Fuel Types

Facilities using digester gas, fuel cell, landfill gas, photovoltaic, solar thermal, tidal current, ocean wave, ocean thermal, and wind technologies have no special fuel requirements. Applicants for facilities using these fuels or resources exclusively may skip to Section VII.

For Biodiesel Applicants

7. Source of biodiesel fuel

*Choose **One***	☐ Biodiesel derived from biomass fuel – answer questions 8-11. ☐ Biodiesel derived from MSW conversion process – answer questions 21-23.

For Biomass Applicants

8. Did the facility commence commercial operations prior to January 1, 2002?

☐ *Yes, please note that facility is not eligible for SEPs* ☐ *No*

9. Indicate current source of biomass fuel supply *(check all that apply)*:

- ☐ Agricultural crops and agricultural wastes and residues.
- ☐ Solid waste materials - Includes waste pallets, crates, dunnage, manufacturing and construction wood wastes; landscape or right-of-way tree trimmings; mill residues resulting directly from milling of lumber; rangeland maintenance residues; and sludge derived from organic sludge.
- ☐ Wood and wood wastes from forest timbering operations, including forest fuel fire reduction, and forest stand improvement.
- ☐ Wood and wood wastes that meet all of the following requirements (if a facility uses wood and wood wastes and the applicant seeks certification as SEP-eligible, the fuel must meet these criteria):
  1) Harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Ch. 8 (commencing with Sec. 4511), Pt. 2, Div. 4, Public Resources Code).
  2) Harvested for the purpose of forest fire fuel reduction or forest stand improvement.
  3) Do not transport or cause the transportation of species known to harbor insect or disease pests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by those agencies.

Facilities using these biomass fuels are eligible for the RPS, regardless of the date they commenced commercial operations.

10. To be eligible for SEPs, an applicant for a “new” or “repowered” biomass facility must agree to use only eligible biomass fuel and to annually provide written attestations from its fuel supplier(s) documenting that the supplier(s) have delivered eligible biomass fuel to the facility. Applicant must also agree to provide documentation, or make documentation available upon request, to the Energy Commission verifying ongoing compliance with these requirements.

☐ Applicant acknowledges and agrees to comply with the above requirements as more fully described in the *Renewable Portfolio Standard Eligibility Guidebook*.

11. For biomass facility operators receiving SEPs only: You must submit an annual report to the Energy Commission describing fuel use as follows: tons of biomass by type of biomass, the air district from which the biomass originated if the fuel may have been open-field burned had it not been used for electricity production, and an attestation from the fuel supplier(s) that the biomass fuel continues to meet the RPS eligibility standards. The report is due to the Energy Commission on February 15th of each year to report on the biomass supply consumed in the previous calendar year.

☐ Applicant acknowledges and agrees to comply with the above requirements as more fully described in the *Renewable Portfolio Standard Eligibility Guidebook*.

For Geothermal Applicants

12. Date facility commenced commence commercial operations

*Choose **One***	☐ Prior to September 26, 1996 *Generation may be eligible for the RPS but only to establish or adjust a retail seller’s baseline.*
	☐ Between September 26, 1996 and January 1, 2002 *Generation may be eligible for RPS but not for SEPs.*
	☐ On or after January 1, 2002 *Generation may be eligible for both RPS and SEPs.*

13. Are you applying for certification for incremental geothermal?

☐ Yes *(complete question 14)* ☐ No *(skip to Section VII)*

Incremental generation from geothermal facilities is eligible for the RPS but is limited to generation resulting from “eligible capital expenditures” as defined in the Renewables Portfolio Standard Eligibility Guidebook. *Incremental geothermal generation may be eligible for SEPs to the extent that the generation meets criteria for a “new” or “repowered” facility.*

14. Eligible capital expenditures

Choose all that apply	☐ The capital expenditure results in replaced generating equipment or increased steam converted to generation. ☐ The capital expenditure does not cause an increase in the decline rate of the reservoir. ☐ The capital project was completed after September 26, 1996. *Only capital expenditures that meet all of the above criteria are considered "eligible."*

15. Please attach the documentation specified in the section titled "Supplemental Instructions for Incremental Geothermal Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook.*

For Hydropower Applicants

16. Facility size

☐ Applicant certifies that total facility size, including any incremental additions to original facility, does not exceed 30 megawatts.

Only hydropower facilities 30 megawatts or less in size qualify for the RPS or RPS and SEPs.

17. Date facility commenced commercial operations (choose one)

☐ Facility commenced commercial operations prior to September 12, 2002 *(complete question 18)*
☐ Facility commenced commercial operations on or after Sept. 12, 2002 *(complete question 19)*
☐ Facility is "repowered" and re-entered commercial operation after September 12, 2002 *(complete questions 18-19)*

Generation may be eligible for RPS or RPS and SEPs

18. Was facility owned by, and/or its generation procured by, a retail seller as of September 12, 2002?

☐ Yes ☐ No

If yes, generation may be eligible only for purposes of establishing a retail seller's RPS baseline. Facility's generation may not be used for adjusting a retail seller's baseline or meeting a retail seller's annual procurement target.

19. "New" or "Repowered" Hydropower Facilities: please check all that apply:

Facility located within California	*Facility located outside California*
☐ The applicant has a permit or license from the State Water Resources Control Board (SWRCB) to appropriate water, which was issued before September 12, 2002. ☐ The applicant can operate its facility under its existing SWRCB permit or license. • *The facility does not require a new or revised permit from the SWRCB for a new appropriation of water.* • *The facility does not require a new permit or license from the SWRCB for a new diversion of water.* • *The facility will not require an increase in the volume or rate of water diverted that would require a new permit or license from the SWRCB.* ☐ The facility does not require an increase in the volume or rate of water diverted under an existing right, even if such a change would not require a water right permit or license from the SWRCB.	☐ The applicant has a permit or license from the applicable governing body to appropriate water, which was issued before September 12, 2002. ☐ The applicant can operate its project under its existing government-issued permit or license. • *The facility does not require a new permit or license from any government body for a new appropriation of water.* • *The facility does not require a new permit or license from any government body for a new diversion of water.* ☐ The facility does not require an increase in the volume or rate of water diverted under an existing right, even if such a change would not require a new permit or license from any government body.

20. Please attach the documentation specified in the section titled "Supplemental Instructions for Small Hydropower Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*

For Municipal Solid Waste Applicants	
21. Type of MSW Facility	
*Choose **One***	☐ MSW combustion facility that meets the following criteria *(skip to Section VII)* *Generation is eligible for the RPS only if the facility is located in Stanislaus County and commenced commercial operations prior to September 26, 1996. Applicant must attach documentation to this application demonstrating that the facility meets both of these requirements. Generation from MSW combustion facilities is only eligible to establish or adjust a retail seller's RPS baseline.* ☐ MSW conversion facility *(answer questions 22-23)* *Facility uses a non-combustion thermal process to convert MSW to a clean-burning fuel that is then used to generate electricity.*
22. MSW conversion facilities must meet **all** of the following criteria to be eligible for the RPS or RPS and SEPs. Please check all that apply: ☐ The technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control. ☐ The technology does not produce any discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code. ☐ The technology does not produce any discharges to surface or groundwaters of the state. ☐ The technology does not produce any hazardous wastes. ☐ To the maximum extent feasible, the technology removes all recyclable materials and marketable green waste compostable materials from the solid waste stream before the conversion process and the owner or operator of the facility certifies that those materials will be recycled or composted. ☐ The facility at which the technology is used is in compliance with all applicable laws, regulations, and ordinances. ☐ The technology meets any other conditions established by the State Energy Resources Conservation and Development Commission. ☐ The facility certifies that any local agency sending solid waste to the facility diverted at least 30 percent of all solid waste it collects through solid waste reduction, recycling, and composting. ☐ The facility certifies that any local agency sending solid waste to the facility is in compliance with Division 30 (Commencing with Section 4000), has reduced, recycled, or composted solid waste to the maximum extent feasible. (The California Integrated Waste Management Board must find that the facility has diverted at least 30 percent of all solid waste through source reduction, recycling, and composting.) Facilities must satisfy these criteria to be eligible for SEPs.	
23. Please attach the documentation specified in the section entitled "Supplemental Instructions for Municipal Solid Waste Conversion Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*.	
For Hybrid System Applicants	
24. Type of Hybrid System:	
*Choose **One***	☐ Pumped Storage Hydropower *(identify energy source used for pumping)* ________________________ *Must use a renewable energy source to be eligible for RPS or RPS and SEPs;* ***only the amount of energy dispatched to the transmission system is eligible.***
	☐ Other *(describe fuels used – attach additional sheets if necessary)* ____________________

25. For Hybrid Systems using fossil fuel (please select A **or** B)

☐ A. Facility commenced commercial operations or was repowered before January 1, 2002:

*If you checked "A", choose **one***	☐ Applicant attests that the percentage of fossil fuel used in the facility does not exceed 25 percent of the total annual energy input of the facility. *Facilities using fossil fuel that were operational or repowered prior to January 1, 2002 may use up to 25 percent fossil fuel and still have the total generation from their facility considered renewable and eligible for the RPS.* ☐ Percentage of fossil fuel used in the facility exceeds 25 percent of the total annual energy input of the facility. *Only the renewable portion of electricity production may qualify for the RPS, and only once an appropriate tracking system is developed to monitor such production.* ☐ Facility was developed and awarded a power purchase contract as a result of a retail seller Interim RPS procurement solicitation approved by the California Public Utilities Commission, and applicant attests that the facility uses no more than 25 *percent* fossil fuel annually on a total energy input basis. *Facilities developed and awarded power purchase contracts as a result of a retail seller's Interim RPS procurement solicitation and approved by the CPUC may use up to 25 percent fossil fuel and count 100 percent of the electricity generated as RPS-eligible.*

☐ B. Facility commenced commence commercial operation or was repowered on or AFTER January 1, 2002:

*If you checked "B", choose **one***	☐ Facility is certified as a Qualifying Small Power Production Facility (QF), and applicant attests that the facility satisfies the fossil fuel use limitations specified in PURPA. *Facilities certified as QFs under the federal Public Utilities Regulatory Policies Act may use up to 25 percent fossil fuel and count 100 percent of the electricity generated as RPS eligible provided the facility otherwise satisfies the applicable California RPS standards.* ☐ Facility is NOT certified as a Qualifying Small Power Production Facility but uses some percentage of fossil fuel. *Only the renewable portion of electricity production may qualify for the RPS, and only once an appropriate tracking system is developed to monitor such production.* ☐ Facility was developed and awarded a power purchase contract as a result of a retail seller's Interim RPS procurement solicitation approved by the California Public Utilities Commission, and applicant attests that the facility uses no more than 25 percent fossil fuel annually on a total energy input basis. *Facilities developed and awarded power purchase contracts as a result of a retail seller's Interim RPS procurement solicitation and approved by the CPUC may use up to 25 percent fossil fuel and count 100 percent of the electricity generated as RPS eligible.*

Section VII: Repowered Facility Information

26. Is applicant requesting certification for RPS and SEP eligibility for a repowered facility that re-entered commercial operations after January 1, 2002?

☐ Yes. Answer questions 27 and 28. ☐ No. Skip to Section VIII

27. Please indicate the method used to demonstrate compliance with the 80 percent threshold:

☐ Tax Records Methodology ☐ Replacement Value Methodology

Applicant must document the value of the capital investments made to the facility and the total value of the repowered facility, and the value of the capital investments must equal at least 80 percent of the total value of the repowered facility.

28. Generally describe the prime generating equipment replaced at the facility: ______________________________

Please attach the documentation specified in the section titled "Supplemental Instructions for Repowered Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*.

The applicant must document that the facility's prime generating equipment is new. For a definition of each renewable resource's prime generating equipment, please see the Renewables Portfolio Standard Eligibility Guidebook.

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Section VIII: Out-of-State Facility Information

29. Is the facility's first point of interconnection to the WECC transmission system located within California?

☐ Yes. Facility is considered an in-state facility for purposes of RPS and SEP eligibility. Skip to Section IX.

☐ No. Answer questions 30-34.

☐ Other. Check here if the facility exclusively serves retail sellers subject to Public Utilities Code Section 399.17. Skip to Section IX

30. Provide the facility NERC ID (the Source point name) ____

The NERC ID refers to the North American Electricity Reliability Council identification Source point name for this facility. The NERC ID is **required** to certify RPS eligibility of a facility that is located outside of California.

31. For RPS eligibility only, applicants for out-of-state facilities must submit documentation showing that the facility meets all of the following criteria (check all that apply):

☐ Facility has guaranteed contracts to sell its generation to a retail seller or the California Independent System Operator (CA ISO).

☐ Facility can demonstrate delivery of its generation to the in-state market hub/zone or in-state substation/node located within the CA ISO control area of the WECC transmission system (or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO).

☐ Applicant agrees to participate in the Energy Commission's RPS tracking and verification system.

32. For SEP eligibility: Applicants for out-of-state facilities must submit documentation showing that their facility meets all of the following criteria (check all that apply, skip to question 33 if not seeking SEP eligibility).

☐ Facility is located within the United States.
Facility may not cause or contribute to any violation of a California environmental quality standard or requirement.

☐ Facility is located outside of the United States.
Facility must be developed and operated in a manner that is as protective of the environment as a similar facility located within California.

☐ Facility is located so that it is/will be connected to the WECC transmission system.

☐ Facility is developed with guaranteed contracts to sells its power to end use customers of California retail sellers during the period in which it will receive SEPs.

☐ Facility can demonstrate delivery of its generation to the in-state market hub/zone or in-state substation/node located within the CA ISO control area of the WECC transmission system (or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO).

☐ Applicant agrees to participate in the Energy Commission's RPS tracking and verification system.

33. To be eligible solely for RPS or also for SEPs, an applicant for an out-of-state facility must agree to comply with the "Delivery Requirements" specified in the "Eligibility of Out-of-State Facilities" section of the *Renewables Portfolio Standard Eligibility Guidebook.*

☐ Applicant acknowledges and agrees to comply with the above requirements as more fully described in the *Renewables Portfolio Standard Eligibility Guidebook.*

34. Please attach the documentation specified in the section titled "Supplemental Instructions for Out-of-State Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*.

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Section IX: General Information

The Energy Commission reserves the right to request additional information to confirm or clarify information provided in this application including any attachments.

The Energy Commission's Accounting Office or its authorized agents, in conjunction with Energy Commission technical staff, may audit any applicant to verify the accuracy of any information included as part of an application for RPS or RPS and SEP certification, pursuant to the *Overall Program Guidebook for the Renewable Energy Program*. As part of an audit, an applicant may be required to provide the Accounting Office or its authorized agents with any and all information and records necessary to verify the accuracy of any information included in the awardee's applications, invoices, or reports. An applicant may also be required to open its business records for on-site inspection and audit by the Accounting Office or its authorized agents for purposes of verifying the accuracy of any information included in the applicant's applications, invoices, and reports.

Certified facilities must notify the Energy Commission promptly of any changes in information previously submitted to the Energy Commission. A facility failing to do so risks losing its certification status. Any changes affecting the facility's certification status should be reported on an amended CEC-RPS-1A form. If there are any changes to the status of a facility's certification, the new information will be posted on the Energy Commission's Web site, and any affected retail seller contracting with that facility will be promptly notified.

Section X: Signature

I am an authorized officer of the above-noted facility owner or a retail seller contracting with the above noted facility owner and hereby submit this application on behalf of said facility owner for certification of the facility as a renewable facility eligible for California's RPS or certification as eligible for California's RPS and SEPs. I have read the above information as well as the *Renewables Portfolio Standard Eligibility Guidebook,* the *Overall Program Guidebook for the Renewable Energy Program,* and the *New Renewable Facilities Program Guidebook* and understand the provisions of these guidebooks and my responsibilities. I acknowledge that the receipt of any certification approval from the California Energy Commission is conditioned on the acceptance and satisfaction of all program requirements as set forth in the *Renewables Portfolio Standard Eligibility Guidebook* and the *Overall Program Guidebook for the Renewable Energy Program*. I declare under penalty of perjury that the information provided in this application and any attachments is true and correct to the best of my knowledge.

Applicant Name: ______________________________

Applicant Title: ______________________________

Signature: ______________________________

Date signed: ______________________________

REMINDER:
HAVE YOU INCLUDED
ALL NECESSARY ATTACHMENTS?

Supplemental Information is required for:
Biodiesel (New or Repowered)
Biomass (New or Repowered seeking SEP-eligibility)
Incremental Geothermal, Hydropower,
New or Repowered Municipal Solid Waste Conversion
Hybrids, Repowered Facilities, Out-of-State Facilities

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California Energy Commission

CEC-RPS-1B
Application for Pre-Certification
California Renewables Portfolio Standard Program

For Pre-certification, please fill out all applicable portions of application, sign, and submit completed form to:

California Energy Commission, Attn: RPS Certification
1516 Ninth Street, MS-45, Sacramento, CA 95814

Please also submit form electronically via e-mail to:
RPSTrack@energy.state.ca.us, subject line "RPS Certification"

To apply for certification, use form CEC-RPS-1B

All data on this form is subject to public disclosure

Section I: Type of Pre-Certification Requested

Choose ***One***	☐ Eligible for California RPS ☐ Eligible for California RPS plus Supplemental Energy Payments (SEPs)
Choose ***One***	☐ Pre-certification ☐ Amended pre-certification ☐ Renewal If this is an amendment or renewal, date of original certification (m/d/yyyy): ____________ If an amendment, note pre-certification number, if applicable. ____________ ***Please note: Pre-certification is available for facilities that are not on line or do not have power purchase contracts with a retail seller at the time of application. To register as Renewable Only (not eligible for RPS or SEP), please use form CEC-1038-E1, available on-line at: www.energy.ca.gov/renewables/documents/index.html***

Section II: Applicant Contact Information

Name: ____________ Title: ____________

Company: ____________

Address: ____________
City: ____________ State: ________ ZIP: ________

Telephone: ____________ Fax: ____________ E-Mail: ____________

Person Completing Form (if different from Applicant Contact): ____________

Section III: Facility Information

Name of Facility: ____________

Location: City: ____________ County: ____________ State: ______

☐ Located within California ☐ Located outside of California

Telephone: ____________ Fax: ____________ E-Mail: ____________

Owner Name: ____________

Owner Address: ____________
City: ____________ State: ________ ZIP: ________

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Owner Telephone: ____________________ Fax:_____________________ E-Mail: ________________________

Please specify any additional names this facility is or has been known by, including names the facility has used in the past, if known: ____

For example, the facility may have changed names or may be part of a group of facilities collectively known by one name.

ID#'s (if known): CEC-REP ____________ CEC-RPS _____________ CEC-Other ____________

QFID ____________ EIA ____________ CA ISO ____________ SO ____________

Other (please explain) __________________

***CEC-REP** refers to the CEC ID# under the Renewable Energy Program.*

***CEC-RPS** refers to the CEC ID# issued under the Renewables Portfolio Standard, if this application is an amendment or renewal.*

***CEC-Other** refers to any other CEC ID# issued.*

***QFID** refers to a unique identifier assigned to a Qualifying Facility by the retail seller contracting for power from the facility.*

***EIA** refers to the number assigned by the Energy Information Administration that is used to report monthly generation data to the EIA.*

***CAISO** refers to the number assigned to the facility by the California Independent System Operator.*

***SO** refers to number assigned to the facility by another system operator, not the CA ISO.*

Location of WECC interconnection: ____

The WECC interconnection is the substation where radial lines from the facility interconnect/will interconnect to the WECC controlled transmission system.

Control area operator for facility: ☐ CA ISO ☐ Other (provide name): ____________________________

Nameplate capacity of facility (in megawatts): ____

*Choose **One***	☐ Facility commenced commercial operations prior to January 1, 2002 (specify date): ________________________________
	☐ New facility, commenced/will commence commercial operation after January 1, 2002 (specify date/expected date): ________________________________
	☐ Repowered facility, re-entered/will re-enter commercial operation after January 1, 2002 (specify date/expected date): ________________________________

Section IV: Pre-Certification Eligibility for Supplemental Energy Payments

1. Is the output from this facility being sold under a long-term contract entered into prior to January 1, 2002 with a California retail seller that includes fixed energy or capacity payments?

   ☐ Yes ☐ No

If yes: A. Date contract executed: ____

B. Retail seller contracted with: ____

C. Does the output from this facility meet the requirements in Public Utilities Code Section 399.6(c)(1)(C) as shown below? ☐ Yes ☐ No (*If yes, attach a detailed explanation. If no, facility is not eligible for SEPs*)

Public Utilities Code Section 399.6(c)(1)(C) – to be eligible for SEPs, <u>all</u> of the following must occur:

1) *The facility's power purchase contract provides that all energy delivered and sold under the contract is paid at a price that does not exceed commission-approved short-run avoided cost of energy.*
2) *Either of the following:*
   a. *The power purchase contract is amended to provide that the kWh used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kWh production, but no greater than the*

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five-year average of the kWh delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive.

b. If a facility's installed capacity as of December 31, 1998, is less than 75 percent of the nameplate capacity as stated in the power purchase contract, the power purchase contract is amended to provide that the kWh used to determine the capacity payment in any time-of-delivery period in any month under the contract shall be equal to the actual kWh production, but no greater than the product of the five-year average of the kWh delivered for the corresponding time-of-delivery period and month, in the years 1994 to 1998, inclusive, and the ratio of installed capacity as of December 31 of the previous year, but not to exceed contract nameplate capacity, to the installed capacity as of December 31, 1998.

3) *The Supplemental Energy Payments are payable only with respect to the kWh delivered in a particular month that exceeds the corresponding five-year average calculated pursuant to clause 2.*

2. Is/will the facility owned by a retail seller or local publicly-owned electric utility? ☐ Yes ☐ No
   Retail seller-owned facilities are not eligible to receive SEPs, but may be eligible for the RPS.

3. Is/will the entire output of the facility intended to be used exclusively on-site (i.e. self generation)? ☐ Yes ☐ No
   On-site generation is not eligible to receive SEPs.

4. Is/will the entire output of facility excluded from paying an applicable competitive transition charge?
   ☐ Yes ☐ No *If yes, facility is not eligible to receive SEPs.*

Section V: Pre-Certification Facility Fuel Type

5. Please indicate energy source that is or will be used by the facility. For hybrid systems, indicate all energy sources used.

☐ Biodiesel *(complete Section VI, questions 7-11)*

☐ Biomass *(complete Section VI, questions 8-11)*

☐ Digester Gas *(skip to Section VII)*

☐ Fuel Cell *(skip to Section VII)*

☐ Geothermal *(complete Section VI, questions 12-15)*

☐ Hydropower *(complete Section VI, questions 16-20)*

☐ Landfill Gas *(skip to Section VII)*

☐ Municipal Solid Waste, combustion *(complete Section VI, question 21)*

☐ Municipal Solid Waste, conversion *(complete Section VI, questions 21-23)*

☐ Photovoltaic *(skip to Section VII)*

☐ Solar Thermal Electric *(skip to Section VII)*

☐ Tidal Current *(skip to Section VII)*

☐ Ocean Wave *(skip to Section VII)*

☐ Ocean Thermal *(skip to Section VII)*

☐ Wind *(skip to Section VII)*

☐ Hybrid System *(complete Section VI, questions 24-25)*

6. Does/will this facility use any fossil fuel? ☐ Yes ☐ No

If yes, please specify average annual percentage on a total heat input basis. If the facility has been operational, please provide the average annual percentage on a total heat input basis for the calendar year immediately prior to the date of application: ______________________

Facilities that use fossil fuel must complete Section VI, questions 24-25 for hybrid systems.

Section VI: Pre-Certification Additional Required Information for Specific Fuel Types

Facilities using digester gas, fuel cell, landfill gas, photovoltaic, solar thermal, tidal current, ocean wave, ocean thermal, and wind technologies have no special fuel requirements. Applicants for facilities using these fuels or resources exclusively may skip to Section VII.

For Biodiesel Applicants

7. Source of biodiesel fuel

*Choose **One***	☐ Biodiesel derived from biomass fuel – answer questions 8-11. ☐ Biodiesel derived from MSW conversion process – answer questions 21-23.

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For Biomass Applicants
8. Did the facility commence commercial operations prior to January 1, 2002? ☐ *Yes, please note that facility is not eligible for SEPs* ☐ *No*
9. Indicate current/anticipated source of biomass fuel supply *(check all that apply)*: ☐ Agricultural crops and agricultural wastes and residues. ☐ Solid waste materials - Includes waste pallets, crates, dunnage, manufacturing and construction wood wastes; landscape or right-of-way tree trimmings; mill residues resulting directly from milling of lumber; rangeland maintenance residues; and sludge derived from organic sludge. ☐ Wood and wood wastes from forest timbering operations, including forest fuel fire reduction, and forest stand improvement. ☐ Wood and wood wastes that meet all of the following requirements (if a facility uses wood and wood wastes and the applicant seeks certification as SEP-eligible, the fuel must meet these criteria): 1) Harvested pursuant to an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Ch. 8 (commencing with Sec. 4511), Pt. 2, Div. 4, Public Resources Code). 2) Harvested for the purpose of forest fire fuel reduction or forest stand improvement. 3) Do not transport or cause the transportation of species known to harbor insect or disease pests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture or the Department of Forestry and Fire Protection, unless approved by those agencies. *Facilities using these biomass fuels are eligible for the RPS, irrespective of the date they commenced commercial operations.*
10. To be eligible for SEPs, an applicant for a “new” or “repowered” biomass facility must agree to use only eligible biomass fuel and to annually provide written attestations from its fuel supplier(s) documenting that the supplier(s) have delivered eligible biomass fuel to the facility. Applicant must also agree to provide documentation, or make documentation available upon request, to the Energy Commission verifying ongoing compliance with these requirements. ☐ Applicant acknowledges and agrees to comply with the above requirements as more fully described in the *Renewable Portfolio Standard Eligibility Guidebook*.
11. For biomass facility operators receiving SEPs only: You must submit an annual report to the Energy Commission describing fuel use as follows: tons of biomass by type of biomass, the air district from which the biomass originated if the fuel may have been open-field burned had it not been used for electricity production, and an attestation from the fuel supplier(s) that the biomass fuel continues to meet the RPS eligibility standards. The report is due to the Energy Commission on February 15th of each year to report on the biomass supply consumed in the previous calendar year. ☐ Applicant acknowledges and agrees to comply with the above requirements as more fully described in the *Renewable Portfolio Standard Eligibility Guidebook*.

For Geothermal Applicants	
12. Date facility commenced/will commence commercial operations	
Choose ***One***	☐ Prior to September 26, 1996 *Generation may be eligible for the RPS but only to establish or adjust a retail seller's baseline.*
	☐ Between September 26, 1996 and January 1, 2002 *Generation may be eligible for RPS but not for SEPs.*
	☐ On or after January 1, 2002 *Generation may be eligible for both RPS and SEPs.*

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13. Are you applying for certification for incremental geothermal?

☐ Yes *(complete question 14)* ☐ No *(skip to Section VII)*

Incremental generation from geothermal facilities is eligible for the RPS but is limited to generation resulting from "eligible capital expenditures" as defined in the Renewables Portfolio Standard Eligibility Guidebook*. Incremental geothermal generation may be eligible for SEPs to the extent that the generation meets criteria for a "new" or "repowered" facility.*

14. Eligible capital expenditures

*Choose **all that apply***	☐ The capital expenditure results/will result in replaced generating equipment or increased steam converted to generation. ☐The capital expenditure does not/will not cause an increase in the decline rate of the reservoir. ☐The capital project was completed after September 26, 1996. *Only capital expenditures that meet all of the above criteria are considered "eligible."*

15. Please attach the documentation specified in the section titled "Supplemental Instructions for Incremental Geothermal Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook.*

For Hydropower Applicants

16. Facility size

☐ Applicant certifies that total facility size, including any incremental additions to original facility, does not/will not exceed 30 megawatts.

Only hydropower facilities 30 megawatts or less in size qualify for the RPS or RPS and SEPs.

17. Date facility commenced/will commence commercial operations (choose one)

☐ Facility commenced commercial operations prior to September 12, 2002 *(complete question 18)*

☐ Facility commenced/will commence commercial operations on/after Sept. 12, 2002 *(complete question 19)*

☐ Facility is "repowered" and re-entered/will re-enter commercial operation after September 12, 2002 *(complete questions 18-19)*

Generation may be eligible for RPS or RPS and SEPs

18. Was facility owned by, and/or its generation procured by, a retail seller as of September 12, 2002? ☐Yes ☐No

If yes, generation may be eligible only for purposes of establishing a retail seller's RPS baseline. Facility's generation may not be used for adjusting a retail seller's baseline or meeting a retail seller's annual procurement target.

19. "New" or "Repowered" Hydropower Facilities: please check all that apply:

Facility located within California	*Facility located outside California*
☐The applicant has a permit or license from the State Water Resources Control Board (SWRCB) to appropriate water, which was issued before September 12, 2002.	☐The applicant has a permit or license from the applicable governing body to appropriate water, which was issued before September 12, 2002.
☐The applicant can operate its proposed facility under its existing SWRCB permit or license. • *The facility does not require a new or revised permit from the SWRCB for a new appropriation of water.* • *The facility does not require a new permit or license from the SWRCB for a new diversion of water.* • *The facility will not require an increase in the volume or rate of water diverted that would require a new permit or license from the SWRCB.*	☐The applicant can operate its proposed project under its existing government-issued permit or license. • *The facility does not require a new permit or license from any government body for a new appropriation of water.* • *The facility does not require a new permit or license from any government body for a new diversion of water.*
☐The facility does not/will not require an increase in the volume or rate of water diverted under an existing right, even if such a change would not require a water right permit or license from the SWRCB.	☐The facility does not/will not require an increase in the volume or rate of water diverted under an existing right, even if such a change would not require a new permit or license from any government body.

20. Please attach the documentation specified in the section titled "Supplemental Instructions for Small Hydropower Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*	
For Municipal Solid Waste Applicants	
21. Type of MSW Facility	
Choose ***One***	☐MSW combustion facility that meets the following criteria *(skip to Section VII)* *Generation is eligible for the RPS only if the facility is located in Stanislaus County and commenced commercial operations prior to September 26, 1996. Applicant must attach documentation to this application demonstrating that the facility meets both of these requirements. Generation from MSW combustion facilities is only eligible to establish or adjust a retail seller's RPS baseline.* ☐ MSW conversion facility *(answer questions 22-23)* *Facility uses or will use a non-combustion thermal process to convert MSW to a clean-burning fuel that is then used to generate electricity.*
22. MSW conversion facilities must meet **all** of the following criteria to be eligible for the RPS or RPS and SEPs. Please check all that apply: ☐ The technology does not/will not use air or oxygen in the conversion process, except ambient air to maintain temperature control. ☐ The technology does not/will not produce any discharges of air contaminants or emissions, including greenhouse gases as defined in Section 42801.1 of the Health and Safety Code. ☐ The technology does not/will not produce any discharges to surface or groundwaters of the state. ☐ The technology does not/will not produce any hazardous wastes. ☐ To the maximum extent feasible, the technology removes/will remove all recyclable materials and marketable green waste compostable materials from the solid waste stream before the conversion process and the owner or operator of the facility certifies that those materials will be recycled or composted. ☐ The facility at which the technology is used/will be used is in compliance with all applicable laws, regulations, and ordinances. ☐ The technology meets/will meet any other conditions established by the State Energy Resources Conservation and Development Commission. ☐ The facility certifies that any local agency sending solid waste to the facility diverted/will divert at least 30 percent of all solid waste it collects through solid waste reduction, recycling, and composting. ☐ The facility certifies that any local agency sending solid waste to the facility is/will be in compliance with Division 30 (Commencing with Section 4000), has reduced, recycled, or composted solid waste to the maximum extent feasible. (The California Integrated Waste Management Board must find that the facility has diverted at least 30 percent of all solid waste through source reduction, recycling, and composting.) Facilities must satisfy these criteria to be eligible for SEPs.	
23. Please attach the documentation specified in the section entitled "Supplemental Instructions for Municipal Solid Waste Conversion Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*.	
For Hybrid System Applicants	
24. Type of Hybrid System:	
Choose ***One***	☐Pumped Storage Hydropower *(identify energy source used for pumping)* ____________________ *Must use a renewable energy source to be eligible for RPS or RPS and SEPs;* ***only the amount of energy dispatched to the transmission system is eligible.***
	☐Other *(describe fuels used – attach additional sheets if necessary)* ________________________

25. For Hybrid Systems using fossil fuel (please select A **or** B)

☐A. Facility commenced commercial operations or was repowered before January 1, 2002:

*If you checked "A", choose **one***	☐ Applicant attests that the percentage of fossil fuel used in the facility does not/will not exceed 25 percent of the total annual energy input of the facility. *Facilities using fossil fuel that were operational or repowered prior to January 1, 2002 may use up to 25 percent fossil fuel and still have the total generation from their facility considered renewable and eligible for the RPS.* ☐ Percentage of fossil fuel used in the facility exceeds/will exceed 25 percent of the total annual energy input of the facility. *Only the renewable portion of electricity production may qualify for the RPS, and only once an appropriate tracking system is developed to monitor such production.* ☐ Facility was developed and awarded a power purchase contract as a result of a retail seller Interim RPS procurement solicitation approved by the California Public Utilities Commission, and applicant attests that the facility uses no more than 25 percent fossil fuel annually on a total energy input basis. *Facilities developed and awarded power purchase contracts as a result of a retail seller's Interim RPS procurement solicitation and approved by the CPUC may use up to 25 percent fossil fuel and count 100 percent of the electricity generated as RPS-eligible.*

☐B. Facility commenced/will commence commercial operation or was/is repowered on or AFTER January 1, 2002:

*If you checked "B", choose **one***	☐ Facility is/will be certified as a Qualifying Small Power Production Facility (QF), and applicant attests that the facility satisfies the fossil fuel use limitations specified in PURPA. *Facilities certified as QFs under the federal Public Utilities Regulatory Policies Act may use up to 25 percent fossil fuel and count 100 percent of the electricity generated as RPS eligible provided the facility otherwise satisfies the applicable California RPS standards.* ☐ Facility is NOT certified as a Qualifying Small Power Production Facility but uses some percentage of fossil fuel. *Only the renewable portion of electricity production may qualify for the RPS, and only once an appropriate tracking system is developed to monitor such production.* ☐ Facility was developed and awarded a power purchase contract as a result of a retail seller's Interim RPS procurement solicitation approved by the California Public Utilities Commission, and applicant attests that the facility uses no more than 25 percent fossil fuel annually on a total energy input basis. *Facilities developed and awarded power purchase contracts as a result of a retail seller's Interim RPS procurement solicitation and approved by the CPUC may use up to 25 percent fossil fuel and count 100 percent of the electricity generated as RPS eligible.*

Section VII: Pre-Certification Repowered Facility Information

26. Is applicant requesting pre-certification for RPS and SEP eligibility for a repowered facility that re-entered or will re-enter commercial operations after January 1, 2002?

☐Yes. Answer questions 27 and 28. ☐No. Skip to Section VIII

27. Please indicate the method used to demonstrate compliance with the 80 percent threshold:

☐ Tax Records Methodology ☐ Replacement Value Methodology

Applicant must document the value of the capital investments made to the facility and the total value of the repowered facility, and the value of the capital investments must equal at least 80 percent of the total value of the repowered facility.

28. Generally describe the prime generating equipment replaced at the facility: ______________________________

Please attach the documentation specified in the section titled "Supplemental Instructions for Repowered Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*.

The applicant must document that the facility's prime generating equipment is new. For a definition of each renewable resource's prime generating equipment, please see the Renewables Portfolio Standard Eligibility Guidebook.

Section VIII: Pre-Certification Out-of-State Facility Information

29. Is or will the facility's first point of interconnection to the WECC transmission system be located in California?

☐ Yes. Facility is considered an in-state facility for purposes of RPS and SEP eligibility. Skip to Section IX.

☐ No. Answer questions 30 – 34 UNLESS the facility is: 1) exclusively serving retail sellers subject to Public Utilities Code Section 399.17, or 2) is not yet on-line. If 1) or 2) applies, skip to Section IX.

☐ Other. Check here if the facility exclusively serves retail sellers subject to Public Utilities Code Section 399.17. Skip to Section IX.

30. Provide the facility NERC ID (Source point name) ____.

The NERC ID refers to the North American Electricity Reliability Council identification Source point name for this facility. The NERC ID is **required** to certify RPS eligibility of a facility that is located outside of California.

31. For RPS eligibility only, applicants for out-of-state facilities must submit documentation showing that the facility meets/will meet all of the following criteria (check all that apply):

☐ Facility has/will have guaranteed contracts to sell its generation to a retail seller or the California Independent System Operator (CA ISO).

☐ Facility can/will be able to demonstrate delivery of its generation to the in-state market hub/zone or in-state substation/node located within the CA ISO control area of the WECC transmission system (or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO).

☐ Applicant agrees to participate in the Energy Commission's RPS tracking and verification system.

32. For SEP eligibility: Applicants for out-of-state facilities must submit documentation showing that their facility meets all of the following criteria (check all that apply, skip to question 33 if not seeking SEP eligibility).

☐ Facility is/will be located within the United States.
Facility may not cause or contribute to any violation of a California environmental quality standard or requirement.

☐ Facility is/will be located outside of the United States.
Facility must be developed and operated in a manner that is as protective of the environment as a similar facility located within California.

☐ Facility is/will be located so that it is/will be connected to the WECC transmission system.

☐ Facility is/will be developed with guaranteed contracts to sells its power to end use customers of California retail sellers during the period in which it will receive SEPs.

☐ Facility can/will demonstrate delivery of its generation to the in-state market hub/zone or in-state substation/node located within the CA ISO control area of the WECC transmission system (or located anywhere in California if applicable CPUC rules allow delivery outside CA ISO).

☐ Applicant agrees to participate in the Energy Commission's RPS tracking and verification system.

33. To be eligible solely for RPS or also for SEPs, an applicant for an out-of-state facility must agree to comply with the "Delivery Requirements" specified in the "Eligibility of Out-of-State Facilities" section of the *Renewables Portfolio Standard Eligibility Guidebook.*

☐ Applicant acknowledges and agrees to comply with the above requirements as more fully described in the *Renewables Portfolio Standard Eligibility Guidebook.*

34. Please attach the documentation specified in the section titled "Supplemental Instructions for Out-of-State Facilities" in the *Renewables Portfolio Standard Eligibility Guidebook*.

Section IX: Pre-Certification General Information

The Energy Commission reserves the right to request additional information to confirm or clarify information provided in this application including any attachments.

The Energy Commission's Accounting Office or its authorized agents, in conjunction with Energy Commission technical staff, may audit any applicant to verify the accuracy of any information included as part of an application for RPS or RPS and SEP pre-certification, pursuant to the *Overall Program Guidebook for the Renewable Energy Program*. As part of an audit, an applicant may be required to provide the Accounting Office or its authorized agents with any and all information and records necessary to verify the accuracy of any information included in the applicant's applications, invoices, or reports. An applicant may also be required to open its business records for on-site inspection and audit by the Accounting Office or its authorized agents for purposes of verifying the accuracy of any information included in the applicant's applications, invoices, and reports.

Pre-certified facilities must notify the Energy Commission promptly of any changes in information previously submitted to the Energy Commission. A facility failing to do so risks losing its pre-certification status. Any changes affecting the facility's pre-certification status should be reported on an amended CEC-RPS-1B form. If there are any changes to the status of a facility's pre-certification, the new information will be posted on the Energy Commission's Web site, and any affected retail seller contracting with that facility will be promptly notified.

Section X: Pre-Certification Signature

I am an authorized officer of the above-noted facility owner or a retail seller contracting with the above noted facility owner and hereby submit this application on behalf of said facility owner for pre-certification of the facility as a renewable facility eligible for California's RPS or pre-certification as eligible for California's RPS and SEPs. I have read the above information as well as the *Renewables Portfolio Standard Eligibility Guidebook,* the *Overall Program Guidebook for the Renewable Energy Program,* and the *New Renewable Facilities Program Guidebook* and understand the provisions of these guidebooks and my responsibilities. I acknowledge that the receipt of any pre-certification approval from the California Energy Commission is conditioned on the acceptance and satisfaction of all program requirements as set forth in the *Renewables Portfolio Standard Eligibility Guidebook* and the *Overall Program Guidebook for the Renewable Energy Program*. I declare under penalty of perjury that the information provided in this application and any attachments is true and correct to the best of my knowledge.

Applicant Name: ____

Applicant Title: ____

Signature: ______________________________ Date signed: ____________

REMINDER: HAVE YOU INCLUDED ALL NECESSARY ATTACHMENTS?

Supplemental Information is required for:
Biodiesel (New or Repowered)
Biomass (New or Repowered seeking SEP-eligibility)
Incremental Geothermal, Hydropower,
New or Repowered Municipal Solid Waste Conversion
Hybrids, Repowered Facilities, Out-of-State Facilities

Tab 1

CEC-RPS-2

Utility Application for Certification of Renewable Facility
California Renewables Portfolio Standard Program

INSTRUCTIONS FOR COMPLETING FORM ARE PROVIDED ON TAB 3

Please complete all applicable fields on the Facility Information sheet (TAB 1), read and sign the attestation (TAB 2), and submit to:
California Energy Commission, Attn: RPS Certification
1516 Ninth Street, MS-45, Sacramento, CA 95814

Form may used to certify multiple facilities
All data on this form is subject to public disclosure

May be submitted electronically via e-mail to:
RPSTrack@energy.state.ca.us, subject line "RPS Certification"
(If submitted electronically, an original signed copy of attestation, along with a hard copy of the completed form, must be submitted to the address above)

Line #	Facility Name	Type of Certification Requested Please Check One				If renewal or amendment, date of original certification	Date of Facility Operation (m-dd-yyyy)	Physical Address			
		Pre	Initial	Amended	Renewal			Street	City	State	ZIP
1		☐	☐	☐	☐						
2		☐	☐	☐	☐						
3		☐	☐	☐	☐						
4		☐	☐	☐	☐						
5		☐	☐	☐	☐						
6		☐	☐	☐	☐						
7		☐	☐	☐	☐						
8		☐	☐	☐	☐						
9		☐	☐	☐	☐						
10		☐	☐	☐	☐						
11		☐	☐	☐	☐						
12		☐	☐	☐	☐						
13		☐	☐	☐	☐						
14		☐	☐	☐	☐						
15		☐	☐	☐	☐						

CEC-RPS-2

Utility Application for Certification of Renewable Facility
California Renewables Portfolio Standard Program

Tab 1 Continued

Line #	If facility is located out of state, check here	Other Names Used by Facility	Technology	Supplemental Information (if applicable; specify category)	Percentage of Fossil Fuel Used, If Any	Nameplate Capacity (in megawatts)
1	☐					
2	☐					
3	☐					
4	☐					
5	☐					
6	☐					
7	☐					
8	☐					
9	☐					
10	☐					
11	☐					
12	☐					
13	☐					
14	☐					
15	☐					

CEC-RPS-2

Utility Application for Certification of Renewable Facility
California Renewables Portfolio Standard Program

Tab 1 Continued

Line #	Other Identification Numbers Used by Facility						
	QFID	CEC-REP	CEC-RPS	CEC-Other	EIA	ISO	Other
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							

CEC-RPS-2

Utility Application for Certification of Renewable Facility
California Renewables Portfolio Standard Program

Tab 1 Continued

Line #	Facility Contact	Title	Company	Address	City	State	ZIP
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							

CEC-RPS-2

Utility Application for Certification of Renewable Facility
California Renewables Portfolio Standard Program

Tab 1 Continued

Line #	Contact Person			Location of WECC Interconnection	Name of Person completing form (if different from Contact Person)	Title	Phone	E-mail
	Phone	Fax	E-Mail					
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								

Tab 2

CEC-RPS-2

Utility Application for Certification
California Renewables Portfolio Standard Program

ATTESTATION

TO BE COMPLETED BY AN AUTHORIZED UTILITY REPRESENTATIVE

The Energy Commission reserves the right to request additional information to confirm or clarify information reported in this application, and to verify the RPS eligibility of any facility identified in the application

The Energy Commission's Accounting Office or its authorized agents, in conjunction with Energy Commission technical staff, may audit any applicant to verify the accuracy of any information included as part of an application for RPS certification, pursuant to the Overall Program Guidebook for the Renewable Energy Program. As part of an audit, an awardee may be required to provide the Accounting Office or its authorized agents with any and all information and records necessary to verify the accuracy of any information included in the awardee's applications, invoices, or reports. An awardee may also be required to open its business records for on-site inspection and audit by the Accounting Office or its authorized agents for purposes of verifying the accuracy of any information included in the awardee's applications, invoices, and reports.

Certified and pre-certified facilities must notify the Energy Commission in a timely manner of any material changes in information previously submitted to the Energy Commission. A facility failing to do so risks losing its certification status. Any changes affecting the facility's certification status should be reported on an amended CEC-RPS-1 form. If there are any changes to the status of a facility's certification, the new information will be posted on the Energy Commission's website and any affected utility contracting with that facility will be promptly notified.

I am an authorized employee of (specify utility) ____________________

and hereby submit this application on behalf of the noted facilities, and the owners of these facilities, for certification as a renewable facility eligible for California's RPS or certification as eligible for California's RPS and SEPs. I have read the above information as well as the Renewables Portfolio Standard Eligibility Guidebook, the Overall Program Guidebook for the Renewable Energy Program, and the New Renewable Facilities Program Guidebook and understand the provisions and my responsibilities. I acknowledge that the receipt of any certification approval from the California Energy Commission is conditioned on the acceptance and satisfaction of all program requirements as set forth in the Renewables Portfolio Standard Eligibility Guidebook and the Overall Program Guidebook for the Renewable Energy Program. I declare under penalty of perjury that the information provided in this form and attachments is true and correct to the best of my knowledge.

Applicant Name: ____________________

Applicant Title: ____________________

Signature: ____________________

Date Signed: ____________________

Tab 3 Instructions for CEC-RPS-2

Explanation of fields used:

Line Number
Used to distinguish multiple certifications.

Facility Name
Specify the name under which the facility will be certified and that will appear on the facilty's certificate of eligibility issued by the Energy Commission.

Type of Certification Requested:
Pre-certification - applies to developers of renewable facilities that are not yet on-line but who are seeking a preliminary determination that their facility will be eligible for the RPS and/or SEPs.
Certification - applies to renewable facilities that are on-line who wish to establish eligibility for the
Amended - applies to facilities already certified as eligible for the RPS and/or SEPs that have undergone material changes since being certified (for example, change of ownership, size of facility, etc.). Facilities that do not notify the Energy Commission in a timely manner of material changes
Renewal - certification must be renewed every two years to ensure that facilities remain eligible for

Date of Certification - For amended applications or applications for renewal, please specify the most recent certification date shown on the facility's certificate issued by the Energy Commission.

Physical Address
If no physical address exists, attach the legal description of the facility location.

If Facility is Located Out-of-State
Please check this box if the facility is located out-of-state, and attach documentation showing that the facility meets all criteria for out-of-state facilities described in the *Renewables Portfolio Standard*

Other Names Used by Facility
Please list all names previously used in the past by the facility, or specify if the facility is part of a group of facilities collectively known by one name. This information will help the Energy Commission to cross-reference facilities listed under multiple names and ensure that there is no double counting

Other Identification Numbers
Facilities may have one or more identification numbers already assigned by the CEC or other organizations. Please provide information per facility as applicable.

QFID - Refers to the unique identifier assigned by the utility contracting for power from the facility.
CEC-REP - Refers to the CEC ID# issued under the Renewable Energy Program.
CEC-RPS - Refers to the CEC ID# issued under the Renewables Portfolio Standard, if this application is an amendment or renewal.
CEC-Other - Refers to ID#s issued by the CEC for the programs other than the Renewable Energy Program or the Renewables Portfolio Standard Program, or for other purposes.
EIA - The number assigned by the Energy Information Administration and used by the facility to report monthly generation data the EIA.
ISO - The number assigned to the facility by the California Independent System Operator.

Tab 3 Instructions for CEC-RPS-2

Other - Please list any other identification numbers used by the facility.

Technology

Please specify one or more of the following:

- Biodiesel
- Biomass
- Digester Gas
- Fuel Cell
- Geothermal
- Incremental Geothermal
- Hydropower (pumped storage hydropower must meet requirements shown in the Renewables Portfolio Standard Eligibility Guidebook, page 16.
- Landfill Gas
- Municipal Solid Waste Combustion - A facility that directly combusts MSW to produce electricity is only eligible for the RPS if it is located in Stanislaus County and was operational prior to September 26, 1996. Applicants for combustion facilities must submit documentation to the Energy Commission demonstrating that the facilities meet these requirements. The generation from such facilities is eligible for the RPS only to initially establish or adjust an IOU's baseline quantity of eligible
- Municipal Solid Waste Conversion (must meet criteria shown in the *Renewables Portfolio Standard Eligibility* Guidebook, pages 13-14.)
- Photovoltaic
- Solar Thermal Electric
- Wind
- Hybrid System (please elaborate)
- Other (please elaborate)

Supplemental Information

Please submit the required supplemental information, as discussed in detail in the *Renewables Portfolio Standard Eligibility Guidebook*, pages 21-30, for facilities in the following categories:

- Repowers, all technologies
- Out-of-State Power
- Hybrid Systems
- New Hydropower
- New Biomass
- Municipal Solid Waste
- Incremental Geothermal

Percentage of Fossil Fuel Used, If Any

A facility that uses some portion of fossil fuel may be considered a hybrid facility if the facility uses more than a designated percentage of fossil fuel. Please refer to the *Renewables Portfolio*

- For facilities that began commercial operation before 1-1-02: all generation is eligible for the RPS as long as the percentage of fossil fuel used does not exceed 25 percent of the total energy input of
- For facilities that began commercial operation after 1-1-02:
  - All generation from facilities using up to 2% fossil fuel may be eligible for the RPS
  - For facilities that use more than 2% fossil fuel, only the renewable portion of the electricity production may qualify for the RPS, and not until an appropriate tracking system for such electricity

Tab 3 Instructions for CEC-RPS-2

Nameplate Capacity (in megawatts)
Please enter the nameplate capacity of the entire facility.

Facility Contact
The facility contact is the contact person for any questions about the technical information about the facility submitted in the application for certification.

Date of Facility Operation (mm-dd-yyyy)
For facilities that are already on-line, enter the date the facility began commercial operations, defined as the date on which a renewable energy facility first delivers power for sale to the procuring retailer seller (consistent with the facility's power purchase contract with the retailer seller).

For facilities that are not yet on-line, enter the date the facility is anticipated to begin commercial

Location of WECC Interconnection
The WECC interconnection is the substation where radial lines from the facility interconnect/will interconnect to WECC-controlled transmission. See the delivery requirements in the *Renewables*

Name of Person completing form, Title, Phone, E-mail
Please enter the name and contact information for the person completing the form in case the Energy Commission has questions about information submitted on the form.

Appendix B - Acronyms

APT	—	annual procurement target
CA ISO	—	California Independent System Operator
CCA	—	community choice aggregator
CIWMB	—	California Integrated Waste Management Board
CPUC	—	California Public Utilities Commission
DG	—	distributed generation
ESP	—	electric service provider
IOU	—	investor owned utility
kWh	—	kilowatt-hour
LFG	—	landfill gas
MSW	—	municipal solid waste
MW	—	megawatt
MWh	—	megawatt-hour
NERC	—	North American Electricity Reliability Council
NRFP	—	New Renewable Facilities Program
PGC	—	Public Goods Charge
PG&E	—	Pacific Gas and Electric Company
PV	—	photovoltaic
REC	—	Renewable Energy Credit/Certificate
REP	—	Renewable Energy Program
RPS	—	Renewable Portfolio Standard
SB	—	Senate Bill
SCE	—	Southern California Edison Company
SDG&E	—	San Diego Gas and Electric Company
SEP	—	supplemental energy payments
SWRCB	—	State Water Resources Control Board
WECC	—	Western Electricity Coordinating Council

Appendix C - Summary of RPS Reporting Requirements

Reporting Party	Reporting Requirement	Due Date
Facility	Certification/ Pre-certification, CEC-RPS-1A or CEC-RPS-1B	Anytime
Out-of-State Facility	Compliance documentation of the NERC tag requirement	May1 , 2005, and annually thereafter
New or Repowered Biomass Facility (or Biodiesel facility using biomass)	Annual attestation from fuel supplier(s) stating verifying ongoing compliance with fuel requirements	February 15, 2005, and annually thereafter
Facility or retail seller	Renewal of Certification/Pre-certification	Once every two years. Facilities certified in 2004 must renew in January 2007. Facilities certified in 2005 must renew in January 2008 and so forth.
Facility or retail seller	Amendment of Certification/ Pre-certification (form to be developed)	As needed
Facility or retail seller	retail seller monthly payment statement showing the amount of energy procured reported annually to the Energy Commission	May1 , 2005, and annually thereafter until data are reported through WREGIS
retail seller	Report on Procurement, CEC-RPS-Track	June 15, 2004, and May 1, 2005, and annually thereafter until data are reported through WREGIS
retail seller	Utility Certification for Pre-Existing Contracts, CEC-RPS-2	Anytime until contract expires or is voluntarily re-negotiated

Appendix X California Solar Initiative Program Handbook

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12-20-06
09:12 AM

California Solar Initiative Program

Handbook

With SB1/CSI Draft Decision noted

December 19, 2006

The California Public Utilities Commission (CPUC) prohibits discrimination in employment, its regulatory programs, and activities on the basis of race, national origin, color, creed, religion, sex, age, disability, veteran status, sexual orientation, gender identity, or associational preference. The CPUC also affirms its commitment to providing equal opportunities and equal access to CPUC regulated facilities and programs. For additional information or to file a complaint contact the State Personnel Board, Office of Civil Rights, Discrimination Complaint Monitoring and Analysis, Kristen Trimarche (916) 653-1621.

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1. Introduction: California Solar Initiative Program

The California Solar Initiative (CSI) Program Handbook is designed to describe the requirements for receiving funding for the installation and operation of solar photovoltaic (PV) projects. As authorized by the California Public Utilities Commission (CPUC or Commission) and Senate Bill 1 (SB 1), the CSI program has a total budget of $2.167 billion to be used over 10 years.[1, 2]

Beginning on January 1, 2007, the CSI program will pay performance-based incentives (PBI) for solar projects equal to or greater than 100 kilowatts (kW[3]), with monthly payments based on recorded kW hours (kWh) of solar power produced over a 5-year period. These PBI will be a flat per-kWh payment for PV system output. The CSI program will pay incentives to solar projects less than 100 kW through an up-front incentive, known as an expected performance-based buydown (EPBB). EPBB is based on an estimate of the system's future performance. These expected-performance incentives combine the benefits of rewarding performance of the PV system with the administrative simplicity of a one-time incentive paid at the time of project installation.

The solar project's Site must be within the service territory of and receive retail level electric service from Pacific Gas and Electric (PG&E), Southern California Edison (SCE), or San Diego Gas & Electric (SDG&E). Municipal electric utility customers are not eligible to receive incentives from the designated Program Administrators.

Responsibility for administration of the CSI program is shared by the following three Program Administrators:

- PG&E—PG&E customers
- SCE—SCE customers
- San Diego Regional Energy Office (SDREO)—SDG&E customers.

Other notable CSI program features include:

- A statewide on-line application process and database
- An open process to draft initial and future CSI Program Handbooks
- A CSI Program Forum to provide a process for stakeholder involvement in the on-going implementation of the CSI program.

1 CPUC Decision 06-08-028, August 24, 2006.

2 California Senate Bill 1 (SB 1), signed into law August 21, 2006. The incentive levels, timelines, total funds, and/or other implementation details reflected in this document may change, pending the outcome of the CPUC's resolution of differences between SB 1 and D.06-08-028.

3 Throughout this Handbook, the use of kW refers to the CEC-AC wattage ratings of kW alternating current inverter output.

1.1 Program Background

In Decision (D.) 06-01-024, the CPUC, in collaboration with the California Energy Commission (Energy Commission), established the California Solar Initiative program, an ambitious incentive program with the goal of ensuring that 3,000 MW of new solar facilities are installed in homes and businesses in California by 2017.[4] In D.06-08-028, the CPUC established implementation details for the CSI program, particularly the adoption of the PBI incentive structure. On August 21, 2006, the Governor signed SB 1, which directs the CPUC and the Energy Commission to implement the CSI program consistent with specific requirements and budget limits set forth in the legislation. The CPUC has a rulemaking in progress to reconcile its decisions with SB1. The CPUC is working with Program Administrators and Parties to revise some handbook sections in order to agree with the CPUC Commissioners' approved Decision on December, 14, 2006. (NOTE: The final handbook will describe the SB1/CSI Draft Decision.)

1.2 CSI Program Budget

This section provides an overview of the CSI program budget as authorized by the CPUC and reviews the megawatt (MW) targets for the program.

The CSI program budget for each Program Administrator is as shown in Table 1.

Table 1
CSI Program Budget by Program Administrator

NOTE: The SB1/CSI Draft Decision changes these numbers)

Utility	% of Total Budget	Budget (in millions)
PG&E	48%	$ 1,039
SCE	37%	$ 801
SDG&E/SDREO[5]	15%	$ 325
Total	100%	$ 2,165

All customer segments are eligible for the CSI program. Table 2 demonstrates the MW expected to be accounted for by customer segments in the CSI program.

Table 2
CSI MW Allocations by Customer Sector

Customer Sector	MW	Percent
Residential	577.50	33%
Non-Residential	1172.50	67%
Total	1,750.00	100%

4 The Energy Commission collaborated with the CPUC in the creation of CSI by this Commission order.

5 SDREO is administering the program on behalf of SDG&E.

1.2.1 Special Funding for Affordable Housing Projects

The CPUC has allocated 10 percent of the overall CSI program budget, or $216 million, to affordable housing/low-income projects. More details will become available through Phase II of the CSI proceeding at the CPUC.

1.3 MW Targets and Step Triggers for CSI Program

The incentive levels for the CSI program will be automatically reduced over the duration of the program based on the volume of MW of solar reservations issued. Projects are counted toward the MW trigger once they are deemed eligible, have paid an application fee (if applicable), and have received a confirmed reservation. The solar incentive levels may vary by Program Administrator service territory, depending on the pace of solar demand. Additionally, incentive levels may differ for residential and Non-Residential customer sectors based on the demand for those customer segments. Table 3 displays the MW targets by Program Administrator service territory and customer class.

Table 3
CSI MW Targets by Utility and Customer Class

NOTE: The SB1/CSI Draft Decision changes these numbers

		PG&E (MW)		SCE (MW)		SDG&E/SDREO (MW)	
Step	**MW in Step**	**Res**	**Non-Res**	**Res**	**Non-Res**	**Res**	**Non-Res**
1	50	-	-	-	-	-	-
2	70	11.1	22.5	8.5	17.4	3.5	7.0
3	100	15.8	32.2	12.2	24.8	5.0	10.1
4	130	20.6	41.8	15.9	32.2	6.4	13.1
5	160	25.3	51.5	19.5	39.7	7.9	16.1
6	190	30.1	61.1	23.2	47.1	9.4	19.1
7	215	34.1	69.1	26.3	53.3	10.6	21.6
8	250	39.6	80.4	30.5	62.0	12.4	25.1
9	285	45.1	91.7	34.8	70.7	14.1	28.6
10	350	55.4	112.6	42.7	86.8	17.3	35.2
Total	**1800**	**277.1**	**562.9**	**213.6**	**434.0**	**86.6**	**175.9**
Total by Utility		840.0		647.6		262.5	
Percent		48%		37%		15%	

1.4 Incentive Structure

The program will offer two types of incentives: EPBB and PBI. The EPBB incentives will be paid based on verified characteristics such as location, system size, shading, and orientation. The

PBI incentive will be a flat cents-per-kWh payment for all output from a solar system over its initial 5 years. The incentive payment levels will automatically be reduced over the duration of the CSI program in 10 steps, based on the volume of MW of solar reservations issued. The EPBB and PBI levels are directly tied to the 10 MW steps as outlined in Table 4. [6]

Table 4
PBI and EPBB Payment Amounts by Step

		EBPP Payments (per watt)			PBI Payments (per kWh)		
MW Step	Statewide MW in Step	Residential	Commercial	Gov't/ Nonprofit	Residential	Commercial	Gov't/ Nonprofit
1	50[7]	n/a	n/a	n/a	n/a	n/a	n/a
2	70	$ 2.50	$ 2.50	$ 3.25	$ 0.39	$ 0.39	$ 0.50
3	100	$ 2.20	$ 2.20	$ 2.95	$ 0.34	$ 0.34	$ 0.46
4	130	$ 1.90	$ 1.90	$ 2.65	$ 0.26	$ 0.26	$ 0.37
5	160	$ 1.55	$ 1.55	$ 2.30	$ 0.22	$ 0.22	$ 0.32
6	190	$ 1.10	$ 1.10	$ 1.85	$ 0.15	$ 0.15	$ 0.26
7	215	$ 0.65	$ 0.65	$ 1.40	$ 0.09	$ 0.09	$ 0.19
8	250	$ 0.35	$ 0.35	$ 1.10	$ 0.05	$ 0.05	$ 0.15
9	285	$ 0.25	$ 0.25	$ 0.90	$ 0.03	$ 0.03	$ 0.12
10	350	$ 0.20	$ 0.20	$ 0.70	$ 0.03	$ 0.03	$ 0.10

As of January 1, 2007, incentives for residential, commercial, Government and Non-Profit entities will be set at Step 2 levels under the CSI program. For the purpose of the CSI program, commercial sectors include agricultural and industrial customers.

Pending a CPUC decision, mixed-use property (properties with both commercial and residential units) may be eligible for the CSI program.

1.4.1 Expected Performance Based Buydown (EPBB) Incentives

The EPBB pays a one-time up-front incentive ($/W) based on a system's estimated future performance. The Program Administrators will use the Energy Commission's CEC-AC method to determine the system's capacity rating. The system rating will be multiplied by a design factor that will consider certain factors (i.e., location, orientation, and shading) that have an influence on system performance.

6 The Commission is currently assessing whether the MW-based reduction plan in D.06.08.028 complies with SB 1 or whether it must adopt annual incentive reductions.

7 The first 50 MW are allocated under the 2006 Self-Generation Incentive Program (SGIP) and are not pro-rated by customer class or service territory. In 2006, most residential systems participated in the Energy Commission's Emerging Renewables Program (ERP).

1.4.1.1 EPBB for New Construction (Note: SB1/CSI Draft Decision would delete this exemption from PBI for new construction)

All Non-Residential new construction projects will be paid EPBB incentives. Residential new construction projects will be funded through the New Solar Homes Partnership (NSHP) administered by the Energy Commission. Again, pending a CPUC decision, new construction projects for mixed-use property (properties with both commercial and residential units) may be eligible for the CSI program.

1.4.2 Performance Based Incentives (PBI)

The CSI program will apply a PBI structure to all systems equal to or greater than 100 kW beginning on January 1, 2007, although any other size system may also opt into the PBI structure. Beginning in January 2010, systems equal to or greater than 30 kW will be on a PBI incentive structure. (NOTE: SB1/CSI Draft Decision would add the PBI requirement for systems equal to or greater than 50 kW for 2008)

The PBI payments will be made over a 5-year period following system installation, submission, and approval of incentive claim materials. Payments will be made on a monthly basis. These payments will be based on the per-kWh incentive rate and the actual energy (kWh) produced in that time period.

The Program Administrator for each utility shall estimate the total 5-year PBI payments for completed projects and deposit this amount in an interest-bearing balancing account to ensure fund security over the period of the expected PBI payments.

1.4.2.1 PBI for Building Integrated Photovoltaic (BIPV) Systems on New Construction, Non-Residential Projects

For projects that have installed building integrated PV systems (BIPV), even those on new construction projects, the CPUC requires the CSI incentives to be paid through a PBI structure.

1.5 CSI Program Forum

CPUC D. 06-08-028 directed that a CSI Program Forum should "provide a public venue for interested parties to identify and discuss ongoing issues related to CSI administration and implementation." The Forum will be used to explore needed updates to this Handbook, as well as substantive program modifications that should be considered, including incentives for non-PV solar projects and energy efficiency requirements. Forum meetings will provide the opportunity for CSI stakeholders to develop consensus-based revisions to the CSI Program Handbook and to the CSI program itself. Beginning in the first quarter of 2007, the Program Administrators and the CPUC Energy Division will convene, facilitate, and develop the agenda for regular public meetings of the Forum. It is anticipated that the meetings will be held at least quarterly, with more frequent meetings as needed during the initial phase of implementing the program.

If the Forum results in consensus on revisions to the CSI Program Handbook, the CPUC has invited the Forum to designate one of its members to file a proposed Handbook revision by

Advice Letter with the Energy Division. If the group achieves consensus for more substantive program modifications that go beyond the level of the Program Handbook, the Forum may designate a member to file a petition to modify a Commission order relating to the CSI program.[8]

1.6 Transition Issues Related to the Emerging Renewables Program and Self Generation Incentive Programs

1.6.1 New Solar Homes Partnership (NSHP)

The Energy Commission will administer the NSHP program that will offer financial incentives for solar PV systems installed on new homes. Information regarding the NSHP program can be found on the Energy Commission's website: www.GoSolarCalifornia.ca.gov.

1.6.2 Emerging Renewables Program (ERP)

The Energy Commission administered the ERP to provide consumers with financial incentives to install renewable energy systems on their property. The ERP provided incentives for the eligible renewable generating technologies.

As of January 1, 2007, the CSI program and the NSHP will replace the ERP program to offer monetary incentives for solar PV systems under 1 MW. The ERP will remain in effect to provide financial incentives for qualifying non-PV self-generation equipment.

ERP applications received by the Energy Commission prior to December 31, 2006 will remain under the oversight of the Energy Commission's ERP program, regardless of whether the project will be completed after January 1, 2007. Current ERP applicants with reservations for PV systems may opt to withdraw their ERP program application and apply for the CSI program or NSHP program after January 1, 2007, provided that the project meets the eligibility requirements of the respective programs. Rules governing the withdrawal or cancellation of the ERP project will apply.

1.6.3 Self-Generation Incentive Program (SGIP)

The Self-Generation Incentive Program (SGIP) provides incentives for the installation of new, qualifying self-generation equipment installed to meet all or a portion of the electric energy needs of a facility. The SGIP complements the ERP by providing incentive funding to larger renewable and nonrenewable self-generation units up to the first 1 MW in capacity.

As of January 1, 2007, the CSI program and the NSHP will replace the SGIP to offer monetary incentives for solar PV systems under 1 MW that displace electricity. The SGIP will remain in effect to provide financial incentives for qualifying non-PV self-generation equipment. (NOTE: There could be an additional discussion of gas-displacing projects from the SB1/CSI Draft Decision)

8 The CSI Program Forum is described in detail on pages 65-67 of D. 06-08-028.

SGIP applications received prior to December 31, 2006 will remain under the oversight of the SGIP Program Administrators, regardless of whether the project will be completed after January 1, 2007, provided that all program requirements and guidelines are met. Current SGIP applicants with reservations for PV systems may opt to withdraw their program application and apply for either the CSI program or NSHP program after January 1, 2007, provided that the project meets the eligibility requirements of the respective programs. Rules governing the withdrawal or cancellation of the SGIP project will apply.

Pending a CPUC decision, applicants who have 1 MW of solar approved through the SGIP program may be eligible for an additional 1 MW under the CSI program. Additionally, pending CPUC approval, the CSI program may accept applications up to 5 MW with incentives being paid only on the first MW installed under the program. (NOTE: the Draft Decision would change this paragraph from “may” to “will.”)

1.7 Future Program Modifications

Future CSI program features could include non-PV solar projects and energy efficiency requirements. The following modifications to the CSI program are also anticipated:

- PBI will be applied to all systems over 30 kW beginning in 2010.
- The default capacity factor will increase from 18 to 20 percent, beginning with Step 4 of the Incentive Adjustment Mechanism.
- Time-differentiated PBI may be investigated for later stages of the program.
- On or before January 1, 2008, the warranty requirements will be increased to a minimum of 5 years for meters.
- (NOTE: THE SB1/CSI Decision contains information on the treatment of non-PV systems)

2. Program Eligibility Criteria and Requirements

The California Solar Initiative (CSI) program offers monetary incentives for systems up to the first 1,000 kW (1 MW) of alternating current generated by an eligible solar energy system. To qualify for incentives, all CSI program eligibility criteria must be satisfied. The effective dates for the CSI program are January 1, 2007 through December 31, 2016 or until the CSI program budget has been fully reserved for each Program Administrator. Program Administrators will begin to accept applications to the CSI program on January 1, 2007.

2.1 The Participants in the CSI Program

Any retail electric distribution customer of Pacific Gas and Electric (PG&E), Southern California Edison (SCE) or San Diego Gas & Electric (SDG&E) is eligible to install a solar project and receive incentives from the CSI program. Within the nomenclature of the CSI program, the person who applies for an incentive will be referred to as an Applicant, a Host Customer, and/or a System Owner.

2.1.1 Host Customer

Any retail electric distribution customer of PG&E, SCE or SDG&E is eligible to install a solar project and receive incentives from the CSI program and can, therefore, be a Host Customer.

The Host Customer must be the utility customer of record at the location where the generating equipment will be located. Any class of customer (industrial, agricultural, commercial, or residential) is eligible to be a Host Customer. The project's Site must be within the service territory of, and receive retail level electric service[9] from, PG&E, SCE, or SDG&E. Municipal electric utility customers are not eligible to receive incentives from the designated Program Administrators.

The Host Customer becomes the incentive reservation holder. The Host Customer may act as the Applicant and/or System Owner. The Host Customer alone will retain sole rights to the incentive reservation and corresponding incentive reservation number. A reservation for a specific Site is not transferable. The Host Customer has the right to designate the Applicant, energy services provider, and/or system installer to act on their behalf. However, the Host Customer shall be party to the CSI program contract.

To be eligible for an incentive, the Host Customer or Applicant must receive a confirmed reservation notice letter from the Program Administrator prior to the Applicant receiving final interconnection authorization from their utility to operate the project in parallel with the grid. If a project cancels due to not meeting the reservation period, they must reapply to the CSI program prior to receiving a final interconnection authorization from their utility to operate the project in parallel with the grid.

9 "…retail level electric service…" means that the Host Customer pays for and receives distribution services, as defined by their respective utility rate schedule.

The following are *not* eligible for incentives under the CSI program:

- Customers who have entered into utility contracts for distributed generation (DG) services (e.g., DG installed as a distribution upgrade or replacement deferral) and who are receiving payment for those services. This does not include third-party ownership arrangements, i.e., power purchase agreements, which are allowed.
- Customers who have entered into agreements that entail the export and sale of electricity from the Host Customer Site. This does not include net energy metering agreements, which are allowed.
- Any portion of customer load that is committed to electric utility interruptible, curtailable rate schedules, programs, or any other state agency-sponsored interruptible, curtailable, or demand-response programs. For electric utility customers who are on an interruptible rate, only the portion of their electric load that is designated as firm service is eligible for the CSI program. Customers must agree to maintain the firm service level at or above capacity of the proposed solar system for the duration of the required applicable warranty period (see Section 2.5). Customers may submit a letter requesting an exemption to the firm service rule if they plan to terminate or reduce a portion of their interruptible load.
- Publicly owned or investor-owned gas, electricity distribution utilities or any electrical corporation (ref. Public Utility Code 218) that generates or purchases electricity or natural gas for wholesale or retail sales.
- Residential new construction systems are not eligible for the CSI program and should apply to the California Energy Commission's New Solar Homes Partnership Program.

2.1.2 System Owner

The System Owner is the owner of the generating equipment at the time the incentive is paid. For example, when a vendor sells a turnkey system to a Host Customer, the Host Customer is the System Owner. In the case of a third-party-owned system (or leased system, for example), the third party (or lessor) is the System Owner.

The System Owner should be designated on the Reservation Request Form, if known at that time, and on the Incentive Claim Form. If different from the Host Customer, the System Owner shall also be a party to the CSI program contract. The Program Administrator may require documentation substantiating equipment ownership.

2.1.3 Applicant

The Applicant is the entity that completes and submits the CSI program application and serves as the main contact person for the CSI Program Administrator throughout the application process. Host Customers may act as the Applicant or they may designate a third party to act as the Applicant on their behalf. Applicants may be third parties (e.g., a party other than the

Program Administrator or the utility customer) such as, but not limited to, engineering firms, installation contractors, equipment distributors, energy service companies (ESCO) and equipment lessors.

2.1.4 Installer

All systems must be installed by appropriately licensed California contractors in accordance with rules and regulations adopted by the State of California Contractors State Licensing Board (CSLB). Installation contractors must have an active A, B, or C-10 license, or a C-46 license for photovoltaic (PV) systems.

Although not required, installation contractors are encouraged to become certified by the North American Board of Certified Energy Practitioners (NABCEP). For additional information on NABCEP, go to www.nabcep.org.

In all cases, systems must be installed in conformance with the manufacturers' specifications and with all applicable electrical and building codes and standards.

To participate in the CSI program, eligible companies that install system equipment must be listed with the Program Administrator. The Program Administrator will request the following information:

- Business name, address, phone, fax, and e-mail address
- Owner or principal contact
- Business license number
- Contractor license number (if applicable)
- Proof of good standing on the records of the California Secretary of State, as required for corporate and limited liability entities
- Reseller's license number (if applicable)

This information must be submitted to the Program Administrator before a company can become eligible to participate in the CSI program. To remain eligible, a company must resubmit this information annually by March 31**.** This annual submittal is required even if the information identified in the company's prior submittal has not changed. In addition, a company must submit updated information any time its reported information has changed. The updated information must be submitted to the Program Administrator within 30 days of the change of any reported information.

The above information must be listed before the Applicant can receive any reservation confirmation or payment. The Program Administrator will compile the information and make it available to consumers to assist them in making purchase decisions and taking any remedial action on their systems. Information about listed installers is posted on the Program Administrator's websites.

2.1.5 Equipment Sellers

To participate in the CSI program, companies that sell system equipment must be certified by the Energy Commission. The Energy Commission requests the following information on their form CEC-1038 R4:

- Business name, address, phone, fax, and e-mail address
- Owner or principal contact
- Business license number
- Contractor license number (if applicable)
- Proof of good standing on the records of the California Secretary of State, as required for corporate and limited liability entities
- Reseller's license number

This information must be submitted to the Energy Commission before a company can become eligible to participate in the CSI program. To remain eligible, a company must resubmit this information annually by March 31**.** This annual submittal is required even if the information identified in the company's prior submittal has not changed. In addition, a company must submit updated information any time its reported information has changed. The updated information must be submitted to the Program Administrator within 30 days of the change of any reported information.

The above information must be certified before the applicant can receive any reservation confirmation or payment. The Energy Commission will compile the information and make it available to consumers to assist them in making purchase decisions and taking any remedial action on their systems. Information about registered equipment sellers is posted on the Energy Commission's website, www.energy.ca.gov.

2.2 Generator System Equipment Eligibility

Currently, only PV systems (i.e., systems that cause direct conversion of sunlight to electricity) are eligible to receive incentives from the CSI program. Details of the eligibility requirements for generation system equipment follow. (NOTE: the SB1/CSI Draft Decision addresses non-PV systems.)

2.2.1 New Equipment, Not Pilot or Demonstration Systems

All major system components (panels and inverters) must be new and must not have been previously placed in service in any other location or for any other application. Rebuilt, refurbished, or relocated equipment is not eligible to receive CSI program incentives, save in rare relocation exceptions (see Sections 2.5 and 2.9).

Components that are critical to the PV systems must have at least 1 year of documented commercial availability to be eligible. Commercially available means that the major solar system components are acquired through conventional procurement channels, installed and operational at a Site. Commercially available does not include field demonstrations for proof-of-concept operation of experimental or non-conventional systems partially or completely paid for by research and development funds. Components that are enhancements to existing products and new models of existing product lines do not have to meet the commercial availability requirement as long as they are UL-certified and performance data exists to allow the Program Administrators to estimate their expected performance.

An alternative method of seeking eligibility for solar systems that use new technologies is to obtain certification from a nationally recognized testing laboratory indicating that the technology meets the safety and/or performance requirements of a nationally recognized standard. System component ratings must also be certified by the CEC as described in section 2.2.4.

As an exception, the Applicant may specify equipment that has not yet received CEC certification, but the equipment must be certified prior to the first incentive payment.

2.2.2 Eligibility of Replacement PV Systems

Any replacement solar systems must meet the criteria for new systems and are eligible for the CSI program only if the removed system did not previously receive an incentive through the CSI program, the Self-Generating Incentive Program, the Energy Commission's Emerging Renewables Program, or Rebuild a Greener San Diego Photovoltaic Incentive Program.

2.2.3 Equipment Must Serve On-Site Electrical Load

To be eligible, the system must be sized so that the amount of electricity produced by the system primarily offsets part or all of the customer's electrical needs at the Site of installation. The expected production of electricity by the system may not exceed the actual energy consumed during the previous 12 months at the Site, as calculated per the following formula:

Maximum System Capacity (kW) = 12-months previous energy usage (kWh) / (0.18 x 8760 hours/year)

The Applicant must show evidence of the system sizing with the submittal of the initial application.

2.2.4 Equipment Certifications and Rating Criteria

System components must be certified through the Energy Commission's program that certifies major components of PV systems and provides lists of eligible equipment. The list of the currently certified equipment is available through:

- The California Energy Commission: www.energy.ca.gov
- California Energy Commission Call Center: (800) 555-7794.

The Program Administrators will confirm that equipment identified in a reservation application meets eligibility requirements prior to providing a confirmed reservation notice letter. As described in Section 2.2.1, one exception would be for new equipment that has not yet received certification but for which the process has been initiated. Equipment is periodically added and removed from the lists of eligible equipment so Applicants should confirm that the components purchased for a system are eligible prior to installing them.

The Energy Commission certifies modules, inverters, and system performance meters. The system must be interconnected to the grid. Inverters and modules must each carry a 10-year warranty, and meters a one-year warranty, in 2007. Eligibility requirements for components are summarized below:

- PV modules must be certified to UL 1703 by a nationally recognized testing laboratory (NRTL).
- Performance meters must measure kWh (or Watt hours) with a manufacturer's uncertainty of ±2 or ±5 percent (depending on rating size and incentive), retain data in the event of a power outage, and be easy to read for the customer's benefit. See Section 11.1.2.
- Inverters must be certified to UL 1741 by a NRTL. They also must have completed the Energy Commission's required weighted efficiency testing.

2.2.5 System Size

The minimum system size eligible for an incentive is 1 kW. While systems sizes up to 5 MW are eligible to participate in the program, the maximum incentive provided under the CSI program is based on a system size no greater than 1 MW. The system size must be calculated using the CEC-AC rating standards,[10] including inverter DC-to-AC losses and a design factor. To calculate the CEC-AC rating, the following formula should be used:

System Size (kilowatts) = Quantity x CEC Rating of Photovoltaic Modules x CEC Inverter Efficiency Rating / 1000 (watts/kilowatt)

Pending CPUC approval, the maximum incentive provided for a Host Customer Site under the CSI program is 1,000 kW (1 MW); however, a Host Customer Site may elect to install up to 5 MW of generation.[11]. (NOTE: The SB1/CSI Draft Decision would remove the “Pending CPUC approval” from the first sentence.) If an Applicant has already received 1 MW of funding from another solar incentive program (such as the SGIP or ERP), they can apply for up to another 1 MW under the CSI program as long as they can demonstrate that the electricity produced by the combined system sizes do not exceed the actual energy consumed during the previous 12 months at the Site, based on the formula provided in Section 2.2.3.

10 The CEC-AC rating standards are based upon 1,000 Watt/m2 solar irradiance, 20 °Celsius ambient temperature, and 1 meter/second wind speed. The CEC-AC Watt rating is lower than the Standard Test Conditions (STC), a Watt rating used by manufacturers.

11 Because the CSI Program and statutes only allow for customers to receive incentives up to the first MW, PBI payments for energy output on systems larger than 1 MW will be prorated based on the ratio of 1 MW to the entire size of the facility. See Section 3.3 for further detail.

2.2.5.1 System Sizing Based on Future Load Growth

In the case of Applicants with new or expanded facilities where no electric bill or where the existing electric bill does not reflect the Applicant's expected expanded consumption, the Applicant must include an engineering estimate. The engineering estimate must include the appropriate substantiation of the forecast of the Host Customer Site's annual energy use (in kWh) if the generating system size is based on future load growth, including new construction, load growth due to facility expansion or other load growth circumstances. Suggested methods of demonstrating load growth include Application for Service with corresponding equipment schedules and single line diagram; building simulation program reports such as eQUEST, EnergyPro, DOE-2, and VisualDOE; or detailed engineering calculations. The Program Administrator will verify the load growth predicted before moving forward with the Confirmed Reservation Notice.

2.3 Energy Efficiency Requirements

(NOTE: the SB1/CSI Draft Decision addresses the requirement for an energy efficiency audit, who could perform it, and exceptions to the audit requirement. Clarifying text will be available soon in this Handbook.)

2.4 Warranty Requirements

In 2007, all systems must have a minimum 10-year warranty provided in combination by the manufacturer and installer to protect the purchaser against system or component breakdown. Warranties must cover the solar generating system only, including PV modules (panels), inverters, and meters, and provide for no-cost repair or replacement of the system or system components, including any associated labor during the warranty period. The warranty must cover the major components of the solar system (PV modules and inverters) against breakdown or degradation in electrical output of more than 15 percent from their originally rated electrical output during the 10-year period.

Self-installed systems must have a minimum 10-year warranty on the equipment to be installed to protect the purchaser against breakdown or electrical output degradation of major system components. In this case, the warranty need not cover the labor costs associated with removing or replacing major components because any repairs would be done by the self-installer or at the self-installer's expense.

For the 2007 program year, meters must have a one-year warranty. On or before January 1, 2008, the warranty requirements will be increased to a minimum of 5 years for meters, unless the CEC establishes alternate requirements.

2.5 Performance and Permanency Requirements

Equipment installed under the CSI program is intended to be in place for the duration of its useful life. Only permanently installed systems are eligible for incentives. This means that the

PV system must demonstrate to the satisfaction of the Program Administrator adequate assurances of both physical and contractual permanence prior to receiving an incentive.

Physical permanence is to be demonstrated in accordance with industry practice for permanently installed equipment. Equipment must be secured to a permanent surface. Any indication of portability, including but not limited to temporary structures, quick disconnects, unsecured equipment, wheels, carrying handles, dolly, trailer, or platform, will deem the system ineligible.

In rare occasions, there may be extenuating circumstances that warrant equipment relocation. The Program Administrators will use their discretion whether to allow the relocation to continue to receive program incentives.

Contractual permanence, corresponding to a time period of 10 years, is to be demonstrated as follows:

- All agreements involving the generation system receiving an incentive are to be provided to the Program Administrator for review as soon as they become available (e.g., at the proof-of-project milestones stage or the incentive-claim stage at the latest). These agreements include, but are not limited to, system purchase and installation agreements, warranties, leases, energy or solar services agreements, energy savings guarantees, and system performance guarantees.
- The System Owner agrees to notify the Program Administrator in writing a minimum of 60 days prior to any change in either the site location of the PV system or change in ownership of the generation system if the change(s) takes place within the applicable warranty period. The warranty period for the CSI program is 10 years.
- If the PV system is removed prior to end of the warranty period, either:
  - The PV system may be installed at another site within the Program Administrator service territory within 6 months. The system installed at the alternate site would not be eligible for an additional CSI EPBB incentive; or
  - The System Owner would be unable to participate in the CSI program for any additional installations under the CSI program, including any active reservations that have not yet been paid.
- If the house or business is sold, the new owners can continue to receive the Performance-Based Incentives (PBI) and be eligible to receive future CSI program incentives if they complete a new interconnection agreement. If the sellers remove the panels, they can continue to receive the incentive payments and be eligible to receive future CSI program incentives if the panels they removed are installed within the same service territory within 6 months, and they complete an interconnection agreement at the new address. PBI recipients will receive a full five year PBI payment period, as long as they reinstall their systems within the specified timeframe.

2.6 Insurance Requirements

The Program Administrators require insurance as a condition for receiving a CSI program incentive because, through the CSI program incentive, the utilities (and SDREO) become part of the customer's decision (and extended process) to install a solar energy system. Consequently, it is appropriate for the Program Administrators and the Commission to impose insurance requirements that will provide protection to those involved in the project and that limit the risk to the Program Administrator (and thus the ratepayers) who fund these projects.

2.6.1 Insurance Requirements for Host Customer and System Owner of Systems

All systems ≥ 30 kW receiving a CSI program incentive will require that the Host Customer and System Owner have the following minimum level of homeowner liability insurance or commercial general liability insurance for the term of the CSI program contract:

- $2,000,000 for each occurrence if the system rating is greater than 100 kW
- $1,000,000 for each occurrence if the system rating is greater than 30 kW and less than or equal to 100 kW

Non residential projects must also fulfill the following general insurance requirements:

Workers' Compensation: Workers' Compensation insurance or self-insurance indicating compliance with any applicable labor codes, laws or statutes, state or federal, at the Site where Host Customer or System Owner performs work.

Business Auto: Auto coverage shall be at least as broad as the Insurance Services Office California Business Auto Coverage Form (CA 00 01 03 06) covering Automobile Liability symbols 7, 8, and 9. Specifically described autos shall include any and all autos that will be used in connection with the project. The limit shall be not less than $1,000,000 each accident for bodily injury and property damage.

Additional insurance requirements and terms are included in the CSI program contract.

Insurance requirements for systems < 30 kW will be equivalent to what is currently required for interconnection to the utility grid.

2.6.2 Insurance Requirements for Installers

Installation contractors must have valid workers compensation, business auto and commercial general liability insurance. Commercial general liability insurance must be in the following amounts:

- $1,000,000 for each occurrence and $2,000,000 aggregate.

- Workers compensation insurance or self-insurance indicating compliance with any applicable labor codes, laws or statutes, state or federal, where Installer performs work.
- Auto coverage shall be at least as broad as the Insurance Services Office California Business Auto Coverage Form (CA 00 01 03 06) covering Automobile Liability symbols 7, 8, and 9. Specifically described autos shall include any and all autos that will be used in connection with the project. The limit shall be not less than $1,000,000 each accident for bodily injury and property damage.

2.6.3 Insurance Requirements for Government

The Program Administrators recognize that some Government entities are self-insured and/or have blanket coverage. The Program Administrators will accept proof of that coverage as long as the Government entity can show that they meet the level of insurance required by the CSI program.

2.7 Interconnection to the Electric Utility Distribution System

Eligible renewable energy systems must be permanently interconnected to the electrical distribution grid of the utility serving the customer's electrical load. Portable systems are not eligible. The system interconnection must comply with applicable electrical codes and utility interconnection requirements.

The Host Customer, or designate, must also submit an application and enter into an interconnection agreement with their local electric utility for connection to the electrical distribution grid. Proof of interconnection and parallel operation is required prior to receiving an incentive payment.

(NOTE: The SB1/CSI Draft Decision would add a new section on the requirement for the Applicant to be on Time of Use Rates. There would also be a definition added in the Definition Section for "Time-of-Use Rates.")

2.8 Metering Requirements

The CSI program requires accurate solar production meters for all projects that receive CSI program incentives. Accurate measurement of solar output is of paramount importance to ensure optimum value for both solar owners and ratepayers. For systems with a system rating of less than 10 kW, a basic meter with accuracy of ±5 percent is required. For systems with a system rating of 10 kW and greater, an interval data meter with accuracy of ±2 percent is required. An extensive discussion on metering is contained in Appendix B.

EPBB program participants must provide Program Administrators or their authorized agents with physical access to the meter for testing or inspection, and if applicable, data gathering. If the customer's meter is located in a place that is not readily accessible, such access will be by appointment. To avoid inconvenience to customers, installers are encouraged to locate meters in areas that are easily accessible.

PBI customers must provide Program Administrators or their authorized agents with physical access to the meter at all times.

2.9 Inspection Requirements

It is the intent of the CSI program to provide incentives for reliable, permanent, safe systems that are professionally installed, and comply with all applicable federal, state, and local regulations. Program Administrators will conduct a system inspection visit for every system rated from 30 kW up to 100kW that have not opted to receive PBI incentive payments in order to verify that the project is installed as represented in the application, is operational, interconnected and conforms to the eligibility criteria of the CSI program. Program Administrators will perform random field inspections to verify system characteristics for systems less than 30 kW. These inspections will reflect a statistically reasonable random sample. Systems receiving a PBI may still be required to have a field inspection.

A mandatory site inspection is required for all relocated equipment. System Owners that have received an EPBB incentive and have relocated their system must orient their relocated equipment to produce at least the same generation as their initial incentive payment was based upon.

2.9.1 Systems that Fail Inspections

If a system fails a field inspection, the Program Administrator will notify the Applicant, Host Customer, and System Owner with the reasons for the field inspection failure. Such reasons for failure may include but are not limited to the following:

- Material mechanical failure: A failure that results in a decline in the expected performance of the system (i.e., one or more of the system components is not operating properly).
- Immaterial mechanical failure: minor failures that can be corrected within 60 days.
- Material compliance failure: the system as verified does not match the application's stated system and/or the system does not meet the CSI program eligibility requirements (i.e., the EPBB characteristics are incorrect, the system components or number of components are incorrect, etc.).
- Immaterial compliance failure: failures that have no impact on the expected performance of the system and can be corrected within 60 days (i.e. submission of erroneous system data).

The Program Administrators will exercise their judgement in assessing the materiality of non-compliance. For either mechanical or compliance failures: If a material failure occurs due to gross negligence or intentional submission of inaccurate system information in an attempt to collect more incentive dollars, the responsible party will be immediately prohibited from participating in the program.

If there is a failed inspection for *mechanical* failures, the Applicant, Host Customer, and/or System Owner will have 60 calendar days to bring the system into compliance after a failed inspection. A subsequent inspection visit will be conducted to determine final approval and will be subject to a re-inspection fee. If the Applicant, Host Customer, and System Owner fail to resolve the failure within the 60 days, or the failed inspection is due to a Material Mechanical Failure, the application will be cancelled, determined to be a failed inspection, and a strike will be imposed against the Installer, Applicant, seller, or other responsible party. The field inspector and/or the Program Administrator will be authorized to identify the responsible party, based on available information obtained during the inspection and from applicable forms. However, this designation will be considered preliminary and is subject to revision upon receipt of additional information or on appeal.

If there is a failed inspection because the verified system is not in *compliance* with the stated system, the Applicant, Host Customer, and/or System Owner will have 60 calendar days to bring the system into compliance as stated on the project application. If the Applicant, Host Customer, and System Owner fail to bring the system to full eligibility within the 60 days, or the failed inspection is due to a Material Compliance Failure, the application will be cancelled, determined to be a failed inspection, and constitute a strike. The strike will be imposed on the entity that signed and submitted the erroneous information on the project application and/or subsequent incentive claim form, unless the Installer or Applicant can demonstrate that another party, such as a seller or consultant, is responsible. The field inspector and the Program Administrator will be authorized to identify the responsible party, based on available information obtained during the inspection and from applicable forms. However, this designation will be considered preliminary and is subject to revision upon receipt of additional information or on appeal.

Project Installers, Applicants, and/or sellers that fail two inspections will be on probation, wherein every project will be inspected. If the entity fails a third inspection, the entity will be disqualified from participating in the CSI program for one year, except in cases of fraud.

For high volume installers (those that install more than 200 systems per year), if the installer accumulates two strikes, the entity will be placed on probation. If no additional strikes are accumulated within the first year, their first strike is removed and they continue on probation until the second strike's probation year ends. If they acquire no additional strikes, the second strike is removed, and they will be restored to a zero-strike status. However, if they acquire an additional strike after the first strike is removed, an additional probation period begins from the last strike. If they accumulate three strikes, they will be disqualified from participating in the program for one year.

If an Installer or Applicant disputes the failed inspection or disqualification, he or she may appeal in writing within 30 days of notification of the failed inspection via US certified mail to the Program Administrator. A panel of all of the Program Administrators and a representative from the Energy Division of the California Public Utilities' Commission will review the appeal. Written appeals should substantiate any reasons he or she believes warrant reconsideration of the failure or disqualification. The appealing party may request an audience with the panel. The panel may also request additional information to substantiate the written appeal. The final decision will be provided to the Applicant or Installer within 60 days of receipt of the written appeal and the appeal decision of the panel shall be final.

2.9.2 Inspector Training Criteria

The CPUC requires that all system inspection visits must be performed by trained personnel, whether the inspection is performed by utility interconnection inspectors, other utility personnel, or contractors. The Program Administrators will develop a site inspectors' training plan that is consistent among the Program Administrators.

3. California Solar Initiative Program Incentive Structure

This section provides a general overview of the California Solar Initiative (CSI) Incentive structure. The CSI program offers two types of incentives: PBI and EPBB. Table 5 provides an overview of the two incentive structures under the CSI program. For the purpose of the CSI program, commercial sectors include agricultural and industrial customers. Typically, the incentive structure is determined by the size of the system installed. However, customers installing smaller systems have the option to choose the PBI structure regardless of the size of their system.

Table 5
CSI Incentive Structures

Type of CSI Incentive	Size Category	Payment Structure	Customers Eligible	Notes
Performance Based Incentive (PBI)	≥ 100 kW	Payments based on $/kWh produced over 5 year term	Residential, Commercial, Government and Nonprofit	❖ Smaller systems may Opt into PBI ❖ PBI is required for Building Integrated PV (BIPV) Systems
Expected Performance Based Buydown (EPBB)	< 100 kW	1 lump sum based on $/watt	Residential, Commercial, Government and Nonprofit	❖ EPBB is required for Non-Residential new construction systems, excluding BIPV. ❖ Residential New Construction projects are funded through the Energy Commission's New Solar Homes Partnership (not CSI)

Both PBI and EPBB incentives are available for residential and Non-Residential customers as displayed in Table 6.

Table 6
Type of CSI Incentive by Customer Sector

Type of CSI Incentive	Size Category	Residential[12]	Commercial	Gov't and Nonprofit
Performance Based Incentive (PBI)	≥ 100 kW[13]	√	√	√
Expected Performance Based Buydown (EPBB)	< 100 kW	√	√	√

12 Residential installations on existing structures. New residential construction projects will be funded through the Energy Commission's New Solar Homes Partnership.

13 Smaller systems may opt-in to receive a PBI incentive rather than the EPBB incentive.

3.1 CSI Program Incentive Trigger Mechanism

The incentive payment levels will automatically be reduced over the duration of the CSI program in 10 steps, based on the volume of MW of confirmed reservations issued within each utility service territory.[14] On average, the CSI incentives are projected to decline at a rate of 7 percent each year following the start of implementation in 2007. The incentives will gradually phase out over the 10 steps. The Table 7 outlines the 10 steps for the incentive levels for the CSI Program.[15]

Table 7
PBI and EPBB Payment Amounts by Step

		EBPP Payments (per watt)			PBI Payments (per kWh)		
MW Step	**Statewide MW in Step**	**Residential**	**Commercial**	**Gov't/ Nonprofit**	**Residential**	**Commercial**	**Gov't/ Nonprofit**
1	50	n/a	n/a	n/a	n/a	n/a	n/a
2	70	$ 2.50	$ 2.50	$ 3.25	$ 0.39	$ 0.39	$ 0.50
3	100	$ 2.20	$ 2.20	$ 2.95	$ 0.34	$ 0.34	$ 0.46
4	130	$ 1.90	$ 1.90	$ 2.65	$ 0.26	$ 0.26	$ 0.37
5	160	$ 1.55	$ 1.55	$ 2.30	$ 0.22	$ 0.22	$ 0.32
6	190	$ 1.10	$ 1.10	$ 1.85	$ 0.15	$ 0.15	$ 0.26
7	215	$ 0.65	$ 0.65	$ 1.40	$ 0.09	$ 0.09	$ 0.19
8	250	$ 0.35	$ 0.35	$ 1.10	$ 0.05	$ 0.05	$ 0.15
9	285	$ 0.25	$ 0.25	$ 0.90	$ 0.03	$ 0.03	$ 0.12
10	350	$ 0.20	$ 0.20	$ 0.70	$ 0.03	$ 0.03	$ 0.10

The duration of that phase-out will be dependent on: (1) whether the incentive budgets are depleted; (2) when the Program Administrators reach their MW goal; or (3) by the end of the program or 2016, whichever comes first. Table 8 displays the MW targets by Program Administrator service territory and customer class.

14 Investor-owned utility service territories only (PG&E, SCE, SDG&E)

15 See footnote 6

Table 8
CSI MW Targets by Utility and Customer Class

(NOTE: The SB1/CSI Draft Decision changes these numbers)

		PG&E (MW)		SCE (MW)		SDG&E/SDREO (MW)	
Step	MW in Step	Res	Non-Res	Res	Non-Res	Res	Non-Res
1	50	-	-	-	-	-	-
2	70	11.1	22.5	8.5	17.4	3.5	7
3	100	15.8	32.2	12.2	24.8	5	10.1
4	130	20.6	41.8	15.9	32.2	6.4	13.1
5	160	25.3	51.5	19.5	39.7	7.9	16.1
6	190	30.1	61.1	23.2	47.1	9.4	19.1
7	215	34.1	69.1	26.3	53.3	10.6	21.6
8	250	39.6	80.4	30.5	62	12.4	25.1
9	285	45.1	91.7	34.8	70.7	14.1	28.6
10	350	55.4	112.6	42.7	86.8	17.3	35.2
Total	**1800**	**277.1**	**562.9**	**213.6**	**434**	**86.6**	**175.9**
Total by Utility		840		647.6		262.5	
Percent		48%		37%		15%	

Projects are counted toward the MW trigger once they are deemed eligible, have paid an application fee (if applicable), and have been issued a confirmed reservation. As the number of MW allocated through the confirmed reservations reaches its maximum within any particular step, the Program Administrators will move to the next step. If there are any MW that remain unused in the previous step due to events such as Applicants dropping out of the process, those MW will be added to the next step, increasing the number in that step and ensuring that no MW are left outstanding.

The CSI program incentive levels may vary by service area, depending on the pace of solar demand in each Program Administrator's territory. Additionally, the CSI program incentive levels may differ based on demand in the residential and Non-Residential customer sectors. Refer to the Program Administrator's website to determine the step and incentive rate that is currently applicable to each customer sector in that utility's service territory. The Program Administrators will include on their websites an indication of the MW of Confirmed Reservations in each customer sector that is as close as possible to real time.

3.2 Expected Performance Based Buydown (EPBB) Incentives

The CSI program will pay incentives to solar projects with system ratings of less than 100 kW through an up-front incentive known as an EPBB. These EPBB incentives are based on an estimate of the system's future performance. EPBB incentives combine the benefits of rewarding performance with the administrative simplicity of a one-time incentive paid at the time of project completion.

The Program Administrators will use the Energy Commission's CEC-AC method to determine the system rating. In addition, the EPBB program will apply to all new construction other than building integrated systems (BIVP), regardless of size.

The following formula determines the EPBB incentive:

EPBB Incentive Payment = Incentive Rate x System Rating x Design Factor

The design factor is a ratio comparing a proposed system to a baseline system as follows:

$$\text{Design Factor} = \frac{\text{Proposed System}}{\text{Baseline System}}$$

The design factor for EBPP will:

- Treat all systems oriented between 180° and 270° equally
- Assign optimal orientation tilt for each compass direction in range of 180° and 270°, optimized for summer production
- Include location-specific criteria to account for weather variation and shading
- Be based on an optimal reference system and location
- Determine optimal reference latitude tilt that relates to local latitude.

3.2.1 Incentives for Residential Installations

Residential installations will be provided a one-time payment under the EPBB program to help reduce the cost of installation provided the system size is less than 100 kW. The amount of the EPBB incentive payment is as calculated pursuant to the formula in Section 3.2, with the incentive rate portion of the formula determined as shown by Table 9.

Table 9
Residential EPBB Incentive Levels by MW Steps and Service Territory

NOTE: The SB1/CSI Draft Decision changes the PG&E, SCE and SDREO numbers

Step	Residential EPBB ($/watt)	PG&E Res (MW)	SCE Res (MW)	SDG&E/SDREO Res (MW)
1	**n/a**	-	-	-
2	**$ 2.50**	11.1	8.5	3.5
3	**$ 2.20**	15.8	12.2	5
4	**$ 1.90**	20.6	15.9	6.4
5	**$ 1.55**	25.3	19.5	7.9
6	**$ 1.10**	30.1	23.2	9.4
7	**$ 0.65**	34.1	26.3	10.6
8	**$ 0.35**	39.6	30.5	12.4
9	**$ 0.25**	45.1	34.8	14.1
10	**$ 0.20**	55.4	42.7	17.3
Total		**277.1**	**213.6**	**86.6**

The CSI program incentive levels may vary by utility service area, depending on the pace of solar demand in each utility's territory. Refer to the Program Administrator's website to determine the currently-effective step and incentive rate.

Incentives for residential new construction projects will be funded through the Energy Commission's New Solar Homes Partnership program.

3.2.2 Incentives for Non-Residential Installations

Non-Residential installations will be provided a one-time payment under the EPBB program to help reduce the cost of installation provided the system size is less than 100 kW. There are different incentive rates for System Owners who are commercial entities or Government or Non-Profit entities. If a Government or Non-Profit entity is not the System Owner, the incentive amount will be determined by the tax status of the System Owner. The amount of the EPBB incentive payment is as calculated pursuant to the formula in Section 3.2, with the incentive rate portion of the formula determined as shown in Table 10.

Table 10
Non-Residential EPBB Incentive levels by MW Step and Service Territory

NOTE: The SB1/CSI Draft Decision changes the PG&E, SCE, and SDREO numbers

Step	Commercial EPBB ($/watt)	Gov't/ Non-Profit EPBB ($/watt)	PG&E Non Res (MW)	SCE Non Res (MW)	SDG&E Non Res (MW)
1	n/a	n/a	-	-	-
2	$ 2.50	$ 3.25	22.5	17.4	7
3	$ 2.20	$ 2.95	32.2	24.8	10.1
4	$ 1.90	$ 2.65	41.8	32.2	13.1
5	$ 1.55	$ 2.30	51.5	39.7	16.1
6	$ 1.10	$ 1.85	61.1	47.1	19.1
7	$ 0.65	$ 1.40	69.1	53.3	21.6
8	$ 0.35	$ 1.10	80.4	62	25.1
9	$ 0.25	$ 0.90	91.7	70.7	28.6
10	$ 0.20	$ 0.70	112.6	86.8	35.2
Total			562.9	434	175.9

Government and non-profit entities will be required to submit verification of their tax-exempt status to receive this incentive amount. Additionally, Government and Non-Profit entities must include a certification under penalty of perjury from their chief financial officer or equivalent that they are a Government or Non-Profit entity and that the system is not receiving and will not in the future receive federal tax benefits through financial arrangements for the entire warranty period of the system (i.e., the System Owner if a third-party, which will be receiving tax benefits from the system).

The CSI program incentive levels may vary by utility service area, depending on the pace of solar demand in each utility's territory. Refer to the Program Administrator's website to determine the currently effective step and incentive rate.

3.3 Performance Based Incentives (PBI)

The CSI program will pay PBI for solar projects with systems equal to or greater than 100 kilowatts (kW), with monthly payments based on recorded kilowatt hours (kWh) of solar power produced over a 5-year period. The Commission has determined that customers who receive incentives under a performance-based approach will be motivated to focus on proper installation, maintenance, and performance of their systems. Therefore, systems equal to or greater than 100 kW are required to participate in the PBI program. In addition, building integrated systems (BIPV), regardless of size, are required to participate in the PBI program. Furthermore, systems of any size may elect to opt into the PBI program.

Once the PBI incentive rate has been determined and a confirmed reservation issued, the $/kWh incentive rate will remain constant for the 5-year term. PBI payments shall be made on a monthly basis after commissioning of the system.

PBI payments will be calculated for solar energy systems that exceed 1 MW in size by prorating the energy output based on the ratio of 1 MW to the size of the facility. Thus, if a customer has installed a 5 MW system, the customer would receive PBI payments for 1/5 of the output of the system. As an alternative, and if possible, the customer may, at its election and cost, separately meter a 1 MW element of a larger system.

3.3.1 PBI for Residential Projects

Monthly payments will be made based on actual electricity generated in kWh as per the monthly reading of the meter. The residential PBI incentive rate ($/kWh) shall be in accordance with Table 11.

Table 11
Residential PBI Incentive Levels by MW Steps and Service Territory

NOTE: The SB1/CSI Draft Decision changes the PG&E, SCE, and SDREO numbers

Step	Residential PBI ($/kWh)	PG&E Res (MW)	SCE Res (MW)	SDG&E/SDREO Res (MW)
1	**n/a**	-	-	-
2	**$ 0.39**	11.1	8.5	3.5
3	**$ 0.34**	15.8	12.2	5
4	**$ 0.26**	20.6	15.9	6.4
5	**$ 0.22**	25.3	19.5	7.9
6	**$ 0.15**	30.1	23.2	9.4
7	**$ 0.09**	34.1	26.3	10.6
8	**$ 0.05**	39.6	30.5	12.4
9	**$ 0.03**	45.1	34.8	14.1
10	**$ 0.03**	55.4	42.7	17.3
Total		**277.1**	**213.6**	**86.6**

The PBI incentive levels may vary by utility service area, depending on the pace of solar demand in each utility's territory. Refer to the Program Administrator's website to determine the currently effective step and incentive rate.

3.3.2 PBI for Non-Residential Projects

There are different incentive rates for commercial entities and for Government or Non-Profit entities that are the System Owners. If a Government or Non-Profit entity is not the System Owner, the incentive amount will be determined by the tax status of the System Owner. The Program Administrators will make the monthly payments based on actual electricity generated in kWh as per the monthly reading of the meter. The incentive amount ($/kWh) will be in accordance with Table 12.

Table 12
Non-Residential PBI Incentive levels by MW Step and Service Territory

NOTE: The SB1/CSI Draft Decision changes the PG&E, SCE and SDG&E numbers

Step	Commercial PBI ($/watt)	Gov't/ Nonprofit PBI ($/watt)	PG&E Non Res (MW)	SCE Non Res (MW)	SDG&E Non Res (MW)
1	n/a	n/a	-	-	-
2	**$ 0.39**	**$ 0.50**	22.5	17.4	7
3	**$ 0.34**	**$ 0.46**	32.2	24.8	10.1
4	**$ 0.26**	**$ 0.37**	41.8	32.2	13.1
5	**$ 0.22**	**$ 0.32**	51.5	39.7	16.1
6	**$ 0.15**	**$ 0.26**	61.1	47.1	19.1
7	**$ 0.09**	**$ 0.19**	69.1	53.3	21.6
8	**$ 0.05**	**$ 0.15**	80.4	62	25.1
9	**$ 0.03**	**$ 0.12**	91.7	70.7	28.6
10	**$ 0.03**	**$ 0.10**	112.6	86.8	35.2
Total			**562.9**	**434**	**175.9**

The PBI incentive levels may vary by the Program Administrators' territory, depending on the pace of solar demand in each territory. Refer to the Program Administrator's website to determine the currently effective step and incentive rate.

Government and Non-Profit entities will be required to submit verification of their tax-exempt status to receive this incentive amount. Additionally, Government and Non-Profit entities must include a certification under penalty of perjury from their chief financial officer or equivalent that they are a Government or Non-Profit entity and that the system is not receiving and will not in the future receive federal tax benefits through financial arrangements for the entire warranty period of the system (i.e., the System Owner if a third-party, which will be receiving tax benefits from the system). This certification must be renewed annually if receiving PBI payments.

3.4 Incentive Limitations

Incentive amounts and project eligibility for the CSI program are limited by a number of factors, including:

- Total eligible project costs
- Other incentives or rebates received
- Project size and Host Customer Site limitations.

3.4.1 Total Eligible Project Costs

No project can receive total incentives (incentives from the CSI program combined with other programs) that exceed total eligible project costs. The Applicant must submit project cost details to report total eligible project costs and to ensure that total incentives do not exceed out-of-pocket expenses for the System Owner. See Appendix A for eligible cost items. Total eligible project costs cover the solar system and its ancillary equipment. Equipment and other costs outside of the project envelope defined in Appendix A are considered ineligible project costs but also must be reported. For large, multifaceted projects where the solar system costs are embedded, applications must include a prorated estimate of the total eligible costs for the solar system. Applications must include the project cost breakdown worksheet available from the Program Administrators' websites.

3.4.2 Other Incentives or Rebates

Customers may not receive CSI program incentives for the same self-generation equipment from more than one Program Administrator (e.g., PG&E, SCE, SDREO). For projects receiving incentives under other programs, the CSI program incentive may be reduced, depending on the source of the other incentive. For projects that receive "other incentives" for the same generating equipment that are funded by California investor-owned utility ratepayers (e.g., utility or Energy Commission public goods charge programs, etc.), the CSI program incentive is discounted by the amount of the other incentive. For projects that receive "other incentives" funded from other sources than utility ratepayers (federal and state grants, air district grants, tax credits, etc.) no adjustment is made to the CSI incentive, except where a CSI incentive would otherwise cause total incentives to exceed total eligibility costs.

In no event may the combined incentives received from CSI program and other funding sources exceed the total eligible project cost. Host Customers, Applicants and System Owners are required to disclose information about all other incentives, including incentives for equipment or systems ancillary to the solar system, post-installation performance payments, or additional incentives. Program Administrators will enter applications into a statewide database that will permit universal tracking of applications for this and other programs.

3.4.3 Right to Audit Final Project Costs

The Program Administrators reserve the right to conduct spot checks to verify that payments were made as identified in the final invoices or agreements provided by equipment sellers and/or installers. As part of these spot checks, the Program Administrators will require Applicants to submit copies of cancelled checks, credit card statements, or equivalent documentation to substantiate payments made to the equipment seller and/or installer. When submitting this documentation, Applicants are encouraged to remove their personal account numbers or other sensitive information identified in the documentation. Applicants must explain the difference if the final amount paid by the Applicant is different from the amount of the purchase or installation shown in any agreement or invoice or in the previously submitted Reservation Request.

If selected for a random audit, Applicants must submit final system cost documentation clearly identifying the final amount paid or legally incurred to purchase the system and the final amount paid to install the system. The cost documentation must provide proof of the final amount paid or legally incurred by the System Owner to the equipment seller and/or installer and provide sufficient information to clearly identify the equipment purchased and the labor paid. The final amount paid or legally incurred to the equipment seller and/or the final amount paid to the installer must match the cost information identified in the Reservation Confirmation and Incentive Payment Claim Form. To meet this requirement, the System Owner must submit final invoices and/or a copy of the final agreement. The actual amount paid or legally incurred by the purchaser to the equipment seller and/or the actual amount paid to the installer must be clearly indicated. If there is no direct proof of actual payment from the System Owner to an appropriately licensed installer or seller, the incentive will be cancelled or reduced.

In addition, the final invoices or agreements should clearly indicate the extent to which the California Solar Initiative program incentive lowered the cost of the system to the System Owner. If the System Owner has entered into an agreement to pay the equipment seller over time rather than in lump sum, the final agreement must indicate the terms of payment and the amount of any deposits or payments paid by Applicant to the equipment seller to date. The System Owner must pay the cost of any system installation prior to submitting a payment request to the Program Administrator.

3.4.4 Site and Host Customer Limitations

There are restrictions on the amount of incentive funding a Host Customer can reserve and receive. Host Customers can reserve up to 1 MW of maximum incentive funding from the CSI program for a single Site for the duration of the CSI program.

3.5 CSI Program Database

One of the notable features of the CSI program is the on-line database. The Program Administrators will establish and maintain an up-to-date database on their websites that will list information on the progress of the CSI program. The Program Administrators will show detailed information on the number of PV systems and confirmed reservations, systems installed from January 2007 forward with links to the archived database of all systems installed under the Energy Commission's Emerging Renewables Program, Self-Generation Incentive Program, and Rebuild a Greener San Diego Photovoltaic Incentive Program.

The information will include the following data from each project:

- Installer
- Seller
- City
- ZIP code
- Utility name
- Technology
- Size (Watts)
- Installed price approval
- PV manufacturer
- PV model
- Inverter manufacturer

- Inverter model
- Date completed
- Date of approved reservation.

Initially, program data will be updated quarterly. It is anticipated that once fully developed, the database will provide program data on a real-time basis.

4. Application Process for California Solar Initiative Projects

Through the California Solar Initiative (CSI) program, funding may be reserved for Applicants who have committed to purchase and install an eligible photovoltaic (PV) system at a given Site. A funding reservation provides the purchaser assurance that the reserved funds will be available when the payment claim is made.

Table 13 describes various situations and identifies the subsections that provide details on how to apply for funding.

Table 13
Summary of Application Procedures by Track

Track	Sector	Application Fee	System Size	Reservation Period	Relevant Section
1	All Residential	**No**	All	12 months	**Section 4.1**
1	Commercial	**No**	Less than or equal to 10 kW	*12 months for retrofit *18 months for new construction projects	**Section 4.1**
1	Government, Non-profit, Public Entities (small projects)	**No**	Less than or equal to 10 kW	12 months	**Section 4.1**
2	Commercial	**Yes**	Greater than 10 kW	*12 months for retrofit projects *18 months for new construction projects	**Section 4.2** **Section 4.2.1**
2	Government, Non-profit, Public Entities	**Yes**	Greater than 10 kW	18 months	**Section 4.2** **Section 4.2.2**

4.1 Residential (All) and Small Non-Residential Projects (≤ 10 kW)

This section describes the application process for all projects installed on a residential Host Customer Site as well as projects less than or equal to 10 kW installed on Non-Residential Host Customer Sites. All residential and small projects are eligible to receive a lump sum EPBB incentive payment. However, there is an option to opt in to receive PBI based on $/kWh produced.

The CSI program uses an on-line application tool to simplify the application process and confirm the rebate amount reserved, contingent on receiving all documents. Section 12 includes a blank copy of the Reservation Request Form and accompanying instructions. To obtain additional blank forms, the forms may be downloaded from the Program Administrators' website.

Figure 1 outlines the application process for residential and small projects less than or equal to 10 kW.

Figure 1
Residential (all) and Small Project Application Process Flow Chart

Applicant	Program Administrator
(1) Step # 1: Submit Reservation Request Form Applicant completes the **Reservation Request Form** and submits a signed copy to program administrator with the required attachments, including the executed installation contract and signed CSI Program contract *(see Section 4.1.2 for a complete list of required attachments).*	***(2) Reservation Request Form Processing*** Program Administrator evaluates the package for completeness and eligibility. o If *incomplete*, requests further information from applicant. o If *ineligible*, sends notification of ineligibility letter via mail. o If *complete and eligible,* proceeds to step 2.
(4) Proceed with Installation. Once the Applicant has received the **Confirmed Reservation Notice Letter** and **Incentive Claim Form,** Applicant proceeds with purchase and installation of the system. System must be operational by the Reservation Expiration Date (*12 months for retrofit and 18 months for new construction) as listed in the* R**eservation Confirmation Letter**.	***(3) Confirmed Reservation Notice Letter and Incentive Claim Form*** Program Administrator sends the **Reservation Confirmation** and **Incentive Claim Form** confirming the reservation dollar amount and reservation expiration date (12 months for retrofit and 18 months for new construction) after approval date
(5) Step # 2: Submit Incentive Claim Form and Required Documentation When project is operational the **Incentive Claim Form** is mailed with required documentation to the Program Administrator on or before the Reservation Expiration Date. *(see Handbook Section 4.4.3.1 for complete list of required attachments).*	***(6) Incentive Claim Form Processing*** Program Administrator reviews the **Incentive Claim** Form and documentation and may conduct a Field Verification Visit. o If *incomplete*, requests further information from applicant. o If *ineligible*, sends notification of ineligibility letter via mail. o If *approved, the Program Administrator* sends Incentive Payment(s) to designated payee.

4.1.1 Two-Step Process for Residential and Small Non-Residential Applicants

There are two primary steps for residential and small Non-Residential Applicants as follows:

1. Complete and submit an Application (on line or available at the Program Administrator's website) and Reservation Application Package

   a. Include copy of executed contract for PV system purchase and installation
   b. See Section 4.7 for a list of required documentation
2. Complete and submit the Incentive Claim Form
   a. See Section 4.7 for a list of required documentation.

Table 14 details the application forms and documentation requirements for the two-step application process.

Table 14
Two-Step Application Process – Forms and Documentation Requirements

Step 1: Reservation Request
Reservation Request Application Checklist
Reservation Request Application with Original Signature
Proof of Electric Utility Service for Site
System Description Worksheet
Electrical System Sizing Documentation (new/expanded load only)
Incentive Calculation Worksheet & EPBB Documentation
Description of other Funding Sources (If applicable)
Evidence of Executed Agreement of System Purchase
Signed CSI Program Contract
Host Customer Certificate of Insurance
System Owner Certificate of Insurance (if different than Host Customer)
Copy of Completed Interconnection Application
Certification of tax-exempt status and AB1407 compliance (Gov't and Nonprofit only)
Step 2: Reservation Confirmation and Claim
Incentive Claim Checklist
Incentive Claim Form with Original Signatures
Installer/Seller EPBB Field Checklist with Original Signature
Proof of Authorization to Interconnect
Copy of Building Permit and Final Inspection signed
Proof of Warranty
Final project Cost Breakdown Worksheet
Final project Cost Breakdown Affidavit
Revised Sizing Calculations (if applicable)
Payee Data Record

4.1.2 Step # 1: Submit Reservation Request Application Package

Once the customer has decided to install a solar system and has an executed contract with their system installer, an Application (on-line or available at the Program Administrator's website) and

Reservation Request Application Package are submitted in the first step of the application process.

The Reservation Request Form must have original signatures of Applicant and Host Customer and should be submitted with the following documentation:

1. Completed Reservation Request Application Checklist
2. Completed Reservation Request Application
    b. Original Signatures of the System Owner and Host Customer required
3. Evidence of Executed Agreement or Contract for System Purchase
4. Signed CSI program contract
5. Host Customer Certificate of Insurance
6. System Owner Certificate of Insurance (if different than the Host Customer)
7. Proof of Electric Utility Service (copy of utility bill)
8. Incentive Calculation Worksheet & EPBB Required documentation
9. Interconnection Application (may be submitted online if available) Check with your Program Administrator.
10. Certification of AB 1407 compliance and tax-exempt status (Government and Non-Profit entities only).

Refer to Section 4.7 for more information on the above-referenced forms and documents.

Detailed instructions are included with the Reservation Request Form. Appendix C includes a blank copy of the Reservation Request Form and accompanying instructions. To obtain additional blank forms, download the forms on line from the Program Administrator's website.

The Host Customer and System Owner must sign the Reservation Request Form.

4.1.3 Incomplete Reservation Requests

If an application is found to require clarification, the Program Administrator will request additional information. Applicants have 20 calendar days to respond to the clarification request with the necessary information. If after 20 calendar days the Applicant has not submitted the requested information, the application will be canceled. Resubmitted application packages will be treated as new applications (i.e., all required documents must be resubmitted) and processed in sequence along with other new applications.

Incentive funds are not reserved until the Program Administrator receives all information and documentation required for the Reservation Request and the project is approved.

4.1.4 Approval of Reservation Request

Once received, the Program Administrator will review the application package for completion and determine eligibility. Applications will also be screened to ensure that the project has not applied for incentives through other Program Administrators or other state- or government-sponsored incentive programs.

Once the Program Administrator approves the reservation request, the Program Administrator will issue a Confirmed Reservation Notice Letter that confirms that a specific incentive amount is reserved for the project. This confirmation notice will also include an Incentive Payment Claim Form.

The system must be purchased, installed, and put into operation by the Reservation Expiration Date (see Section 4.1.4.1 for length of reservation) as listed in the Confirmation Reservation Notice Letter. The Incentive Payment Claim Form will list the specific reservation dollar amount and the Reservation Expiration Date. For more information on the Incentive Claim Form package, refer to Section 4.7.

4.1.4.1 Reservation Period

Incentives can be reserved for up to 12 months for residential retrofit projects and commercial retrofit projects. Incentives can be reserved for up to 18 months for government, non-profits and public entities and also for new construction projects.

4.1.5 Step # 2: Submit Incentive Claim Form Package

After the solar system is purchased, installed, and put into operation, the Applicant should submit the Incentive Claim Form and the required supporting documentation. For information on submitting the Incentive Claim Form package, refer to Section 4.7.3.

4.2 Non-Residential Projects (>10 kW) and PBI Projects

This section describes the application process for all Non-Residential projects >10 kW for commercial and industrial, Government, Non-Profit, and Public Entities and for any project receiving payment under a PBI structure.

Please note that Non-Residential projects (>10kW) may opt into the two-step process if they would like to, but are still subject to the eligibility requirements based on their system size and type. See section 4.1.1 for required timelines and paperwork.

The Applicant can expedite the three step process by providing the requisite information to the program administrators in two steps. Non-residential projects (>10 kW) are still subject to the eligibility requirements based on their system size and type, including the submission of any required application fees. See section 4.2.3 for required timelines and paperwork.

The CSI program anticipates an on-line application tool to simplify the application process.

4.2.1 Application Process Flow Chart for Commercial Industrial Applicants (>10 kW)

Figure 2 documents the application process for commercial and industrial customers.

Figure 2
Commercial and Industrial (> 10 kW) Application Process Flow Chart

Applicant	Program Administrator
(1) Step # 1: Submit Reservation Request Form and Application Fee Applicant completes the **Reservation Request Form** and submits a signed copy to program administrator with the **Application Fee** and the required attachments *(see Section 4.2.4 for a complete list of required attachments)*. →	***(2) Reservation Request Form Processing*** Program Administrator evaluates the package for completeness and eligibility. o If *incomplete*, requests further information from applicant. o If *application fee missing*, sends invoice. o If *ineligible*, sends notification of ineligibility letter and returns application fee via mail. o If *complete, eligible,* and fee paid proceeds. ↓
← ***(4) Receives*** the **Confirmed Reservation Notice Letter** and **Program Contract.** Applicant has 60 days to gather documentation required for next stage. ↓	***(3) Confirmed Reservation Notice Letter and Program Contract*** Program Administrator sends the **Reservation Confirmation** and **Program Contract.** The letter specifies a reservation number and dollar amount for which the project has been conditionally reserved.
(5) Step 2: Submit Proof of Project Milestone Within 60 days of receiving the **Confirmed Reservation Notice Letter** and **Program Contract,** Applicant mails the signed **Program Contract** and required documentation to the Program Administrator *(see Section 4.2.7.1 for complete list of required attachments)*. →	***(6) Proof of Project Milestone Processing*** Program Administrator reviews documentation: o If *incomplete*, requests further information from applicant. o If *ineligible*, sends notification of ineligibility letter via mail. o If *approved,* proceeds to next stage. ↓
← ***(8) Proceed with Installation.*** Once the Applicant has received the **Reservation Confirmation** and **Incentive Claim Form,** Applicant proceeds with purchase and installation of the system. System must be operational by the Reservation Expiration Date *as listed in the* **Reservation Confirmation Letter**. ↓	***(7) Reservation Confirmation and Incentive Claim Form*** Program Administrator sends a **Reservation Confirmation Letter** and **Incentive Claim Form** confirming the reservation dollar amount and reservation expiration date (12 months for retrofit and 18 months for new construction).
(9) Step 3: Submit Incentive Claim Form and Required Documentation When project is operational the signed **Reservation Confirmation** and **Incentive Claim Form** is mailed with required documentation to the Program Administrator on or before the Reservation Expiration Date. *(see Section 4.4.3.1 for complete list of required attachments)*. →	***(10) Incentive Claim Form Processing*** Program Administrator reviews **Incentive Claim** Form and documentation and may conduct a Field Verification Visit. o If *incomplete*, requests further information from applicant. o If *ineligible*, sends notification of ineligibility letter via mail. o If *approved,* the Program Administrator sends Incentive Payment(s) to designated payee.

4.2.2 Application Process Flow Chart for Government, Non-Profit, and Public Entities (>10 kW)

Figure 3 documents the application process for Government, Non-Profit, and Public Entities.

Figure 3
Government, Non-Profit, and Public Entities (> 10 kW) Application Process Flow Chart

Applicant	Program Administrator

(1) Step # 1: Submit Reservation Request Form and Application Fee

Applicant completes the **Reservation Request Form** mails signed copy to program administrator with the **Application Fee** (OR requests to be invoiced) along with required attachments including the AB 1407 Public Entity Certification and verification of tax exempt status *(see Section 4.2.3 for complete list of required attachments).*

(2) Reservation Request Form Processing

Program Administrator evaluates the package for completeness and eligibility.

- If *incomplete*, requests further information from applicant.
- If *invoice requested*, sends invoice.
- If *ineligible*, sends notification of ineligibility letter and returns application fee via mail.
- If *complete, eligible,* and fee paid proceeds.

(3) Confirmed Reservation Notice Letter and Program Contract

Program Administrator sends the **Reservation Confirmation.** The letter specifies a reservation number and dollar amount for which the project has been conditionally reserved. The **CSI Program Contract** will be sent after receipt of the RFP or equivalent for system purchase and installation.

(4) Applicant receives the **Confirmed Reservation Notice Letter.**

Applicant has 60 days to submit a copy of the RFP or equivalent for system purchase and installation (see Section 4.2.7). Upon receipt, the Program Administrator will issue the **CSI Program Contract**.

(5) Step 2: Submit Proof of Project Milestone

Within 240 days of receiving the **Confirmed Reservation Notice Letter** and **Program Contract,** Applicant mails the signed **Program Contract** and required documentation to the Program Administrator *(see Section 4.2.7.1 for complete list of required attachments).*

(6) Proof of Project Milestone Processing

Program Administrator reviews documentation:

- If *incomplete*, requests further information from applicant.
- If *ineligible*, sends notification of ineligibility letter via mail.
- If *approved,* proceeds to next stage.

(7) Reservation Confirmation and Incentive Claim Form

Program Administrator sends a **Reservation Confirmation Letter** and **Incentive Claim Form** confirming the reservation dollar amount and reservation expiration date (18 months).

(8) Proceed with Installation.

Once the Applicant has received the **Reservation Confirmation** and **Incentive Claim Form,** Applicant proceeds with purchase and installation of the system. System must be operational by the Reservation Expiration Date *as listed in the* **Reservation Confirmation Letter**.

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(9) Step 3: Submit Incentive Claim Form and Required Documentation

When project is operational the signed **Reservation Confirmation** and **Incentive Claim Form** is mailed with required documentation to the Program Administrator on or before the Reservation Expiration Date. *(see Section 4.4.3.1 for complete list of required attachments).*

(10) Incentive Claim Form Processing

Program Administrator reviews **Reservation Confirmation** and **Incentive Claim** Form and documentation and may conduct a Field Verification Visit.

- If *incomplete*, requests further information from applicant.
- If *ineligible*, sends notification of ineligibility letter via mail.
- If *approved,* the Program Administrator sends Incentive Payment(s) to designated payee.

4.2.3 Three-Step Process for Non-Residential Applicants (> 10 kW)

There are three primary steps for Non-Residential Applicants with systems larger than 10 kW as follows:

1. Complete and submit the Reservation Application Package (on line or available at the Program Administrator's website) and Application fee
    a. See Section 4.2.5 for a list of supporting documentation required
2. Complete and submit the Proof of Project Milestone Package
    a. Refer to Section 4.7.2 for list of supporting documentation required
3. Complete and submit an Incentive Claim Form Package
    a. See Section 4.7.3 for list of supporting documentation required.

Table 15 details the application forms and documentation requirements for the three-step application process.

Table 15
3-Step Application Process – Forms and Documentation Requirements

Step 1: Reservation Request
Reservation Request Application Checklist
Reservation Request Application with Original Signature
Proof of Electric Utility Service for Site
System Description Worksheet
Electrical System Sizing Documentation
Incentive Calculation Worksheet & EPBB Documentation
Description of other Funding Sources (If applicable)
Evidence of Executed Agreement of System Purchase
Application Fee
Certification of tax-exempt status and AB1407 compliance (Government, Non-profit, and Public Entities only)
Step 2: Proof of Project Milestone
Completed Proof of Project Milestone Checklist
Host Customer Certificate of Insurance
System Owner Certificate of Insurance (if different than Host Customer)
Copy of Completed Interconnection Application
Copy of executed contract for system installation
Copy of executed alternative System Ownership agreement (if System Owner is different than Host Customer)
Project Cost Breakdown Worksheet
Revised Sizing Calculations (If applicable)
Revised Incentive Calculation Worksheet (If applicable)
CSI Program Contract with Original Signature
Copy of RFP or solicitation (Government, Non-profit, and Public Entities only)
Step 3: Incentive Form Package
Incentive Claim Checklist
Incentive Claim Form with Original Signatures
Installer/Seller EPBB Field Checklist with Original Signature
Proof of Authorization to Interconnect
Copy of Building Permit and Final Inspection sign-off
Proof of Warranty
Final Project Cost Breakdown Worksheet
Final Project Cost Affidavit
Final Incentive Calculation Worksheet
Revised Sizing Calculations (if applicable)
Payee Data Record

4.2.4 Step # 1: Request to Reserve Funding

This subsection applies to all Non-Residential Applicants with solar systems larger than 10 kW, regardless of whether the Applicant is a private or public entity. To reserve a specified incentive amount, Applicants must submit the Reservation Request Form, Application Fee, and all required documentation attachments. The Reservation Request Form and instructions can be downloaded from the local Program Administrator's website.

Section 12 includes a blank copy of the Reservation Request Form and accompanying instructions. The System Owner and Host Customer must always sign the Reservation Request Form. In additional, all Applicants applying for incentives must provide the following:

1. Completed Reservation Request Application Checklist
2. Completed Reservation Request Application w/ original signatures
3. Proof of electric utility service
4. Electrical system sizing documentation
5. System description worksheet
6. Incentive Calculation Worksheet & EPBB Required documentation
7. Description of other funding sources
8. Certification of tax-exempt status and compliance with AB1407 (Government, Non-Profit and Public Entities only).

For more information on the above referenced forms and documents, go to Section 4.7.

4.2.5 Application Fee Process

In addition to the Reservation Request Form and Required Attachments, Applicants will also be required to submit an application fee. Applicants with projects that are residential, or less than or equal to 10 kW, need not pay an application fee.

The application fee is 1 percent of the unadjusted requested CSI program incentive amount. Application fees will be rounded to the nearest dollar amount. The formula for the EPBB or PBI fee is as follows:

Application Fee = (Design Factor System Size x current applicable/equivalent EPBB incentive rate) x 1%

- Applicants may submit the application fee with the Reservation Request Form with original signatures. If application fee is not received with the Reservation Request Form, the Program Administrators will invoice the Host Customer (utility customer of record) after review of the Reservation Request Form package.
- The Host Customer will have 30 days to submit payment for the application fee in order to activate the Reservation Request. The payment must reference the project application number.
- Program Administrators will accept payments from either the Applicant or a third party on behalf of the Host Customer for a particular project; however, a returned application fee shall only be paid to the Host Customer.
- Program Administrators will only accept application fees in the form of a check. Cash, credit cards, money orders, promissory notes, etc. will not be accepted.

- Application fees will be linked to reservation numbers, not to the project sites; therefore, the project must be completed under the same reservation number as the one linked to the application fee.
- Upon verification of the installed CSI project and initial incentive payment, the application fee will be returned in full to the Host Customer.
- No interest shall be paid on application fees.

4.2.5.1 Failure to Submit Application Fee

- Returned checks will result in the Program Administrator rejecting the Reservation Request form.
- Failure to submit payment within 30 days will result in the cancellation of the Reservation Request.

4.2.5.2 Return of Application Fee

- If upon eligibility screening the project does not qualify for the CSI program, the application fee will be returned in full to the Host Customer.
- If a project that has received an Incentive Claim Form from the Program Administrator is withdrawn due to extenuating circumstances beyond the Applicant's control, the application fee may be returned pending discussion and agreement of the Program Administrators. This will be determined on a case-by-case basis.

4.2.5.3 Forfeit of Application Fee

- Once a confirmed reservation is granted and the project is cancelled or withdrawn by the Applicant and/or Host Customer, the application fee will be forfeited.
- Once a confirmed reservation is granted and the Program Administrator rejects the project for failing to meet adequate proof of project milestone or reservation expiration date requirements, the application fee will be forfeited.
- If a project reservation is allowed to lapse and the project is later built under a new reservation, the application fee for the previous reservation will be forfeited.

All forfeited application fees will be re-allocated to the Program Administrator's incentive budget.

4.2.5.4 Effect of Change of System Change on Application Fee

- If a confirmed reservation is granted and the incentive level has been reduced (due to Commission directive, moving to the next step , etc.), the Applicant and Host Customer will be notified and given 20 calendar days to submit in writing a request to withdraw their reservation request without losing their application fee. Upon receipt of a request to withdraw, the application fee shall be returned to the Host Customer. If the Applicant fails to withdraw the reservation request within 20 calendar days, the application will be processed at the new, lower incentive level.

If the application is not withdrawn within the 20-day period, the Applicant will forfeit the application fee if it subsequently withdraws or fails to pursue its project.

- Application fees will be retained until the completion of the proposed CSI project and will not be adjusted downward due to changes in system size or incentive amount.

4.2.6 Approval of Reservation Request

Once received, the Program Administrator will review the application package for completeness and determine eligibility. Applications will also be screened to ensure that the project has not applied for incentives through other Program Administrators or other state- or government-sponsored incentive programs.

4.2.6.1 Incomplete Reservation Requests

Incentive funds are not reserved until the Program Administrator receives all information and documentation required for the Reservation Request Form Package, the application fee and the project is approved.

If an application is found to require clarification, the Program Administrator will request the information necessary to process that application further. Applicants have 20 calendar days to respond to the requested clarification with the necessary information. If after 20 calendar days, the Applicant has not submitted the requested information the applications will be canceled. Application packages that are resubmitted after such a cancellation will be treated as a new application (i.e., all required documents must be resubmitted) and processed in sequence along with other new applications.

4.2.6.2 Approval of Reservation Request

Once a Reservation Request Form package is determined to be complete and eligible, the Program Administrator will reserve a specific dollar amount for a specified system size. The Program Administrator will send a Confirmed Reservation Notice Letter to the Applicant.

The Confirmed Reservation Notice Letter documents that a specific incentive amount has been reserved for a project. The letter will list, at a minimum, the approved incentive amount and the date that the Proof of Project Milestone package must be submitted. The Confirmed Reservation Notice Letter also will list the required information that Applicants must submit by the Proof of Project Milestone.

Once the application documentation has successfully fulfilled the Proof of Project Milestone documentation, the Program Administrator will issue an Incentive Claim Form with a Reservation Expiration Date of 12 months for commercial retrofit projects, 18 months for commercial new construction projects, and 18 months for Governmental, Non-Profit, and Public Entities from the date of the initial Confirmed Reservation Notice Letter.

Refer to Section 4.2.7 for more information on the Proof of Project Milestone requirements.

4.2.6.3 Reservation Period

The initial reservation is valid only until the Proof of Project Milestone Date. The Proof of Project Milestone Date will be 60 calendar days after the date of the Confirmed Reservation Notice Letter for residential and commercial projects. Within noted calendar days of the date the Confirmed Reservation Letter, the Applicant must submit to their Program Administrator the Proof of Project Milestone package. All project advancement criteria, including returning a signed CSI program contract, must be satisfied. Once the Applicant has sufficiently demonstrated that the project is advancing, the Program Administrator will issue an Incentive Claim Form. The Applicant will have 12 months to complete the project from the date that the Confirmed Reservation Notice Letter is issued for retrofit projects and 18 months for new construction projects.

4.2.6.4 Reservation Period for Government, Non-Profit and Public Entity Projects

The initial reservation is only valid for until the Proof of Project Milestone date. Within 60 days after the Confirmed Reservation Notice letter, Government, Non-Profit and public entities must turn in the Proof of Project Milestone checklist and a copy of the RFP or other solicitation for the installation of the project. Then, Government, Non-Profit, and Public Entities will have an additional 180 days to provide the entire Proof of Project Milestone package. All project advancement criteria, including returning a signed CSI program contract, must be satisfied. Once the Applicant has sufficiently demonstrated that the project is advancing, the Program Administrator will issue an Incentive Claim Form. The Applicant will have 18 months to complete the project from the date that the Confirmed Reservation Notice Letter is issued.

4.2.7 Step # 2: Submit Proof of Project Milestone Package

Within 60 calendar days (240 days for Governmental entities) of the date on the Confirmed Reservation Letter, the Proof of Project Milestone package with all supporting documentation must be submitted to demonstrate to the Program Administrator that the project is progressing and that there is a sustained commitment to complete the project within the allowed timeline. The specific requirements by sector are as follows:

- Non-Residential projects greater than 10 kW and projects that are receiving a PBI payment within 60 days of the Confirmed Reservation Notice Letter must submit a Proof of Project Milestone package, including all required documentation.
- Government, Non-profit, and Public Entities, within 60 calendar days of the date of the Confirmed Reservation Letter, must submit a copy of the issued request for proposal (RFP or equivalent) for purchase or installation of the solar system. Within 240 calendar days of the date of the Confirmed Reservation Letter, they must satisfy all proof of project milestone criteria, including all required documentation.

Once the Applicant has successfully met Proof of Project Milestone requirements, the Program Administrator will issue an Incentive Claim Form with a Reservation Expiration Date of 12 months from the date of the initial Confirmed Reservation Notice Letter for commercial retrofit projects, 18 months for commercial new construction projects, and 18 months from the date of the initial Confirmed Reservation Notice Letter for Governmental, Non-Profit, and Public Entities.

4.2.7.1 Required Attachments to Demonstrate Project Milestone

The following documentation must be submitted on or before the Proof of Project Milestone date indicated in the Confirmed Reservation Letter.

1. Completed Proof of Project Milestone Checklist
2. CSI Program Contract with original signatures
3. Host Customer Certificate of Insurance
4. System Owner Certificate of Insurance
5. Copy of Completed Interconnection Application
6. Copy of Executed Agreement to Purchase or Lease
7. Project Cost Breakdown Worksheet
8. Revised Sizing Calculations (if applicable)
9. Revised Incentive Calculation Worksheet (if applicable).

For more information on the above-referenced forms, go to Section 4.7.

4.2.7.2 Incomplete Proof of Project Milestone

If submitted Proof of Project Milestone documentation is received by the Proof of Project Milestone Date but requires clarification, the Program Administrator will request the information necessary to process that application further. Applicants have 20 calendar days to respond with the necessary information. If, after 20 calendar days, the Applicant has not submitted the requested information, the applications will be canceled.

4.2.7.3 Proof of Project Milestone Extensions

In general, no extensions to the Proof of Project Milestone date are permitted.

4.2.7.4 Submitting Proof of Project Milestone

Once the Proof of Project Milestone package is complete and all the required attachments are secured, Applicants must submit their application package to the Program Administrator for review. To ensure confirmation of receipt, it is recommended that documentation is to be delivered to the appropriate Program Administrator by certified or overnight mail. No faxes or hand deliveries will be accepted.

4.2.7.5 Approval of Proof of Project Milestone

Once Applicants have successfully met the Proof of Project Milestones requirements, the Program Administrator will issue an Incentive Claim Form. This form will list the specific reservation dollar amount and the Reservation Expiration Date. Upon project completion and prior to the Reservation Expiration Date, Applicants must submit a completed Incentive Claim Form along with all of the necessary documentation to request an incentive payment.

For more information on how to submit an Incentive Claim, refer to Section 4.4.3.

4.2.8 Step # 3: Submit Incentive Claim Form Package

Refer to Section 4.7.3 for more information about the requirements associated with submitting the Incentive Claim Form package.

4.3 Changes to Reservations

4.3.1 Extending the Reservation Expiration Date

A request to extend the Reservation Expiration Date is limited to a maximum of 180 calendar days of additional time. Any request must include a written explanation of why the extension is required and how much additional time is needed. Approval of a request for a change in Reservation Expiration Date will not change or modify any other reservation condition. Failure to submit the Incentive Claim Form package by the original or extended Reservation Expiration Date will result in a cancellation of the application. The Applicant should submit a time extension in writing to the Program Administrators. In describing the reason for the time extension request, the Applicant should provide information on the following to aid the Program Administrators in their decision to grant an extension:

1. Circumstances were beyond the control of the reservation holder that prevented the system from being installed as described in the reservation request. Describe the need and reasons for the request.
2. If there was a problem in the permitting process and it was the cause of delay, provide documentation, such as any correspondence with the building department, to support this explanation.
3. Cost documentation must demonstrate that the system purchaser has incurred at least 50 percent of the reserved system's total purchase price. However, in cases where this amount exceeds the purchaser's contribution then the purchaser may still retain 10 percent of the total system cost and meet this cost documentation requirement. Attach copies of paid invoices, checks or other verifying documentation to the Request for Project Extension Form.
4. Documentation of any equipment installed at the site.

In order for any project to receive an extension, the Applicant must show documentation of a purchase order or commitment from a PV panel manufacturer to supply the necessary equipment.

The Program Administrator reserves the right to perform a Site inspection to verify the status of the project installation prior to granting the request for extension. If required, the Program Administrator shall notify the Applicant and schedule the Site visit within 10 days of notification.

4.4 Incentive Payment Process

Once a system is completed, Applicants may request payment of the incentive amount listed on their Incentive Payment Claim Form. A project is considered completed when it is completely installed, interconnected, permitted, paid for, and capable of producing electricity in the manner and in the amounts for which it was designed.

To receive the incentive, all CSI program requirements must be met and a complete Incentive Claim Form package is submitted prior to the Reservation Expiration Date.

The Program Administrator reserves the right to withhold final incentive payment pending review and approval of the incentive claim documentation and field inspection results if that project is determined to require a field inspection.

4.4.1 Requesting an Incentive Payment

After an eligible solar system is completed, Applicants may request payment of the incentive amount listed on their Incentive Claim Form. Payment will be disbursed once the Program Administrator verifies that the solar system is completed and meets all the eligibility requirements of the CSI.

To request an incentive payment, the Applicant completes and submits the Incentive Claim Form. Both Host Customer and System Owner must sign the Claim Form.

Please note that no incentive payment will be made until the Program Administrator has inspected and found that the system is operational and interconnected if that project is determined to require a field inspection. For further information regarding field inspections, refer to Section 4.6.

The completed Incentive Claim Form must be submitted to the Program Administrator on or before the Reservation Expiration Date, together with all required attachments described below.

4.4.2 Assignment of Incentive Payment to Third Party

The designated payee of the incentive payment may assign his or her right to receive the payment to a third party by completing the Payment Assignment Form and submitting it with the Incentive Payment Claim Form. The Payment Assignment Form may not be submitted by fax as original signatures are required to process the assignment.

4.4.3 Incentive Payment Claim Form Package

The Applicant must submit the Incentive Claim Form package, complete with all required attachments, to the Program Administrator prior to the Reservation Expiration Date. The Host Customer and System Owner must read, sign, and date the Incentive Payment Claim Form. This form must be returned to the Program Administrator by mail, as original signatures are required to process a payment

4.4.3.1 Required Documents

In addition to the completed Incentive Claim Form, Applicants must submit the following documents when requesting an incentive payment:

1. Incentive Claim Form Checklist
2. Incentive Claim Form with original signatures
3. Installer/Seller EPBB Field Checklist with Original Signature
4. Proof of Authorization to Interconnect
5. Copy of Building Permit and Final Inspection Sign Off — includes EPBB Compliance
6. Proof of Warranty
7. Final Project Cost Breakdown Worksheet
8. Final Project Cost Breakdown Affidavit
9. Final Incentive Calculation Worksheet
10. Revised Sizing Calculations (if applicable)
11. Payee Data Record

For more information on the above-referenced forms, go to Section 4.7.

4.4.4 Submitting an Incentive Claim Form Package

Once the Incentive Claim Form package is complete and all the required attachments are secured, Applicants must submit their application package to the Program Administrator for review. To ensure confirmation of receipt, it is recommended that documentation be delivered to the appropriate Program Administrator by certified or overnight mail. No faxes or hand deliveries will be accepted.

Applicants are advised to keep a copy of the Incentive Claim Form package along with all required documentation for their records.

4.4.4.1 Incomplete Incentive Claim Form Packages

If an incentive claim form package is incomplete or is found to require clarification, the Program Administrator will request the information necessary to process that application further. Applicants have 20 calendar days to respond to the requested clarification with the necessary information.

If after 20 calendar days, the Applicant has not submitted the requested information, the request for payment may be denied.

If an Incentive Claim Form package is not received by the expiration date of the Incentive Claim Form, or the Incentive Claim Form package indicates that the project is otherwise ineligible, the Program Administrator will send a written notice stating the reasons why the project is ineligible and the project will be rejected. If this is the case, the Applicant or Host Customer may reapply for a incentive reservation but will be subject to the eligibility requirements, incentive levels, and funding available at that time of reapplication.

4.4.5 Incentive Check Payment and Terms

Upon final approval of the incentive claim form documentation and completed field verification visit, the Program Administrator will issue the incentive in approximately 30 days for EPBB incentive payments. For PBI payments, the Program Administrator will issue the first incentive payment within 30 days of the first scheduled performance output meter read. Payment will be made to the Host Customer or a third party (as designated), as indicated on the Incentive Claim Form, and will be mailed to the address provided. As the reservation holder, the Host Customer may assign payment to a third party by submitting a completed payment assignment form to the Program Administrator with the Incentive Claim Form. A payment assignment form can be requested from the Program Administrator or downloaded from the Program Administrator website. The lump sum incentive payment issued constitutes final and complete payment.

4.4.5.1 Expected Performance Based Buydown (EPBB) Incentive Payment Terms

Most residential systems will receive an EPBB incentive. The EPBB incentive will be a one-time lump sum payment to help reduce the cost of installing a residential PV system. Upon final approval of the incentive claim form package and completed field inspection visit, if applicable, the Program Administrator will issue the incentive in approximately 30 days.

The lump sum EPBB incentive payment issued constitutes final and complete payment.

4.4.5.1.1 Performance Based Incentive Payment Terms

Incentives for systems equal to or greater than 100 kW, building integrated PV systems, or systems less than 100 kW who elect to opt in, will receive the performance based incentive (PBI) payments. PBI will be paid based on the actual kWh output of the system.

PBI payments will be made monthly and paid out over a 5-year period. The monthly PBI payment shall be calculated as follows:

Monthly PBI Incentive Payment = Incentive Rate x Measured kWh Output[16]

Upon final approval of the incentive claim form documentation and completed field verification visit, if applicable, the Program Administrator will issue the first PBI incentive payment approximately 30 days after the first scheduled performance output meter read. PBI payments will continue to be paid on a monthly basis for the next 60 months (5 years).

Payments will be made to the Applicant, Host Customer, or a third party (as designated), as indicated on the Incentive Payment Claim Form. At the discretion of Program Administrators, payments may either be mailed to the address provided or paid via credits on the utility bill. The

[16] Because the CSI Program and statues only allow for customers to receive incentives up to the first MW, PBI payments for energy output on systems larger than 1 MW will be prorated based on the ratio of 1 MW to the entire size of the facility. See Section 3.3 for further detail.

Host Customer may assign payment to a third party by submitting a completed payment assignment form to the Program Administrator with the Incentive Claim Form. A payment assignment form can be requested from the Program Administrator or downloaded from the Program Administrator's website.

If a monthly payment is determined to be incorrect due to a faulty meter read, the correction will be made in the next available payment period.

If a Host Customer moves during the 5-year period, they must notify the Program Administrator, who may make subsequent adjustments to the CSI program.

The 60th monthly PBI incentive payment constitutes final and complete payment.

4.5 System Changes Affecting Incentive Amount

The Program Administrator will expect a system to be installed as described in the Reservation Request Form. However, it is recognized that changes may occur during installation and that changes may be necessary in some circumstances.

If the installed system is smaller in output than specified in the Reservation Request Form or subsequent updates, the incentive amount will be calculated using the installed system size. If the installed system is larger than that originally in the Reservation Request Form or subsequent updates, the incentive will be recalculated based upon the installed system size, with the incremental addition to the system receiving the current level of incentive. If the size of the increase moves the system from the EPBB structure to the PBI structure, the entire system will receive the PBI based upon the current incentive level.

If the increase in size occurs after the expiration date of the Confirmed Reservation, the incremental addition will be considered a new project and must submit a Reservation Request with its required documentation.

If the entire available budget for a Program Administrator is reserved for other projects and there is no available funding, the Program Administrator cannot increase the reserved incentive amount.

4.6 Field Inspection

4.6.1 Field Inspections

Program Administrators will conduct field inspection visits on a statistically reasonable random sample of projects less than 30 kW. Upon receipt of a complete Incentive Payment Claim Form package, the Applicant's project may be randomly selected for a field inspection visit to verify that the system is installed as represented in the application, is operational, is interconnected and conforms to the eligibility criteria of the CSI program. All projects between 30 kW and 100 kW in system size are required to receive a field inspection to verify the accuracy of system data submitted in the original CSI program incentive application. Projects equal to or over 100 kW may also be randomly selected for field verification visits.

If randomly selected or required, the field inspection visit will be scheduled within 15 calendar days of receipt of the completed Incentive Claim Form package. Field inspections will be conducted concurrent with review and approval of the incentive payment. Incentive payments will be contingent on the field inspection visit and may be adjusted depending on the results of the field inspection.

4.6.2 Trained Inspectors

Field inspections shall be performed by trained personnel certified to perform CSI program system inspections. The Program Administrators will develop a site inspectors training plan that is consistent among the participating Program Administrators.

4.6.3 Failed Field Inspection

If the field inspection determines that the installed system varies from the documentation, it will result in a failed field inspection. If a system fails a field inspection, the Program Administrator will notify the Applicant, Host Customer, and System Owner with the reasons for the field inspection failure.

Please refer to Section 2.9.1 for more information regarding situations that constitute a failure.

4.7 Application Forms and Documentation

The following section discusses each of the forms and documentation requirements listed in the subsections above. Refer to the subsection describing the process for your application type to determine which of the following documents are required for your situation.

4.7.1 Reservation Request Package and Required Documentation

4.7.1.1 Reservation Request Application Checklist

All Reservation Request Form submittals must be accompanied by a completed and signed checklist. All forms are available from the Program Administrators' website.

4.7.1.2 Reservation Request Application Form

To reserve a specified incentive amount, a Reservation Request Form must be submitted with all required documentation attached. The seller, installer, and any other third party providing service related to a system installation should be identified on the application form, together with a description of services provided.

4.7.1.3 Proof of Electric Utility Service for the Site

Eligibility requirements restrict participation in the CSI program to customers who are located in PG&E, SCE, or SDG&E service territories and physically connected to the electric utility transmission and distribution system. All applications must include a copy of a recent electric utility bill that shows the service address of the installation Site, the name of the Host Customer, and electric energy usage for the Site. All pages of a utility bill should be submitted to ensure that this information is provided. The utility bill should be no older than 6 months from the date of application. For new construction, the Applicant must receive confirmation from the serving utility.

4.7.1.4 System Description Worksheet

All Applicants are required to complete and submit a System Description Worksheet.

4.7.1.5 Electrical System Sizing Documentation

To confirm that participating distributed generation systems will not exceed the capacity of the Host Customer's previous 12-month historical usage, all Applicants must submit a copy of the data and calculations used to determine system size.

4.7.1.6 Incentive Calculation Worksheet

All Applicants are required to complete and submit an Incentive Calculation Worksheet, which calculates the incentive and adjusts for other incentives and project cost.

4.7.1.7 Description of Other Funding Sources

When applicable, Applicants must disclose all project funding and/or project assistance sources that reduce the System Owner's otherwise out-of-pocket expenses for the project. This funding or assistance (e.g., gifted equipment) may be from any other source, and received before, during or after equipment installation.

4.7.1.8 Additional Requirements for Residential and Small Non-Residential Projects (< 10 kW)

4.7.1.8.1 Copy of Executed Agreement of Solar System Purchase

For residential and small Non-Residential (<10 kW) applications, the Applicant must submit a copy of an executed agreement to purchase and install the solar system at the time of submitting the Reservation Request Application Form.

4.7.1.8.2 Copy of Application for Interconnection Agreement

For residential and small Non-Residential (<10 kW) projects, Applicants must submit a copy of the Application for Interconnection to the local utility grid. This final Interconnection Agreement will be a legal contract between the Host Customer and the electric utility. Because the power from the solar system housed on the Host Customer's Site will likely be exported to the grid, it is critical that the utility be confident that the system is operating safely and in parallel with the grid, which helps to assure the safety and reliability of the electric distribution and transmission system.

4.7.1.8.3 CSI Program Contract with Original Signature

For residential and small Non-Residential (<10 kW) projects, a CSI Program Contract with original signatures should be submitted with the Reservation Request Form package. The Host Customer and System Owner (if different) must sign the CSI Program Contract.

4.7.1.8.4 Host Customer Certificate of Insurance

All Applicants must provide Host Customer proof of insurance in accordance with Section 2.6 of the CSI Program Contract. Section 2.6 provides details on the minimum insurance requirements.

4.7.1.8.5 System Owner Certificate of Insurance (if different than Host Customer)

All Applicants must provide System Owner proof of insurance (if different than Host Customer) in accordance with Section 2.6 of the CSI Program Contract. Section 2.6 provides details on the minimum insurance requirements.

4.7.1.9 Additional Requirements for Government and Non-profit projects

4.7.1.9.1 Certification of tax-exempt status and AB1407 compliance

Any Government and Non-Profit entities must include a certification under penalty of perjury from their chief financial officer or equivalent that they are a Government or Non-Profit entity and that the system is not receiving, and will not in the future receive, federal tax benefits through financial arrangements (i.e., the System Owner if a third-party, which will be receiving tax benefits from the system). This certification must be renewed annually if receiving PBI payments.

Additionally, any public entity applying for CSI program incentives must certify that it has voided any existing law, under its authority, that prohibits or restricts the installation or use of a solar energy system in accordance with the requirements set forth in AB 1407.

4.7.2 Proof of Project Milestone Package (for Projects on a Three-Step Process)

4.7.2.1 Completed Proof of Project Milestone Checklist

All Proof of Project Milestone submittals must be accompanied by a completed and signed checklist.

4.7.2.2 Host Customer Certificate of Insurance

All Applicants must provide Host Customer proof of insurance in accordance with Section 2.6 of the CSI Program Contract. Section 2.6 provides details on the minimum insurance requirements.

4.7.2.3 System Owner Certificate of Insurance (if different than Host Customer)

All Applicants must provide System Owner proof of insurance (if different than Host Customer) in accordance with Section 2.6. Section 2.6 provides details on the minimum insurance requirements.

4.7.2.4 Copy of Completed Interconnection Application

Customers must submit a copy of the Application for Interconnection to the local utility grid. This final Interconnection Agreement will be a legal contract between the Host Customer and the electric utility. Because the power from the solar system housed on the Host Customer's Site will likely be exported to the grid, it is critical that the utility be confident that the system is operating safely and in parallel with the grid, which helps to ensure the safety and reliability of the electric distribution and transmission system.

4.7.2.5 Copy of Executed Agreement to Purchase or Lease

Applicants must submit a copy of executed contract for purchase and installation of the system, and/or alternative System Ownership agreement. Agreements must be legally binding and clearly spell out the scope of work, terms, price, solar system components to be installed. Agreements must be signed by appropriate parties (supplier/installer, Host Customer, Applicant and/or System Owner). In the case of alternate System Ownership arrangements, the System Owner must provide a copy of their agreement(s) to purchase and install a system.

The Applicant must provide copies of executed purchase and/or installation agreements with the Reservation Request, and the information must be internally consistent and must be consistent with the Reservation Form. Agreements for the purchase of a system or system equipment must be in writing and must include, at a minimum, the following information:

- The quantity, make and model number (as shown on the Energy Commission lists of eligible equipment) for the PV modules, inverters, and system performance meters
- The total purchase price of the system before applying the incentive
- Language indicating the purchaser's commitment to buy the system
- Printed names and signatures of the purchaser and equipment seller's authorized representative.

Installation contracts must comply with the Contractors State License Board (CSLB) requirements. In addition, these contracts must contain the following information:

- Name, address and contractor's license number of the company performing the system installation
- Site address for the system installation
- Description of the work to be performed
- Total agreed price to install the system
- Payment terms (payment dates and dollar amounts)

- Printed names and signatures of the purchaser and the company's authorized representative.

Please refer to the CSLB website for more information on CSLB guidelines at www.cslb.ca.gov.

Entities without a valid A, B, C-10 or C-46 contractor's license may not offer installation services or charge for installation in any agreement.

The above requirements are sufficient evidence of an agreement to purchase and install a system for cases where a contractor sells and installs the system.

4.7.2.6 Project Cost Breakdown Worksheet

All Applicants, including for turnkey and lease projects, must submit a breakdown of known and estimated project cost. For a list of total eligible project cost elements to be reported, see Appendix A. Applicants are required to use the Project Cost Breakdown worksheet (spreadsheet), available from the Program Administrator's website or by e-mail request. The Program Administrator reserves the right to revise Confirmed Reservation amount pending a review and approval of total eligible project cost and incentive amounts applied for or received.

4.7.2.7 Revised Sizing Calculations

When applicable, the Applicant must submit a thorough description of any changes that have occurred in the system design affecting size or incentive amount subsequent to the initial application submittal.

4.7.2.8 Revised Incentive Calculation Worksheet

When applicable, all Applicants are required to complete and submit a revised Incentive Calculation Worksheet if system or project changes have resulted in a change to the incentive amount. The Incentive Calculation Worksheet calculates the incentive and adjusts for other incentives and project cost.

4.7.2.9 CSI Program Contract with Original Signature

All Proof of Project Milestone submittals must include an executed CSI Program Contract with original signatures. The Host Customer and System Owner must sign the CSI Program Contract.

4.7.2.10 Additional Requirements for Government and Non-Profit Entities

4.7.2.10.1 Request for Proposal (RFP) Documentation

Within 60 days after the Confirmed Reservation Notice letter, Government, Non-Profit, and Public Entities must submit a copy of the RFP, Notice to Invite Bids, or similar solicitation issued for the installation, lease, and/or purchase of the system proposed for the project. The RFP must include sufficient documentation details including the scope of work, schedule, terms, budget, and system components to be installed.

For Government, Non-Profit, and Public Entities not issuing an RFP for the project, all Proof of Project Milestone documentation listed in Section 4.7.2 must be submitted within Proof of Project Milestone Date.

4.7.3 Incentive Claim Form Package

4.7.3.1 Incentive Claim Form Checklist

All Incentive Claim Form packages must include a completed and signed checklist.

4.7.3.2 Confirmation and Incentive Claim Form with Original Signatures

A completed Incentive Claim Form must be submitted. It must be read, completed, and signed by both the Host Customer and System Owner (if different). The installer's name, telephone number and contractor license number must be included with the completed Incentive Claim Form. Only applications with original signatures on a single form will be accepted. Any changes in the system upon completion of the project must include supporting documentation and a recalculated incentive.

4.7.3.3 Installer/Seller EPBB Field Checklist with Original Signature

This checklist must be filled out and submitted with the Claim package for all EPBB rebates. It must be confirmed on site and requires original signatures from the CSI approved and listed Seller/Installer confirming the as-built quantity and model numbers of inverters, meters, and modules, as well as tilt, orientation, shading, etc. as required for final calculation of the EPBB rebate.

4.7.3.4 Proof of Authorization to Interconnect

The Applicant must demonstrate that the system is interconnected to the utility distribution grid and that the utility has approved this interconnection for the system's operation at the Site of installation. The Applicant must demonstrate this by submitting a copy of the signed letter from their electric utility granting the permission to interconnect and operate in parallel with the local grid. A copy of the final interconnection agreement must also be submitted.

For questions on the interconnection process, see Section 5.1.

4.7.3.5 Copy of Building Permit and Final Inspection Sign Off

A copy of the final building inspection report must be submitted to demonstrate that the project meets all codes and standards of the permitting jurisdiction. The name and address on the final building permit and final inspection signoff must match the name and address shown on the Incentive Payment Claim Form.

Contact your local permitting jurisdiction to learn about permitting requirements.

4.7.3.6 Proof of Warranty

A Proof of Warranty Form, providing evidence of a 10-year warranty on system installation must be completed and signed by the appropriate party(ies) and given to the System Owner. See Section 2.4 for details.

4.7.3.7 Final Project Cost Breakdown Worksheet & Affidavit

A final project cost breakdown worksheet must be submitted substantiating the claimed eligible project cost. The Program Administrator reserves the right to withhold final incentive payment pending review and approval of project cost and receipt of supporting documentation. For a list of total eligible project costs, see Appendix A. The Program Administrator reserves the right to periodically audit Applicant's and Host Customer's records, see the CSI program contract.

4.7.3.8 Final Project Cost Affidavit

An affidavit signed by the System Owner or purchaser of the system (if other than the System Owner) must be submitted substantiating that the claimed eligible project cost is correct and has been paid in full.

4.7.3.9 Final Incentive Calculation Worksheet

All Applicants are required to complete and submit a Final Incentive Calculation Worksheet if system or project changes have resulted in a change to the incentive amount. The Incentive Calculation Worksheet calculates the incentive and adjusts for other incentives and project cost.

4.7.3.10 Revised Sizing Calculations (if applicable)

Where applicable, applications must include a thorough description of any changes that have occurred in the system design effecting size or incentive amount since the initial application submittal.

4.7.3.11 Payee Data Record

When the Applicant completes the Payee Data Record, the Program Administrator's will have the necessary information to aid in keeping accurate records and providing timely incentive payments.

5. Other Installation Requirements and Continuing Site Access Requirements

5.1 Connection to the Utility Distribution System

All solar electric systems receiving incentives under the California Solar Initiative (CSI) program must be connected to the local electric utility's distribution system. The interconnection, operation, and metering requirements for solar systems shall be in accordance with the local electric utility rules for customer generating facility interconnections. To connect a solar system to the utility distribution system, Host Customers, and/or System Owners will be required to execute certain documents such as, but not limited to, an Application to Interconnect a Generating Facility and a Generating Facility Interconnection Agreement or Net Energy Metering Agreement with the local electric utility.

A copy of Generating Facility Interconnection Agreement or Net Energy Metering Agreement also must be submitted with the utility's written letter authorizing parallel operation to the Program Administrator prior to the reservation expiration date.

Applicants, Host Customers, and System Owners are solely responsible to submit interconnection applications to the appropriate electric utility interconnection department as soon as the information to do so is available to prevent any delays in system parallel operation.

5.1.1 How to Apply For Interconnection of CSI Projects

For more information on electric grid interconnections, please contact your local utility (investor-owned utilities are listed below). It is the sole responsibility of the CSI program System Owner and Host Customer to seek and obtain approval to interconnect the solar electric system to a utility's electric distribution system. System Owners and Host Customers participating in the CSI program should immediately contact the utility to seek guidance on how to apply for interconnection. Contact information is listed below.

5.1.1.1 Pacific Gas & Electric (PG&E)

Website: www.pge.com/gen
Email: gen@pge.com
Phone: (415) 972-5676 (PG&E Generation Interconnection Hotline)

5.1.1.2 San Diego Gas & Electric (SDG&E)

Website: www.sdge.com/business/self_generation.shtml

Contact information for photovoltaics and wind systems:	
Net Metering Team San Diego Gas & Electric PO Box 129831, CP52F San Diego, CA 92123-9749 Phone: (858) 636-5585 Email: netmetering@semprautilities.com	**Ken Parks** San Diego Gas & Electric PO Box 129831, CP52F San Diego, CA 92123-9749 Phone: (858) 636-5581 Email: kparks@semprautilities.com

5.1.1.3 Southern California Edison (SCE)

NEM Program Administrator
Southern California Edison
2244 Walnut Grove Avenue
Rosemead, Ca 91770
Phone: (626) 302-9680
E-mail solarNEM@sce.com

6. Additional Information

6.1 Circumstances Requiring Additional Documentation

6.1.1 Owner or Self-Installed System

In situations where the System Owner installs the system, the Applicant must provide the following information during the first or second stage of the application process:

- An equipment purchase agreement as described above, or
- In cases where there is not a signed agreement to purchase equipment the purchaser may provide invoices or receipts showing that at least 10 percent of the system equipment purchase price (generating equipment and inverters) has been paid to the seller(s).[17]

6.1.2 Contractor-Installed System with Separate Seller and Installer

In situations where the owner is purchasing the system from one company and hiring a separate company (licensed contractor) for installation, the owner must obtain proof of his or her commitment to purchase and install the system in separate documents as follows:

- An equipment purchase agreement as described above, or
- In cases where there is not a signed purchase agreement the owner may provide invoices or receipts showing that at least 10 percent of the system equipment purchase price (generating equipment and inverters) has been paid to the seller(s), and
- An installation contract from the second company as described above.

17 An example of this situation is where the purchaser buys new equipment via the Internet or mail order.

7. Measurement and Evaluation Requirements

To be eligible for CSI incentives, all Applicants, Host Customers, and System Owners must agree to comply with the terms and requirements of the measurement and evaluation program. This includes providing access to the Program Administrators and/or third-parties contracted by the California Public Utilities Commission and/or Program Administrator access to the site and any available data and information collected on the system.

8. Definitions and Glossary

This section provides a list of acronyms used and definitions of key concepts in this handbook.

8.1 Acronyms

AB (as in AB 1407): Assembly Bill

AC: Alternating Current

AMI: Advanced Metering Infrastructure

BIPV: Building Integrated Photovoltaic

CEC: California Energy Commission

CEC-AC: California Energy Commission Alternating Current, refers to inverter efficiency rating

CPUC: California Public Utilities Commission

CSI: California Solar Initiative

CSLB: Contractors State License Board

DC: Direct Current

ERP: Emerging Renewables Program

EPBB: Expected Performance-Based Buydown

ESCO: Energy Service Company

IDR: Interval Data Recorder

IOU: Investor-Owned Utility

KW: Kilowatt

KWH: Kilowatt-hour

M&E: Measurement and Evaluation

M&V: Measurement and Verification

MW: Megawatt

NABCEP: North American Board of Certified Energy Practitioners

NRTL: Nationally Recognized Testing Laboratory

NSHP: New Solar Homes Partnership

PBI: Performance-Based Incentives

PG&E: Pacific Gas and Electric Company

PIER: Public Interest Energy Research

PTC: PVUSA Test Conditions

PV: Photovoltaic

PY: Program Year

SB (as in SB 1): Senate Bill

SCE: Southern California Edison Company

SDG&E: San Diego Gas & Electric Company

SDREO: San Diego Regional Energy Office

SGIP: Self Generation Incentive Program

STC: Standard Test Conditions

UL (as in UL 1703): Underwriters Laboratories, Inc.

8.2 Definitions

AB 1407:
Assembly Bill 1407, codified as California Civil Code section 714, was signed by Governor Davis on September 3, 2003. Among other things, this legislation voids and makes unenforceable any existing covenant, restriction, or condition contained in any deed, contract, security instrument, or other instrument affecting real property, as specified, that prohibits or restricts the installation or use of a solar energy system, excepting provisions that impose reasonable restrictions on solar energy systems. This statute also mandates that whenever approval is required for the installation or use of a solar energy system, that such approval be processed in the same manner as approval of an architectural modification, and not be willfully avoided or delayed. Any Public Entity (see definition) may not receive funds from a state-sponsored grant or loan program, including the CSI, for solar energy if it fails to comply with these requirements. A Public Entity must certify that it is meeting these requirements when applying for these grants or loans. Please see California Civil Code section 714 for full statutory requirements and further detail.

Affidavit:
An affidavit is a written statement in writing, sworn to before a notary public or other approved officer. In the CSI program, the Final Project Cost Breakdown and Affidavit includes the final Project cost breakdown worksheet, along with a signed affidavit substantiating the claimed eligible Project cost.

Alternating Current (AC):
Electric current that reverses direction, usually many times per second. Opposite of direct current (DC). Most electrical generators produce alternating current. Under the CSI program, PV electric output calculations must always be made using the CEC-AC rating standards which include inverter DC to AC conversion losses.

Applicant:
The entity, either the Host Customer, System Owner, or third party designated by the Host Customer, that is responsible for the development and submission of the CSI application materials and the main point of communication between the CSI Program Administrator for a specific CSI Application.

Application Fee:
An Application Fee is required once the Reservation Request has been submitted for all Non-Residential projects over 10 kW. Where applicable, the Application Fee is 1% of unadjusted requested CSI incentive and is refundable, in general, when the Project is completed and the incentive is paid, anytime before the application receives a Confirmed Reservation, or after that time, so long as the project is withdrawn due to extenuating circumstances beyond the Host Customer's control. Application fees are also refunded anytime before the application receives a Conditional Reservation, or after that time, so long as the project is withdrawn due to extenuating circumstances beyond the Host Customer's control.

Azimuth Orientation:
Azimuth is the horizontal angular distance between the vertical plane containing a point in the sky and true south. To qualify for incentives in the CSI program, all PV systems with an azimuth orientation between 180 degrees and 270 degrees, facing south, southwest and west, will be treated equally.

Backup Generators:
Backup generators operate as short-term temporary replacement for electrical power during periods of utility power outages. In addition to emergency operation they ordinarily operate for testing and maintenance. Backup generators do not produce enough power to be sold or otherwise supplied to the grid or provide power to loads that are simultaneously serviced by a utility electric grid. Backup generators only service customer loads that are isolated from the grid either by design or by manual or automatic transfer switch.

Building Integrated Photovoltaic (BIPV):
Building integrated PV systems are solar electric systems in which the PV panels constitute part of the building's roof or facade, replacing conventional building materials. For example, solar shingles may replace conventional asphalt shingles, providing roof protection while producing electricity.

Calendar Days:
All dates and schedules in the CSI are measured in calendar days, which include all days of the week.

California Energy Commission (CEC):
California’s primary energy policy and planning agency. Created in 1974 and headquartered in Sacramento, the Commission has responsibility for activities that include forecasting future energy needs, promoting energy efficiency through appliance and building standards, and supporting renewable energy technologies. On August 21, 2006, the Governor signed Senate Bill (SB 1) which directs the CPUC and the CEC to implement the CSI program consistent with specific requirements and budget limits set forth in the legislation.

California Public Utilities Commission (CPUC):
The CPUC regulates a number of industries including the electric utility industry that impact public well-being. Among other activities, the CPUC establishes service standards and safety rules and authorizes rate changes. The CPUC, in conjunction Senate Bill 1 (SB 1), has authorized the California Solar Initiative (CSI). In CPUC Decision (D.) 06-01-024, the California Public Utilities Commission (CPUC) established the CSI program. In D.06-08-028, the CPUC established implementation details for the CSI program.

California Solar Initiative (CSI):
The California Solar Initiative program pays incentives to solar photovoltaic (PV) projects in the three California IOU service territories. This Handbook is designed to describe the requirements for receiving funding under the CSI. The program was authorized by the California Public Utilities Commission (CPUC) and Senate Bill 1 (SB 1). Responsibility for administration of the CSI Program is shared by Pacific Gas and Electric Company – PG&E customers; Southern California Edison Company – SCE customers; and San Diego Regional Energy Office (SDREO) – SDG&E customers.

Capacity Factor:
The ratio of the electrical energy produced by the generating system during a specific period, to the electrical energy the generating system could have produced if it had operated at full capacity rating during the same period.

Capacity Rating:
The capacity rating is a load that a power generation unit, such as a photovoltaic system, is rated by the manufacturer to be able to meet or supply. The Program Administrator will verify system capacity rating to confirm the final incentive amount.

CEC-AC Rating:
The CSI Program Administrators will use the California Energy Commission's CEC-AC method to measure nominal output power of photovoltaic cells or modules to determine the system's rating in order to calculate the appropriate incentive level. The CEC-AC rating standards are based upon 1,000 Watt/m^2 solar irradiance, 20 degree Celsius ambient temperature, and 1 meter/second wind speed. The CEC-AC Watt rating is lower than the Standard Test Conditions (STC).

Commercial:
Commercial entities are defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and for-profit health, social, and educational institutions. For the purpose of CSI, commercial sectors include agricultural and industrial customers.

Contractor:
A person or business entity who contracts to erect buildings, or portions of buildings, or systems within buildings. Under the CSI program, all systems must be installed by appropriately licensed California contractors in accordance with rules and regulations adopted by the State of California Contractors State Licensing Board.

Contractors State License Board (CSLB):
Installation contracts for photovoltaic systems installed under the CSI program must comply with the Contractors State License Board (CSLB) requirements. Please refer to the CSLB website for more information on CSLB guidelines at: www.cslb.ca.gov.

CSI Program Forum:
The CSI Program Forum was established in CPUC D.06-08-028 to provide a public venue for interested parties to identify and discuss ongoing issues related to CSI administration and implementation. The forum will be used to provide input on any needed updates to this Handbook and future more substantive program modifications that may be considered. For more information on the CSI Program Forum, refer to Section 1.5.

Curtailable Rate Schedule:
Also referred to as an interruptible rate schedule. A type of rate schedule that allows the transmission provider to interrupt all or part of a transmission service under specified terms due to constraints that reduce the capability of the transmission network to provide that service. Under the CSI program, generation which serves any portion of a customer's load that is

committed to curtailable rate schedules, programs or any other such state agency-sponsored demand-response programs is not eligible for incentives.

Demand-Response:
Demand response refers to the reduction of customer energy usage at times of peak usage. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling. Under the CSI program any generation serving a portion of customer load that is committed to demand-response programs or on curtailable rate schedules is not eligible for incentives.

Design Factor:
The Design Factor is a ratio comparing a proposed system's expected generation output with that of a baseline system. The Design Factor is used in calculating the EPBB incentive (it is multiplied by the system rating and the incentive rate to determine EPBB incentives).

Direct Current (DC):
Electric current in which electrons are flowing in one direction only; which is the opposite of alternating current (AC). Under the CSI program, photovoltaic electric output calculations must always be made using the CEC-AC rating standards which include inverter DC to AC conversion losses.

Electric Utility:
The Host Customer's local electric transmission and distribution service provider for their Site.

Electrical Distribution Grid:
A network of power stations transmission circuits, and substations conducting electricity. Under the CSI program, eligible renewable energy systems must be permanently interconnected and operating parallel to the electrical distribution grid of the utility serving the customer's electrical load.

Emerging Renewables Program (ERP):
The ERP is an Energy Commission program offering cash rebates on eligible grid-connected renewable energy electric-generating systems.

Energy Service Company (ESCO):
A business entity that designs, builds, develops, owns, operates or any combination thereof self-generation Projects for the sake of providing energy or energy services to a Host Customer.

Energy Service Provider (ESP):
An entity that provides electric power and ancillary services (including but not limited to aggregators, brokers, and marketers, but excluding utilities) to an end use customer. Also referred to as an Electric Service Provider.

Expected Performance Based Buydown (EPBB):
The EPBB incentive methodology pays an up-front incentive to participants installing systems less than 100 kW in size that is based on a system's expected future performance. EPBB incentives combine the performance benefits of PBI with the administrative simplicity of a one-

time incentive paid at the time of project installation. The EPBB Incentive will be calculated by multiplying the incentive rate by the system rating by the design factor.

Firm Service Level:
Power supplies that are guaranteed to be delivered under terms defined by contract. For electric utility customers who are on a interruptible or curtailable rate, only generation that serves the portion of their electric load that is designated as firm service is eligible for CSI incentives. Under the CSI program, Customers must agree to maintain the firm service level at or above capacity of the proposed generating system for the duration of the required applicable warranty period. Customers may submit a letter requesting an exemption to the firm service rule if they plan to terminate or reduce a portion of their available load.

Government:
A Government entity is any federal, state, or local government agency. Federal government entities include the Air Force, Army, Navy, Marines, Postal Service, General Services Administration, and all other Federal agencies or departments. State government entities include the University of California, California State University, Department of Corrections, Department of General Services, the combination of the Department of Developmental Services and CalTrans, the combination of the California Youth Authority and the Department of Mental Health, and all other state agencies and departments. Local government entities include cities, counties, school districts, and water districts.

Host Customer:
An individual or entity that meets all of the following criteria: 1) has legal rights to occupy the Site, 2) receives retail level electric service from PG&E, SCE, or SDG&E, 3) is the utility customer of record at the Site 4) is connected to the electric grid, and 5) is the recipient of the net electricity generated from the solar equipment.

Hybrid System:
A self-generation system that combines more than one type of distributed generation technology and is located behind a single Electric Utility service meter.

Incentive Adjustment Mechanism:
A mechanism for solar incentives to automatically decline each year based upon MW reserved over the 10 years of the CSI. The adjustment mechanism reduces the statewide incentive level when specified MW levels, or "triggers," of solar installations are achieved. [May change to include calendar year trigger, pending reconciliation of SB 1 and CPUC Decision]

Interconnection Agreement:
A legal document authorizing the flow of electricity between the facilities of two electric systems. Under the CSI program, eligible renewable energy systems must be permanently interconnected and operating in parallel to the electrical distribution grid of the utility serving the customer’s electrical load. Portable systems are not eligible. Proof of interconnection and parallel operation is required prior to receiving an incentive payment.

Interruptible Rate Schedule:
The right of a utility to interrupt all or part of electric service due to system or generation constraints. May also be called a Curtailable Rate Schedule. Under the CSI program,

generation which serves any portion of customer load that is committed to such rate schedules or any other state agency-sponsored curtailable or demand-response program is not eligible for incentives.

Interval Data Recorder (IDR):
IDR is a metering device capable of recording minimum data required. Minimum data requirements include (a) hourly data required for the Direct Access settlement process; and (b) data required to bill the utility's distribution tariffs including 15-minute demand data--also referred to as Hourly Metering.

Inverter:
An electric conversion device that converts direct current (DC) electricity into alternating current (AC) electricity.

Inverter Efficiency:
The AC power output of the inverter divided by the DC power input.

Investor Owned Utility (IOU):
For purposes of the CSI, this refers to Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company.

Kilowatt (kW):
A unit of electrical power equal to 1,000 watts, which constitutes the basic unit of electrical demand. The watt is a metric measurement of power (not energy) and is the rate (not the duration over which) electricity is used. 1,000 kW is equal to 1 megawatt (MW). Throughout this Handbook, the use of kW refers to the CEC-AC wattage ratings of kW alternating current inverter output.

Kilowatt Hour (kWh):
The use of 1,000 watts of electricity for one full hour. Unlike kW, kWh is a measure of energy, not power, and is the unit on which the price of electrical energy is based. Electricity rates are most commonly expressed in cents per kilowatt hour.

Lessor:
A person or entity who rents property to another under a lease. Under the CSI program, in the case of a third-party owned system (or leased system, for example), the lessor is classified as the System Owner.

Load:
Either the device or appliance which consumes electric power, or the amount of electric power drawn at a specific time from an electrical system, or the total power drawn from the system. Peak load is the amount of power drawn at the time of highest demand.

Maximum Site Electric Load:
The peak (maximum) kW demand at the Site, regardless if served by the existing generator, the local utility or a combination of the two.

Measurement and Evaluation (M&E):
A process or protocol to evaluate the performance of an energy system. As a condition of receiving incentive payments under the CSI program, System Owners and Host Customers agree to participate in Measurement and Evaluation (M&E) activities as required by the CPUC. M&E activities will be performed by the Program Administrator or the Program Administrator's independent third-party consultant and include but are not limited to, periodic telephone interviews, on-site visits, development of a M&E Monitoring Plan, access for installation of metering equipment, collection and transfer of data from installed system monitoring equipment, whether installed by Host Customer, System Owner, a third party, or the Program Administrator.

Measurement and Verification (M&V):
A process or protocol to confirm the actual energy savings realized from a project once the project is implemented and operating.

Megawatt (MW):
Unit of electrical power equal to one million watts; also equals 1,000 kW.

Meter:
A device used to measure and record the amount of electricity used or generated by a consumer. The CSI program requires accurate solar production meters for all solar projects that receive incentives. Systems under 10 kW require a meter accurate to within 5%, while systems 10 kW and larger require a more precise meter accurate to within 2%.

Modules:
Under the CSI program, a module is the smallest complete environmentally protected assembly of interconnected photovoltaic cells. Modules are typically rated between 50 and 200 W.

Nationally Recognized Testing Laboratory (NRTL):
The Occupational Safety and Health Administration's (OSHA) Directorate of Science, Technology, and Medicine operates a program that certifies private sector organizations as NRTLs, which subsequently judges that specific equipment and materials ("products") meet consensus-based standards of safety for use in the U.S. workplace. Under the CSI program, PV Modules must be certified to UL 1703 by a Nationally Recognized Testing Laboratory (NRTL). Inverters must be certified to UL 1741 by a NRTL.

Net Energy Metering Agreement:
An agreement with the local utility which allows customers to reduce their electric bill by exchanging surplus electricity generated by certain renewable energy systems such as the PV systems the CSI subsidizes. Under net metering, the electric meter runs backwards as the customer-generator feeds extra electricity back to the utility. The CSI program permits net energy metering agreements.

New Construction:
New construction is defined as the construction of new buildings or major renovations of existing buildings. Residential new construction systems are not eligible for the CSI program, and should apply to the California Energy Commission's New Solar Homes Partnership Program.

New Solar Homes Partnership (NSHP):
A California Energy Commission program offered as of January 1, 2007 that works with home builders and the building industry to accelerate the growth of PV in residential new construction.

Non Profit:
A Non-Profit institution is an entity not conducted or maintained for the purpose of making a profit, and is registered as a 501(c)3 corporation. No part of the net earnings of such entity accrues or may lawfully accrue to the benefit of any private shareholder or individual.

North American Board of Certified Energy Practitioners (NABCEP):
A professional association developing a voluntary national certification program for solar practitioners. Although not required by the CSI program, installation contractors are encouraged to become certified by the NABCEP.

Pacific Gas & Electric Company (PG&E):
An investor owned utility (IOU). The utility that provides natural gas and electricity to most of Northern California.

Parallel Operation:
The simultaneous operation of a self-generator with power delivered or received by the electrical utility while interconnected to the grid. Parallel Operation includes only those PV systems that are interconnected with the Electric Utility distribution system for more than 60 cycles.

Performance Based Incentives (PBI):
The CSI program will pay Performance Based Incentives (PBI) for solar projects equal to or larger than 100 kilowatts (kW), with monthly payments based on recorded kilowatt hours (kWh) of solar power produced over a five-year period. Solar projects receiving PBI incentives will be paid a flat per kWh payment monthly for PV system output that is serving on Site load. The monthly PBI incentive payment is calculated by multiplying the incentive rate by the measure kWh output.

Photovoltaic (PV):
A technology that uses a semiconductor to convert light directly into electricity.

Power Purchase Agreements:
An agreement for the sale of electricity from one party to another, where the electricity is generated and consumed on the Host Customer Site. Agreements that entail the export and sale of electricity from the Host Customer Site do not constitute on-site use of the generated electricity and therefore are ineligible for the CSI.

Program Administrator (PA):
For purposes of the CSI program, PG&E, SCE & SDREO (which administers the program on behalf of SDG&E).

Program Year (PY):
January 1 through December 31.

Proof of Project Milestone Date:
The Proof of Project Milestone Date is the date when required information to demonstrate that a Project seeking CSI incentives is moving forward is due.

Project:
For purposes of the CSI, the "Project" is the installation and operation of the proposed eligible PV system, as described by the submitted Reservation Request documentation.

Public Entity:
Includes the United States, the state and any county, city, public corporation, or public district of the state, and any department, entity, agency, or authority of any thereof.[18]

Rebuild A Greener San Diego Photovoltaic Incentive Program:
San Diego area program authorized by the CPUC Resolution E-3860, created to provide incentives to homeowners rebuilding homes affected by the October 2003 wildfires. The Rebuild a Greener San Diego Photovoltaic Incentive Program accepted applications from April 1, 2006 through May 31, 2006.

Renewable:
Electricity supplied by energy sources that are naturally and continually replenished, such as wind, solar power, geothermal, small hydropower, and various forms of biomass.

Reservation Expiration Date:
The Reservation Expiration Date is the date up to when the project is active in the CSI program.

Residential:
Residential entities are private household establishments that consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use.

Retrofit:
A retrofit is a modification of an existing building or facility to include new systems or components.

San Diego Gas & Electric Company (SDG&E):
One of California's four investor-owned utilities (IOU's). SDG&E provides natural gas and electricity to San Diego County and southern Orange County in southern California. It is owned by Sempra Energy. The CSI program is available to customers of PG&E, SCE and SDG&E.

San Diego Regional Energy Office (SDREO):
A Non-Profit 501(c)3 corporation that implements the CSI program on behalf of SDG&E.

Self Generation Incentive Program (SGIP):
The SGIP, created pursuant to California Assembly Bill 970, provided financial incentives for business and residential customers who install up to 5.0 MW of "clean" distributed generation

18 Source: CALIFORNIA CODES - PUBLIC CONTRACT CODE, SECTION 21611

equipment onsite. The current program runs through December 31, 2007. The SGIP was extended in modified form for certain technologies through AB1685.

Seller:
Any person or business entity that transfers property or property rights by sale in commerce. To participate in the CSI program, companies who sell system equipment must be certified by the CEC or some approved third party.

Senate Bill 1 (SB 1):
This Senate Bill establishes the goals of installing 3,000 MW of solar generation capacity in the state of California, establishing a self-sufficient solar industry, and placing photovoltaic systems on 50 percent of new California homes within 13 years. The bill was signed into law on August 21, 2006, and it becomes effective date on January 1, 2007. SB 1 requires the CPUC, in implementing the California Solar Initiative (CSI) to adopt performance-based subsidies (e.g. subsidies that pay based on the amount of electricity produced) by January 1, 2008 where 100% of incentives are based on performance for all PV systems 100 kW and larger, and 50% of incentives are based on performance for systems 30 kW and larger. Performance-based subsidies are encouraged, but not required, for smaller systems. Moreover, SB 1 authorizes the CPUC to award $101 million in subsidies for solar thermal systems and authorizes the CPUC to award $50 million for solar research and development. The bill requires municipal utilities to establish solar energy programs in support of the 3,000 MW goal and raises the net metering cap from 0.5 percent to 2.5 percent.

Site:
The Host Customer's premises, consisting of all the real property and apparatus employed in a single enterprise on an integral parcel of land undivided, excepting in the case of industrial, agricultural, oil field, resort enterprises, and public or quasi-public institutions divided by a dedicated street, highway or other public thoroughfare or railway. Automobile parking lots constituting a part of and adjacent to a single enterprise may be separated by an alley from the remainder of the premises served. Separate business enterprises or homes on single parcel of land undivided by a highway, public road, and thoroughfare or railroad would be considered for purposes of CSI as separate Sites. Each individual Site must be able to substantiate sufficient electrical load to support the proposed system size.

Solar Irradiance:
Radiant energy emitted by the sun, particularly electromagnetic energy. In the CSI program the CEC-AC rating standards are based upon 1,000 Watt/m^2 solar irradiance, 20 degree Celsius ambient temperature, and 1 meter/second wind speed. The CEC-AC watt rating is lower than the Standard Test Conditions (STC), a watt rating used by manufacturers.

Southern California Edison Company (SCE):
An investor owned utility (IOU), that provides electricity in a 50,000-square mile service territory in Southern California.

Standard Test Conditions (STC):
A watt rating used by manufacturers of photovoltaic cells or modules. The CEC-AC watt rating used in the CSI is lower than the Standard Test Conditions.

System Size:
For purposes of the CSI program, system capacity is defined as the expected electrical output of a given photovoltaic system based upon CEC-AC rating standards. Under the CSI program, the expected production of electricity by the system may not exceed the actual energy consumed during the previous 12 months at the Site.

System Installer:
The System Installer is responsible for installing for the Host Customer the photovoltaic system that will be eligible to receive CSI program incentives. A qualified solar system installer should be able to evaluate factors that will affect photovoltaic system performance, such as the orientation (tilt and direction) of the system, wire length and size, shading, module output mismatch, inverter efficiency, module cleanliness, and other factors.

System Owner:
The owner of the PV system at the time the incentive is paid. For example, in the case when a vendor sells a turnkey system to a Host Customer, the Host Customer is the System Owner. In the case of a leased system, the lessor is the System Owner.

UL Listed:
Tested and listed by the Underwriters Laboratories, Inc. In the CSI program, PV modules must be certified to UL 1703 by a Nationally Recognized Testing Laboratory (NRTL). Inverters must be certified to UL 1741 by a NRTL.

Vendor:
A seller of property, goods, or services. According to the CSI program, in cases when a vendor sells a PV system to a Host Customer, the Host Customer is the System Owner.

Warranty:
A promise, either written or implied, that the material and workmanship of a product are without defect or will meet a specified level of performance over a specified period of time. In the CSI program, inverters and modules must each carry a 10 year warranty, and meters a one-year warranty. The warranty may be provided in combination by the manufacturer and installer. On January 1, 2008, the warranty requirements will be increased to a minimum of five years for meters.

9. Program Administrator Contact Information

Potential Host Customers and their Applicant s can receive more information and apply for incentive funding through the following Program Administrators:

9.1 Pacific Gas & Electric (PG&E)

Website:	www.pge.com/solar
Email Address:	solar@pge.com
Contact Person:	Program Manager, California Solar Initiative Program
Telephone:	(800) 743-5000
Fax:	(415) 973-2510
Mailing Address:	PG&E Integrated Processing Center P.O. Box 7265 San Francisco, CA 94120-7265

9.2 San Diego Regional Energy Office (SDREO)

Website:	www.csi.sdenergy.org
Email Address:	csi@sdenergy.org
Contact Person:	Nathalie Osborn, Program Manager
Telephone:	(858) 244-1177/(866)-sdenergy
Fax:	(858) 244-1178
Mailing Address:	San Diego Regional Energy Office Attn: SELFGEN Program Manager 8690 Balboa Avenue Suite 100 San Diego, CA 92123

9.3 Southern California Edison (SCE)

Website:	www.sce.com/rebatesandsavings/CaliforniaSolarInitiative/
E-mail Address:	greenh@sce.com
Contact Person:	Program Manager, California Solar Initiative Program
Telephone:	(800) 799-4177
Fax:	(626) 302-6253
Mailing Address:	Southern California Edison 2131 Walnut Grove Avenue, G03, 3rd Floor, B10 Rosemead, California 91770

10. Appendix A: Description of Total Eligible Project Costs

10.1 Eligible Project Cost Items

The California Solar Initiative program collects information on photovoltaic system project costs solely for reporting purposes. The following costs may be included in total eligible project cost:

1. Photovoltaic equipment capital cost
2. Engineering and design costs
3. Construction and installation costs. For projects in which the generation equipment is part of a larger project, only the construction and installation costs directly associated with the installation of the energy generating equipment are eligible.
4. Engineering feasibility study costs
5. Interconnection costs, including:
    a. Electric grid interconnection application fees
    b. Metering costs associated with interconnection
6. Building permitting costs
7. Warranty and/or maintenance contract costs associated with eligible project cost equipment
8. Sales tax and use tax
9. On-site system measurement, monitoring and data acquisition equipment.
10. Customers may claim certain mounting surface costs as eligible project costs. Costs may include mounting surfaces for the photovoltaic module and/or the materials that provide the primary support for the modules. Only the percentage of mounting surface directly under the photovoltaic module is eligible.
11. Cost of capital included in the system price by the vendor, contractor or subcontractor (the entity that sells the system) is eligible if paid by the System Owner.

11. Appendix B: Metering Requirements

The following Appendix contains detailed information with respect to the minimum metering and monitoring requirements for participation in the CSI Program. These minimum requirements were developed to increase owner knowledge of system performance, foster adequate system maintenance, and thereby ensure ratepayer incentives result in expected levels of solar generation.

CSI Program participants are required to install the following metering related components based on the size of their system and type of program participation (i.e. EPBB or PBI):

Table 16
Metering Summary

	5% Meter (Inverter Integrated)	2% Meter (Standalone Meter)	PMRS
EPBB < 10kW	Required	Optional	Required*
EPBB ≥ 10kW and <20 kW	N/A	Required	Required*
EPBB > 20 kW	N/A	Required	Required
PBI (All System Sizes)	N/A	Required	Required

Notes:

- PMRS stands for Performance Monitoring and Reporting System
- *Required unless the cost of the PMRS fall above the cost cap (the cost of the minimum metering, communication, and reporting system over the first five years for each solar installation size grouping shall be less than 1% of total installed cost for systems up to 30 k and 0.5% for larger systems. See CPUC Decision D.06-08-028). The customer seeking exemption must demonstrate to the Program Administrator that they were not able to satisfy the metering requirements within the applicable cost cap.
- N/A = Not Applicable

Recipients of CSI funding are not precluded or penalized from purchasing or installing a performance monitoring system that exceeds the minimum requirements or any cost caps. The selection of performance monitoring system and service provider is made at the recipient's choice and expense.

As with other required solar system components, all installed meters and Performance Monitoring and Reporting Systems (PMRS) must be listed with the Energy Commission. Lists of qualifying meters and PMRS Systems can be found on the California Energy Commission's website (www.energy.ca.gov).

Detailed information on these summarized requirements follows.

11.1 Minimum Meter Requirements

All systems must be installed with a meter or meters so that the System Owner and Program Administrator can determine the amount of energy produced by the system and the System Owner may support proper system operation and maintenance. The meter must be listed with the Energy Commission and must meet the minimum meter requirements of this section.

The California Energy Commission's list of qualifying meters can be found at: (www.energy.ca.gov).

11.1.1 Meter Type

For all systems with a CEC-AC rating of 10 kW or higher the installed meter(s) must be a separate Interval Data Recording (IDR) meter(s), or a complete system that is functionally equivalent to an IDR meter recording data no less frequently than every 15 minutes. Installed meter(s) for systems below 10 kW do not need to be separate IDR meters and may be internal to the inverter(s). Program Administrators may have additional meter functionality requirements for systems receiving PBI, as the utilities will use these meters to process PBI payments and system compatibility may be required. For example, meters and service panels must meet all local building codes and utility codes. Each Program Administrator will maintain a publicly-available list of any additional functionality requirements. Please consult your Program Administrator to determine whether any additional requirements apply.

11.1.2 Meter Accuracy

The installed meter(s) must be accurate to ±5% for all systems with a CEC-AC rating below 10kW (a "±5% Meter") and ±2% for all systems with a CEC-AC rating of 10 kW or higher or for systems receiving PBI payments (a "±2% Meter").

11.1.3 Meter Measurement

Meters must measure net generated energy output as well as instantaneous power.

11.1.4 Meter Testing Standards

±2% Meters must be tested according to all applicable ANSI C-12 testing protocols. ±5% Meters must be tested to testing protocols as defined by the California Energy Commission.

11.1.5 Meter Certification

The accuracy rating of ±2% Meters must be certified by an independent testing body (i.e., a NRTL such as UL or TUV).

The accuracy rating of ±5% Meters must be certified by the manufacturer of the ±5% Meter or an independent testing body (i.e., a NRTL such as UL or TUV).

All test results or NRTL documentation supporting the certification must be maintained on file for inspection by the Commission or Energy Commission.

11.1.6 Meter Communication / Data Transfer Protocols

Protocols for the minimum required Solar Performance / Output Data must enable any Independent Performance Monitoring and Reporting Service Provider to communicate with the meter to obtain the minimum required Solar Performance / Output Data from the meter. The data transfer protocol provided to the utility must satisfy servicing utility requirements.

11.1.7 Meter Data Access

All meters must provide the Performance Monitoring and Reporting Service Provider with the ability to access and retrieve the minimum required Solar Performance / Output Data from the meter using the Meter Communication / Data Transfer Protocols. In the event that the system is not required to have a Performance Monitoring and Reporting Service (PMRS) as shown in the summary table above, the Program Administrator must work with the System Owner to develop a means to retrieve the minimum required Solar Performance/Output Data from the meter.

11.1.8 Meter Display

All meters must provide a display showing the meter's measured net generated energy output and measured instantaneous power. This display must be easy to view and understand. This display must be physically located on the meter or inverter, and it may also be located on a remote device.

11.1.9 Meter Memory and Storage

All meters must have the ability to retain collected data in the event of a power outage. Meters that are reporting data remotely must have sufficient memory to retain 60 days of data if their standard reporting schedule is monthly and 7 days of data if their standard reporting schedule is daily. Meters that do not remotely report their data must retain 60 days of data. In all cases meters must be able to retain lifetime production.

11.2 Minimum Communication Requirements

All systems must be installed with some form of communication capability that will provide meaningful feedback to System Owners and Program Administrators. For all systems greater than 20 kW, and where otherwise possible, the systems should have remote communicating capability whereby performance data can be collected, accessed remotely, and uploaded for processing by a PMRS. For systems smaller than 20 kW, there is no specific communication technology requirement (e.g. telephone modem, cable, wireless, utility's existing meter reading system, etc), but as discussed above, the meter display must be accessible to the System Owner, and the Program Administrator must be provided means to retrieve data to collect performance data.

11.3 Minimum Performance Monitoring & Reporting Capability Requirements (see Table 16)

In order to enable system owners to properly maintain and evaluate the performance of their systems and to allow Program Administrators to monitor the performance of systems receiving CSI incentives, a Performance Monitoring and Reporting System must be installed to monitor and report on the following minimum data points and all monitoring, data collection, data retention, and reporting must be performed as specified in the corresponding sub-sections below.

The Performance Monitoring and Reporting System must be listed with the Energy Commission and must meet the minimum requirements of this section.

The California Energy Commission's list of qualifying performance monitoring system providers can be found at www.energy.ca.gov

11.3.1 Required Solar Performance / Output Data

The Performance Monitoring and Reporting System must monitor, record, and report on instantaneous AC kW and net kWh Generated by the PV system.

11.3.2 Minimum Report Delivery Requirements

The Performance Monitoring and Reporting System must provide for the electronic delivery of reports.

11.3.3 Time Granularity of Acquired Data

The Performance Monitoring and Reporting System must log all Required Solar Performance / Output Data points no less frequently than once every 15 minutes.

11.3.4 Frequency of Data Collection

The Performance Monitoring and Reporting System must remotely acquire and process all data points no less frequently than once per day.

11.3.5 Minimum Reporting Requirements

The Performance Monitoring and Reporting System must provide the following reports based on acquired, processed, and analyzed data:

- Data as collected and summarized by hour, day, month, and year.
- System alerts that indicate a non-functioning or poorly functioning system.

11.3.6 Frequency of Data Reporting

The Performance Monitoring and Reporting System must at all times provide system owners with on-demand access to all reports required by Section 11.3.5. Time sensitive reports (i.e. System Alerts) shall be made available within 24 hours of the monitoring service provider receiving the recorded data points which, when analyzed, indicated a problem with the system.

11.3.7 Data Retention Policy

The performance monitoring system must retain and provide the System Owner and Program Administrator with remote access to 15 minute average data for a minimum of five years for PBI program participants and two years for EPBB program participants.

11.4 Independence of Performance Monitoring & Reporting Service Provider

The entity responsible for providing and administering the Performance Monitoring and Reporting System shall not be affiliated with the incentive recipient, or any solar manufacturer or installer.

11.5 Eligible Recipients of Information

Subject to the stated Data Privacy restrictions appearing in Section 11.5.3, the performance monitoring system must at a minimum provide each group listed below with access to data as defined.

11.5.1 System Owner

The performance monitoring system shall at a minimum provide System Owners and/or host site customers (if different) with access to all Required Solar Performance / Output Data.

11.5.2 Program Administrators

The performance monitoring system shall at a minimum provide Program Administrators with all data listed in Section 11.3 for all systems.

11.5.3 Data Privacy

Protecting the privacy of System Owners and host site customers is of the highest order. As such, data shall be collected, processed, and reported to the System Owner and the Program Administrator in accordance with this Appendix. The PMRS may provide data to third parties, including installers and host customers (if different than the system owners), provided the System Owner has consented in writing to the release of such performance data.

11.6 Advanced Metering Infrastructure (AMI) Coordination

To the extent AMI coordination is an important component of PBI or EBPP program administration, the Commission will re-evaluate the requirements of this section at that time.

11.7 Overall Cost Constraint

As described in Table 16, all recipients of CSI funding with systems sizes greater than or equal to 20 kW, or participating in the PBI program regardless of system size, are required to install a performance monitoring system with 5 years of service that meets all of the applicable minimum standards defined in this Appendix.

Recipients of CSI funding are not precluded or penalized from purchasing or installing a performance monitoring system that exceeds the minimum requirements or any cost caps. The selection of performance monitoring system and service provider is made at the recipient's choice and expense.

To the extent that a recipient of CSI funding is not required to install a PMRS, the recipient of CSI funding is still required to install a metering system that meets all applicable parts of Section 11.1 (See Table 16).

12. Appendix C: Contract and Forms

13. Index

Appendix XI CEC List of Commercial Financing Alternatives

FINANCING OPTIONS FACT SHEET P500-03-032F

Commercial Financing Options For Renewable Energy Systems

CALIFORNIA ENERGY COMMISSION

Renewable Energy Program
1516 Ninth Street, MS 45
Sacramento, CA 95814-5512

RENEWABLE ENERGY PROGRAM
CALIFORNIA ENERGY COMMISSION

Harness the Power All Around Us

For information on renewable energy options and incentives in California

Energy Commission Website
www.consumerenergycenter.org

Energy Commission Call Center
1-800-555-7794

Relying on Renewable

Are you interested in reducing your energy costs by using renewable energy, but do not have the capital to afford the equipment? This fact sheet highlights various loan programs currently available.

Loan Program Basics
Loan products can be divided into two categories—secured and unsecured. As a general rule, unsecured loans have shorter terms (1-3 years) and relatively high interest rates. Unsecured loans are also known as business credit cards or business line of credit. Secured loans have longer terms and relatively lower interest rates, with the rate and term dependent upon the strength of the collateral and the creditworthiness of the borrower. Collateral can be in the form of equipment or real property.

Subsidized and targeted loans are also available to minority and women-owned businesses via the Small Business Administration. Generally, these loans are offered with a 'guaranty' by a state or federal agency to secure the loan.

Commercial Business Resources
On the reverse, you will find a list of lenders that offer attractive financing solutions. This fact sheet details a variety of financial loan products targeted directly at investments in renewable energy. To find out more about specific financing options, log onto the web addresses detailed for the particular lender you are interested in, or use the contact telephone numbers listed. Please visit the Energy Commission's website or call the Energy Call Center (see left) for information on renewable energy options and incentives in California.

LOAN EXAMPLES ($45,000)

Term and Rate	5 years @ 5%	10 years @ 8%	15 years @ 9%
Monthly Payment	-$866	-$559	-$465
Energy Savings	$243	$243	$243
Interest Savings	$46	$73	$85
Tax Credit Savings	$452	$226	$151
Net Monthly Payment	-$125	-$17	+$14

A business owner in Concord with an annual electricity bill of $20,000 is considering the purchase of a 10 kW (AC) photovoltaic (PV) system with an installed cost of $85,000. After receiving the Energy Commission "rebate" the net cost of the system would be $45,000. Savings in year one from PV electricity production at their current utility rates is projected to be $2,918. If they finance the net cost of the system of $45,000 with a 15 year loan at 9% interest it would result in an annual payment of $5,580. This business owner would also save $42,454 in taxes resulting from the 10% Federal Business Energy Tax Credit, 15% California Solar Tax Credit, State and Federal Depreciation and deductions for interest expenses. If the business paid cash for the system, the simple payback term would be 6.1 years. If electricity rates continue to rise the payback time would be shorter. If you would like to evaluate the savings for your situation, use the Clean Power Estimator found at the Energy Commission website (see left).

Assumptions: Annual electricity production from the PV system in Concord is estimated to be 18,265 kWh. The annual electricity used was 18,262 kWh. The current utility rates for this example range from about $.14 to $.23 per kWh. Tax savings were estimated assuming the business owner is in a 34% federal and 8.5% state tax bracket.

MAY 2004

Commercial Financing Options For Renewable Energy Systems

	Loan Program	Contact	Loan Amount	Term	Interest Rate
Equipment Secured Loans	Energy Efficiency Improvement Loan Program	Safe-Bidco www.safe-bidco.com	$250,000 Max Up to 10 yrs Savings	5 yrs	5.00%
	Equipment Efficiency Loan Program	Credit America www.creditamericafunding.com	No Limits	5 to 25 yrs	Prime plus 1-3%
	Equipment Efficiency Loan Program	GE Capital www.gecapital.com tel: 800.243.2222	No Limits	5 to 25 yrs	Prime plus 1-3%
	Equipment Efficiency Loan Program	PFG Energy Capital www.pfgenergy.com tel: 800.559.2755	No Limits	5 to 25 yrs	Prime plus 1-3%
	SBA 7(a) & Low Doc	SBA / Small Business Administration / Bank www.sbaonline.sba.gov	$1,000,000 @ 90% Guaranty	10 to 20 yrs	Fixed / Variable
	SBA 504	SBA / Small Business Administration / Bank (as above)	$750,000	10 to 20 yrs	Fixed / Variable
Real Estate Secured Loans	Collateral Mortgages	Collateral Mortgage, Ltd. www.collateral.com tel: 205.978.1840	No Maximum	15 to 30 yrs	Fixed / Variable
	SBA 7(a) & Low Doc	SBA / Small Business Administration / Bank (as above)	$1,000,000 @ 90% Guaranty	10 to 20 yrs	Fixed / Variable
	SBA 504	SBA / Small Business Administration / Bank	$750,000 Max	10 to 20	Fixed / Variable
Unsecured Loans	Commercial Loan	Credit America (as above)	$50,000	5 to 7 yrs	Fixed / Variable
	Commercial Loan	GE Capital (as above)	$50,000	5 to 7 yrs	Fixed / Variable
	Commercial Loan	PFG Energy Capital (as above)	$50,000	5 to 7 yrs	Fixed / Variable
	SBA 7(a) & Low Doc	SBA / Small Business Administration / Bank (as above)	$1,000,000 @ 90% Guaranty	10 to 20 yrs	Fixed / Variable
	SBA Express	Small Business Administration (as above)	$150,000	15 to 20	Market
Guaranty Loans	Business & Industry Loan Guaranty	USDA Rural Business Service www.rurdev.usda.gov/rd/ tel: 530.792.5805	$1 million to $10 million	1 to 10 yrs	Fixed / Variable - Near prime
	Business Loan Guaranty	California Trade & Commerce Agency http://commerce.ca.gov/business/small	90% Loan Guaranty	1 to 10 yrs	Fixed
	CA Loan Guaranty Program	California Trade & Commerce Agency (as above)	80% Guaranty	1 to 15 yrs	3 to 7 yrs
	Rural Utility Service	USDA Rural Utility Service	$500,000 to $5 million	Negotiated	Fixed / variable
	SBA 7(a) & Low Doc	SBA / Small Business Administration / Bank (as above)	$1,000,000 @ 90% Guaranty	10 to 20 yrs	Fixed / Variable
	SBA Express	Small Business Administration (as above)	$150,000	15 to 20 yrs	Market
Subsidized Loans	CalCAP	California Pollution Control Finance Authority www.treasurer.ca.gov/cpcfa/smallbusiness.htm	$20,000 to $ 2.5m	Short and long term	Fixed / Variable
	Equipment Efficiency Loan Program	Sacramento Municipal Utility District (SMUD) www.smud.org/pv/index.html	No Limit	10 yrs	8.7 to 10.5%
	PV Pioneer	Sacramento Municipal Utility District (SMUD)	$4/mo Premium	10 yrs	Purchase Option
	Small Business and Non Profit Energy Efficient Improvement	Safe-Bidco (as above)	$250,000 Max	5 yrs	5%
Third Party Loans	Energy Purchase Agreement	Alten Energy Services, Inc.	No Limit	No Limit	Discount Prices
	Energy Purchase Agreement	World Energy Services Technologies	No Limit	No Limit	Discount Prices

The California Energy Commission does not endorse any one lending organization. Eligibility varies for each financing option. Availability of financing options may vary. Contact individual provider for more information.

Appendix XII Renewable Energy Generation & Equipment Cost Analysis

Total Renewable Energy Generation Savings

Facility	Total Capacity Solar + Wind (kW)	Wind (kWh)	Solar (kWh)	Total (kWh)	Utility Rate ($0.08/kWh)	Total Savings ($)
Gusehu Administration Building	25	5,880	18,000	23,880	$ 0.09	$ 2,149
Howonquet Community Center	30	8,400	24,000	32,400	$ 0.10	$ 3,240
Lucky 7 Fuel Mart	15	0	18,000	18,000	$ 0.08	$ 1,440
Howonquet Head Start & Day Care Center	20	5,880	12,000	17,880	$ 0.09	$ 1,609
Lucky 7 Casino	100	0	120,000	120,000	$ 0.07	$ 8,400

Energy Generation Cost Analysis

Solar	Available Southern Facing Roof Area (sqft)	System Size (kW DC)	Estimated Generation (kWh/yr)	Total System Cost @ $7/Watt	Federal 30% ITC ($)	Tribal System Payback (years)	Investment Partner Net System Cost after FITC ($)
Gusehu Administration Building	2000	15	18000	$ 105,000	$ 31,500	65	$ 73,500
Howonquet Community Center	2600	20	24000	$ 140,000	$ 42,000	58	$ 98,000
Lucky 7 Fuel Mart	1800	15	18000	$ 105,000	$ 31,500	73	$ 73,500
Howonquet Head Start & Day Care Center	1600	10	12000	$ 70,000	$ 21,000	65	$ 49,000
Lucky 7 Casino	12,000	100	120000	$ 700,000	$ 210,000	83	$ 490,000

Wind	Ave Windspeed (mph)	Ave Wind Power Density (W/m^2)	Estimated Monthly Generation (kWh) (1)	Estimated Annual Generation (kWh)	Annual Net Metering Credit ($/kWh)	Total System Cost Bergey 10kW System ($)	Federal 30% ITC ($)	Tribal Net System Cost ($)	Tribal System Payback (years)	Investment Partner Net System Cost after FITC ($)
Gusehu Administration Building	8	300	490	5,880	$ 529	$ 38,000	$ 11,400	$ 30,062	72	$ 26,600
Howonquet Community Center	9	400	700	8,400	$ 840	$ 38,000	$ 11,400	$ 21,200	45	$ 26,600
Howonquet Head Start & Day Care Center	8	300	490	5,880	$ 529	$ 38,000	$ 11,400	$ 30,062	72	$ 26,600

Tax Partner MACRS Depreciation Schedules

Solar	Investment Partner Net Cost After FITC ($)	Investment Partner Depreciable Amount	% Deduction Per Year: Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total 100%	Final Cost in Yr 6 after Depreciation	Payback @ ($0.08 X Annual Generation)
Percentage		34%	20%	32%	19.20%	11.52%	11.52%	5.76%	100%		
Gusehu Administration Building	$ 73,500	$ 24,990	$ 4,998	$ 7,997	$ 4,798	$ 2,879	$ 2,879	$ 1,439	$ 24,990	$ 48,510	30
Howonquet Community Center	$ 98,000	$ 33,320	$ 6,664	$ 10,662	$ 6,397	$ 3,838	$ 3,838	$ 1,919	$ 33,320	$ 64,680	27
Lucky 7 Fuel Mart	$ 73,500	$ 24,990	$ 4,998	$ 7,997	$ 4,798	$ 2,879	$ 2,879	$ 1,439	$ 24,990	$ 48,510	34
Howonquet Head Start & Day Care Center	$ 49,000	$ 16,660	$ 3,332	$ 5,331	$ 3,199	$ 1,919	$ 1,919	$ 960	$ 16,660	$ 32,340	30
Lucky 7 Casino	$ 490,000	$ 166,600	$ 33,320	$ 53,312	$ 31,987	$ 19,192	$ 19,192	$ 9,596	$ 166,600	$ 323,400	39

Wind	Investment Partner Net Cost After FITC ($)	Investment Partner Depreciable Amount (Tax Bracket)	% Deduction Per Year: Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total 100%	Final Cost in Yr 6 after Depreciation	Payback @ ($0.08 X Annual Generation)
Percentage		34%	20%	32%	19.20%	11.52%	11.52%	5.76%	100%		
Gusehu Administration Building	$ 26,600	$ 9,044	$ 1,809	$ 2,894	$ 1,736	$ 1,042	$ 1,042	$ 521	$ 9,044	$ 17,556	33
Howonquet Community Center	$ 26,600	$ 9,044	$ 1,809	$ 2,894	$ 1,736	$ 1,042	$ 1,042	$ 521	$ 9,044	$ 17,556	21
Howonquet Head Start & Day Care Center	$ 26,600	$ 9,044	$ 1,809	$ 2,894	$ 1,736	$ 1,042	$ 1,042	$ 521	$ 9,044	$ 17,556	33

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Appendix XIII PP&L Site Generation Procedures & Qualifications

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

700 N.E. Multnomah, Suite 550
Portland, OR 97232

Thank you for your interest in a generation project in your area. PacifiCorp is looking forward to assisting with the interconnection of this environmentally friendly generating facility should it proceed.

Interconnection Process Summary
PacifiCorp currently uses the FERC process for all generation interconnections to ensure that each new facility receives equal treatment. In addition, these procedures help ensure that each project is properly interconnected to maintain the safety and reliability of the electrical system for the generator and existing customers. I have enclosed several documents that describe the interconnection process in full.

The interconnection process typically takes about 18 months, including construction, and it begins when the facility owner submits to PacifiCorp: (1) a completed interconnection application, and (2) payment of a study deposit, as all costs to study and interconnect the generator will be borne by the facility owner.

Following the receipt of the completed application and deposit, PacifiCorp will schedule a scoping meeting with the facility owner to discuss interconnection options and any necessary technical studies.

Once the studies are complete and it is determined that the interconnection may proceed safely (including the determination of any additional equipment or facilities that the developer may be required to install), the facility owner will be asked to sign a Small Generator Interconnection Agreement (SGIA) or a QFSGIA if they are connecting as a Qualified Facility. All of these procedures are described in detail in the attachments to this letter.

Application and Next Steps
The first attached document is the Small Generation Interconnection Procedures (SGIP), which describes in detail the required interconnection steps, timelines, and responsibilities of the facility owner, the project developer, and PacifiCorp.

The second attached document is "Attachment O: Attachments to Small Generator Interconnection Procedures". Appendix 2 of this document contains the "Small Generator Interconnection Request", the submission of which along with the deposit is the firs step in beginning the interconnection process. We will notify the developer/facility owner when we have received the interconnection request and clarify any data issues that might prevent us from moving to the next step in the interconnection process.

I look forward to assisting the involved parties in this process should they decide to proceed. If the developer plans to sell power to PacifiCorp Energy, they will also need to contact John Younie at PacifiCorp Energy, (503) 813-5957 to set up a Purchase Power Agreement.

Sincerely,

James Tanneberger
Transmission Consultant
503-813-6138

The facility owner or developer would use the following addresses to send the completed request and deposit to PacifiCorp.

<u>If using US Mail</u>
PacifiCorp Transmission,
PO Box 2757, Portland OR 97208-2757

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V. SMALL GENERATION INTERCONNECTION SERVICE

Generator Interconnection Procedures Applicable to Generating Facilities No Larger than 20 MW

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49 Application

49.1 Applicability

49.1.1 A request to interconnect a certified Small Generating Facility (See Appendices 3 and 4 to Attachment O of the Tariff for description of certification criteria) no larger than 2 MW shall be evaluated under the section 50 Fast Track Process. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kW shall be evaluated under the Appendix 5 to Attachment O of the Tariff 10 kW Inverter Process. A request to interconnect a Small Generating Facility larger than 2 MW but no larger than 20 MW or a Small Generating Facility that does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 51 Study Process.

49.1.2 Capitalized terms used herein shall have the

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meanings specified in the Glossary of Terms in Appendix 1 to Attachment O of the Tariff or the body of these procedures.

49.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.

49.1.4 Prior to submitting its Interconnection Request (Appendix 2 to Attachment O of the Tariff), the Interconnection Customer may ask the Transmission Provider's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Transmission Provider shall respond within 15 Business Days.

49.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all Transmission Providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric

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reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

49.1.6 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

49.2 Pre-Application

The Transmission Provider shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the Transmission Provider's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Transmission Provider shall comply with reasonable requests for such information.

49.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the Transmission Provider, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the Transmission Provider within three Business Days of receiving the Interconnection Request. The Transmission Provider shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the Transmission Provider shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the

Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the Transmission Provider.

49.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the Transmission Provider and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

49.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

49.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

49.5.2 An option to purchase or acquire a leasehold site for such purpose; or

49.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

49.6 Queue Position

The Transmission Provider shall assign a Queue Position based upon the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Transmission Provider shall maintain a single queue per geographic region. At the Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

49.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

50 Fast Track Process

50.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating

Facility with the Transmission Provider's Transmission System if the Small Generating Facility is no larger than 2 MW and if the Interconnection Customer's proposed Small Generating Facility meets the codes, standards, and certification requirements of Appendices 3 and 4 to Attachment O of the Tariff , or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

50.2 Initial Review

Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens.

50.2.1 Screens

50.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff.

50.2.1.2 For interconnection of a proposed Small Generating Facility to a radial

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distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider’s electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

50.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW[1].

50.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the

1 A spot Network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. (Standard Handbook for Electrical Engineers, 11th edition, Donald Fink, McGraw Hill Book Company)

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distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

50.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

50.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages

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on the Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

50.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

50.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

50.2.1.9 The Small Generating Facility, in

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aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

50.2.1.10 No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.

50.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

50.2.3 If the proposed interconnection fails the screens, but the Transmission Provider determines that the Small Generating Facility may nevertheless be interconnected consistent with safety,

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reliability, and power quality standards, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

50.2.4 If the proposed interconnection fails the screens, but the Transmission Provider does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

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50.3 Customer Options Meeting

If the Transmission Provider determines the Interconnection Request cannot be approved without minor modifications at minimal cost; or a supplemental study or other additional studies or actions; or at significant cost to address safety, reliability, or power quality problems, within the five Business Day period after the determination, the Transmission Provider shall notify the Interconnection Customer and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider shall:

50.3.1 Offer to perform facility modifications or minor modifications to the Transmission Provider's electric system(e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Transmission Provider's

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electric system; or

50.3.2 Offer to perform a supplemental review if the Transmission Provider concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, and provide a non-binding good faith estimate of the costs of such review; or

50.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 51 Study Process.

50.4 Supplemental Review

If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within 15 Business Days of the offer, and submit a deposit for the estimated costs. The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 20 Business Days of the invoice without interest.

50.4.1 Within ten Business Days following receipt of the deposit for a supplemental review, the

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Transmission Provider will determine if the Small Generating Facility can be interconnected safely and reliably.

50.4.1.1 If so, the Transmission Provider shall forward an executable interconnection agreement to the Interconnection Customer within five Business Days.

50.4.1.2 If so, and Interconnection Customer facility If so, and Interconnection Customer facility modifications are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Transmission Provider shall forward an executable interconnection agreement to the Interconnection Customer within five Business Days after confirmation that the Interconnection Customer has agreed to make the necessary changes at the Interconnection Customer's cost.

50.4.1.3 If so, and minor modifications to the Transmission Provider's electric system are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under the Fast Track Process, the Transmission Provider shall forward an executable interconnection agreement to the Interconnection Customer within ten Business Days that requires the Interconnection Customer to pay the costs of such system modifications prior to interconnection.

50.4.1.4 If not, the Interconnection Request will continue to be evaluated under the section 51 Study Process.

51 Study Process

51.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Transmission System if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

51.2 Scoping Meeting

51.2.1 A scoping meeting will be held within ten Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The Transmission Provider and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

51.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Transmission Provider should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the Transmission Provider shall provide the Interconnection Customer, as soon as possible, but not later than five Business Days after the scoping meeting, a feasibility study agreement (Appendix 6 to Attachment O of the Tariff) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

51.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return

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the executed feasibility study agreement within 15 Business Days. If the Parties agree not to perform a feasibility study, the Transmission Provider shall provide the Interconnection Customer, no later than five Business Days after the scoping meeting, a system impact study agreement (Appendix 7 to Attachment O of the Tariff) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

51.3 Feasibility Study

51.3.1 The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

51.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

51.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Appendix 6 to Attachment O of the Tariff).

51.3.4 If the feasibility study shows no potential for adverse system impacts, the Transmission Provider shall send the Interconnection Customer a facilities study agreement, including an outline

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of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Transmission Provider shall send the Interconnection Customer an executable interconnection agreement within five Business Days.

51.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

51.4 System Impact Study

51.4.1 A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

51.4.2 If no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are

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identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

51.4.3 In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five Business Days following transmittal of the feasibility study report, the Transmission Provider shall send the Interconnection Customer a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

51.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been

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conducted, the Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement.

51.4.5 If the feasibility study shows no potential for transmission system or Distribution System adverse system impacts, the Transmission Provider shall send the Interconnection Customer either a facilities study agreement (Appendix 8 to Attachment O of the Tariff), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

51.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

51.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

51.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

51.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") –

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whether investor-owned or not – the Interconnection Customer may apply to the nearest Transmission Provider (Transmission Owner, Regional Transmission Operator, or Independent Transmission Provider) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

51.5 Facilities Study

51.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the Interconnection Customer along with a facilities study agreement within five Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the Interconnection Customer within the same timeframe.

51.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the Transmission Provider's interconnection queue, the Interconnection Customer must return the executed

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facilities study agreement or a request for an extension of time within 30 Business Days.

51.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

51.5.4 Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The Transmission Provider may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the Transmission Provider may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Transmission Provider, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the Transmission Provider shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and

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critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

51.5.5 A deposit of the good faith estimated costs for the facilities study may be required from the Interconnection Customer.

51.5.6 The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement.

51.5.7 Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days.

52 Provisions that Apply to All Interconnection Requests

52.1 <u>Reasonable Efforts</u>

The Transmission Provider shall make reasonable efforts to meet all time frames provided in these procedures unless the Transmission Provider and the Interconnection Customer agree to a different schedule. If the Transmission Provider cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure

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to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

52.2 Disputes

52.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

52.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

52.2.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

52.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

52.2.5 Each Party agrees to conduct all negotiations in

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good faith and will be responsible for one-half of any costs paid to neutral third-parties.

52.2.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

52.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the Transmission Provider's specifications.

52.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The Transmission Provider must be given at least five Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

52.5 Confidentiality

52.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures

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all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

52.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

52.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

52.5.2.2 Each Party is entitled to equitable

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relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

52.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC. The Party shall notify the other Party when it is notified by FERC that a request to release Confidential Information has been received by

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FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

52.6 Comparability

The Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The Transmission Provider shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the Transmission Provider, its subsidiaries or affiliates, or others.

52.7 Record Retention

The Transmission Provider shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

52.8 Interconnection Agreement

After receiving an interconnection agreement from the Transmission Provider, the Interconnection Customer shall

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have 30 Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement, or request that the Transmission Provider file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

52.9 Coordination with Affected Systems

The Transmission Provider shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The Transmission Provider will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an

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Affected System shall cooperate with the Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

52.10 Capacity of the Small Generating Facility

52.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

52.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

52.10.3 The Interconnection Request shall be evaluated using the maximum rated capacity of the Small Generating Facility.

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ATTACHMENT O

ATTACHMENTS TO SMALL GENERATOR INTERCONNECTION PROCEDURES
(Refer to Part V of the Tariff)

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APPENDIX 1 TO SGIP

Glossary of Terms

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 50 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Appendix 5 to Attachment O of the Tariff.

Affected System – An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Business Day – Monday through Friday, excluding Federal Holidays.

Distribution System – The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility no larger than 2 MW that includes the section 50 screens, customer options meeting, and optional supplemental review.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others,

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but rather to be acceptable practices, methods, or acts generally accepted in the region..

Interconnection Customer – Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities – The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider’s Transmission System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider’s Transmission System to accommodate the interconnection with the Small Generating Facility to the Transmission Provider’s Transmission System. Network Upgrades do not include Distribution Upgrades.

Party or Parties – The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Queue Position – The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is

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established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Small Generating Facility - The Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Study Process - The procedure for evaluating an Interconnection Request that includes the section 51 scoping meeting, feasibility study, system impact study, and facilities study.

Transmission Owner - The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider - The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System - The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades - The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

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APPENDIX 2 TO SGIP

SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

Transmission Provider: ______________________________

Designated Contact Person: ______________________________

Address: ______________________________

Telephone Number: ______________________________

Fax: ______________________________

E-Mail Address: ______________________________

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP section 49.5, documentation of site control must be submitted with the Interconnection Request.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ______________________________

Contact Person: ______________________________

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Mailing Address: ____

City: __________________________ State: ___________________ Zip: ______________

Facility Location (if different from above): ___________________________________

Telephone (Day): __________________ Telephone (Evening): _______________________

Fax: ______________________________ E-Mail Address: ____________________________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ____

Title: ____

Address: ____

____

Telephone (Day): __________________ Telephone (Evening): _______________________

Fax: ______________________________ E-Mail Address: ____________________________

Application is for: _____ New Small Generating Facility
_____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: ________________________
____

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___
To Supply Power to the Interconnection Customer? Yes ___ No ___
To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

____ ______________________________
(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

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Contact Name: ____

Title: ____

Address: ____

____

Telephone (Day): ____________________ Telephone (Evening): __________________________

Fax: ______________________________ E-Mail Address: ______________________________

Requested Point of Interconnection: ____

Interconnection Customer's Requested In-Service Date: ___________________________________

Small Generating Facility Information
Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___Solar ___Wind ___Hydro Hydro Type (e.g. Run-of-River):_____________
___Diesel ___Natural Gas ___Fuel Oil ___Other (state type) __________________

Prime Mover: ___Fuel Cell ___Recip Engine ___Gas Turb ___Steam Turb
___Microturbine ___PV ___Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: ________kW (Typical) Generator Nameplate kVAR: ________

Interconnection Customer or Customer-Site Load: _________________kW (if none, so state)

Typical Reactive Load (if known): _________________

Maximum Physical Export Capability Requested: ______________ kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. ____________________	______________________________
2. ____________________	______________________________
3. ____________________	______________________________
4. ____________________	______________________________
5. ____________________	______________________________

Is the prime mover compatible with the certified protective relay package? ____Yes ____No

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Generator (or solar collector)
Manufacturer, Model Name & Number: ____
Version Number: _____________________

Nameplate Output Power Rating in kW: (Summer) _____________ (Winter) ______________
Nameplate Output Power Rating in kVA: (Summer) _____________ (Winter) ______________

Individual Generator Power Factor
Rated Power Factor: Leading: _____________Lagging: _______________

Total Number of Generators in wind farm to be interconnected pursuant to this
Interconnection Request: ________ Elevation: ______ ___Single phase ___Three phase

Inverter Manufacturer, Model Name & Number (if used): ___________________________________

List of adjustable set points for the protective equipment or software: __________________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _________ Instantaneous ___ or RMS? ___

Harmonics Characteristics: ____

Start-up requirements: ____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____________
(*) Neutral Grounding Resistor (If Applicable): ____________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: _______ P.U.
Direct Axis Transient Reactance, X'_d: ___________P.U.
Direct Axis Subtransient Reactance, X''_d: ______________P.U.
Negative Sequence Reactance, X_2: _________ P.U.
Zero Sequence Reactance, X_0: ____________ P.U.
KVA Base: __________________________
Field Volts: ______________
Field Amperes: ______________

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Induction Generators:

Motoring Power (kW): _______________
I_2^2t or K (Heating Time Constant): _______________
Rotor Resistance, Rr: _______________
Stator Resistance, Rs: _______________
Stator Reactance, Xs: _______________
Rotor Reactance, Xr: _______________
Magnetizing Reactance, Xm: _______________
Short Circuit Reactance, Xd": _______________
Exciting Current: _______________
Temperature Rise: _______________
Frame Size: _______________
Design Letter: _______________
Reactive Power Required In Vars (No Load): _______________
Reactive Power Required In Vars (Full Load): _______________
Total Rotating Inertia, H: ______________ Per Unit on kVA Base

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___Yes ___No

Will the transformer be provided by the Interconnection Customer? ____Yes ____No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: ___________kVA
Transformer Impedance: _______% on __________kVA Base

If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

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Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: __________________ Type: _______________ Size: ________Speed: ______________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: __________
Load Rating (Amps): _______ Interrupting Rating (Amps): ________ Trip Speed (Cycles): __________

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

Setpoint Function	Minimum	Maximum
1. _______________________	__________	__________
2. _______________________	__________	__________
3. _______________________	__________	__________
4. _______________________	__________	__________
5. _______________________	__________	__________
6. _______________________	__________	__________

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: _________ Type: ______ Style/Catalog No.: ________ Proposed Setting: __________
Manufacturer: _________ Type: ______ Style/Catalog No.: ________ Proposed Setting: __________
Manufacturer: _________ Type: ______ Style/Catalog No.: ________ Proposed Setting: __________
Manufacturer: _________ Type: ______ Style/Catalog No.: ________ Proposed Setting: __________
Manufacturer: _________ Type: ______ Style/Catalog No.: ________ Proposed Setting: __________

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

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Manufacturer: ____
Type: _____________ Accuracy Class: _ Proposed Ratio Connection: ____

Manufacturer: ____
Type: _____________ Accuracy Class: _ Proposed Ratio Connection: ____

Potential Transformer Data (If Applicable):

Manufacturer: ____
Type: _____________ Accuracy Class: _ Proposed Ratio Connection: ____

Manufacturer: ____
Type: _____________ Accuracy Class: _ Proposed Ratio Connection: ____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) ____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ___Yes ____No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: ______________________________Date: ____________

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APPENDIX 3 TO SGIP

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

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APPENDIX 4 TO SGIP

Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Appendix 3 to Attachment O of the Tariff, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer’s literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no

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further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

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APPENDIX 5 TO SGIP

Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company").

2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

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7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

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Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per SGIP section 49.5, documentation of site control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer

Name: ______________________________

Contact Person:______________________________

Address: ______________________________

City: ______________ State: __________ Zip: ________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________ E-Mail Address: ______________

Contact (if different from Interconnection Customer)

Name: ______________________________

Address: ______________________________

City: ______________ State: __________ Zip: ________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________ E-Mail Address: ______________

Owner of the facility (include % ownership by any electric utility): ______________

Small Generating Facility Information

Location (if different from above): ______________________________

Electric Service Company: ______________________________

Account Number: ______________________________

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Inverter Manufacturer:____________________Model________________________________

Nameplate Rating: _____ (kW) _____ (kVA) ______ (AC Volts)

Single Phase _______ Three Phase_____

System Design Capacity: _________ (kW) _______ (kVA)

Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell ☐

Turbine ☐ Other _____________

Energy Source: Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas ☐

Fuel Oil ☐ Other (describe) ______________________________

Is the equipment UL1741 Listed? Yes___ No ___

If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date: _____________Estimated In-Service Date: ____________

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Appendices 3 and 4 to Attachment O of the Tariff, or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. ____________________	______________________________
2. ____________________	______________________________
3. ____________________	______________________________
4. ____________________	______________________________
5. ____________________	______________________________

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____

Title: ______________________________________ Date: ____________

Contingent Approval to Interconnect the Small Generating Facility

(For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

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Company Signature: ____

Title: ___________________________________ Date: ___________

Application ID number: __________________

Company waives inspection/witness test? Yes___ No___

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Issued on: April 27, 2006 Effective on: April 1, 2006

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Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes______ No ______

Interconnection Customer: ____

Contact Person:____

Address: ____

Location of the Small Generating Facility (if different from above):

____

City: ____________________________ State: ________________ Zip Code: _______

Telephone (Day): ____________________ (Evening): ____________________________

Fax: ______________________________ E-Mail Address: _________________________

Electrician:

Name: ____

Address: ____

City: ____________________________ State: ________________ Zip Code: _______

Telephone (Day): ____________________ (Evening): ____________________________

Fax: ______________________________ E-Mail Address: _________________________

License number: ___________________________________

Date Approval to Install Facility granted by the Company: ___________________

Application ID number: _____________________________

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local

building/electrical code of ____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

____

Print Name: ____

Date: ___________

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Issued on: April 27, 2006 Effective on: April 1, 2006

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As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: ____

Company: ____

Address:____

____

City, State ZIP: ______________________________________

Fax: __________________

Approval to Energize the Small Generating Facility (For Company use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature: ____

Title: _____________________________________ Date: ____________

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

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Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 **Construction of the Facility**
The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 **Interconnection and Operation**
The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

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2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 **Safe Operations and Maintenance**
The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 **Access**
The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 **Disconnection**
The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 **Indemnification**
The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

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7. 0 **Insurance**
The Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 **Limitation of Liability**
Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 **Termination**
The agreement to operate in parallel may be terminated under the following conditions:

9.1 **By the Customer**
By providing written notice to the Company.

9.2 **By the Company**
If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 **Permanent Disconnection**
In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 **Survival Rights**
This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 **Assignment/Transfer of Ownership of the Facility**
This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

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APPENDIX 6 TO SGIP

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this _____ day of _____________ 20__ by and between ____ , a ___________________ organized and existing under the laws of the State of _____________________ , ("Interconnection Customer,") and __________________________ , a _______________ existing under the laws of the State of _________________________ , ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on _________________________; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential

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Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed____________________________	Signed_________________________
Name (Printed):_______________	Name (Printed):_______________
Title:________________________	Title:________________________

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

Attachment A to
Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on ____________________________:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

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APPENDIX 7 TO SGIP

System Impact Study Agreement

THIS AGREEMENT is made and entered into this _____ day of _____________ 20__ by and between ____, a __________________ organized and existing under the laws of the State of _____________________, ("Interconnection Customer,") and ____________________, a _____________________ existing under the laws of the State of ________________________, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on ____________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades

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associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the one half the good faith estimated cost of a transmission system impact study may be required from the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

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Issued on: April 27, 2006 Effective on: April 1, 2006

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IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed________________________	Signed________________________
Name (Printed):_______________	Name (Printed):_______________
Title:________________________	Title:________________________

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

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Attachment A to System Impact Study Agreement

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

APPENDIX 8 TO SGIP

Facilities Study Agreement

THIS AGREEMENT is made and entered into this _____ day of _____________ 20___ by and between _______________________________, a _________________ organized and existing under the laws of the State of _________________, ("Interconnection Customer,") and ____________________________, a ___________________________existing under the laws of the State of __________________________, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on _____________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small

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Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of the good faith estimated facilities study costs may be required from the Interconnection Customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit

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exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed________________________	Signed________________________
Name (Printed):_______________	Name (Printed):_______________
Title:________________________	Title:________________________

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

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Attachment A to
Facilities Study Agreement

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections: ___________

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes _________ No ______

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation?
Yes ____________ No _____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

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Physical dimensions of the proposed interconnection station:

___

Bus length from generation to interconnection station:

___

Line length from interconnection station to Transmission Provider's Transmission System.

___

Tower number observed in the field. (Painted on tower leg)*:

___

Number of third party easements required for transmission lines*:

___

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider's service area?

Yes _____________ No _____________ If No, please provide name of local provider:

___

Please provide the following proposed schedule dates:

Begin Construction Date:___________________________

Generator step-up transformers receive back feed power Date:___________________________

Generation Testing Date:___________________________

Commercial Operation Date:___________________________

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APPENDIX 9 TO SGIP

SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA)

(For Generating Facilities No Larger Than 20 MW)

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

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This Interconnection Agreement ("Agreement") is made and entered into this _____ day of ____________, 20__, by ________________________ ("Transmission Provider"), and __________________________________ ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties."

Transmission Provider Information

Transmission Provider: ____________________________________
Attention: ____
Address: ____
City: _______________________ State: ___________ Zip: ______
Phone: ________________ Fax: _________________

Interconnection Customer Information

Interconnection Customer: ________________________________
Attention: ____
Address: ____
City: _______________________ State: ___________ Zip: ______
Phone: ________________ Fax: _________________

Interconnection Customer Application No: _____________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) except for those submitted under the 10 kW Inverter Process contained in SGIP Appendix 5 to Attachment O of the Tariff.

1.2 This Agreement governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the Transmission Provider's Transmission System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for

Issued by: Jack E. Stamper, Regulatory Manager
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separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Transmission Provider.

1.4 Nothing in this Agreement is intended to affect any other agreement between the Transmission Provider and the Interconnection Customer.

1.5 <u>Responsibilities of the Parties</u>

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Transmission Provider shall construct, operate, and maintain its Transmission System and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Transmission Provider and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of

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their respective lines and appurtenances on their respective sides of the point of change of ownership. The Transmission Provider and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Transmission Provider's Transmission System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The Transmission Provider shall coordinate with all Affected Systems to support the interconnection.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the applicable control area, including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth in the Tariff or by the applicable system operator(s) for the Transmission Provider's Transmission System and; 2) the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Transmission Provider's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all similarly situated generators in the control area on a comparable basis.

Issued by: Jack E. Stamper, Regulatory Manager
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The requirements of this paragraph shall not apply to wind generators.

1.8.2 The Transmission Provider is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Small Generating Facility when the Transmission Provider requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1. In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.

1.8.3 Payments shall be in accordance with the Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to a regional transmission organization or independent system operator FERC-approved rate schedule. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb reactive power under this Agreement, the Parties agree to expeditiously file such rate schedule and agree to support any request for waiver of the Commission's prior notice requirement in order to compensate the Interconnection Customer from the time service commenced.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Transmission Provider of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Transmission Provider may, at its own expense, send qualified personnel to the Small Generating Facility site to

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inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Transmission Provider a written test report when such testing and inspection is completed.

2.1.2 The Transmission Provider shall provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Transmission Provider of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Transmission Provider shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Transmission Provider shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Transmission Provider shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the Transmission Provider's Transmission System without prior written authorization of the Transmission Provider. The Transmission Provider will provide such authorization once the Transmission Provider receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Transmission Provider may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small Generating Facility first produces energy to inspect the interconnection, and observe the

Issued by: Jack E. Stamper, Regulatory Manager
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commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Transmission Provider at least five Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Transmission Provider shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by the FERC. The Transmission Provider shall promptly file this Agreement with the FERC upon execution, if required.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ten years from the Effective Date or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Agreement (if required), which notice has been accepted for filing by FERC.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Transmission Provider 20 Business Days written notice.

3.3.2 Either Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the Transmission Provider's Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this SGIA or such non-terminating Party otherwise is responsible for these costs under this SGIA.

3.3.4 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.5 This provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions -- "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, the Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency

Conditions, the Transmission Provider may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility. The Transmission Provider shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility. The Interconnection Customer shall notify the Transmission Provider promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Transmission Provider's Transmission System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Transmission Provider may interrupt interconnection service or curtail the output of the Small Generating Facility and temporarily disconnect the Small Generating Facility from the Transmission Provider's Transmission System when necessary for routine maintenance, construction, and repairs on the Transmission Provider's Transmission System. The Transmission Provider shall provide the Interconnection Customer with five Business Days notice prior to such interruption. The Transmission Provider shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the Transmission Provider may suspend interconnection service to effect immediate repairs on the Transmission Provider's Transmission System. The Transmission Provider shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Transmission Provider shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

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3.4.4 Adverse Operating Effects

The Transmission Provider shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the Transmission Provider's Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Transmission Provider may disconnect the Small Generating Facility. The Transmission Provider shall provide the Interconnection Customer with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from the Transmission Provider before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the Transmission System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Transmission Provider's prior written authorization, the latter shall have the right to temporarily disconnect the Small Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, and the Transmission Provider's Transmission System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Issued by: Jack E. Stamper, Regulatory Manager
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Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Transmission Provider shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Transmission Provider.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Transmission Provider's Interconnection Facilities.

4.2 Distribution Upgrades

The Transmission Provider shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Transmission Provider and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this article 5 shall apply unless the interconnection of the Small Generating Facility requires Network Upgrades.

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5.2 Network Upgrades

The Transmission Provider or the Transmission Owner shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Transmission Provider and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Transmission Provider elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer.

5.2.1 Repayment of Amounts Advanced for Network Upgrades

The Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to the Transmission Provider and Affected System operator, if any, for Network Upgrades, including any tax gross-up or other tax-related payments associated with the Network Upgrades, and not otherwise refunded to the Interconnection Customer, to be paid to the Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under the Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Small Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC’s regulations at 18 C.F.R. § 35.19 a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. The Interconnection Customer may assign such repayment rights to any person.

5.2.1.1 Notwithstanding the foregoing, the Interconnection Customer, the Transmission Provider, and any applicable Affected System operators may adopt any alternative payment schedule that is mutually agreeable so long as the Transmission Provider and said Affected System operators take one of the following actions no later than five years from the Commercial Operation Date: (1) return to the Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or “(2) declare in writing that the Transmission Provider or any applicable Affected System

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

operators will continue to provide payments to the Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the commercial operation date.

5.2.1.2 If the Small Generating Facility fails to achieve commercial operation, but it or another generating facility is later constructed and requires use of the Network Upgrades, the Transmission Provider and Affected System operator shall at that time reimburse the Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the generating facility, if different, is responsible for identifying the entity to which reimbursement must be made.

5.3 Special Provisions for Affected Systems

Unless the Transmission Provider provides, under this Agreement, for the repayment of amounts advanced to any applicable Affected System operators for Network Upgrades, the Interconnection Customer and Affected System operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to Affected System operator as well as the repayment by Affected System operator.

5.4 Rights Under Other Agreements

Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Small Generating Facility.

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Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Transmission Provider shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by the Parties.

6.1.2 Within three months of completing the construction and installation of the Transmission Provider's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Transmission Provider shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Transmission Provider for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Transmission Provider shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Transmission Provider within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Transmission Provider shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) requesting appropriate

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

amendments to Attachment 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Transmission Provider's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Transmission Provider, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction where the Point of Interconnection is located. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Transmission Provider's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Transmission Provider under this Agreement during its term. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Transmission Provider and must specify a reasonable expiration date.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment

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This Agreement may be assigned by either Party upon 15 Business Days prior written notice and opportunity to object by the other Party; provided that:

7.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Transmission Provider of any such assignment;

7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Transmission Provider, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Transmission Provider of any such assignment.

7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.

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Issued on: April 27, 2006 Effective on: April 1, 2006

7.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or

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any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in article 7.6.2, the defaulting Party shall have 60 calendar days from

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance

8.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Transmission Provider, except that the Interconnection Customer shall show proof of insurance to the Transmission Provider no later than ten Business Days prior to the anticipated commercial operation date. An Interconnection Customer of sufficient credit-worthiness may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

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8.2 The Transmission Provider agrees to maintain general liability insurance or self-insurance consistent with the Transmission Provider's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Transmission Provider's liabilities undertaken pursuant to this Agreement.

8.3 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

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9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this Agreement prior to the release of the Confidential Information to FERC. The Party shall notify the other Party to this Agreement when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

Article 10. Disputes

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006   Effective on: April 1, 2006

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10.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with FERC policy and Internal Revenue Service requirements.

11.2 Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of __________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

PacifiCorp Original Sheet No. 299-27
FERC Electric Tariff,
5th Rev Volume No. 11

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. FERC expects all Transmission Providers, market participants, and Interconnection Customers interconnected to electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall

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remain primarily liable to the other Party for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

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FERC Electric Tariff,
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Original Sheet No. 299-29

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:

Interconnection Customer: ______________________
Attention: ______________________
Address: ______________________
City: ______________ State: ________ Zip: ______
Phone: ______________ Fax: ______________

If to the Transmission Provider:

Transmission Provider: ______________________
Attention: ______________________
Address: ______________________
City: ______________ State: ________ Zip: ______
Phone: ______________ Fax: ______________

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: ______________________
Attention: ______________________
Address: ______________________
City: ______________ State: ________ Zip: ______

Transmission Provider: ______________________
Attention: ______________________
Address: ______________________
City: ______________ State: ________ Zip: ______

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

Interconnection Customer: ____________________________
Attention: ____
Address: ____
City: ______________________ State:_________ Zip:______
Phone: _____________________ Fax: ________________

If to the Transmission Provider:

Transmission Provider: _______________________________
Attention: ____
Address: ____
City: ______________________ State:_________ Zip:______
Phone: _____________________ Fax: ________________

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: ____________________________
Attention: ____
Address: ____
City: ______________________ State:_________ Zip:______
Phone: _____________________ Fax: ________________

Transmission Provider's Operating Representative:

Transmission Provider: _______________________________
Attention: ____
Address: ____
City: ______________________ State:_________ Zip:______
Phone: _____________________ Fax: ________________

13.5 Changes to the Notice Information

Either Party may change this information by giving five Business Days written notice prior to the effective date of the change.

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Original Sheet No. 299-31

Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Transmission Provider

Name: ____

Title: ____

Date: ____________________

For the Interconnection Customer

Name: ____

Title: ____

Date: ____________________

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

Attachment 1 to SGIA

Glossary of Terms

Affected System – An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Business Day – Monday through Friday, excluding Federal Holidays.

Default – The failure of a breaching Party to cure its breach under the Small Generator Interconnection Agreement.

Distribution System – The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission,

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department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Interconnection Provider, or any Affiliate thereof.

Interconnection Customer – Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities – The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider’s Transmission System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider’s Transmission System to accommodate the interconnection of the Small Generating Facility with the Transmission Provider’s Transmission System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, Independent System Operator, control area, or the Transmission

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Provider's requirements, including those set forth in the Small Generator Interconnection Agreement.

Party or Parties – The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the Small Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – The Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Tariff – The Transmission Provider or Affected System's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider – The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System – The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades – The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

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Original Sheet No. 299-35

Attachment 2 to SGIA

Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, the Transmission Provider, or the Transmission Owner. The Transmission Provider will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

Issued by: Jack E. Stamper, Regulatory Manager
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Attachment 3 to SGIA

One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

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Original Sheet No. 299-37

Attachment 4 to SGIA

Milestones

In-Service Date: ____________________

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	**Responsible Party**
(1)	____________________	____________
(2)	____________________	____________
(3)	____________________	____________
(4)	____________________	____________
(5)	____________________	____________
(6)	____________________	____________
(7)	____________________	____________
(8)	____________________	____________
(9)	____________________	____________
(10)	____________________	____________

Agreed to by:

For the Transmission Provider______________________Date___________

For the Transmission Owner (If Applicable)_________Date________

For the Interconnection Customer___________________Date__________

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Issued on: April 27, 2006 Effective on: April 1, 2006

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Original Sheet No. 299-38

Attachment 5 to SGIA

Additional Operating Requirements for the Transmission Provider's Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs

The Transmission Provider shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the Transmission Provider's Transmission System.

Issued by: Jack E. Stamper, Regulatory Manager
Issued on: April 27, 2006 Effective on: April 1, 2006

PacifiCorp Original Sheet No. 299-39
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Attachment 6 to SGIA

Transmission Provider's Description of its Upgrades and Best Estimate of Upgrade Costs

The Transmission Provider shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Transmission Provider shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

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Issued on: April 27, 2006 Effective on: April 1, 2006

Pacific Power & Light Company — Original Cal.P.U.C.Sheet No. 1492-E
Portland, Oregon — Canceling Cal.P.U.C.Sheet No.

SCHEDULE NO. CG-5

PURCHASE FROM COGENERATORS AND SMALL POWER PRODUCERS

AVAILABLE

For qualifying facilities located in the territory served by Company in California. This schedule and the rates found within are in lieu of separately negotiated rates between the qualifying facility and the Company,

APPLICABLE

To all non-utility owners or operators of qualifying facilities (Sellers) who are willing and able to enter into a written contract and where facilities are classified as new capacity pursuant to 18C.F.R. 292.304(b)(1).

MONTHLY BILLING

The monthly billing to the qualifying facility shall be the sum of the Basic Charge specified hereunder and the monthly billings for takings from Company in accordance with the applicable schedule or schedules for the type of service received.

DEFINITIONS

Qualifying Facility means either a cogeneration facility or small power production facility not greater than 80 megawatts capacity as defined hereunder:

(a) Cogeneration Facility means a facility which produces electric energy together with steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

(b) Small Power Production Facility means a facility which produces electric energy using as a primary energy source biomass, waste, renewable resources, or any combination thereof.

(c) Peak Hours includes the hours from 7 a.m. through 10 p.m. on any day Monday through Saturday inclusive.

CONDITIONS OF SERVICE

All purchases shall be accomplished according to the terms and conditions of a written contract.

RATES FOR SALES

All sales by Company to Sellers shall be in accordance with standard rate schedules filed by Company with the Commission.

(Continued)

Issued by

Advice Letter No. 199-E — Fredric D. Reed (Name) — Date Filed April 16, 1987

Decision No. — Senior Vice President (Title) — Effective May 8, 1987

TF6 CG-5-1.E — Resolution No.

Pacific Power & Light Companv
Portland, Oregon

Revised Cal.P.U.C.Sheet No. 1978-E
Canceling Original Cal.P.U.C.Sheet No. 1493-E

SCHEDULE NO. CG-5

PURCHASE FROM COGENERATORS AND SMALL POWER PRODUCERS
(Continued)

RATES FOR PURCHASES

Capacity: A qualifying facility will qualify for 100% of the annual capacity payment, listed below, for performance equivalent to an 80% capacity factor during the peak hours during the period December through April.

The Qualifying Facility shall select from the following alternatives capacity rate for purchase by Company. Such selected alternative shall remain in effect for the term of the written contract.

Alternative 1. Nominal: The capacity payment shall be in nominal terms, which remain constant at the level shown below for all years of a written contract.

Year	Capacity Payment ($/kW-Year)	Year	Capacity Payment ($/kW-Year)
1994	61.81	2005	81.14
1995	57.39	2006	84.17
1996	61.81	2007	87.08
1997	50.30	2008	91.03
1998	51.60	2009	95.74
1999	68.27	2010	101.44
2000	70.57	2011	105.94
2001	73.21	2012	110.03
2002	75.83	2013	114.94
2003	77.68	2014	119.77
2004	78.82		

Alternative 2. Time of Delivery: The Company shall pay monthly for all separately metered capacity at avoided capacity cost effective at time-of-delivery.

ENERGY

The Qualifying Facility shall select from the following alternative energy rates for purchase by Company. Such selected alternative shall remain in effect for the term of the written contract.

(Continued)

Issued by

Advice Letter No. 257-E — Robert V. Sirvaitis (Name) — Date Filed March 14, 1994

Decision No. 93-12-016 — Director, Pricing (Title) — Effective May 1, 1994

TF6 CG-5-2.E — Resolution No.

Pacific Power & Light Company		Revised	Cal.P.U.C.Sheet No. 1979-E
Portland, Oregon	Canceling	Original	Cal.P.U.C.Sheet No. 1494/1495-E

SCHEDULE NO. CG-5

PURCHASE FROM COGENERATORS AND SMALL POWER PRODUCERS
(Continued)

Alternative 1. Nominal: Energy delivered to and accepted by Company from a qualifying facility shall be in nominal terms, which remain constant at the level shown below for all years of a written contract.

Year	Energy Payment (cents/kWh)	Year	Energy Payment (cents/kWh)
1994	1.66	2005	3.43
1995	1.76	2006	3.56
1996	1.79	2007	3.68
1997	1.89	2008	3.85
1998	2.05	2009	4.05
1999	2.89	2010	4.29
2000	2.98	2011	4.48
2001	3.10	2012	4.65
2002	3.21	2013	4.86
2003	3.28	2014	5.06
2004	3.33		

Alternative 2. Time of Delivery: The Company shall pay monthly for all separately metered kilowatt-hours of qualifying facility generation at avoided costs effective at time-of-delivery.

SEASONAL DIFFERENTIATION

The qualifying facility shall have the option of seasonally differentiated rates for purchases. The Company shall make the seasonal differentiation available upon request.

CHANGE OF RATE

Rates for purchases will be revised annually as appropriate pursuant to the Public Utilities Commission of the State of California. This schedule will remain in effect until Company's purchases under this schedule and/or previous PURPA purchases are equal to 80 megawatts.

RULES AND REGULATIONS

Service hereunder is subject to the General Rules and Regulations contained in Company's regularly filed and published tariff and to those prescribed by regulatory authorities.

(Continued)

Issued by

Advice Letter No. 257-E	Robert V. Sirvaitis	Date Filed	March 14, 1994
	Name		
Decision No. 93-12-016	Director, Pricing	Effective	May 1, 1994
	Title		
TF6 CG-5-3.E		Resolution No.	

Pacific Power & Light Company		Revised	Cal.P.U.C.Sheet No.	2369-E
Portland, Oregon	Canceling	Original	Cal.P.U.C.Sheet No.	2312-E

Schedule No. NEM-35

NET METERING SERVICE

APPLICABILITY

Applicable on a first-come, first-served basis to a residential, small commercial, commercial, industrial, or agricultural Customer that owns and operates a solar or wind electrical generating facility, or a hybrid system of both, with a capacity of not more than one megawatt that is located on the Customer's owned, leased, or rented premises, is interconnected and operates in parallel with the Utility's transmission and distribution facilities, and is intended primarily to offset part of all of the Customer's own electrical requirements. This provision shall be available until the time that the total rated generating capacity used by the eligible Customer-generators equals one-half of one percent of the aggregate Customer peak demand of the Utility. This Schedule is offered in compliance with Cal. Pub. Util. Code Ann. § 2827, *et seq.* (West 2002).

TERRITORY

Within the entire territory served in California by the Utility.

DEFINITIONS

Net Energy Metering is the difference between electricity supplied through the electric grid and electricity generated by an eligible Customer-generator and fed back to the electric grid over a 12-month period.

BILLING

An eligible residential or small commercial Customer-generator shall be billed, at the end of the 12-month period following the date of the Utility's final interconnection of their system, and on the anniversary date thereafter, for electricity used during that period. The Utility shall determine if the eligible Customer-generator was a net consumer or a net producer of electricity during that time period.

If the electricity supplied by the Utility exceeds the electricity generated by the eligible residential or small commercial Customer-generator, the eligible residential or small commercial Customer-generator is a net energy consumer and shall be billed for the net energy supplied to the Utility as follows:

For eligible Customer-generators taking service under tariffs employing "baseline" and "over baseline" rates, any net monthly consumption of electricity shall be calculated according to the terms of the contract or tariff to which the same Customer would be assigned to if the customer did not use an eligible solar or wind electrical generating facility, except that eligible Customer-generators shall not be assessed standby charges on the electrical generating capacity or the kilowatthour production of an eligible solar or wind electrical generating facility. If those same Customer-generators are net generators over a billing period, the net kilowatthours generated shall be valued at the same price per kilowatthour as the Utility would charge for the baseline quantity of electricity during that billing period, and if the number of kilowatthours generated exceeds the baseline quantity, the excess shall be valued at the same price per kilowatthour as the Utility would charge for electricity over the baseline quantity during that billing period.

(Continued)

Issued by

Advice Letter No.	311-E	D. Douglas Larson Name	Date Filed	November 20, 2002
Decision No.		VP, Regulation Title	Effective	January 1, 2003
TF6 NEM-35-1.E			Resolution No.	

Pacific Power & Light Company		Revised	Cal.P.U.C.Sheet No.	2370-E
Portland, Oregon	Canceling	Revised	Cal.P.U.C.Sheet No.	2357-E

Schedule No. NEM-35

NET METERING SERVICE
(Continued)

BILLING (continued)

For eligible Customer-generators taking service under tariffs employing "time of use" rates, any net monthly consumption of electricity shall be calculated according to the terms of the contract or tariff to which the same Customer would be assigned to if the customer did not use an eligible solar or wind electical generating facility, except that eligible customer-generators shall not be assessed standby charges on the electrical generating capacity or the kilowatthour procustion of an eligible solar or wind electrical generating facility. When those same Customer-generators are net generators during any discrete time of use period, the net kilowatthours produced shall be valued at the same price per kilowatthour as the Utility would charge for retail kilowatthour sales during that same time of use period.

For all residential or small commercial Customer-generators and for each monthly period, the net balance of moneys owed to the Utility for net consumption of electricity or credits owed to the Customer-generator for net generation of electricity shall be carried forward until the end of each 12-month period.

For all commercial, industrial, and agricultural Customer-generators the net balance of moneys owed shall be paid in accordance with the electric service provider's normal billing cycle, except that if the commercial, industrial, or agricultural customer-generator is a net electricity producer over a normal billing cycle, any excess kilowatthours generated during the billing cycle shall be carried over to the following billing period as a monetary value, calculated according to the same procedure as for residential and small commercial Customer-generators, and appear as a credit on the Customer-generator's account, until the end of the 12-month period.

If the electricity generated by the eligible Customer-generator exceeds the electricity supplied by the Utility, the eligible Customer-generator is a net energy producer and the Utility shall retain any excess kWh generated during the prior 12-month period.

SPECIAL CONDITIONS

1. The annualized net energy metering calculation shall be made by measuring the difference between the electricity supplied to the eligible Customer-generator and the electricity generated by the eligible Customer-generator and fed back to the electric grid over a 12-month period. In the event the energy generated exceeds the energy consumed during the 12-month period, no payment will be made for the excess energy delivered to the Utility's grid. If the Utility is the Customer's Electric Service Provider, this condition may be modified where the Customer has a signed contract to sell any portion of the Customer generated energy to the Utility.

(Continued)

Issued by

Advice Letter No.	311-E	D. Douglas Larson Name	Date Filed	November 20, 2002
Decision No.		VP, Regulation Title	Effective	January 1, 2003

TF6 NEM-35-2.E

Resolution No.

Pacific Power & Light Company		Revised	Cal.P.U.C.Sheet No.	2371-E
Portland, Oregon	Canceling	Original	Cal.P.U.C.Sheet No.	2314-E

Schedule No. NEM-35

NET METERING SERVICE
(Continued)

SPECIAL CONDITIONS (continued)

2. If the Utility is not the Customer's Electric Service Provider, the Utility may recover from the Customer-generator's Electric Service Provider the incremental costs of metering and billing service related to net energy metering in an amount set by the Commission.

3. Net Energy Metering shall be accomplished using a single meter capable of registering the flow of electricity in two directions. An additional meter or meters to monitor the flow of electricity in each direction may be installed with the consent of the customer-generator, at the expense of the Company, and the additional metering shall be used only to provide the information necessary to accurately bill or credit the customer-generator or to collect solar or wind electric generating system performance information for research purposes. If the existing electrical meter of an eligible customer-generator is not capable of measuring the flow of electricity in two directions, the customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is able to measure electricity flow in two directions.

4. If the Customer-generator refuses consent for dual metering, and due to billing purposes a single bi-directional meter cannot be installed, the Utility shall have the right to refuse interconnection.

5. Customer shall furnish and install on Customer's side of the meter a safety disconnect switch which shall be capable of fully disconnecting the Customer's energy generating equipment from the Utility's electric service. The disconnect switch shall be located adjacent to the Utility's meters and shall be of the visible break type in a metal enclosure which can be secured by a padlock. The disconnect switch shall be accessible to utility personnel at all times. The Utility shall have the right to disconnect the Facility from The Utility's supply at the disconnect switch when necessary to maintain safe electrical operating conditions or, if in The Utility's sole judgement, the Facility at any time adversely affects The Utility's operation of its electrical system or the quality of The Utility's service to other Customers.

6. If the Utility is the Customer's Electric Service Provider, the Utility shall provide net electricity consumption information on each regular bill to every eligible residential or small commercial Customer-generator. The consumption information shall contain the current monetary balance owed to the Utility for net electricity delivered/consumed since the last 12-month period ended. The Utility shall permit the Customer to pay monthly for net energy delivered/consumed.

(Continued)

Issued by

Advice Letter No.	311-E	D. Douglas Larson Name	Date Filed	November 20, 2002
Decision No.		VP, Regulation Title	Effective	January 1, 2003
TF6 NEM-35-3.E			Resolution No.	

Pacific Power & Light Company Original Cal.P.U.C.Sheet No. 2372-E
Portland, Oregon Canceling Cal.P.U.C.Sheet No.

Schedule No. NEM-35

NET METERING SERVICE
(Continued)

SPECIAL CONDITIONS (continued)

7. A net metering system used by a Customer shall include, at the Customer's own expense, all equipment necessary to meet applicable safety, power quality, and interconnection requirements established by the National Electrical Code, National Electrical Safety Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories. The Utility's written approval of the Customer's protection-isolation method to ensure generator disconnection in case of a power interruption from the Utility is required before service is provided under this Schedule.

8. Notwithstanding any other provisions within this Schedule, any wind energy project greater than 50 kW, but not exceeding one megawatt ("wind energy co-metering") shall be subject to the following additional requirements:

   The eligible customer-generator shall be required to utilize a meter, or multiple meters, capable of separately measuring electricity flow in both directions. All meters shall provide "time-of-use" measurements of electricity flow, and the customer shall take service on a time-of-use rate schedule. If the existing meter of the eligible customer generator is not a time-of-use meter or is not capable of measuring total flow of energy in both directions, the eligible customer-generator is responsible for all expenses involved in purchasing and installing a meter that is both time-of-use and able to measure total electricity flow in both directions. This condition shall not restrict the ability of an eligible customer-generator to utilize any economic incentives provided by a government agency or the electric service provider to reduce its costs for purchasing and installing a time-of-use meter.

   The consumption of electricity from the Utility for wind energy co-metering by an eligible customer-generator shall be priced in accordance with the standard rate charged to the eligible customer-generator in accordance with the rate structure to which the customer would be assigned if the customer did not use an eligible wind electrical generating facility. The generation of electricity provided to the Utility shall result in a credit to the eligible customer-generator and shall be priced in accordance with the generation component established under the applicable structure to which the customer would be assigned if the customer did not use an eligible wind electrical generating facility.

(Continued)

Issued by

Advice Letter No. 311-E D. Douglas Larson Date Filed November 20, 2002
Name
Decision No. VP, Regulation Effective January 1, 2003
Title

TF6 NEM-35-4.E Resolution No.

Pacific Power & Light Company
Portland, Oregon

Original Cal.P.U.C.Sheet No. 2373-E
Canceling Cal.P.U.C.Sheet No.

Schedule No. NEM-35

NET METERING SERVICE
(Continued)

SPECIAL CONDITIONS (continued)

9. The Utility shall make all necessary forms and contracts for net metering service available for download from its website.

10. The Utility shall ensure that requests for establishment of net energy metering are processed in a time period not exceeding that for similarly situated customers requesting new electric service, but not to exceed 30 working days from the date the Utility receives a completed application form for net metering service, including a signed interconnection agreement from an eligible customer-generator and the electric inspection clearance from the governmental authority having jurisdiction. If the Utility is unable to process the request within the allowable timeframe, the Utility shall notify both the customer-generator and the Commission of the reason for its inability to process the request and the expected completion date.

11. The Utility shall ensure that requests for an interconnection agreement from an eligible customer-generator are processed in a time period not to exceed 30 working days from the date the Utility receives a completed application form from the eligible customer-generator for an interconnection agreement. If the Utility is unable to process the request within the allowable timeframe, the Utility shall notify the customer-generator and the Commission of the reason for its inability to process the request and the expected completion date.

Issued by

Advice Letter No. 311-E — D. Douglas Larson (Name) — Date Filed November 20, 2002

Decision No. — VP, Regulation (Title) — Effective January 1, 2003

TF6 NEM-35-5.E

Resolution No.

Appendix XIV PP&L Tariff Schedules for Rancheria

Pacific Power & Light Company — Revised Cal.P.U.C.Sheet No. 2758-E
Portland, Oregon — Canceling Revised Cal.P.U.C.Sheet No. 2455-E

Schedule No. A-25

GENERAL SERVICE
LESS THAN 20 KW

APPLICABILITY

Applicable to single-phase or three-phase alternating current electric service, at such voltage as the Utility may have available at the Customer's premises, for all electric service loads which have not registered 20 kW or more, more than once in any consecutive 18 month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this Schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for Customer's electric generation or other energy sources.

Non-profit group living facilities taking service under this Schedule may be eligible for a twenty percent (20%) low-income rate discount on their monthly bill, if such facilities qualify to receive service under the terms and conditions of Schedule No. AL-6.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94.

	Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate
Basic Charge						
Single-Phase/Month	$10.00					$10.00
Three-Phase/Month	$13.75					$13.75
Energy Charge/kWh for all kWh	4.427¢	0.457¢	0.134¢	3.659¢	0.262¢	8.939¢

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100 and Schedule S-191.

Minimum Monthly Charge

The monthly Minimum Charge shall be the Basic Charge for the current month. A higher minimum may be required under contract to cover special conditions.

(Continued)

Issued by

Advice Letter No. 337-E — Andrea L. Kelly (Name) — Date Filed December 21, 2006

Decision No. (D)06-12-011, (D)06-12-036 — VP, Regulation (Title) — Effective January 1, 2007

TF6 A-25-1.E — Resolution No.

Pacific Power & Light Company | Revised Cal.P.U.C.Sheet No. 2759-E
Portland, Oregon | Canceling Revised Cal.P.U.C.Sheet No. 1437-E

Schedule No. A-25

GENERAL SERVICE
LESS THAN 20 KW
(Continued)

GENERATION AND TRANSMISSION DEMAND

The Generation and Transmission Demand shall be the maximum measured 15-minute integrated demand in kilowatts occurring during the month.

SPECIAL CONDITIONS

At the utility's option, a demand meter will be installed when the utility estimates that a customer's demand may exceed 20 kw per month.

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a customer from minimum monthly charges.

TERM OF CONTRACT

Not less than one year.

RULES AND REGULATIONS

Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

Issued by

Advice Letter No. 337-E | Andrea L. Kelly (Name) | Date Filed December 21, 2006

Decision No. (D)06-12-011 (D)06-12-036 | VP, Regulation (Title) | Effective January 1, 2007

TF6 A-25-2.E | Resolution No. ______

Pacific Power & Light Company		Revised	Cal.P.U.C.Sheet No. 2760-E
Portland, Oregon	Canceling	Revised	Cal.P.U.C.Sheet No. 2456-E

Schedule No. A-32

GENERAL SERVICE
20 kW AND OVER

APPLICABILITY

Applicable to single-phase or three-phase alternating current electric service, at such voltage as the Utility may have available at the Customer's premises, for electric service loads which have ever registered 20 kW or more, more than once in any consecutive 18 month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for Customer's electric generation or other energy sources.

Non-profit group living facilities taking service under this Schedule may be eligible for a twenty percent (20%) low-income rate discount on their monthly bill, if such facilities qualify to receive service under the terms and conditions of Schedule No. AL-6.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Distribution Demand, Generation and Transmission Demand, Energy, and Reactive Power Charges; plus Delivery and Metering Adjustments.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All monthly billings shall be adjusted in accordance with Schedule ECAC-94.

	Distrib.	**FERC Trans.**	**Calif. Trans.**	**Gener-ation**	**Public Purpose**	**Total Rate**
Basic Charge						
Single-Phase/Month	$10.00					$10.00
Three-Phase/Month	$13.75					$13.75
Distribution Demand Charge/kW	$1.25					$1.25
Generation & Transmission Demand Charge/kW		$1.45	$0.30	($0.90)		$.85
Reactive Power Charge/kVar				60.000¢		60.000¢
Energy Charge/kWh for all kWh	3.002¢			3.635¢	0.252¢	6.889¢

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100 and Schedule S-191.

(Continued)

Issued by

Advice Letter No.	337-E	Andrea L. Kelly (Name)	Date Filed	December 21, 2006
Decision No.	(D)06-12-011 (D)06-12-036	VP, Regulation (Title)	Effective	January 1, 2007

TF6 A-32-1.E Resolution No.

Pacific Power & Light Company		Revised	Cal.P.U.C.Sheet No.	1921-E
Portland, Oregon	Canceling	Revised	Cal.P.U.C.Sheet No.	1740-E

Schedule No. A-32

GENERAL SERVICE
20 kW AND OVER
(Continued)

Minimum Charge:

The Monthly Minimum Charge shall be the sum of the Basic Charge, the Generation and Transmission Demand Charge, and the Distribution Demand Charge for the current month. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge:

The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 40% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 60¢ per kvar of such excess reactive demand.

DELIVERY AND METERING VOLTAGE ADJUSTMENTS

The above monthly charges are applicable without adjustment for voltage when delivery and metering are at Company's standard secondary distribution voltage.

Metering: For so long as metering voltage is at Company's available primary distribution voltage of 11 kV or greater, the above energy charges except for the Schedule S-99 Reimbursement Fee, will be reduced by 1.0%. A Primary Metering Charge of $60 per month will be added where such deliveries are metered at the delivery voltage.

Delivery: For so long as delivery voltage is at Company's available primary distribution voltage of 11 kV or greater, the above Distribution Demand Charges will be reduced by 30.0%.

When a new delivery or an increase in capacity for an existing delivery is, at request of customer, made by means of Company-owned transformers at a voltage other than a locally standard distribution voltage, the above Distribution Demand Charges for any month will be increased by 30.0%.

Company retains the right to change its line voltage or classifications thereof at any time, and after reasonable advance notice to any customer affected by such change, such customer then has the option to take service at the new line voltage or to accept service through transformers to be supplied by Company subject to the voltage adjustments above.

(Continued)

Issued by

Advice Letter No.	255-E	Robert V. Sirvaitis Name	Date Filed	12/10/93
Decision No.	93-12-016	Director, Pricing Title	Effective	1/1/94

TF6 A-32-2.E

Resolution No. ____________

Pacific Power & Light Company		Revised	Cal.P.U.C.Sheet No.	2761-E
Portland, Oregon	Canceling	Original	Cal.P.U.C.Sheet No.	1992-E

Schedule No. A-32

GENERAL SERVICE
20 kW AND OVER
(Continued)

DISTRIBUTION DEMAND

The Distribution Demand shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

GENERATION AND TRANSMISSION DEMAND

The Generation and Transmission Demand shall be the maximum measured 15-minute integrated demand in kilowatts occurring during the month.

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal customer from minimum monthly charges.

TERM OF CONTRACT

Not less than one year.

RULES AND REGULATIONS

Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

Issued by

Advice Letter No.	337-E	Andrea L. Kelly	Date Filed	December 21, 2006
		Name		
Decision No.	(D)06-12-011 (D)06-12-036	VP, Regulation	Effective	January 1, 2007
		Title		

TF6 A-32-3.E Resolution No.

Pacific Power & Light Company — Revised Cal.P.U.C.Sheet No. 2762-E
Portland, Oregon — Canceling Revised Cal.P.U.C.Sheet No. 2457-E

Schedule No. A-36

LARGE GENERAL SERVICE - Optional
100 KW AND OVER

APPLICABILITY

Applicable to electric service loads which have not registered less than 20 kW or more than 500 kW more than once in a consecutive 18-month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this Schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for Customer's electric generation or other energy sources.

Non-profit group living facilities taking service under this Schedule may be eligible for a twenty percent (20%) low-income rate discount on their monthly bill, if such facilities qualify to receive service under the terms and conditions of Schedule No. AL-6.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Distribution Demand, Generation and Transmission Demand, Energy, and Reactive Power Charges; plus Delivery and Metering Adjustments.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94.

	Distrib.	**FERC Trans.**	**Calif. Trans.**	**Generation**	**Public Purpose**	**Total Rate**
Basic Charge	$180.00					$180.00
Distribution Demand Charge/kW	$2.30					$2.30
Generation & Transmission Demand Charge/kW		$1.45	$0.15	$0.70		$2.30
Reactive Power Charge/kVar				60.000¢		60.000¢
Energy Charge/kWh for all kWh	1.894¢			2.524¢	0.261¢	4.679¢

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100, and Schedule S-191.

(Continued)

Issued by

Advice Letter No. 337-E — Andrea L. Kelly (Name) — Date Filed December 21, 2006

Decision No. (D)06-12-011 (D)06-12-036 — VP, Regulation (Title) — Effective January 1, 2007

TF6 A-36-1.E — Resolution No.

Pacific Power & Light Company Revised Cal.P.U.C.Sheet No. 1924-E
Portland, Oregon Canceling Revised Cal.P.U.C.Sheet No. 1444-E

Schedule No. A-36

LARGE GENERAL SERVICE - Optional
100 KW AND OVER
(Continued)

Minimum Charge:
Monthly Minimum Charge shall be the Basic Charge plus the Generation and Transmission Demand Charge and the Distribution Demand Charge for the current month. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge:
The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 40% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 60¢ per kvar of such excess reactive demand.

DELIVERY AND METERING VOLTAGE ADJUSTMENTS
The above monthly charges are applicable without adjustment for voltage when delivery and metering are at Company's standard secondary distribution voltage.

Metering: For so long as metering voltage is at Company's available primary distribution voltage of 11 kV or greater, the above energy charges except for the Schedule S-99 Reimbursement Fee, will be reduced by 1.0%. A Primary Metering Charge of $60 per month will be added where such deliveries are metered at the delivery voltage.

Delivery: For so long as delivery voltage is at Company's available primary distribution voltage of 11 kV or greater, the above Distribution Demand Charges will be reduced by 30.0%.

When a new delivery or an increase in capacity for an existing delivery is, at request of customer, made by means of Company-owned transformers at a voltage other than a locally standard distribution voltage, the above Distribution Demand Charges for any month will be increased by 30.0%.

Company retains the right to change its line voltage or classifications thereof at any time, and after reasonable advance notice to any customer affected by such change, such customer then has the option to take service at the new line voltage or to accept service through transformers to be supplied by Company subject to the voltage adjustments above.

(Continued)

Issued by

Advice Letter No. 255-E Robert V. Sirvaitis Date Filed 12/10/93
Name
Decision No. 93-12-016 Director, Pricing Effective 1/1/94
Title

TF6 A-36-2.E Resolution No.____________

Schedule No. A-36

LARGE GENERAL SERVICE - Optional
100 KW AND OVER
(Continued)

DISTRIBUTION DEMAND
The Distribution Demand shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

GENERATION AND TRANSMISSION DEMAND
The Generation and Transmission Demand shall be the maximum measured 15-minute integrated demand in kilowatts occurring during the month.

CONTINUING SERVICE
Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal customer from minimum monthly charges.

TERM OF CONTRACT
Utility may require customer to sign a written contract which will have a term of not less than five years.

RULES AND REGULATIONS
Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

(Continued)