In-City Renewable Resource Executive Summary for the Theoretical, Technical, and Economic Potential for Renewable Energy Resource Development in the City and County of San Francisco as part of the CCA Program (Task 1 of 5 and Task 2 of 5 Reports)

(DRAFT)

Prepared for the
San Francisco
Public Utilities Commission

August 11, 2009

Contract No.: **CS No.: CS-920R-A**

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I. Introduction to Task 1 and Task 2 Reports

The San Francisco Public Utilities Commission (SFPUC) retained George E. Sansoucy, P.E., LLC (GES) to prepare a series of reports on the theoretical, technical, and economic potential for renewable energy resource development in the City and County of San Francisco (CCSF). These draft reports are the first step in assessing in-city resources relative to out-of-city options. The draft reports are working documents that are anticipated to be used in conjunction with subsequent reports that assess the availability and economics of out-of-city supply options.

The purpose of these reports is to assess the availability and economic potential of renewable energy resources within the CCSF that could be utilized as a component of the Community Choice Aggregation (CCA) program. The reports will be kept in draft format until all five tasks are completed and reviewed by the SFPUC.

II. Theoretical and Technical Potential for Renewable Energy Resource Development in the City and County of San Francisco as part of the CCA Program (Task 1 of 5)

The scope of this analysis involved an initial screening of all commercially available renewable energy technologies considered feasible to deploy within the CCSF jurisdiction. Once these technologies were identified, additional variables such as natural resource availability, technical limitations, land use restrictions, and siting constraints were considered to identify the theoretical and technical potential within the CCSF. The technologies and projects identified as feasible within the CCSF are diverse and provide a wide range of electric supply options capable of meeting the CCA program directives. The technical potential of the six categories is estimated at approximately 300 megawatts (MW) of generation capacity with the ability to produce 1.7 million megawatt-hours (MWh) per year prior to economic constraints.

Table ES-1
Existing and Technical Potential of Renewable Resources in the CCSF Prior to Economic Consideration

Category	Resources Currently Installed in CCSF (MW)[1]	Resources Identified in Report: Technical Potential (MW)	Estimated Annual Energy (MWh)[2]	Average Capacity Factor[3]
Solar PV	7	100	130,000	15%
Wind Power	0.5	15	30,000	23%
Tidal Power	0	3	2,400	10%
Biogas[4]	3	55	435,000	90%
Fuel Cells	0.255	10	43,800	50%
CHP	30	130	1,025,000	90%
Total	**40.8**	**313**	**1,666,200**	

[1] Megawatt (MW): The standard measure of electricity power plant generating capacity. One megawatt is equal to 1,000 kilowatts or 1 million watts.
[2] Megawatt-hour (MWh): A unit or energy or work equal to 1,000 kilowatt-hours or 1 million watt-hours.
[3] Capacity Factor (CF): A measure of the productivity of a power plant, calculated as the amount of energy that the power plant produces over a set time period, divided by the amount of energy that would have been produced if the plant had been running at full capacity during that same time interval.
[4] Biogas assumes transportation into the CCSF via interstate pipeline.

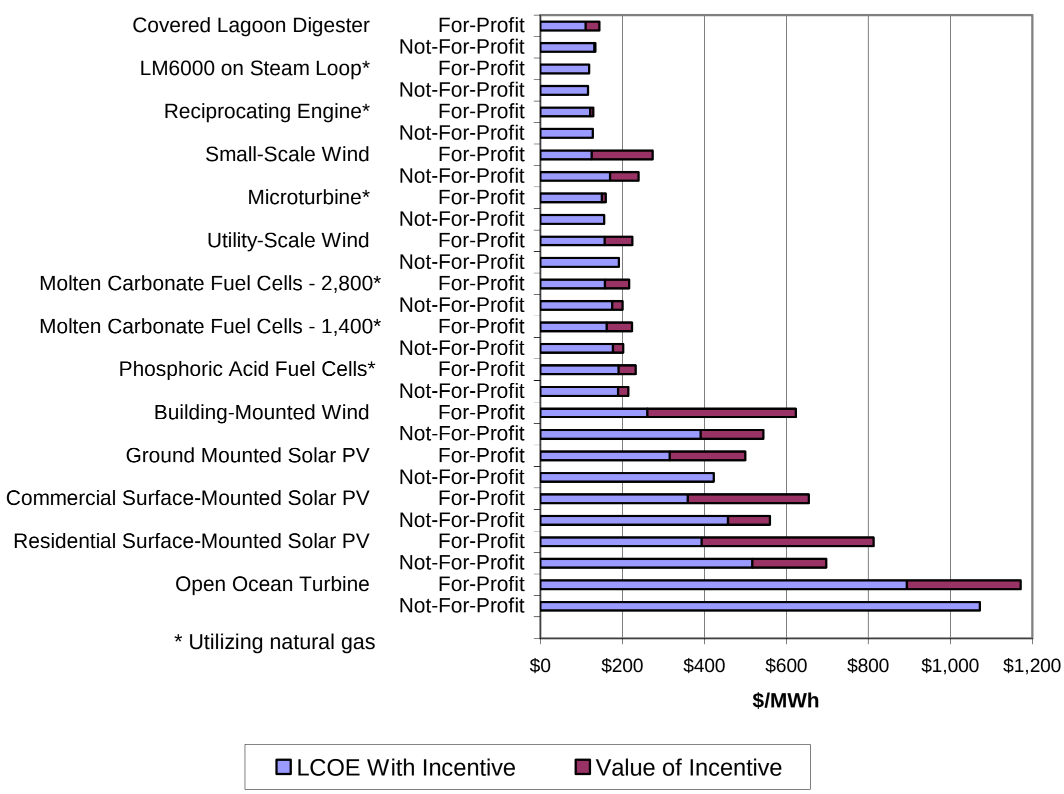
III. Economic Potential for Renewable Energy Resource Development in the City and County of San Francisco as part of the CCA Program (Task 2 of 5)

The economic potential is based on the Levelized Cost of Electricity (LCOE) associated with each technology identified in the Theoretical and Technical Potential (Task 1) Report under two ownership scenarios. The first scenario assumes for-profit ownership with the electricity being delivered to the CCA program via a power purchase agreement (PPA). The second scenario assumes the renewable resource is owned by a not-for-profit entity such as the CCSF or quasi-governmental entity created to own the generation on behalf of the CCA program using H Bonds or other forms of tax exempt revenue bonds to finance these projects. The for-profit scenario allows the owner/developer to utilize all incentives available at the federal level through the U.S. Tax Code. The LCOE, for the purposes of this analysis, is defined as the cost per unit of electricity required to recover the invested capital, cover annual operating and maintenance (O&M) expenses, and provide debt and equity investors their respective rates of return.

The LCOE of the theoretically and technically possible renewable energy resources identified in the Task 1 report was developed using the spreadsheet models developed by GES. A separate model was developed for each ownership structure that addresses the capital structure and ability of each ownership type to take advantage of incentives available to renewable resources. The model calculates the LCOE of each renewable resource over a 20-year period, which is a typical period for this type of analysis, based on resource-specific cost and operating data and market-based assumptions about financing, federal and State tax liability or benefits, and other incentives available to each technology. The 20-year period is selected to reflect typical useful lives of projects, debt financing periods which typically do not exceed 20 years, and is a long enough period to reflect future costs associated with each unit relative to other market alternatives. The for-profit model minimizes the LCOE while maintaining debt financing requirements and equity returns necessary to satisfy investor requirements. The not-for-profit model develops the LCOE by calculating the revenue requirements associated with each project assuming 100% debt financing and no federal or State income tax benefits or liability.

The results of each analysis are set forth in Figure ES-1. A general discussion of these results is provided below along with a summary of the assumptions and results for each resource category.

Figure ES-1
Levelized Cost of Electricity (LCOE)
Including Incentives and LCOE Without Incentives
(in ascending order by For-Profit)



The LCOEs shown in Figure ES-1 illustrate the total cost of each resource with and without incentives utilizing an LCOE spreadsheet model designed to minimize the cost of electricity. The LCOE for each resource is presented based on for- and not-for-profit ownership structures and takes into account the value of the various federal, state, and local incentives. The LCOE with incentives represents the price at which these resources could provide power to the CCA program utilizing the existing incentives. The total LCOE is presented to measure the total cost of the resources absent any incentives.

Theoretical and Technical Potential for Renewable Energy Resource Development in the City and County of San Francisco as part of the CCA Program (Task 1 of 5)

(DRAFT REPORT)

Prepared for the
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Acronyms

AC	Alternating Current
AD	Anaerobic Digestion
BAA QMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
CAISO	California ISO
CCA	Community Choice Aggregation
CCSF	City and County of San Francisco
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DBI	Department of Building Inspection
DC	Direct Current
EPC	Environmental Power Corporation
EPRI	Electric Power Research Institute
ERP	Energy Renewable Program
FERC	Federal Energy Regulatory Commission
GES	George E. Sansoucy, P.E., LLC
GHG	Greenhouse Gases
HRA	HRA Engineering
HRSG	Heat Recovery Steam Generator
IOU	Investor-Owned Utilities
ITC	Investment Tax Credit
kW	Kilowatts
kWh	Kilowatt-hours
kWh/m^2-day	Kilowatt-hours per square meter per day
MACRS	Modified Accelerated Cost Recovery System
MCFC	Molten Carbonate Fuel Cells

MW	Megawatts
MWh	Megawatt-hours
NEPA	National Environmental Policy Act
NREL	National Renewable Energy Laboratory
NRG	NRG Thermal LLC
PAFC	Phosphoric Acid Fuel Cells
PEMFC	Proton Exchange Membrane Fuel Cells
PG&E	Pacific Gas and Electric Company
PTC	Production Tax Credits
PV	Photovoltaic
RPS	Renewable Portfolio Standards
SCR	Selective Catalytic Reduction
SF Bay	San Francisco Bay
SF Environment	San Francisco Department of the Environment
SFPUC	San Francisco Public Utilities Commission
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SOFC	Solid Oxide Fuel Cells
TPY	Tons per year
W/m^2	Watts per square meter
WWTP	Wastewater Treatment Plant

1.1 Overview of Theoretical and Technical Potential

George E. Sansoucy, P.E., LLC (GES) was retained by the San Francisco Public Utilities Commission (SFPUC) to prepare a report on the theoretical and technical potential for renewable energy resource development in the City and County of San Francisco (CCSF) as part of its Community Choice Aggregation (CCA) program.

Theoretical and Technical Potential of Each Resource Category Considered Feasible for In-City Development

Resource Category	Potential
• Solar	Moderate to High
• Wind	Low
• Tidal	Low
• Biogas Generation	Moderate to High
• Fuel Cells	Moderate
• Combined Heat and Power (CHP)	Moderate to High

The purpose of this report is to assess the availability of renewable energy resources within the CCSF that could be utilized as a component of the CCA program. In particular, this report addresses the ability to "roll-out" renewable energy resources within the CCSF jurisdiction. These resources are being considered as one component of a larger resource mix to satisfy the electric needs of CCA program participants. Subsequent reports commissioned by the SFPUC address out-of-city renewable resource alternatives, the economics of the roll-out, and the potential impact on the CCA program rates relative to those expected to be charged by Pacific Gas and Electric Company (PG&E).

The scope of this analysis involved an initial screening of all commercially available renewable energy technologies considered feasible to deploy within the CCSF jurisdiction. Once these technologies were identified, additional variables such as natural resource availability, technical limitations, land use restrictions, and siting constraints were considered to identify the theoretical and technical potential within the CCSF. The results of this analysis identified the following six general resource categories which could be deployed within the CCSF: solar, wind, tidal, biogas delivered from out-of-city resources to be used in-city, fuel cells, and combined heat and power (CHP).[1]

Theoretical potential represents the total resources capable of being deployed without consideration of land use, resource availability, or other non-economic factors. Technical potential represents the subset of the theoretical potential after considerations

[1] Fuel cells and CHP or cogeneration, fired utilizing a renewable fuel source such as biogas, are considered a renewable resource. However, even utilizing a natural gas cogeneration or CHP resource typically creates environmental benefits due to the high operating efficiency and has, for this reason, been included in this report. All biogas estimates are based on in-city generation utilizing out-of-city biogas resources with delivery to the CCSF via pipeline.

are made for land use restrictions, siting constraints, regulatory prohibitions, and natural resource availability. The technologies and projects identified as feasible within the CCSF are diverse and provide a wide range of electric supply options capable of meeting the CCA program directives. The technical potential of the six categories is estimated at approximately 300 megawatts (MW) of generation capacity with the ability to produce 1.7 million megawatt-hours (MWh) per year prior to economic constraints which are addressed in a subsequent Task 2 economic potential report commissioned by the SFPUC.

Examples of the resources considered include: 1 kilowatt (kW) wind turbines capable of operating ten 100 watt light bulbs when resources permit, a 400 kW fuel cell capable of providing sufficient electricity for a small office tower, and a 50 MW CHP unit that could power a significant portion of the downtown. Table 1-1 is a summary of the six categories and provides a comparison of the existing capacity and the potential capacity and estimated annual generation by resource type that are technically possible within the CCSF. The biogas generation potential assumes out-of-city production and transportation to in-city generation via pipeline. The resources identified below represent only supply options and do not contemplate energy efficient technologies or demand-side management which would be complementary to these supply-side resources.

Table 1-1
Existing and Technical Potential
of Renewable Resources in the CCSF
Prior to Economic Consideration

Category	Resources Currently Installed in CCSF (MW)[1]	Resources Identified in Report		
		Technical Potential (MW)	Estimated Annual Energy (MWh)[2]	Average Capacity Factor[3]
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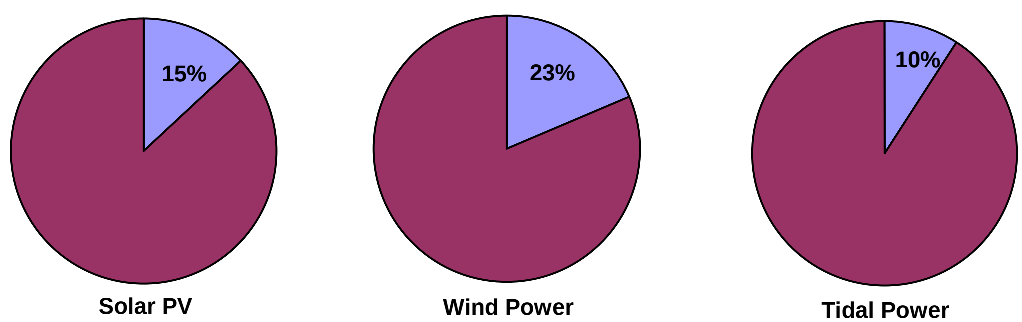
[4] Biogas assumes transportation into the CCSF via interstate pipeline.

As illustrated in Table 1-1, solar and CHP systems have the greatest potential due to high levels of solar energy and the number of potential hosts for CHP systems. Tidal and wind power systems have the least potential in the CCSF due to low wind strengths and limited tidal resources for deployment of these technologies.

Table 1-1 also demonstrates the annual potential of each resource to satisfy customer demand based on available generation which is directly related to available resources. Solar, wind, and tidal resources are considered intermittent and are at the mercy of Mother Nature for their annual generation, which in the CCSF is between 10 and 25% of their annual potential. Figure 1-1 illustrates the amount of the year each intermittent resource is capable of operating at full output and the amount of generation that an alternative source will have to provide in meeting customer demand.

Figure 1-1
Percent of the Year Each Resource
Is Capable of Operating at Full Output



The approximately 300 MW of in-city supply-side resources that are considered technically possible correspond to approximately 1.7 million MWh of annual generation and represents a reasonable assessment of in-city resources the CCA program could utilize in meeting its program directives.

Subsequent reports will address the economic potential and viability of these resources in the CCA program and the impact on customer rates. The results of these subsequent reports are anticipated to reduce the total technical resources based on economic constraints associated with the price of electricity necessary to justify the construction of each resource. The results of the economic potential report (Task 2) will provide a more realistic estimate of in-city supply-side resources that could be utilized in connection with the CCA program.

2.1 Theoretical and Technical Potential Introduction

The San Francisco Public Utilities Commission (SFPUC) retained George E. Sansoucy, P.E., LLC (GES) to prepare this report on the theoretical and technical potential for renewable energy resources that could be developed within the City and County of San Francisco (CCSF). This report is intended to assist the SFPUC in assessing the potential resources that could be deployed in the CCSF and included as supply resources for its Community Choice Aggregation (CCA) program. This program calls for 360 megawatts (MW) of renewable, distributed generation or energy efficiency measures to be included as part of the supply mix serving customer loads, with approximately 210 of the total 360 MW preferred within the jurisdictional boundaries of the CCSF. The 210 MW of in-city resources include 31 MW of solar, 72 MW of local renewables, and 107 MW of local energy efficiency.

Purpose and Use of Report

- This report investigates the theoretical and technical potential for in-city resources as a component of the 360 MW roll-out and 51% Renewable Portfolio Standards.
- Subsequent reports will address out-of-city renewable resources and the potential economic impact on CCA program rates relative to various mixes of renewable resources.

The 360 MW roll-out of renewable resources is just one component of a larger electric portfolio that will be required to serve the CCA program customers. Assuming that 100% of the customers taking service from Pacific Gas and Electric Company (PG&E) within the CCSF were served by the CCA program, the program portfolio would need approximately 750 MW of capacity with electric deliveries in the range of 3.5 million megawatt-hours (MWh) per year. In addition to the overall procurement requirements, the program calls for 51% of the 3.5 million MWh delivered annually to be produced by renewable resources by 2017, or 1.8 million MWh per year of renewable energy. In comparison, the statewide average for renewable resources is approximately 12%.[2] This almost five-fold increase in renewable requirements over PG&E's current delivery of renewable resources is an ambitious goal that will require the CCA program to look both within and outside of the CCSF to procure a sufficient level of renewable resources.

This report (Task 1 of 5) is the first in a series that will address the feasibility, cost, and rate consequences of the in-city renewable resource roll-out and the 51% renewable energy requirements by 2017. The subsequent tasks are summarized as follows:

[2] http://www.energy.ca.gov/renewables/index.html

- Task 2 includes the economic potential of those resources considered theoretically and technically viable within the CCSF. This task will address the cost of these resources to CCA program customers using the estimated capital cost, operating and maintenance expense, and financial incentive for each of the resources selected and analyze the use of both for-profit and not-for-profit capital structures and financing.

- Task 3 includes an analysis of out-of-city renewable resources and the cost to CCA program customers relative to the in-city resources identified in Tasks 1 and 2. This task assesses the cost of those resources in a manner identical to that used in Task 2.

- Task 4 is a comparison of the information and costs developed in Tasks 1 through 3 relative to whether these resources are cost effective and allow the CCA program to "meet or beat" PG&E's expected rates for CCA program customers.

- Task 5 is a report setting forth any recommendations that could enhance the CCA program based on the investigations and analyses set forth in Tasks 1 through 4.

2.2 CCA Program Background Discussion

In 2004, the CCSF elected to institute a CCA program and provide electric and other related services to its constituents located within its jurisdiction. The program proposed by the CCSF is one of the most ambitious in the nation and seeks to establish renewable energy standards more stringent than those adopted by the State of California (State). The CCA program has a specific bidding requirement relative to a defined 360 MW roll-out of resources that may be incorporated into the supply portfolio used to provide electricity to the CCA participants. This bidding requirement calls for a specified amount of renewable energy resources, efficiency, and conservation measures that would be included in the 360 MW roll-out. The CCA program is also designed to attain a 51% renewable portfolio standard (RPS) by 2017 and will exceed the green power requirements imposed on investor-owned utilities (IOU) like PG&E which are required to have 20% RPS by 2010 as established in the State's energy action plan and approved by the California Public Utilities Commission (CPUC).

In 2007, San Francisco adopted Ordinances 146-07 and 147-07 which call for a bidding requirement associated with the roll-out of 360 MW of renewable energy resources. This requirement is as follows:

> "A CCA RFP will set as a bidding requirement that each qualifying energy supplier must include within its proposed rates, including all costs, a rollout of 360 Megawatts (MW) of renewable electric resources,

> comprised of at least 31 MW of solar photovoltaic cells, 72 MW of local renewable distributed generation such as fuel cells, and 107 MW of local energy efficiency and conservation measures, along with investment in a 150 MW wind turbine farm, all of which may be financed with City revenue bonds issued without voter approval pursuant to Charter Section 9.107.8, to the extent feasible."[3]

The bidding requirements set forth by the city ordinance may necessitate the addition of new resources and/or conservation within the CCSF and potentially require additional transmission infrastructure and/or interconnections. This report addresses the theoretical and technical potential for these new renewable energy resources within the CCSF.

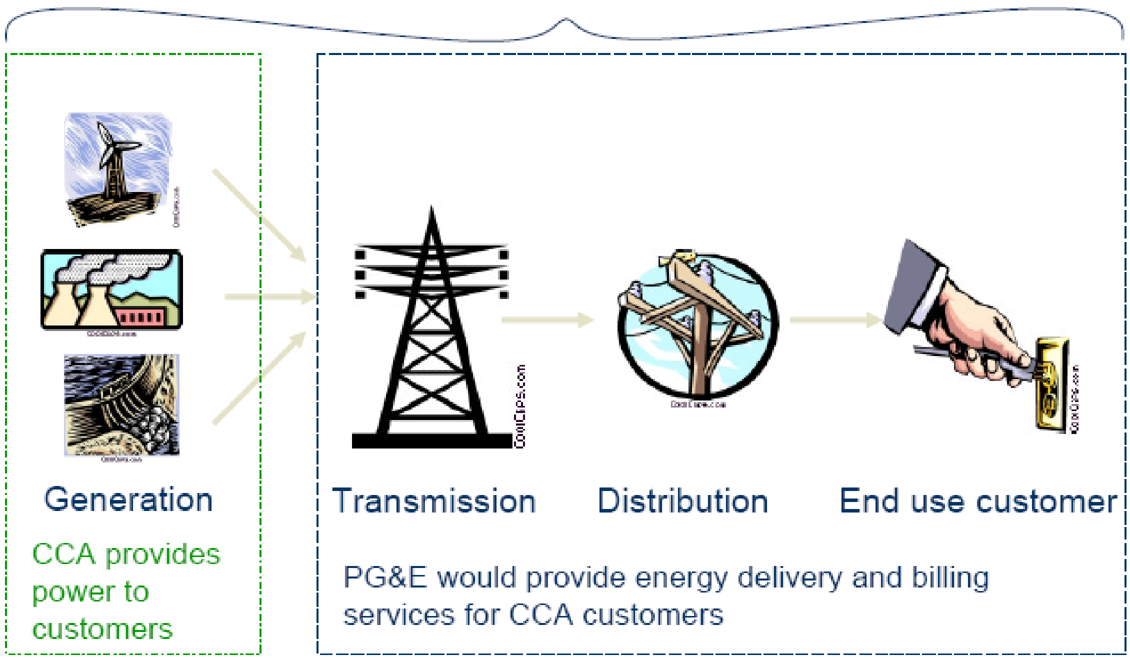
2.3 Resource Types Necessary to Serve the CCA Customer Program

The implementation of the CCA program will require that, among other things, sufficient electric resources are available to serve the program customers. PG&E will no longer be responsible for supplying the resources necessary to serve the customers that are part of the CCA program, but will be responsible for the transmission and distribution of the electricity as well as meter reading and billing. The expectation is that the CCA program supply mix will utilize a wide range of renewable and non-renewable supply-side resources as well as energy efficiency and demand-side management programs to ensure that the electricity delivered to its customers is cost effective, reliable, and meets the criteria set forth by the CCA program directives.

In order to understand the range of potential supply- and demand-side resources required to serve the CCA program customers' electric requirements, it is helpful to understand the basics of electric delivery and the responsibility of both the CCA program and PG&E in ensuring reliable and cost effective service to customers within the CCSF. The electric system can be broken down into three basic components which are 1) supply or generation, 2) transmission, and 3) distribution. All three of these components are necessary for reliable electric delivery to the customer. Figure 2-1 is an illustration of the components necessary for the operation of a complete electric system and the responsibility of both the CCA program and PG&E.

[3] San Francisco Board of Supervisors Ordinance Number 147-07, 6/12/07, p. 4.

Figure 2-1
Illustration of Electric System Components



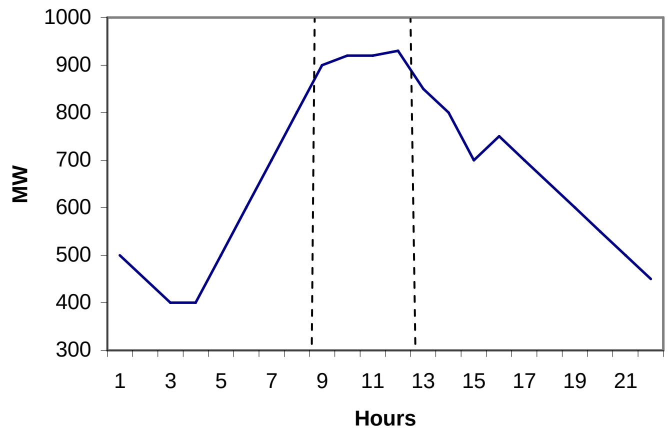
Source: SFPUC Power Enterprise *Community Choice Aggregation Program Status Update, February 10, 2009*, p. 5.

In providing electric customers with generation or demand response resources, the CCA program will have to ensure that its mix of resources meet both the physical requirements of the customer and the goals of the CCA program. This will require that the selected resource mix matches the demands of electric customers instantaneously over the course of a day, month, and year. In providing this service, the resource mix required will need to have various performance characteristics that ensure this balance between customer demand and corresponding supply meets the stringent physical requirements of the electric system.

> **Electric Units of Measure**
>
> - **Watt** – Basic measure of electricity (think of 60 or 100 Watt light bulbs
> - **Kilowatt (kW)** - 1,000 Watts or enough electricity to power ten 100 Watt light bulbs
> - **Megawatt (MW)** – 1,000 Kilowatts or enough energy to operate a medium-sized office tower
> - **Kilowatt-hour (kWh)** – Represents one kW operating for one hour
> - **Megawatt-hour (MWh)** – Represents one MW operating for one hour

To illustrate this point, a typical peak load profile for the CCSF is shown in Figure 2-2 for a 24-hour period. This illustration shows the MW demand for electricity over the course of a day and the magnitude of the resources necessary to satisfy these demands. In this example, a peak system requirement of approximately 750 MW plus a reserve, to ensure against unexpected plant outages, will be necessary to serve customer demand in the hours of 8:00 AM to 12:00 PM. This example also illustrates how this "peak demand" only lasts for several hours and that the resources being utilized must be able to increase and decrease their output to match this demand.

Figure 2-2
Illustrative Hourly Loads
for a High Usage Electric Day



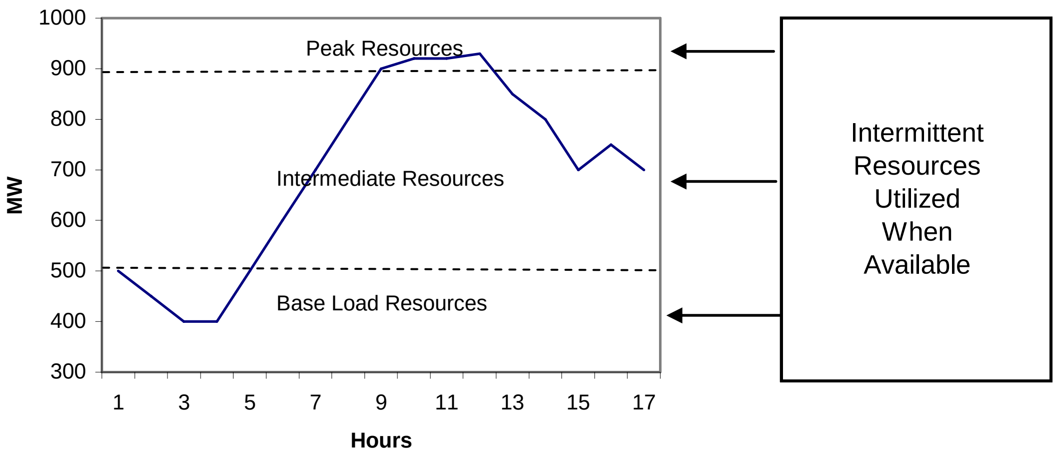
In order to serve this type of load, the resource mix will have to rely upon several types of generating technologies, demand-side resources, and peak shaving or storage resources as it is typically not physically possible or economically feasible for a single resource or supply to meet these variations.

In satisfying the customer demand as set forth in Figure 2-2, the CCA program resource mix will employ base load, intermediate, peaking, and intermittent supply-side resources and demand-side measures, each designed and priced to match a particular component of the hourly customer load. These resources could be owned by the CCA program or contracted on a long- or short-term basis, depending on the cost and benefits associated with each option. Figure 2-3 illustrates that portion of the day's load each type of resource will typically satisfy.

2.3.1 Discussion of Supply-Side Resources

The scope of this report is to address supply-side resources. Therefore, the following discussion focuses on how the supply-side resources would satisfy customer demand. However, in the overall CCA program resource mix, a variety of demand-side resources and programs are expected to be employed to assure appropriate conservation and load management.

Figure 2-3
Illustrative Hourly Loads and
Corresponding Supply Resource



The base load electric requirements are those experienced around-the-clock, as illustrated in Figure 2-3, and represent approximately 500 MW of power demand in this example. These types of resources typically include nuclear, certain hydroelectric projects, biomass, combined heat and power (CHP), and other fossil-fired plants that run continuously in most hours of the year. These resources typically have high upfront capital costs but low operating costs as each is expected to operate a significant percentage of the year, typically greater than 80%.

Intermediate or cycling units are those units operated daily but typically only during the peak hours[4] to satisfy the electric demand during hours when usage is elevated. These units are not expected to operate every day and often are not operated during weekends when electric demand is low. These resources are typically fossil-fired units that operate approximately 30% of the year and can be depended upon to start and follow electric demand over the course of the day and shutdown during times of low demand.

Peaking resources are those units necessary for only a few minutes or hours each day that can be relied upon at the height of electric demand. These units are also almost always fossil-fired and operate less than 5% of the year.

In addition to these three general categories of resources, a fourth category is used in this report to characterize those resources that operate intermittently and

[4] Peak hours typically represent the hours Monday through Friday 6:00 AM to 10:00 PM, or 16 hours per day.

includes most renewable resources. The Federal Energy Regulatory Commission (FERC)[5] has defined an intermittent resource as "an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints."[6]

Intermittent resources are intended to be available to operate 100% of the time, but due to environmental constraints such as the lack of wind or sun, are at the mercy of Mother Nature for the generation of electricity.[7] Therefore, these resources provide some level of capacity in meeting electric demands but almost always will require back-up resources, usually fossil-fired, to compensate for potential failures to operate.

In addition to supply-side resources, measures to lower demand also can be used to satisfy electric customers' requirements. These demand-side measures include actions such as turning off air conditioners during times of peak consumption to avoid the use of supply-side resources in the system.

Supply Resource Categories

- **Base Load Units** – Resources capable and intended to operate at or near full load around-the-clock
- **Intermediate Units** – Resources that cycle daily to meet changing load requirements
- **Peaking Resources** – Operate infrequently to meet high electric demand
- **Intermittent Resources** – Cannot store a fuel source and therefore cannot be counted on to meet demand demand

A mix of all of the above-referenced resources in varying quantities will be required to satisfy CCA program customer demand and requirements. Therefore, the renewable energy resources discussed in this report should be considered in context of the overall program requirements and the benefits that each resource brings to the supply portfolio.

2.3.2 Demand-Side and Energy Efficiency Resources

The CCA program directive calls for "107 Megawatts of local energy efficiency and conservation measures" as part of its resource mix used to satisfy CCA customers' electric demand. A review of these resources is beyond the scope of

[5] The FERC regulates the price, terms, and conditions of power sold in interstate commerce and regulates the price, terms, and conditions of all transmission services. FERC is the federal counterpart to state utility regulatory commissions.
[6] FERC Inbalance Provision for Intermittent Resources, Docket No. RMO5-10-000.
[7] Wind, photovoltaic (PV) solar, tidal power, and some hydroelectric resources are considered intermittent resources as these units cannot store their fuel to coincide with times of peak demand in the electric system.

the Task 1 report. However, it is anticipated that these resources will be part of the program supply mix and include such things as demand reduction, electric efficiency measures, and peak shaving opportunities throughout the CCSF.

2.4 Scope of the Theoretical and Technical Potential for Supply-Side Resources in the CCSF

The scope of our analysis is to provide the theoretical and technical potential for supply-side renewable energy resource development in the CCSF jurisdiction that could be deployed to meet the CCA program requirements. This analysis takes a broad approach in attempting to integrate different study sources and existing information into a single report that addresses the potential for supply-side renewable energy resources in the CCSF. The existing base of knowledge forms the foundation of this report which is supplemented with additional analyses and information gathered independently.

In preparing this report, GES and its subcontractor, HRA Engineering (HRA) worked with the SFPUC and other city departments to identify and utilize the existing data sets, reports, and other information relative to the potential renewable energy options in the CCSF. This existing body of knowledge was supplemented by literature reviews and interviews with market participants to gather data about the theoretical and technical potential for renewable energy resource deployment within the CCSF. This information and investigation was utilized to form our estimate of the theoretical and technical potential for renewable energy resource deployment in the CCSF.

2.5 Theoretical and Technical Potential Report Organization (Task 1)

The report is organized into the following sections which set forth the information gathered, analyses performed, and conclusions drawn.

- **Section 3.0 Methodology and Assumptions**

  This section describes the general approach employed in this report, extent of the research performed, technologies analyzed, and methodology and general assumptions. The results of the initial resource screening are discussed along with a discussion of generic project characteristics and economic assumptions relative to each of the selected technologies.

Sections 4.0 through 9.0 develop resource-specific analyses and conclusions for theoretical and technical potential deployment in the CCSF jurisdiction. Technologies analyzed in these sections include:

- **Section 4.0 Solar Photovoltaic (PV)**

  The solar PV section of the report provides an overview of this technology, the existing amount of PV in the CCSF, the potential for additional deployment, and an analysis of the project characteristics and economic requirements of typical installations. These installations included 5 kW (DC) residential and 100 kW (DC) commercial rooftop installations and a 5,000 kW (DC) ground-mounted installation similar to that being developed at the Sunset Reservoir for the SFPUC.

- **Section 5.0 Wind Power**

  The wind power section provides an overview of available turbine sizes, the potential wind resources in the CCSF, and a discussion of the potential for this type of development relative to the in-city wind resources. This section provides the technical and economic requirements for a three 1 kW building-mounted turbine installation, two 250 kW of tower-mounted turbines, and a 7,500 kW utility-scale installation comprised of three 2,500 kW tower-mounted turbines.

- **Section 6.0 Tidal Power**

  The tidal power section addresses the potential for tidal energy in the San Francisco Bay (SF Bay) based upon information from various studies. An overview of tidal power utilization is presented, as well as development within the State and throughout the country. Generic project characteristics and economic requirements are presented for a 2,400 kW tidal power system in SF Bay.

- **Section 7.0 Biogas Production outside of the CCSF Delivered Via Pipeline**

  This section analyzes the potential for biogas both within the CCSF as well as the potential for this type of development outside of the CCSF capable of producing biogas for utilization within the CCSF. A discussion of the project characteristics and economic requirements is presented for a typical small-scale 250 kW anaerobic digestion system which produces electricity and a large-scale biogas production facility capable of producing sufficient biogas for approximately 10 MW of electrical generation. Biogas availability assumes production out-of-city with gas delivered via pipeline. Thus, biogas could then be used in stand-alone generating units or CHP resources like those discussed in this report.

- **Section 8.0 Fuel Cells**

  The fuel cell section provides an overview of the various commercially available technologies and their deployment in the State and the CCSF. An overview of the project characteristics and economic requirements of various fuel cell installations is presented including 400 kW, 1,400 kW, and 2,800 kW units produced by various manufacturers.

- **Section 9.0 Combined Heat and Power (CHP)**

  The CHP section provides an overview of various systems and installations that could be utilized in the CCSF. This section addresses the technical and economic requirements of these resources and the potential for deployment in the CCSF. An overview of the project characteristics and economic requirements is presented for a small 65 kW microturbine, a 1,000 kW reciprocating engine, and a large-scale CHP unit associated with the downtown steam loop.

2.6 Subsequent Tasks 2 through 5

In addition to the information in this report on the theoretical and technical potential within the CCSF, subsequent tasks will address the economic potential of these resources as well as the economics of resources outside of the CCSF. Therefore, in utilizing the results set forth in this report, it is necessary to consider the economic potential of the in-city resources relative to out-of-city options in assessing the appropriate CCA program supply mix.

3.1 Report Methodology Introduction

The resources selected for inclusion in this report were those considered commercially viable and feasible to construct within the CCSF jurisdiction and large enough for inclusion in the CCA program supply portfolio. The technologies were chosen after consideration for renewable resource availability, technical limitations, land use restrictions, and siting constraints. In determining which technology to analyze, consideration was given to all renewable resource categories which include solar, hydroelectric, hydrokinetic, geothermal, biomass, wind, and combined heat and power.

The resources included in this report are solar PV, wind, tidal power, biogas or anaerobic digestion, fuel cells, and CHP. The theoretical and technical potential for the deployment of these resources within the CCSF are set forth in the subsequent sections of this report. The Task 2 report will address the economic potential of these resources.

Initial resource screening eliminated several technologies considered unsuitable for deployment in the CCSF due to either commercial availability, lack of sufficient natural resources, or potential size of resource. These included the following:

- Solar thermal resources were eliminated as a technology for this report because of their large footprint and need for more solar radiance than is typically experienced in the CCSF jurisdiction.

- Hydroelectric resources include a variety of potential resources such as pumped storage, run-of-the-river technologies, and in-pipe hydroelectric projects. With the exception of in-pipe hydroelectric generation, these resources are not considered geographically feasible for locations within the CCSF. In-pipe hydroelectric projects have potential for in-city deployment in the SFPUC water infrastructure. An example includes the SFPUC's installation of a 200 kW University Mound Renewable Hydroelectric Project located at its McLaren Pumping Plant. However, a review

In-City Resources Considered Feasible for the CCA Program

- Solar PV
- Wind
- Tidal
- Biogas
- Fuel Cells
- CHP

In-City Resources Considered Unfeasible for the CCA Program

- Solar Thermal
- Conventional Hydroelectric
- Geothermal
- Solid Fuel Biomass
- Offshore Wind and Wave

Out-of-City Resources Considered In Task 3 Report

- Solar Thermal
- Geothermal
- Biomass
- Large-Scale Wind

of these resources indicates that only small quantities of this resource are available and not in sufficient quantity to act as a supply resource for the CCA program. Therefore, while this resource is feasible, there is not enough potential in the CCSF to act as a significant supply resource for the CCA program.

- Geothermal was eliminated due to the lack of available resources in the CCSF jurisdiction.
- Solid fuel biomass such as wood or agricultural waste also was eliminated due to the limited amount of fuel available in the CCSF and difficulty in permitting a new solid fuel combustion source in the CCSF.
- Offshore wind and wave or hydrokinetic facilities were considered in this report but not included as reasonable supply options for the CCA program due to the developing nature of the technologies. Offshore wind and wave projects are anticipated to be available in the future and could, at that time, contribute to the CCA supply mix.

The potential for solar thermal, geothermal, solid fuel biomass, and large-scale wind technologies as part of the CCA program supply mix are addressed in the Task 3 report. The remaining resources and technologies are considered in this report and discussed below.

3.2 Screening for Commercial Availability

The initial screening process considered the commercial availability of each technology. Commercially available typically means that several of the units or systems have been deployed and are readily available in the marketplace. Renewable resource technologies that are only in the testing or demonstration phase and not considered mature were excluded from this report, with the exception of tidal power which is considered to be between demonstration and commercially available.

The screening for commercial availability eliminated evolving technologies such as wave or hydrokinetic and offshore wind projects as none of these technologies have been deployed commercially in the U.S. In addition, there may be certain technologies within the general categories addressed that have future promise, but currently are not commercially available. These are discussed, where appropriate, in each section to address the inclusion or exclusion of a certain system or technology.

3.3 Screening for Geographic Consideration

In determining the renewable energy resource potential in the CCSF jurisdiction for each category, consideration was given to both existing land uses and the characteristics of natural resources within the CCSF jurisdiction. Therefore, the existing land use and development will be the starting point for the theoretical and technical potential as it identifies the total potential area under which future resources can be deployed within the CCSF.

Using existing development and land uses as a starting point allows for reasonable analysis of the potential resource compatibility with existing development throughout the CCSF and provides a realistic near-term estimate of those resources that could be used in the CCA program. For example, while it may be possible to remove buildings or make theoretic estimates of how much ground-mounted solar could be deployed if public parks were used, these types of assumptions are not considered reasonable within the scope of this report.

3.4 General Resource Characteristics Categories and Description

The determination of the technical potential for renewable energy resources in the CCSF jurisdiction requires the identification of generic technologies which are potential candidates for both deployment in the CCSF and inclusion in the CCA program based on both technical and economic characteristics. The generic technology characteristics were compared with resource availability and other data to determine which options are theoretically and technically possible. For example, while it may be theoretically possible to construct a wind turbine in the CCSF, if there are insufficient winds to operate the facility it was not considered technically possible.

In most instances, several generic technologies were considered to address the largest range of practical supply options. Multiple unit installations were also included which ranged in size and technology to assure that various configurations were accounted for in this report and also in the economic potential report (Task 2) as project economics typically improve with larger installations. These assumptions are addressed in Sections 4 through 9 for each resource category. The following generic project characteristics and economic requirements were considered for each technology.

3.4.1 Output of Selected Resources

The units of measure associated with electricity supply resources are typically kilowatt (kW) or MW, and sometimes watts, and represent the maximum output of a resource.

In presenting information in this report on various generic technologies, every effort was made to use consistent units of measure, such as kW or MW, within the sections to allow for easier comparisons. However, due to the large magnitude of some estimates the units of measure were changed for ease of presentation. Therefore, the following descriptions are set forth to assist the reader in understanding the relationship of the electrical measures used to determine a resource capability and output.

The basic measure of electricity is a watt and in this report refers to an alternating current (AC) watt unless indicated otherwise. An example of a watt would be a light bulb which uses 100 watts. In measuring larger units of electric demand or supply, kilowatts are typically used and represent 1,000 watts. An example of a kilowatt would be enough electricity to operate ten 100 watt light bulbs. In the CCSF, a typical residential electric account requires a little over 1 kW to serve its load. A medium-sized commercial account would require approximately 50 kW of electric capacity to serve its electric demand.

In measuring larger amounts of electrical capacity, MW is used and represents 1,000 kW. Units such as MW are used in estimating larger electric loads, such as the CCA program's anticipated load which is expected to exceed 750 MW (equal to 750,000 kW or 750,000,000 watts). This illustration is an example of why units are sometimes changed for ease of presentation due to the magnitude of the numbers being discussed in each section.

The net output for electric systems is based on manufacturer ratings of the generator equipment after losses associated with operation and is quoted in AC watts. These ratings assume a typical installation and will vary based on site-specific conditions and equipment installation.

3.4.2 Resource's Anticipated Output Relative to Theoretical Potential

The capacity factor represents the ratio of estimated output from a generating resource over a period of time relative to the output it would have produced had it operated at full output during this same time period. In this report, the period of time is estimated at one year, or 8,760 hours, and the generating output is the system's net output available to satisfy demand. The formula for calculating the capacity factor is shown as follows:

$$\frac{Actual\ or\ Estimated\ Output}{(Net\ Capable\ Output\ x\ 8{,}760\ hrs/yr)} = Annual\ Capacity\ Factor\ (\%)$$

A sample capacity factor calculation is a 1 kW solar PV installation that produced 1,577 kWh of electricity over the period of one year for consumption in a residential unit. The capacity factor for this system would be calculated as follows.

$$\frac{1{,}577\ kWh}{(1\ kW\ x\ 8{,}760\ hrs/yr)} = 18\%\ Capacity\ Factor$$

Since no unit is capable of operating 100% of the time due to maintenance requirements, lack of natural resources, or lack of market demand, each resource will have a different expected capacity factor. These are provided for each generic technology identified based on resource availability and the system's technical requirements.

3.4.3 Resource Specific Characteristics and Nature of Resource Requirements

The generation characteristics set forth for each resource include its expected duty cycle in meeting electric demand and includes categories for base load, intermediate or cycling units, peaking units, or units that are intermittent and cannot store a fuel source and are provided for each resource to allow for comparisons between the technologies and the type of load each might serve in the CCA program supply mix.

In addition to the duty cycle, units are characterized based on whether the technology is mature or evolving. This provides insight as to expected market penetration and potential improvements in either efficiency or the costs set forth for each technology as evolving technologies will tend to decline in price in response to greater market demand and increased competition.

3.4.4 Construction Period

The estimated construction period provides an indication of lead time necessary for installation of various technologies. These estimates take into consideration the period of time from project conception to commercial operation. The estimates are based on reasonable forecasts using past experience with the construction period required for similar projects. Construction period will typically increase relative to a project's size and complexity.

3.4.5 Overnight Capital Costs

The overnight capital cost for each technology is based on average overnight costs for typical installations and expressed in 2009 dollars (2009$). Overnight costs do not include any interest during construction (IDC), inflation, or other carrying costs and assume the project was constructed overnight with no consideration for actual construction periods. The costs associated with IDC, owner's cost inflation, and land acquisitions are addressed in the economic potential report (Task 2). The prices are typically expressed in dollars per kilowatt. If an alternative unit is utilized, an explanation is presented for the variation. Overnight costs include permitting, equipment installation and interconnection and are reasonable estimates of typical installation costs. Site-specific situations may result in actual costs deviating from these estimates due to site conditions and construction requirements being more or less difficult than the generic site considerations.

Overnight costs for technologies are based on average estimates for installation in the CCSF. These estimates have been confirmed with vendors and other studies prepared for similar purposes, where possible. The costs do not include land acquisition which is addressed in the Task 2 report, where appropriate, as these costs will vary by technology.

The necessary electrical and natural gas infrastructure was assumed to be at the site and sufficient for project development. Electric interconnection cost is based upon the size of the unit and type of connection required. Generating technologies with ratings of less than 1,000 kW were assumed to utilize a net metering interconnection. Units between 1 MW and 20 MW were assumed to utilize the small generator interconnection procedures for connection to either the distribution or transmission system. Generators with capacity greater than 20 MW were assumed to follow the large generator interconnection procedures and connect to the transmission system.

3.4.6 Operating and Maintenance Expenses

The operating and maintenance expense for each technology was estimated based on both the fixed and variable operating costs of the technology. The annual fixed expense is expressed in 2009$ per kilowatt-year ($/kW-yr) and the variable expense is expressed in 2009$ per megawatt-hour ($/MWh). A discussion of these expenses is set forth for the each generic technology.

In certain instances, units will require periodic capital replacements or maintenance. These costs have been estimated whenever possible to provide realistic life cycle costs for each technology.

3.4.7 Applicable Incentives

There are a number of economic incentives available for the installation and operation of renewable energy technologies. These incentives are offered by federal, state, and local government to promote the construction of renewable technologies that otherwise would not be viable in a competitive market. The following discussion provides a brief overview of the incentives available to developers and owners.

3.4.7.1 Federal Incentives Specific to Renewables

The federal incentives for renewable energy are primarily offered through the Internal Revenue Codes in the form of tax deductions such as accelerated depreciation, tax credits, or more recently the ability to receive grants and loans for renewable energy. The major incentives include 26 USC § 45 - Production Tax Credits (PTC), § 48 Investment Tax Credits (ITC), and § 168 Accelerated Depreciation.

Investment Tax Credits and Grants

The American Recovery and Reinvestment Act of 2009 (ARRA-2009) provides for the expansion and extension of several tax-related renewable energy provisions. In lieu of taking the PTC or ITC, eligible taxpayers may apply for grants to the Secretary of the Treasury for a non-discretionary grant of between 10 and 30% of the cost associated with an eligible project. The grant is not subject to federal tax, but the basis of the project is reduced by 15%. Construction must commence during 2009 and 2010 and the project must be in commercial operation before the date the eligible ITC expires.[8]

These grants are in lieu of PTC available under § 45, which allows for an income tax credit ranging from 1 to 2.1¢/kWh for eligible renewable energy resources. These payments escalate and are for a period of 10 years after the date the facility is placed in service. The in-service deadlines are as follows:[9]

- January 1, 2013 for wind
- January 1, 2014 for biomass, landfill gas, trash, qualified hydropower, marine and hydrokinetic
- January 1, 2017 for fuel cells, small wind, solar, geothermal, microturbines, CHP, and geothermal heat pumps

Accelerated Depreciation

Section 168 contains a provision for Modified Accelerated Cost Recovery System (MACRS) which allows for the investment in eligible resources to be recovered through accelerated depreciation deductions. The program has no expiration and eligible resources qualify for 5-year 200% declining-balance depreciation.[10]

[8] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US53F&State=federal&currentpageid=1&ee=1&re=1
[9] Ibid.
[10] Ibid.

Clean Renewable Energy Bonds (CREBs)

CREBs may be used by certain entities in primarily the public sector to finance renewable resources. The resources are generally the same as those which qualify for PTCs. CREBs may be issued to governmental entities, electric cooperatives, and certain lenders. The loan is issued with a zero percent interest rate and the bond holder receives federal tax credits in lieu of interest.

Participation in the program is limited by the volume of bonds allocated by Congress for the program. Participants must file with the IRS for a CREB allocation and then issue the bonds within a specified time period.

Other Incentives

The ARRA-2009 incentives discussed above are those most likely to benefit the projects identified in this report. There are other programs and incentives that provide loans and other benefits to taxpayers for measures associated with non-electric energy efficiency and reduction and improvements such as weatherization or modernization of utility systems.

In addition to the incentives provided by the ARRA-2009, there are additional incentives associated with renewable resources provided at the federal level. A summary of the most relevant are discussed below.

- New Markets Tax Credits (NMTC) – The NMTC Program permits taxpayers to receive a credit against federal income taxes for making qualified equity investments in designated Community Development Entities (CDEs). Substantially all of the qualified equity investment must in turn be used by the CDE to provide investments in low-income communities. The credit provided to the investor totals 39% of the cost of the investment and is claimed over a seven-year credit allowance period. In each of the first three years, the investor receives a credit equal to 5% of the total amount paid for the stock or capital interest at the time of purchase. For the final four years the value of the credit is 6% annually. Investors may not redeem their investments in CDEs prior to the conclusion of the seven-year period. An organization wishing to receive awards under the NMTC Program must be certified as a CDE by the Community Development Financial Instituti9ons Fund (the Fund) of the U.S. Department of the Treasury.
- Community Reinvestment Act (CRA) Credits – Enacted by Congress in 1977, the CRA program is intended to encourage banks to help meet the credit needs of the communities in which they operate, including low- and moderate-income neighborhoods, consistent with safe and sound banking operations. The CRA requires that each insured depository

institution's record in helping meet the credit needs of its entire community be evaluated periodically, and this record is taken into account in considering an institution's application for deposit facilities, mergers and acquisitions. Banks are constantly looking for ways to meet their CRA requirements; therefore, solar PPAs for businesses in low- and moderate-income neighborhoods in their service territories may be very attractive. While CRA credits may not provide additional financial incentives for solar projects, they may increase banks' appetites to invest in such projects.

3.4.7.2 State Incentives

California offers additional incentives to promote the development of renewable resources that include programs for solar, wind, and other resources. A summary of these incentives is provided below.

- California Solar Initiative (CSI) – The CSI program offers monetary incentives for systems up to the first 1,000 kW of an eligible solar energy system. The effective dates for the program are 1/1/2007 – 12/31/2016 or until the CSI budget has been reached. These rebates apply to electric distribution customers in California.[11]

- California Energy Commission Emerging Renewable Program (ERP) – The ERP provides electric customers with a financial incentive to develop renewable energy systems and utilize an emerging renewable technology such as wind, fuel cells, or anaerobic digestion systems. The consumer and the energy system must satisfy a number of requirements. The customer must receive electricity distribution service at the site of installation from an existing in-state electric corporation such at PG&E, and the customer must generate electricity to offset on-site load. The program provides rebates of $2,500/kW for the first 7.5 kW and $1,500/kW for the second increment up to 30 kW for wind turbines. Fuel cell and other systems would receive $3,000/kW for up to 30 kW. These rebates will decline over time pursuant to program guidelines.[12]

- California Self-Generation Incentive Program (SGIP) – This program provides incentives to qualified distributed generation projects under 5 MW. The incentive is a function of type of installation and fuel utilized. In addition, incentives decline relative to unit size. The incentives range from $2,625 to $4,500/kW.[13]

[11] http://www.consumerenergycenter.org/erprebate/index.html
[12] http://www.gosolarcalifornia.org/csi/index.html
[13] SGIP and your company, Center for Sustainable Energy California at http://www.cpuc.ca.gov

3.4.7.3 Local Incentives

- San Francisco Incentives – The GoSolarSF program provides additional funds for residential and commercial solar installations. The range of the incentive varies depending on type of host site and installer utilized. A summary of the program and applicable incentives is provided below.

Type	Residential Incentive Levels	Amount
Basic	Any SF property owner	$2,000
Environmental Justice	CARE customers, CALHome enrollees & residences in 94107 & 94124 zip codes	$3,500
Workforce Development	Installer hires City's Workforce Development Program graduates	$4,000
Additional Payments (To an incentive above)	Low-income: Applications received on or after Feb. 1, 2009	$7,000
	City Installer: Using an installer with principal place of business in San Francisco	$1,000
	Business Incentive Level	
Basic	$1,500/kW of installed solar capacity (Installer must be Workforce-Development Certified)	up to $10,000
	Non-Profit Incentive Levels	
Non-Residential	Non-residential buildings owned and occupied by non-profits, or owned by government entities and occupied by non-profits	$1,500/kW no cap
Multi-Unit, Residential	Multi-unit residential buildings owned and operated by non-profits (for-profit, multi-unit residential buildings can qualify if 75% of the units are designated as affordable housing for a period of no less than 30 years) • Up to $150,000 • Additional $100,000 incentive available on a matching-fund basis • Total Limit: $250,000	$4,500/kW

Source: GoSolarSF Brochure at http://sfwater.org/detail.cfm/MC_ID/17/MSC_ID/400/C_ID/3910

The incentives associated with each of the renewable technologies considered in this report will be used to analyze the economic potential of each supply resource.

3.4.8 Efficiency of Technology at Producing Electricity

The efficiency of various technologies will vary and is typically dependent on the resource's ability to convert kinetic or potential energy into electricity. Resources that convert solar or kinetic energy are measured based on the system's efficiency at which these resources convert this energy into electricity.

In the case of units that utilize biogas or natural gas, the system efficiency represents the amount of fuel which is converted to electricity. These figures are expressed in the unit's heat rate or Btu/kWh produced on a HHV[14] basis. A heat rate reflects the Btus required for producing one kilowatt-hour of electricity. Electric generating facilities with low heat rates are more efficient than units with high heat rates.

The most efficient electric generating systems, typically combined cycle units, have operating heat rates of 7,000 to 8,000 and reflect efficiencies approaching 60%.

3.4.9 Permitting and Emissions Requirements

The permitting process for renewables requires consideration of federal, State, and local guidelines such as the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA) as well as local zoning and land use requirements. These permitting requirements typically require the development of environmental analyses and related documents prior to approval of large renewable projects. In addition, resources that have emissions will be required by meet the Bay Area Air Quality Management District (BAAQMD) requirements.

The DBI process is typical for new construction in the CCSF and common to most forms of construction. This process involves submitting an initial set of plans plus a fee for the permit.

The CEQA was enacted in 1970 in response to the growing awareness of environmental issues. The CEQA process provides decision-makers and the public with an objective analysis of the impact proposed projects will have on the physical environment. The process is designed to ensure that project impacts are disclosed and that the process involves public participation.

[14] HHV stands for higher heating value of a fuel and is defined as the amount of heat released by a specific quantity once it is combusted and the product has returned to a temperature of 25°C.

A summary of the in-city CEQA review process is provided below.[15]

> Environmental review under CEQA is administered for all departments and agencies of the CCSF by the Major Environmental Analysis (MEA) division of the Planning Department (the Department). Projects subject to CEQA are those that have the potential for resulting in a physical change of some magnitude on the environment and that require a discretionary decision by the CCSF, such as public works construction and related activities, developments requiring permits (which in the CCSF are discretionary and thus not exempt from CEQA), use permits, activities supported by assistance from public agencies, enactment and amendment of zoning ordinances, and adoption or amendment of the General Plan or elements thereof.
>
> The environmental review process begins with a determination by the Department as to whether or not a discretionary action by the CCSF falls within a class of projects that are exempt from environmental evaluation pursuant to State Guidelines for implementation of CEQA. Projects that are exempt generally include small-scale new construction or demolition, some changes of use, some additions, and other generally small-scale projects. Projects that do not require a permit may be issued environmental exemptions over the counter at the Department.
>
> For projects requiring a permit, exemptions may be issued by the Department or may be referred to MEA staff. In the latter case, the project sponsor (private applicant or government agency) submits an Environmental Evaluation (EE) application to the MEA. After the completed EE application has been submitted, an Initial Study is prepared for the proposed project by MEA. Projects are evaluated on the basis of the information supplied in the EE application, any additional information required from the applicant, research, and contact with affected public agencies, citizens groups, and concerned individuals is done by or under the direction of MEA.
>
> If during the Initial Study process the Department determines that the proposed project would not have a significant effect on the environment, a Preliminary Negative Declaration (PND) is issued. If the Initial Study anticipates that the project would result

[15] http://www.sfplanning.org

in significant impacts on the environment, the project may be revised to include mitigation measures; an Environmental Impact Report (EIR) may not be necessary if the project sponsor agrees to mitigate such impacts to a level that is less than significant. In such cases, a Preliminary Mitigated Negative Declaration (PMND) is issued.

However, the Department may determine that the project could have a significant effect on the environment and that an EIR is required. If an EIR is required, the sponsor must prepare an Administrative Draft EIR (ADEIR) which is submitted to the MEA. Once the MEA determines the ADEIR is acceptable, it is accepted by the Department for consideration by the San Francisco Planning Commission (the Commission) at a public hearing.

If the Commission determines that the proposed project would have a significant effect on the environment, it may approve a project by one of two ways: (1) require changes in the project to reduce or avoid environmental damage if it finds such changes feasible (generally via alternatives and/or mitigation), or (2) find that changes are infeasible and make a statement of overriding considerations. CEQA requires decision-makers to balance the benefits of a proposed project against its unavoidable environmental risks in determining whether to approve the project. If the benefits of a proposed project would outweigh the unavoidable adverse environmental effects, those adverse effects may be considered “acceptable.” The Commission must, in such cases, state in writing the specific reasons to support its action based on the Final EIR (FEIR) and/or other information in the record.

The BAAQMD process is specific to installations which produce the emissions of pollutants through the burning of natural gas or biogas in equipment which produces electricity. The BAAQMD grants the authority to construct and permit to operate a combustion source. The permit typically requires that installations satisfy the Best Available Control Technology (BACT) for emission sources relative to harmful air emissions. The technologies proposed for inclusion in the CCA program and discussed in this report are assumed to satisfy the BAAQMD requirements for air emissions either due to type of technology utilized to produce electricity, such as fuel cells, or through pollution control technology like selective catalytic reduction (SCR) or similar technologies.

3.5 PG&E System Description

As stated in the Introduction section, PG&E is responsible for the transmission and delivery of electricity within the CCSF and is subject to oversight and rules established by the CPUC and the California ISO (CAISO).[16] The operation of this system is a complex undertaking and as such, PG&E is the entity responsible for analyzing the impact associated with the addition of an electric resource within its transmission and distribution system. Figure 3-1 is a map of the SF Bay area transmission infrastructure owned by PG&E. These transmission lines form the general system over which electricity is delivered to and throughout the CCSF.

[16] The CAISO is a not-for-profit public-benefit corporation charged with operating the majority of California's high-voltage wholesale power grid.

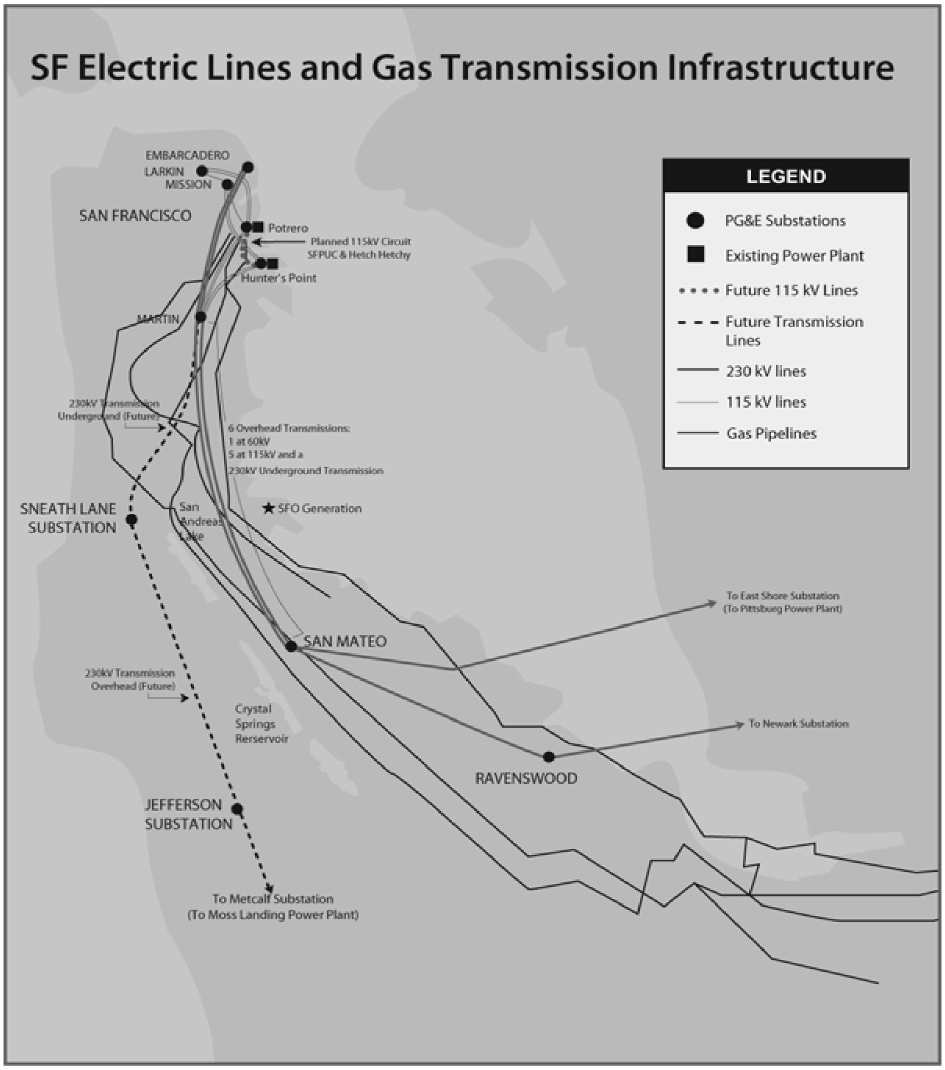


Figure 3-1 – San Francisco Electric Lines and Gas Transmission Infrastructure
Note: Hunter's Point is shown on this map but has been removed from service.
Source: http://www.spur.org/documents/030801_article_01.shtm

The transmission system map shown in Figure 3-1 is general in nature and shows the large 230 kV lines to and within the CCSF. The map does not show the Trans Bay cable which is expected to deliver additional capacity into the city from north of the CCSF. There are additional electric transmission lines throughout the city that provide service to customers that can be utilized for the interconnection of electric generators. As the CCSF is a net importer of electricity, it is reasonable to assume that the addition of generation in the city will be a benefit to the overall electric system.

In developing cost estimates for various resources, the estimates provided reflect the cost of interconnection into the PG&E or regional electric system. In the case of units larger than 1 MW, the costs assure that an interconnection study is performed by PG&E and that no extraordinary transmission costs are required for interconnection. Interconnections can cost up to $1 million and may require the owner and/or developer of a project to spend millions of dollars for electric system upgrades in order to connect to the PG&E system. While it is possible that such large interconnection costs could result form certain installations, it is beyond the scope of this report to address all possible consequences associated with interconnecting new units. The interconnections associated with projects of less than 1,000 kW were assumed to be net metered interconnections at the distribution level. Projects with outputs of more than 1,000 kW are assumed to require either a small or large generator interconnection. These costs are included in the construction cost for each project.

3.6 Existing Resources in the CCSF Considered for Comparison to Technical Potential

In analyzing the resource potential for each technology, the existing and planned resources were taken into consideration. The quantification of existing and planned resources provides a measure of the market penetration of each resource type within the CCSF and provides a baseline against which to confirm estimates of theoretical, technical, and economic potential. For example, after several years of renewable resource incentives, little wind generation is currently installed in the CCSF. Therefore, it is reasonable to conclude that the potential for such a resource is relatively low.

3.7 Theoretical and Technical Potential Summary

The theoretical and technical potential is a function of available natural resources, existing land use, and development within the CCSF jurisdiction. The resources are assumed to be deployed within the CCSF jurisdiction and rely upon existing land area and/or improvements for deployment unless stated otherwise. These resource-specific assumptions used to estimate the potential for each resource are provided along with the estimated total potential of each resource, both in terms of capacity as well as annual energy production.

4.1 Solar Photovoltaic (PV) Introduction

> **Solar Facts**
>
> - 825± MW of solar capacity in California
> - 7± MW of solar capacity in the CCSF
>
> Three systems considered for supply mix:
>
> - 5 kW (DC) residential rooftop system (see Section 4.6.1)
> - 100 kW (DC) commercial rooftop system (see Section 4.6.2)
> - 5,000 kW (DC) ground-mounted tracking system (see Section 4.6.3)
>
> There is an estimated technical potential of 100± MW in the CCSF with an annual energy production of 130,000± MWh.
>
> Resource type: Intermittent

Solar power technologies use the energy from the sun to generate electricity and include technologies that use semi-conductor materials such as PV to produce electricity directly from the sun's energy, or systems that capture the heat of the sun to drive a turbine which produces electricity typically referred to as solar concentrating or solar thermal. The various solar power technologies vary in size and design but each is dependent upon the amount and strength of the sun's energy for the production of electricity.

In assessing the solar potential for the CCSF, the initial screening eliminated solar concentrating or solar thermal plants as requiring more solar energy and land than is available in the CCSF. This type of solar energy system is considered in the Task 3 report which addresses the potential for out-of-city resources that can be used as part of the CCA program supply mix.

Solar PV technology is capable of being deployed within the CCSF utilizing both distributed behind-the-meter and large-scale ground-mounted installations. There are approximately 10,000 MW of solar capacity in the U.S. with California's share representing over 75%.[17] This high level of solar penetration suggests that certain regions of California are both well suited for solar energy development and that the State and other entities provide attractive incentives to owners of PV systems that promote installation.

4.2 Solar PV System Project Characteristics

The amount of energy captured form the sun is a function of the solar PV device and the available sunlight. Solar PV systems are currently designed to have power output ratings of a few kilowatts up to several MW that utilize multiple panel installations. As with other renewable technologies, the economies of the project typically improve with

[17] Solar Energy Industries Association (SEIA) *US Solar Industry Year in Review 2008*.

larger installations due to the fixed construction costs being spread over more megawatt-hours when the system is operating.

The electric production from a PV solar system depends on the materials utilized and the intensity of the solar radiation on the cell. Single, or polycrystalline silicon cells, are most widely used today. Crystalline cells are manufactured by growing single crystal ingots which are spliced into cell size material. Thin film solar cells are made from layers of semi-conductor material only a few micrometers thick. These materials make application more flexible as thin-filmed PV can be integrated into roof tiles or windows. Currently, the commercial PV markets are dominated by silicon-based cells with about 85% of the solar systems deployed today using crystalline silicon.[18]

A solar PV system utilizes three main components which are 1) the solar PV panel(s), 2) the inverter(s), and 3) the interconnection and are typically modular in nature and scalable to meet various sizes. Installations are assumed to be on south facing roofs or oriented to an optimal angle. A system can also incorporate a tracking system that allows the module to optimize relative to the sun's position. This optimization allows for a greater amount of energy capture and corresponding electric generation. The solar PV system installation is assumed to be free of tree or building shading.

There are two basic designs or applications for PV installations which include 1) surface-mounted and 2) ground-mounted installations.

4.2.1 Description of Typical Surface-Mounted Installations

Surface-mounted systems are typically located on the roof of a residential or commercial building and used to both satisfy the building's electric demand and also deliver electricity to the electric system. Figure 4-1 shows the 3 kW roof-mounted installation at the Yoga Garden in San Francisco.

Figure 4-1 - Roof-Mounted Solar System

[18] Black & Veatch *Renewable Energy Transmission Initiative, Phase 1A, Final Report*, April 2008, p. 5-26.

4.2.2 Description of Typical Ground-Mounted Installations

Ground-mounted systems are typically utility-grade and of large scale for use in the production of electricity for delivery to several customers through the utility's transmission/distribution system. Examples of a utility-grade PV plant are the Sacramento Municipal Utility District's (SMUD) 3± MW PV installation at Rancho Seco, California, shown in Figure 4-2, as well as the future 5± MW Sunset Reservoir project that was approved in the CCSR.

Figure 4-2 - Ground-Mounted PV System

The typical capacity factor for a PV installation in the CCSF can range from approximately 10 to 25%, depending on design and location. Solar PV systems are intermittent resources that rely on available sunlight to produce electricity and are typically not reliable on a firm basis capable of satisfying peak demand.

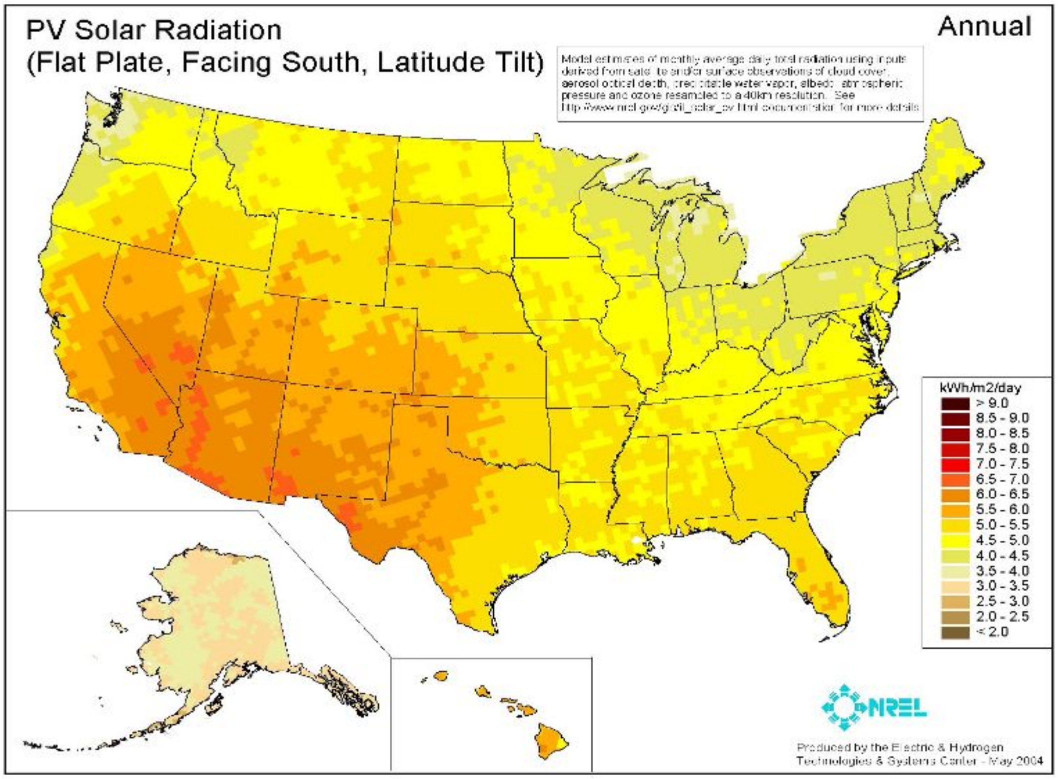
4.3 Geographic Considerations for Solar PV Installations

The amount of insolation available at a particular location determines the potential for solar electric generation. Insolation is a measure of solar radiation received on a given surface area in a given time and is commonly expressed as average irradiance in kilowatt-hours per square meter per day (kWh/m^2-day). Insolation values are highest in the summertime and in areas of lower latitudes with drier climates and clear skies.

Figure 4-3 shows that the southwestern states of Nevada, Arizona, and New Mexico tend to have the highest insolation values, between 6 and 7.5 kWh/m^2-day, while California's Central Valley and southern parts of the State also have insolation values ranging from 5 to 7 kWh/m^2-day.[19]

[19] CEC *California Solar Resources*, April 2005, p. 5, (CEC-500-2005-072-D).

Figure 4-3
PV Solar Radiation in the U.S.



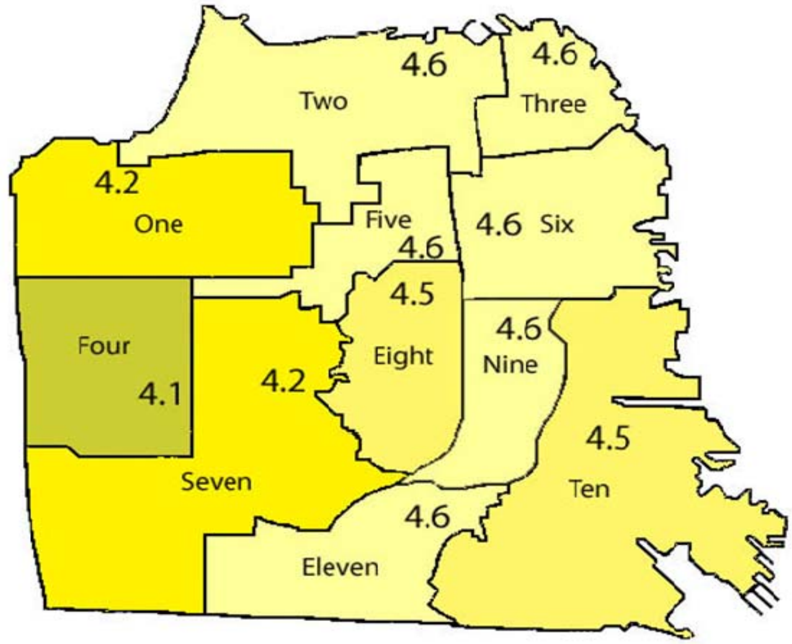
Source: http://www.nrel.gov/gis/solar.html

4.4 CCSF Solar Potential Based on SFPUC Monitoring Stations

The solar PV potential in the CCSF has been measured utilizing 11 solar monitoring stations deployed by the SFPUC throughout the CCSF. As shown in Figure 4-4, these monitoring stations indicate solar insolation of between 4.1 and 4.6 kWh/m^2-day. This information is utilized in the city solar mapping program to assess the solar potential at any particular location throughout the city. The solar mapping stations indicate solar potential is slightly less than that indicated by the National Renewable Energy Laboratory's (NREL) country-wide map which indicates the CCSF should have solar in the range of approximately 5 kWh/m^2-day.

Figure 4-4
San Francisco Solar Monitoring Stations
And Estimated Insolation Values

Location		Insolation
District	Zip Code	kWh/m²/day
1	94121	4.19
2	94123	4.56
3	94133	4.60
4	94116	4.09
5	94117	4.64
6	94102	4.57
7	94116	4.18
8	94114	4.47
9	94110	4.63
10	94124	4.54
11	94134	4.58
Average		4.46



Source: http://www.sfog.us/solar/sfsolar.htm

4.5 Existing Amount of Solar PV in the CCSF

For more than ten years, the State and CCSF have aggressively promoted the installation of alternative resources, particular solar, as a means of providing renewable energy and lower air emissions. These programs have resulted in approximately 7 MW of solar installation in the CCSF jurisdiction which is just under 1% of the statewide solar capacity. The CCSF has introduced GoSolarSF to provide additional incentives and promote the continued penetration of solar.

4.6 Generic Solar PV Characteristics

In assessing the potential for solar PV, several generic installations were reviewed to assess the ability of each to be deployed within the CCSF. The insolation values are those from the San Francisco International Airport which are equal to the average found in the CCSF.[20] The generic installations considered include surface-mounted and a large-scale ground-mounted system that utilizes axis tracking.[21] The installations assume silicon-based PV units manufactured by Sharp Corporation and are considered to have mid-range efficiencies. The units are assumed to operate intermittently and have

[20] http://www.sfog.us/solar/sfsolar.htm
[21] Axis tracking allows the panels to optimize relative to the sun's energy.

capacity factors that range from 18.5 to 23%. However, there are several manufacturers and technologies that could produce similar results.

The typical PV installations discussed below are assumed to be located on south facing surfaces unobstructed by trees, buildings, or other obstacles. The surface-mounted installations are assumed to be located only on the portion of a rooftop with a south facing orientation and are sized to demonstrate typical conditions throughout the CCSF. In utilizing surface-mounted systems, it was assumed that the building structure had the weight bearing capacity to accept the installation and no consideration was given to building or roof reinforcement. The units are assumed to have a 25- to 30-year useful life and a degradation factor of approximately 0.5%/year.

While it may be possible to locate a greater number of solar panels on east or west facing roofs, generation potential typically diminishes and affects the project's economics. Therefore, in assessing typical installations, it is assumed that units are located and oriented at an optimal angle for maximum economic potential.

In actual application, surfaces may accommodate a larger or smaller number of panels due to orientation or load bearing capabilities. However, the ability to scale PV systems allows for those variations with little change in project economics relative to the generic installations set forth in this report. For example, a 5.5 kW (DC) system is estimated to cost approximately the same as the 5 kW (DC) system included as a generic system on a $/kW basis and has similar technical and economic characteristics. Therefore, roof or surface area may vary slightly but similar installations are expected to have characteristics comparable to the generic installations.

Table 4-1 is a summary of the technical and economic requirements for generic installations. The information is based on a study conducted by HRA for GES on solar installations in the CCSF.

Table 4-1
Technical and Economic Requirements
for Generic Solar PV Installations

Description	Surface Mounted		
	Residential PV 5 kW (DC)	**Commercial PV 100 kW (DC)**	**Ground Mounted PV 5,000 kW (DC)**
Project Characteristics			
Plant Capacity (kW) (AC)	4.2	84.2	4,194
Typical Duty Cycle	Intermittent	Intermittent	Intermittent
Unit Life (years)	30	30	30
Typical Area Required (sq. ft.)	500±	8,200±	871,200±
Availability Factor	98%	98%	98%
Capacity Factor	18.5%	18.5%	24%
MWh/year	6.8	136.5	8,817
Construction Period	< 1 year	< 1 year	> 1 year
Technology Status	Mature	Mature	Mature
Module Efficiency	13%-14%	13%-14%	13%-14%
Economic Characteristics (2009$)[1]			
Capital Cost ($/kW)	$10,000	$8,300	$8,000
Fixed O&M ($/kW-year)	$75	$45	$25
Non-Fuel Variable O&M ($/kW-yr)	N/A	N/A	N/A
Capital Replacements ($/kW)	$1,200	$800	$600
Applicable Incentives	GoSolarSF, CSI 30% ITC 5 yr. MACRS	GoSolarSF, CSI 30% ITC 5 yr. MACRS	GoSolarSF 30% ITC 5 yr. MACRS

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).

4.6.1 Narrative Description of Residential Rooftop System – 5 kW (DC)

Project Characteristics

The installation considered in this report had a gross power production of 5 kW (DC) and net output of 4.2 kW and is used to illustrate typical technical and economic characteristics.[22] The system is comprised of 22 solar panels rated at 224 watts DC and requires approximately 400 to 500 square feet of unobstructed south-facing roof area for installation. The optimal capacity factor is estimated at 18.5%.

[22] PV systems consume approximately 20% of the electric DC energy internally and AC net output is approximately 80% of the DC rating.

Economic Characteristics

The estimated cost of the installation is $10,000/kW, or approximately $42,000. This would include the purchase of the units, a typical roof-mounted installation, an indoor inverter, and net metering electric interconnection. The operating costs are estimated at $75/kW-yr and reflect cleaning and maintenance of the system. The inverter is estimated to have a 10-year life and has a replacement cost of approximately $7,500.

4.6.2 Narrative Description of Commercial Rooftop System – 100 kW (DC)

Project Characteristics

The installation in this report has a gross power production of 100 kW (DC) and net output of 84.2 kW and is used to illustrate typical technical and economic characteristics. The system is comprised of 446 solar panels rated at 224 watts DC and requires approximately 8,200 square feet of unobstructed south-facing roof area for installation. The optimal capacity factor is estimated at 18.5%.

Economic Characteristics

The estimated cost of the installation is $8,300/kW, or approximately $700,000. This would include the purchase of the unit, a typical roof-mounted installation, an indoor inverter, and net metering electric interconnection. The operating costs are estimated at $45/kW-yr and reflect cleaning and maintenance of the system. The inverter is estimated to have a 10-year life and has a replacement cost of approximately $100,000.

4.6.3 Narrative Description of Ground-Mounted System – 5,000 kW (DC)

Project Characteristics

The ground-mounted system considered in this report is a solar tracking installation with a gross power production of 5,000 kW (DC) and net output of 4,194 kW. The system is comprised of 22,321 solar panels rated at 224 watts DC and designed to track the sun's movement for optimum electric production. The area required for installation is approximately 20 acres. The optimal capacity factor is estimated at 24%.

Economic Characteristics

The estimated cost of the installation is $8,000/kW or approximately $34 million. This would include the purchase of the unit, a ground-mounted system, outdoor inverter, axis tracking system, and a utility interconnection. The operating costs are estimated at $25/kW-yr and reflect cleaning and maintenance of the system. The inverter is estimated to have a 10-year life and has a replacement cost of approximately $5 million.

4.7 Theoretical and Technical Potential Conclusion for the use of Solar PV in the CCSF

The theoretical potential for solar PV systems in the CCSF is a function of the available surface and ground-mounted siting opportunities with unobstructed southern exposure and the efficiency of the PV modules. The theoretical potential has been addressed in several studies produced by the California Energy Commission (CEC) which indicated a theoretical potential of approximately 500 MW in the CCSF. Discussions with the San Francisco Department of the Environment (SF Environment) indicate that this is a reasonable theoretical estimate.

The theoretical potential figure represents those resources that could be deployed prior to consideration of land use and surface monitoring constraints such as load bearing capabilities of existing structure and layout of mechanical systems. Therefore, the technical potential of the theoretical resource is estimated to be less than the theoretical potential due to these limitations.

The technical potential of solar PV resources in the CCSF is considered to be far less than the theoretical potential due to the limitations identified above. The SFPUC has identified several projects with a combined capacity of approximately 45 MW that could be developed on city-owned property in the CCSF and includes approximately 30 MW of ground-mounted solar. A summary of these projects is provided in Table 4-2.

Table 4-2
Proposed SFPUC Solar Generation Project Description and Associated Capacity in kW AC

Description	kW AC
Phase 1 2009/2010	
Sunset Reservoir - North Basin	4,500
Chinatown Public Health Center	21
Muni Ways & Means - 700 Pennsylvania	101
Muni Woods - 1095 Indiana Street	83
Davies Symphony Hall	171
City Hall	80
Long Term 2011-2015	
Stanford Heights Reservoir	1,040
SFGH Parking Garage - 24th & Utah	400
Bus Washing Facility 15th & Harrison	800
Tesla, Ground-mounted	4,000
Sunol, Ground-mounted	20,000
University Mound - North Basin	1,600
Pulgas Reservoir	2,080
Sutro Reservoir	1,600
Hunters Point (Parcel E) Ground-mounted	8,000
Total	**44,476**

The projects in Table 4-2 are considered to be, for the purpose of this study, both theoretically and technically possible, before consideration of economic constraints associated with the actual development of the project. In addition to these projects, it is reasonable to assume that there are at least another 50 MW of solar PV projects that are technically possible in the CCSF associated with non-city owned buildings and vacant land. Therefore, including this additional 50 MW would bring the total technical potential of solar in the CCSF to approximately 100 MW prior to any economic considerations, or about 20% of the theoretical potential.

A figure of 100 MW is considered reasonable and reflects the reality that not all theoretically possible installations are technically possible or economically justified. The technical potential of 100 MW is more than 10 times the current solar PV installations in the CCSF. Assuming an average 15% capacity factor would result in approximately 130,000 MWh per year associated with the technical potential in the CCSF.

4.8 Data Sources

The following sources have been used in compiling data for this section.

- HRA Engineering *Feasibility Study for Solar & Wind Power in the City & County of San Francisco*, March 27, 2009
- George Simons and Joe McCabe *California Solar Resources*, April 2005
- Black & Veatch *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, April 2006
- Navigant Consulting, Inc. *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County*, September 2007

The following interviews were conducted in connection with this section.

- John Doyle, Manager Energy Generation Projects, SFPUC
- Johanna Partin, Renewable Energy Manager, San Francisco Department of the Environment

5.1 Wind Power Introduction

Wind energy systems convert the movement of air to power by means of a rotating turbine and generator. The amount of energy in the wind which is extracted by the wind turbine increases with the cube of the wind speed. Wind strength is typically rated on a scale of Class 1 to Class 7 with Class 1 being poor and Class 7 being excellent. In general, wind strength increases at higher elevations and is why modern turbines have heights of approximately 80 meters, or 260 feet.[23]

Cumulative nationwide wind capacity is now estimated at more than 25,170 MW. California is anticipated to have 10% of this wind capacity, or approximately 2,500 MW.[24] Typical utility-scale wind systems consist of multiple wind turbines that range in size from 1.5 to 2.5 MW. Wind energy system installations commonly range from a single 1.5 MW turbine to commercial wind farms that can be as large as 740± MW such as the Horse Hollow Wind Energy Center located in Texas. Throughout the U.S., the use of a single turbine is common for powering municipal buildings or industrial facilities.

Wind Facts

- 2,500± MW of wind capacity in California
- 0.5± MW of wind capacity in the CCSF

Three systems considered for supply mix:

- 3 kW building-mounted system (see Section 5.6.1)
- 500 kW small-scale wind turbine installation (see Section 5.6.2)
- 7,500 kW utility-scale wind turbine installation (see Section 5.6.3)

There is an estimated technical potential of 15± MW in the CCSF with an annual energy production of 30,000± MWh.

5.2 Wind Power Project Characteristics

Wind turbines are currently designed to have power output ratings of a few kilowatts up to units as large as 5 MW. Typically, the economics of a project improve with the installation of larger turbines due to the fixed cost associated with construction being spread over more megawatt hours when the unit is operating. Historically, a 52 kW turbine was considered large in the 1980s but now is not considered economical in farm installations as units in the range of 1.5 to 2.5 MW are typical commercial units.

The three basic categories of wind energy systems in this report include 1) building-mounted systems of less than 10 kW, 2) small-scale wind consisting of a single turbine

[23] Assuming 10 feet per story, this would equal a 26-story building.
[24] http://www.awea.org/projects.

or multiple small turbines, and 3) large-scale utility wind projects. The size and number of turbines utilized in each of these applications will vary based on wind and land available for siting turbines. Resource availability and economic factors also play into the potential cost benefit analysis of single or multiple turbines.

5.2.1 Description of Typical Building-Mounted Wind

Building-mounted wind installations typically associated with residences, businesses, and institutional installations are generally smaller than 10 kW and can be installed behind-the-meter for use by the local electric customer. Building-mounted wind units may be easier to site due to their size and are more suitable for a greater number of locations. In estimating the theoretical potential in the CCSF, a 3 kW turbine system comprised of three 1 kW turbines was considered for installation. Figure 5-1 shows an AVX1000 building-mounted wind turbine.

Figure 5-1 – Building-Mounted Wind Turbine

5.2.2 Description of Small-Scale Wind

Small-scale wind is developed around a single turbine or multiple turbines on a single site. While these projects range in size, they are typically less than 1,500 kW. A 500 kW turbine wind project consisting of two turbines was considered in this analysis for location in the CCSF.

5.2.3 Description of Utility-Scale Wind

Utility-scale wind projects consist of multiple turbines with individual turbines ranging in size from 1.5 to 2.5 MW of installed capacity. While projects of 2,000 MW or larger have been proposed throughout the U.S., typical sizes are in the range of 100 MW. These installations typically require higher levels of wind and significantly more land due to the spacing requirement of multiple turbines. Figure 5-2 shows the Montezuma-3 wind turbines in Collinsville, California.

Figure 5-2 - Montezuma-3 Wind Turbines

Wind energy is a variable or intermittent resource and has capacity factors ranging from a low of 10% to a high of 40%. The capacity factor of an installation depends on the wind strength and the energy capture of the wind turbine equipment.

5.3 Geographic Considerations for Wind Installations

Wind strength is rated on a scale from Class 1 through 7. Class 4 and higher is generally considered necessary for a site to be economically viable, but some sites with Class 3 wind may be acceptable, depending on cost of construction and available transmission line access. Classes 1 and 2 are generally not economically viable for utility-scale power generation, but may be acceptable for small-scale wind projects. Table 5-1 is a summary of wind classes and associated wind power density.

Table 5-1
Classes of Wind Strength

Wind Power Class	10 m (33 ft)		50 m (164 ft)	
	Wind Power Density (W/m2)	Speed[1] m/s (mph)	Wind Power Density (W/m2)	Speed[1] m/s (mph)
1 (Poor)	0 - 100	4.4 (9.8)	0 - 200	5.6 (12.5)
2	101 - 150	5.1 (11.5)	201 - 300	6.4 (14.3)
3	151 - 200	5.6 (12.5)	301 - 400	7.0 (15.7)
4	201 - 250	6.0 (13.4)	401 - 500	7.5 (16.8)
5	251 - 300	6.4 (14.3)	501 - 600	8.0 (17.9)
6	301 - 400	7.0 (15.7)	601 - 800	8.8 (19.7)
7 (Excellent)	401 - 1,000	9.4 (21.1)	801 - 2,000	11.9 (26.6)

Note: Vertical extrapolation of wind speed based on the 1/7 power law.
[1] Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea-level conditions. To maintain the same power density, speed increases 3%/1000 m (5%/5000 ft) elevation.

Source: http://www.eia.doe.gov/cneaf/solar.renewables/page/wind/wind.html.

Over the last decade, several studies have been undertaken to map wind strength throughout the U.S. and California. This work is typically done with high resolution maps showing wind speed and power density. In California, this work has been undertaken by public entities such as the NREL and CEC, as well as a private company, AWS Truewind.[25] The result of this work is publicly available and typically utilized as a starting point for locating wind power systems. Figure 5-3 shows the annual wind power in the State.

[25] AWS Truewind *Intermittency Analysis Project: Characterizing New Wind Resources in California*, CEC-500-2007-014, February 2007.

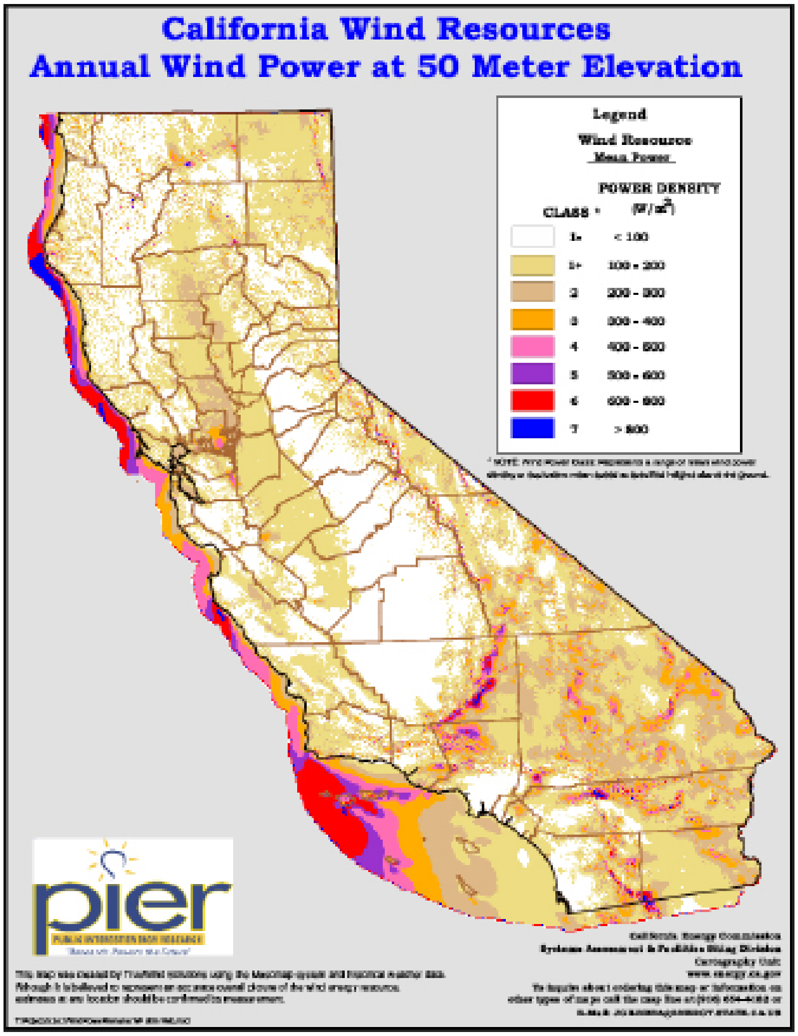


Figure 5-3 – California Wind Resources Annual Wind Power
Source: Edward F. McCarthy and Associates *Wind Resource Assessment for City-Owned Land in San Francisco County and Along the Hetch-Hetchy Right-of-Way*, March 31, 2007.

While wind studies and databases such as those identified above provide a starting point for determining wind potential of a study region, there are shortcomings in this data which includes the fact that the wind maps are based on atmospheric models and not actual wind speed. Therefore, developers of potential wind turbine sites typically use site-specific devices to capture several years of wind speed data at sites before determining whether to move forward with the development of a wind energy facility. The reason for the site-specific model is that it is more accurate than climate models.

5.4 CCSF Wind Potential Based on SFPUC Monitoring Stations

The SFPUC and CEC have undertaken wind resource assessments specific to the CCSF. These studies looked at specific wind monitoring locations throughout the city. Sites were selected for monitoring wind resources in connection with the Itron, Inc. report *City and County of San Francisco Wind Resource Assessment Project Task 5: Data Analysis and Reporting Final Report*, September 2004 prepared for the CEC. The locations of the wind monitoring sites in the CCSF are set forth in Figure 5-4.

Figure 5-4
Wind Monitoring Sites in San Francisco

The results of the CEC study indicated that the wind strength in the CCSF is limited and that with "the exception of Twin Peaks the wind energy resources at the monitoring sites appear to be quite modest relative to levels customarily associated with wind energy generation development. From the standpoint of economic feasibility of prospective wind energy generation facilities a wind power class equal to 1 is generally considered 'very poor' or 'poor'. In the case of small turbines, under the right circumstances (e.g., valuation of generated electricity at a high retail rate) a wind power class of 2 may be sufficient to justify development on financial grounds."[26] As can be seen from the information in Table 5-2, only the Twin Peaks location had a wind power class greater than Class 2.

[26] CEC *City and County of San Francisco Wind Resource Assessment Project, Task 5: Data Analysis and Reporting, Final Report*, September 2004, p. 6.

Table 5-2
Characteristics of Six Wind Monitoring Sites

Monitored Site	Coordinates (approximate)	Mount Type	Instrument Height Above Roof/Ground (feet)	Quantity of Data Compiled/Collected (months)	Wind Power Class
Pier 39 (PIER)	37° 48' North 122° 24' West	Roof	24	5	1
S.F. Zoo (ZOO)	37° 44' North 122° 30' West	Ground	30	9	1
Treasure Island (TI)	37° 49' North 122° 22' West	Roof	12	12	2
Hunters Point (HP)	37° 43' North 122° 22' West	Ground	33	14	1
Twin Peaks (TWIN)	37° 45' North 122° 27' West	Ground	60	8	4
S.F. Airport (SFO)	37° 37' North 122° 23' West	Ground	33	142	2

Source: CEC *City and County of San Francisco Wind Resource Assessment Project* Task 5: Data Analysis and Reporting Final Report, September 2004, p. 27.

The information in Table 5-2, as well as the studies prepared for the CCSF, indicates that wind strength in the CCSF jurisdiction is limited and that there are few potential sites for viable wind turbine installations. This is further supported by the low penetration of wind turbines in the CCSF.

5.5 Existing Amount of Wind Power in the CCSF

According to the SF Environment, there are six wind turbines in the CCSF with an estimated total installed capacity of less than 500 kW. The lack of more wind turbine installations in the CCSF, relative to approximately 2,500 MW[27] statewide, demonstrates the poor wind conditions throughout most of the CCSF. However, new wind turbines and lower costs may increase the potential for deployment of this resource in the future.

5.6 Generic Wind Turbine Characteristics

The wind energy systems selected for this report are based on a review of available technologies that could be deployed in the CCSF. This review identified a wide range of options available to market participants from small-scale building-mounted systems to large-scale utility-sized turbines. The installations considered for deployment in the CCSF consist of a 3 kW system comprised of three 1 kW units, a 500 kW system

[27] http://www.awea.org/pubs/factsheet/market-update.pdf

comprised of two 250 kW units, and a 7,500 kW project comprised of three 2,500 kW turbines.

Since the installations are assumed to be located within the CCSF, the ground-mounted installations will require a special permit due to the CCSF's current height limitation for ground-mounted systems. Building-mounted systems do not require a special permit if the units do not extend 10 to 16 feet above the roof and do not exceed 20% of the roof area.

Table 5-3 is a summary of the technical and economic characteristics associated with each of the installations.

Table 5-3
Technical and Economic Requirements
for Generic Wind Turbine Installations

Description	Building-Mounted 3 kW	Small-Scale 500 kW	Utility-Scale 7,500 kW
Project Characteristics			
Plant Capacity (kW)	3	500	7,500
Typical Duty Cycle	Intermittent	Intermittent	Intermittent
Unit Life (years)	10	30	30
Typical Area Required (acre)	N/A	4 - 5	30
Availability Factor	98%	98%	98%
Capacity Factor	15%	20%	20%
MWh/year	3.9	876	16,425
Construction Period	< 1 year	> 1 year	> 1 year
Technology Status	Mature	Mature	Mature
Economic Characteristics (2009$)[1]			
Capital Cost ($/kW)	$6,400	$3,260	$2,500
Fixed O&M ($/kW-year)	$50	$50	$30
Non-Fuel Variable O&M ($/kW-yr)	N/A	N/A	N/A
Capital Replacements ($/kW)	$1,000	$800	$800
Applicable Incentives	CA Self-Gen 30% ITC 5 yr. MACRS	CA Self-Gen 30% ITC 5 yr. MACRS	30% ITC 5 yr. MACRS

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).

5.6.1 Narrative Description of Building-Mounted Wind Turbine – 3 kW

Project Characteristics

The wind power system considered in this report for assessing the technical and economic characteristics of building-mounted units consisted of three 1 kW turbine generator units and an electrical interconnection. The expected life of these units is 10 to 20 years depending on replacements. The area required for the system is less than 50 square feet and has a height of 4 feet. The size and design of the 1 kW building-mounted turbines allow for the optimum siting of these resources throughout the CCSF. This optimum siting is anticipated to allow these units to maximize available wind potential and, for the purposes of the economic analysis, wind characteristics similar to those of Twin Peaks were considered reasonable. Therefore, the capacity factor of these units was based upon the wind data for Twin Peaks, even though the units are expected to be sited throughout the CCSF.

Economic Characteristics

The estimated cost of the installation is $6,400/kW or approximately $20,000. This would include the purchase of the unit, installation, and a net metering electric interconnection. The operating costs are estimated at $50/kW-yr and reflect cleaning and maintenance of the unit. The operation and maintenance required would include visual inspection, checking and tightening bolts, changing oils, and providing appropriate lubricants.

5.6.2 Narrative Description of Small-Scale Wind Turbine – 500 kW

Project Characteristics

The wind power system considered in this report for assessing the technical and economic characteristics of small-scale wind consisted of two 250 kW turbine installations. The expected life of the units is 30 years. The system has a net output of 500 kW and includes two Wind Energy Solutions (WES) 250 kW turbines installed at a height of 50 meters, or approximately 165 feet. The area required for installation is approximately 4 to 5 acres. The system's capacity factor of approximately 20% is based on the turbines' power curve and wind resources comparable to those found on Treasure Island. Therefore, Class 2 to 3 wind strength is considered reasonable given the size of the units and the ability to optimize the siting of the two turbines to maximize wind potential.

Economic Characteristics

The estimated cost of the installation is $3,260/kW, or approximately $1.63 million. This would include the purchase of the units, installation, and a net metering electric interconnection. The operating costs are estimated at $50/kW-yr and reflect cleaning and maintenance of the unit. The operation and maintenance required would include visual inspection, checking and tightening bolts, changing oils, and providing appropriate lubricants. At approximately 10-year intervals, blades and bearings may need replacement along with the inverter. The estimated capital cost of these replacements is $800/kW.

5.6.3 Narrative Description of Utility-Scale Wind Turbine – 7,500 kW

Project Characteristics

The wind power system considered in this report for assessing the technical and economic characteristics of large-scale wind consisted of three 2,500 kW turbine installations. The expected life of these units is 30 years. The system has a net output of 7,500 kW and assumes three Liberty 2,500 kW turbines installed at heights of 80 meters, or approximately 260 feet. The area required for installation is approximately 30 acres[28] and the capacity factor is estimated at 20% assuming Class 2 wind. The system's capacity factor is based on the turbine's power curve and wind resources comparable to those found on Treasure Island. Therefore, Class 2 to 3 wind strength is considered reasonable given the size of the units and ability to optimize siting three individual turbines.

Economic Characteristics

The estimated cost of the installation is $2,500/kW, or approximately $18.75 million. This would include the purchase of the units, installation, and a utility interconnection. The operating costs are estimated at $30/kW-yr and include typical maintenance and full-time monitoring of the installation. Inverter replacements are anticipated every 5 to 10 years at a cost of approximately $800/kW.

5.7 Theoretical and Technical Potential Conclusion for the use of Wind Power in the CCSF

The theoretical potential for wind energy systems in the CCSF is based on the California wind maps and high-level estimates of wind turbine installations using available land area and wind potential. The total land area in the CCSF is

[28] Depending on the siting of the units, significantly more land area may be required due to setbacks and spacing of units.

approximately 278 km^2,[29] or 69,500 square acres. According to the 2005 CEC wind maps, there were no areas in the CCSF suitable for high wind speed equal to or greater than Class 4 at a 70 meter hub height. There were approximately 45 km^2 of low wind speed areas which include wind classes greater than Class 2 but less than Class 4. Therefore, the CCSF would not be considered ideally suited for wind turbine installation and the wind potential in the CCSF is based on these lower wind speeds and limited theoretical wind potential.

Assuming that, on average, wind turbine installations require 50 acres per turbine and that the larger 2.5 MW turbines are used would result in approximately 20 acres per MW. Applying this to the theoretical potential of approximately 11,250 acres would result in a theoretical potential in the CCSF of about 560 MW operating at low wind speed. The theoretical potential does not account for siting or other technical constraints.

The existing data on wind speeds in the CCSF and the limited number of existing wind turbines indicates the technical potential for wind energy systems in the CCSF is much lower than the theoretical potential. The low wind speeds typically experienced by the CCSF combined with a lack of significant vacant land available for deployment of wind turbines resulted in no large-scale wind farms being considered technical feasible in the CCSF.

However, it is reasonable to assume that installations comprised of three or fewer turbines could be located within the CCSF. Examples of these would be single units or multiple units located on Twin Peaks or along the waterfront. Assuming that single installations could technically be located throughout the CCSF, it is reasonable to assume that 15 MW of wind capacity could be located throughout the CCSF before consideration of the economic potential of these installations. This 15 MW is a qualitative estimate based on a review of available land, existing development, and the current low penetration of wind turbines in the CCSF.

The 15 MW technical potential would require that the units be distributed throughout the CCSF to take advantage of siting opportunities and the best wind potential. This would concentrate the units on the waterfront and along the Twin Peaks ridge. In addition, it is possible that smaller turbines and building-mounted units could contribute to the technical potential.

The estimated energy production associated with 15 MW of installed capacity with an average capacity factor of 22.5% would result in 30,000 MWh per year.

[29] km^2 equals 250 acres

5.8 Data Sources

The following sources have been used in compiling data for this section.

- HRA Engineering *Feasibility Study for Solar & Wind Power in the City & County of San Francisco*, March 27, 2009
- AWS Truewind *Intermittency Analysis Project: Characterizing New Wind Resources in California*, February 2007
- Itron, Inc. *City and County of San Francisco Wind Resource Assessment Project Task 5: Data Analysis and Reporting Final Report*, September 2004
- Edward F. McCarthy & Associates *Wind Resource Assessment and Theoretical Energy Analysis for the Meteorological Monitoring Site at the SF Zoo and Assessment of Other County-Owned Lands on the Western Boundary of the City and County of San Francisco*, October 2005
- Dora Yen-Nakafuji California Wind Resources, CEC-500-2005-071-D, April 2005
- Edward F. McCarthy & Associates *Wind Resource Assessment for City-Owned Land in San Francisco County and Along the Hetch-Hetchy Right-of-Way*, March 31, 2007
- California Wind Energy Collaborative *Impact of Past, Present and Future Wind Turbine Technologies on Transmission System Operation and Performance*, May 2006
- American Wind Energy Association *Wind Power Outlook 2008*
- Angela Rodoni *Offshore Wind*, August 2008
- American Wind Energy Association *Wind Energy for a New Era - An Agenda for the New President and Congress*, November 2008

The following interviews were conducted in connection with this section.

- John Doyle, Manager Energy Generation Projects, SFPUC
- Johanna Partin, Renewable Energy Manager, San Francisco Department of the Environment

6.1 Tidal Power Introduction

Tidal power systems convert the movement or motion of the earth, sun, and moon into electricity. Tidal force is produced by the moon and the sun in combination with the earth's rotation and is responsible for the generation of tides. Tidal energy systems capture this energy and convert it into electric energy. Tidal power accounts for only a small fraction of the worldwide electric capacity. Currently, the only tidal power in the U.S. is the Roosevelt Island Tidal Energy pilot project in New York City's East River that could generate up to 10 MW.[30] There are no commercial tidal projects currently located in the State.

Tidal Facts

- No commercial tidal power installations currently operating in the U.S.

One system considered for supply mix:

- 2,400 kW open ocean turbine (see Section 6.5.1)

There is an estimated technical potential of 3$\pm$ MW in the CCSF with an annual energy production of 2,400$\pm$ MWh.

Resource type: Intermittent

6.2 Tidal Power Project Characteristics

Tidal systems are an evolving technology and, as such, no single tidal turbine system is considered standard technology nor are there any commercial-scale facilities located in the U.S.. Tidal generators extract energy from currents in a similar way as wind turbines extract energy from air currents. Industry standards suggest that tides must move at speeds of at least 2 knots for typical tidal projects to be economically feasible.[31]

Tidal turbines are currently being developed which range in size from 100 kW to 1.5 MW. Typically, the economics of the project improve with the installation of larger turbines due to fixed costs associated with construction being spread over more megawatt-hours when the unit is in operation. There are three basic types of tidal energy systems which include 1) tidal stream systems, 2) barrage systems, and 3) tidal lagoon systems. The size and number of turbines utilized in each of these applications will vary depending on tide velocity and available area for siting turbines.

Tidal systems have energy output that is more predictable than wind or solar, but are still an intermittent generating resource as the units do not store fuel and cannot be counted on to meet peak demands.

[30] http://www.verdantpower.com/what-initiative
[31] URS *Tidal Power Feasibility Study, San Francisco Public Utilities Commission*, March 2008, p. 18.

6.2.1 Description of Tidal Stream Systems

Tidal stream systems use the kinetic energy of moving water to power turbines, very similar to the way wind turbines use moving air. This is the most common type of turbine system as it can be utilized in a vast area of a bay or river and does not require ponding of tidal currents. Figure 6-1 shows two Verdant Power Free Flow Turbines awaiting installation at the Roosevelt Island Tidal Energy Project in New York City.

Figure 6-1 - Verdant Tidal Turbines

6.2.2 Description of Barrage Systems

Barrage systems make use of the potential energy and the difference in height, or head, between high and low tides. Barrage systems are typically dams across the full width of a tidal estuary and require significant civil engineering infrastructure and a viable site for installation. In addition, environmental issues make barrage systems that block tidal estuaries more difficult to permit and less appealing options than free flow turbines from an environmental standpoint. There are currently three tidal power plants in the world – in France, Russia, and Nova Scotia.[32] Figure 6-2 shows the tidal barrage system on the estuary of the Rance River in Bretagne, France which is operated by Électricité de France.

Figure 6-2 - Tidal Barrage System

[32] http://www.gov/ns.ca/energy/renewables/public-education/tidal.asp

6.2.3 Description of Tidal Lagoon System

Tidal lagoon systems are similar to barrage systems but are typically constructed more like conventional hydroelectric facilities. Figure 6-3 shows an image of a lagoon being planned within the Severn estuary in the United Kingdom.

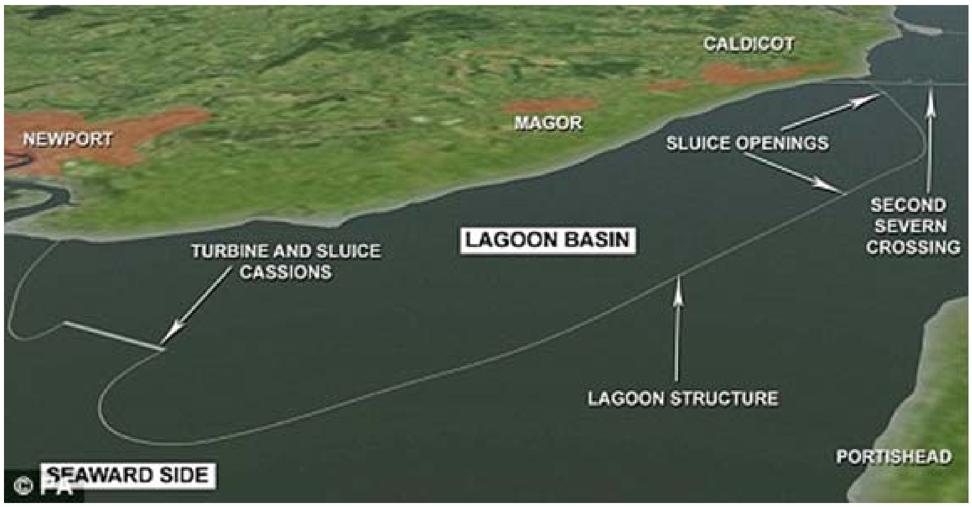


Figure 6-3 - Image of Tidal Lagoon System

6.3 Geographic Considerations for Tidal Power Installations

Tidal currents are not rated like wind classes however, like wind turbines, the location of tidal turbines is critical to extract sufficient energy from the moving current to generate electricity and justify installation. For the successful extraction of energy from tidal currents, the systems need to be located in areas with fast current where natural flows are concentrated between obstacles. Examples of these are entrances to bays and rivers around rocky points or between islands or other land masses.

In the last several years, sites throughout the U.S. and the world have been identified as having potential for installation of tidal turbines. In 2006, several locations in the U.S. and Canada were identified in a high-level feasibility study performed by the Electric Power Research Institute (EPRI) and included a site in the SF Bay.

Table 6-1 is a summary of the seven tidal sites and estimated MW capacity identified by EPRI in the feasibility study.

Table 6-1
Seven Tidal Sites Identified in EPRI Feasibility Study

Location	Available Power (MW)	Extractable Power[1] (MW)
Knik Arm, Alaska	116.0	17.4
Tacoma Narrows, Washington	106.0	16.0
Golden Gate, San Francisco, California	237.0	35.5
Muskeget Channel, Massachusetts	13.3	2.0
Western Passage, Maine	104.0	15.6
Head Harbor Passage, New Brunswick	43-100[2]	6.5-15[2]
Mines Passage, Nova Scotia	1,013.0	152.0
Total	**1,689.3**	**253.5**

[1] Extractable power is limited to 15% of available power.
[2] The total is comprised of the high end of the range.
Source: EPRI TP-008-NA, *North American Tidal In-Stream Energy Conversion Technology Feasibility Study* , June 11, 2006.

The EPRI study concluded that a relatively small amount of electric generation could be produced using tidal turbines due to a limited number of sites suited for this type of development. This is one of the factors why, to date, there are no commercial tidal facilities in the U.S. In addition, a review of the EPRI study by URS, Black & Veatch, and others found that it overestimated the extractable power in the SF Bay and may have similar issues with the other sites.

6.4 San Francisco Bay Tidal Power Potential

In addition to the high-level EPRI study, the SFPUC commissioned a tidal power feasibility study by URS and PG&E commissioned an independent study by Black & Veatch. Both studies estimated that the EPRI study had overstated the extractable power in the SF Bay and the estimated tidal resources were approximately 10% of those estimated by EPRI, or 1 to 3 MW. The URS study indicated that as of 2008 it did not consider a tidal power project in the vicinity of the SF Bay to be commercially feasible.[33] A review of these studies suggest that the total tidal power in the SF Bay is relatively modest and in the range of 3 MW or less.

6.5 Generic Tidal Power System Characteristics

Since there is little real world data on the development of tidal energy systems, the technical and economic characteristics of possible tidal turbine systems was developed from the studies prepared by URS and EPRI. This information is considered to provide the best basis for developing generic unit characteristics for deployment in the SF Bay.

[33] URS *Tidal Power Feasibility Study, San Francisco Public Utilities Commission*, March 2008, p. ES-3.

In developing the estimate for technical and economic characteristics, the natural resources and depth of the foundation make technology selection and construction of the system difficult. According to the URS study, "no in-stream power unit has been installed at the 50 m depth of the sill."[34] Therefore, the depth and location make installing equipment east of the Golden Gate Bridge more difficult than other sites and may result in actual costs being higher than those presented below. However, these estimates are considered reasonable for this report and provide a basis for the resource potential in the SF Bay.

The generic tidal turbine system is assumed to consist of two 1,200 kW units. These units are at the large end of the capacity range for this type of turbine and were selected to maximize energy capture and economic potential. Table 6-2 provides a summary of the technical and economic requirements of the project.

Table 6-2
Technical and Economic Requirements
for Tidal Turbine Installations

Description	Open Ocean Turbine
Project Characteristics	
Plant Capacity (kW)	2,400
Typical Duty Cycle	Intermittent
Unit Life (years)	30
Typical Area Required (sq. ft.)	N/A
Availability Factor	90%
Capacity Factor	10 - 15%
Construction Period	> 1 year
Technology Status	Evolving
Economic Characteristics (2009$)[1]	
Capital Cost ($/kW)	$7,700
Fixed O&M ($/kW-year) @ 5% Capital	$385
Non-Fuel Variable O&M ($/kW-yr)	N/A
Capital Replacements ($/kW-yr)	$125
Applicable Incentives	30% ITC 5 yr. MACRS

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).

[34] Ibid, p. 21.

6.5.1 Narrative Description of Tidal Stream System

Project Characteristics

For purposes of this report, it is assumed that two units could be installed east of the Golden Gate Bridge, resulting in a resource utilization of approximately 2,400 kW. The units are assumed to be similar to the Strangford Commercial Demonstrator identified in the URS study and pictured in Figure 6-4.

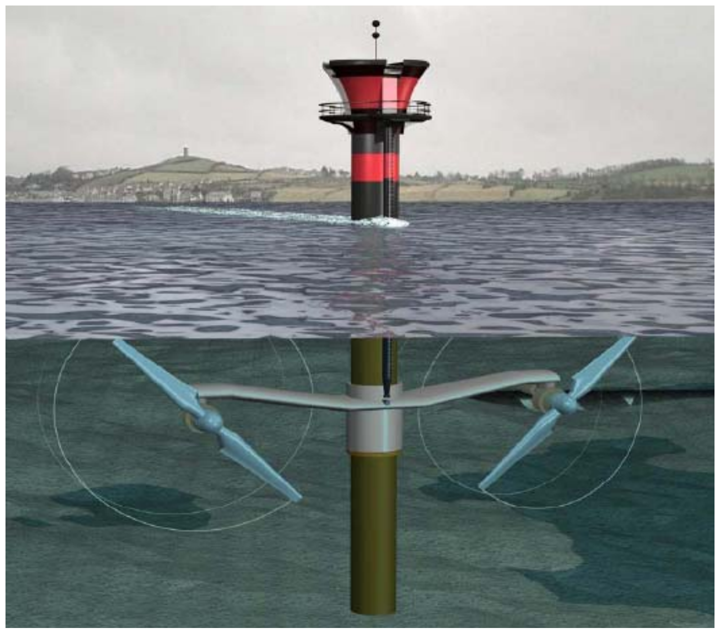


Figure 6-4 Strangford Commercial Demonstrator

Each turbine system will consist of a turbine, foundation, submarine cable, and interconnect to a single land-side utility interconnection. The capital cost assumptions utilized in Table 6-2 were developed utilizing information in the URS study.

Annual energy calculations for the units were based on the URS study and the associated computer modeling of the total flows around the Golden Gate Bridge. The URS study concluded that annual currents at the sill were calculated to contain approximately 15,000 kWh/m^2.[35]

The efficiency at which the turbine system captures this energy is assumed to be approximately 45% efficient with a 10% loss for internal consumption. The URS study assumed 18 meter diameter turbines rated at 1,200 kW which would capture 3,150,000 kWh/year and produce usable power of 1,215,000 kWh/year per unit.[36]

[35] Ibid, p. 22.
[36] Ibid.

This annual production would translate into a total annual generation for the two units of approximately 2,400,000 kWh and result in a capacity factor for the total installation of approximately 11.4% based on installed capacity of 2,400 kW.

Economic Characteristics

The estimated cost of the 2,400 kW project is $7,700/kW or $18.5 million and includes the turbine units' installation and utility interconnection. These costs are based on estimates in the URS study. The operation and maintenance figures of $385/kW-yr represent fixed costs of operation.

6.6 Theoretical and Technical Potential Conclusions for the use of Tidal Power in the CCSF

The theoretical potential for the tidal capacity on the east side of the SF Bay could be as high as 15 MW based on the available tidal resources. However, due to the utilization of the resource by other stakeholders[37] and the sensitivity of its ecological system, the technical potential is likely to be in the range of 1 to 3 MW.[38] Therefore, the theoretical and technical potential for a tidal energy system is considered to be 3 MW and at the high end. The capacity factor of the installations is approximately 10% and energy production potential is approximately 2,400 MWh per year.

> The 1 to 3 MW of technical potential is considered reasonable but has greater technical risk than other resources discussed in this report due to the developing nature of the technology.

6.7 Data Sources

The following sources have been used in compiling data for this section.

- EPRI *System Level Design, Performance, Cost and Economic Assessment – San Francisco Tidal In-Stream Power Plant*, EPRI-TP-006-SF CA, June 10, 2006.
- URS *Tidal Power Feasibility Study, San Francisco Public Utilities Commission*, March 2008.

The following interview was conducted in connection with this section.

- John Doyle, Manager Energy Generation Projects, SFPUC

[37] The consideration of other stakeholders includes commercial and recreational activities that use the SF Bay. These interests would have to be weighed with the use of the resource for power generation.
[38] URS *Tidal Power Feasibility Study, San Francisco Public Utilities Commission*, March 2008, p. 19.

7.1 Biogas Production Introduction

Biogas is considered an out-of-city resource that could be used in conjunction with in-city resources such as CHP or other forms of generation. The biogas would be delivered via the interstate pipeline system to the CCSF. Biogas production is the result of organic matter breaking down, in the absence of oxygen, into methane, hydrogen, and carbon monoxide which can be mixed with oxygen and combusted or used in a fuel cell to produce electricity. The two primary types of biogas are landfill gas or digester gas. The discussion of biogas presented below focuses on the second method of producing biogas, anaerobic digestion (AD). Landfill gas was considered but there is limited potential for additional landfill gas production as most landfill gas is currently being utilized for electric generation.

AD is the process by which microorganisms break down the volatile solids in organic matter which include carbohydrates, proteins, and fats in an environment devoid of oxygen. During the first stage of this process, bacteria convert the organic solids into volatile organic acids. During a second stage, methanogenic bacteria convert the acids into methane (CH4), carbon dioxide (CO2), and water vapor. This process produces biogas with 55 to 75% methane concentration, depending on the process. AD systems are utilized for the production of biogas which is then either further processed into pipeline-grade fuel or combusted in an electric generator or CHP system.

Biogas Facts

- Biogas is an out-of-city resource that can be transported to the CCSF for use in CHP or electric generation
- 358± MW of capacity using landfill and AD-derived biogas in California
- 3± MW of of biogas production at CCSF wastewater treatment plants

Two systems considered for supply mix:

- 250 kW internal combustion facility capable of transmitting output to the CCSF (see Section 7.5.1)
- Large-scale biogas facility capable of producing biogas for 10 MW of generation inside or outside of the CCSF (see Section 7.5.2)

There is an estimated technical potential of 55± MW in the CCSF with an annual energy production of 435,000± MWh.

Resource type: Base Load

The development of AD systems is typically associated with a source of biomass to reduce feedstock transportation costs and enhance project economics. These systems are typically small and consist of units that produce sufficient biogas for electric generators, ranging in size from 30 kW up to 1,000 kW.

7.2 Biogas Project Characteristics

AD systems differ in design, retention time, and operating temperature. Two basic types of digesters are batch digesters which are loaded with biosolids and emptied when digestion is complete and continuous digester systems where a steady supply of biosolids is introduced and the resulting biogas is continuously removed. Almost any organic matter can be processed through an AD system and includes yard waste, sewage, and animal waste. The exception to this is large, woody waste which is unable to degrade fast enough for the digestion process. While digesters can be configured in any size, certain economies of scale must be met to justify the construction of a facility.

There are several types of digesters that could be located within or outside the CCSF. The type of digester will depend on the footprint available as well as the type of organic matter being introduced to the system. The three most common types of digesters are 1) covered lagoons, 2) plug flow digesters, and 3) upright mix digesters. A discussion of each type of system is provided below.

7.2.1. Description of Covered Lagoons

Covered lagoon digesters have the largest footprint but are the least expensive to construct. This type of digester makes a poor choice in areas with high land value or limited space such as the CCSF. The digesters have a gas-tight flexible cover that can be placed on an existing or new constructed lagoon. Covers are typically made of high density polyethylene.

This type of system does not use complex equipment but does require regular maintenance such as removal of accumulated solids. Biogas yields from covered lagoon systems tend to be relatively low. Figure 7-1 shows a covered lagoon digester located at Royal Farms in Tulare, California.

Figure 7-1 - Covered Lagoon Digester

7.2.2 Description of Plug Flow Digesters

Plug flow digesters are horizontal concrete tanks or corrosion resistant metal and take up less space than covered lagoon digesters. This type of digester is heated to keep temperatures constant and the biosolid is continuously moved through the tank in a viscous plug. Retention time in plug flow digesters is approximately 20 days.

This type of digester requires biosolids or manure of 11 to 14% solids. Biogas yields tend to be higher than that achieved with covered lagoons. Figure 7-2 shows a plug flow digester used on dairy farms.

Figure 7-2 - Plug Flow Digester

7.2.3 Description of Upright Mix Digesters

Upright mix digesters are composed of a vertical tank, usually concrete or steel. The tank contains an agitation system that prevents the formation of a crust on the surface of the biosolid and insures complete contact with active microorganisms. In this type of system solids can be in the range of 2 to 10%. Upright mix digester systems are heated to optimize anaerobic decomposition and have in and out valves for biosolids and/or manure.

Upright mix digesters require a relatively small footprint and have the highest yield. However, they also have the highest capital cost of any of the digester systems. Figure 7-3 shows the digesters at the Oceanside Wastewater Treatment Plant located near the San Francisco Zoo. The facility was completed in 1993 and treats wastewater from the west side of the CCSF.

Figure 7-3 - Upright Mix Digesters

There are several benefits associated with an AD system in addition to the production of biogas. These include:

- Reduce pathogens and odor found in the effluent
- Capture and destruction of methane
- Conversion of organic nitrogen into ammonium that is better suited for agricultural use

Byproducts from the process include fertilizer and bedding which can be sold or used on a host farm. AD systems typically produce a steady supply of biogas and are typically base loaded forms of generation and are considered capable of meeting peak resource requirements due to the predictability and storage capability of the fuel source.

7.3 Geographic Considerations for Biogas Production

AD systems are typically located at the source of organic matter or biomass which can be used as feedstock for the digester, usually a host farm. However, the advantage of certain AD systems is that the digester can be located at the source of the organic matter and the biogas injected into a pipeline system for delivery to end users. The biogas can then be used for electric generation at remote locations, in this case, the theoretical use within the CCSF. Therefore, sources of biomass were reviewed both in and outside of the CCSF to address the potential of biogas as a feedstock for renewable generation within the CCSF.

A review of organic matter or biosolids available in the CCSF jurisdiction resulted in the identification of the CCSF composting program which produced approximately 100,000 tons per year (TPY) of food waste and/or yard debris. The CCSF currently composts this material for delivery to farms and vineyards outside the CCSF. This level of feedstock is relatively minor and not considered capable of supporting an AD facility in the CCSF. In addition to the food and yard waste, there are no other industries located within the CCSF jurisdiction that produce waste in sufficient quantities to develop AD systems. Therefore, the potential for biogas production or electricity from biogas would depend on resources located outside of the CCSF. This potential is addressed in Section 7.6 below.

7.4 Existing CCSF Installations Utilizing Biogas

A review of AD systems in the CCSF revealed two wastewater treatment plants (WWTP) that currently utilize AD to produce biogas. These systems utilize covered lagoon AD systems to produce biogas which is then combusted in CHP systems at the respective WWTP. The systems include a 1,160 kW system at the Oceanside WWTP and a 1,950 kW system at the Southeast WWTP.

It should also be noted that PG&E is currently purchasing biogas from Environmental Power Corporation's (EPC) Texas biogas facility and from a facility in Fresno County owned by BioEnergy for delivery to its pipeline system. This type of purchase and delivery mechanism could be utilized in the CCA program with the generation within or outside of the CCSF jurisdiction.

7.5 Generic Biogas Characteristics

The most common digester employed in California is the covered lagoon system due to the practice of using water to manage animal waste as opposed to scraping waste which is more common in eastern states. While lagoon systems are most common, plug or mixed batch digesters have greater energy potential and were also considered in this analysis as being the technologies most likely to be deployed on a large scale basis. Therefore, a typical 250 kW AD system utilizing a covered lagoon system is presented in this report along with a large-scale system capable of producing biogas that could be transported to the CCSF jurisdiction.

7.5.1 Narrative Description of Covered Lagoon Anaerobic Digester – 250 kW

The covered lagoon AD system is the most common in the State and is assumed to be associated with an internal combustion generator set which is the most robust form of electric generation for use with biogas. Table 7-1 is a summary of a typical system that could be located in the State.

Table 7-1
Technical and Economic Requirements
for a Covered Lagoon Digester Installation

Description	Covered Lagoon Digester
Project Characteristics	
Plant Capacity (kW)	250
Biogas (mmBtu)	30,000±
Typical Duty Cycle	Base Load
Unit Life (years)	20
Typical Area Required (sq. ft.)	300,000±
Availability Factor	90%
Capacity Factor	90%
Annual Generation (MWh)	1,643
Construction Period	> 1 year
Technology Status	Mature
Economic Characteristics (2009$)[1]	
Capital Cost ($/kW)	$5,500
Fixed O&M ($/kW-year)	$200
Non-Fuel Variable O&M ($/MWh)	$30
Capital Replacements ($/kW)	N/A
Applicable Incentives	ERP 30 ITC 5 yr. MACRS
Emissions Data	
NOx (lbs/MWh)	1.7
SOx (lbs/MWh)	0.4
CO2 (lbs/MWh)[2]	see Note

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).

[2] CO2 assumes natural gas fuel.

Note: AD biogas is assumed to be carbon neutral. SB 1368 identifies the whole fuel cycle characteristics of biogas and the net emission characteristics.

Project Characteristics

The covered lagoon digester and generating facility is assumed to be base loaded and capable of operating a significant number of hours during the year. The life of the system is estimated at 20 years with proper maintenance and is expected to take more than one year to permit and construct.

A typical system would include a single lagoon approximately 1,000 x 250 x 15 feet deep with an airtight cover. The internal combustion generator sets would include either two 125 kW generator sets or a single 250 kW set.

In developing the estimates for biogas production, general sources were reviewed to determine average production rates for various AD systems. These estimates are theoretical in nature and based on average site conditions for California. In addition, the figures do not take into consideration co-digestion of food or other organic waste which can substantially increase methane levels in the biogas and electric potential.

Depending on the waste feedstock and system design, biogas ranges from 55 to 75% pure methane gas. A covered lagoon system in California is estimated to produce approximately 45 ft^3/day/cow[39] of biogas with a methane content of 60%.[40] Therefore, a 250 kW generator operating 24 hours would produce 6,000 kWh and, at a heat rate of 13,500 Btu/kWh, would require approximately 3,000 cows, or the equivalent organic matter, to operate at full output.

Economic Characteristics

The cost estimate for the system is based on a typical installation but may vary depending on location and specific site requirements. The estimated cost of the digester and associated equipment is $5,500/kW and includes the covered lagoon, internal combustion generator set, and electrical interconnection.[41]

The total annual expenses for the system were based on a review of the cost to operate AD systems in California which range between $75,000 and $100,000/year. It is assumed that 50% of the total cost is fixed and 50% is variable expenses. Therefore, assuming an annual cost of $100,000, the fixed expense is $200/kW-yr and the variable expense is $30/MWh.

The annual allowance for replacements and system repairs is $100/kW and includes unforeseen maintenance and major maintenance of general systems that is anticipated every three years.

[39] *Dairy Power Production Program, Dairy Methane Digester System Program Evaluation Report*, August 2006, p. 61.
[40] Ibid, p. 91.
[41] Based on a review of AD system costs in California.

7.5.2 Narrative Description of Large-Scale Biogas Production

A second biogas-only production facility was considered as a supply resource for the CCA program when combined with a generating resource. This system is a mixed batch digester similar to the facilities being developed by EPC throughout the U.S. and produces pipeline-grade biogas. Figure 7-4 illustrates the process flow for a typical large-scale biogas facility.

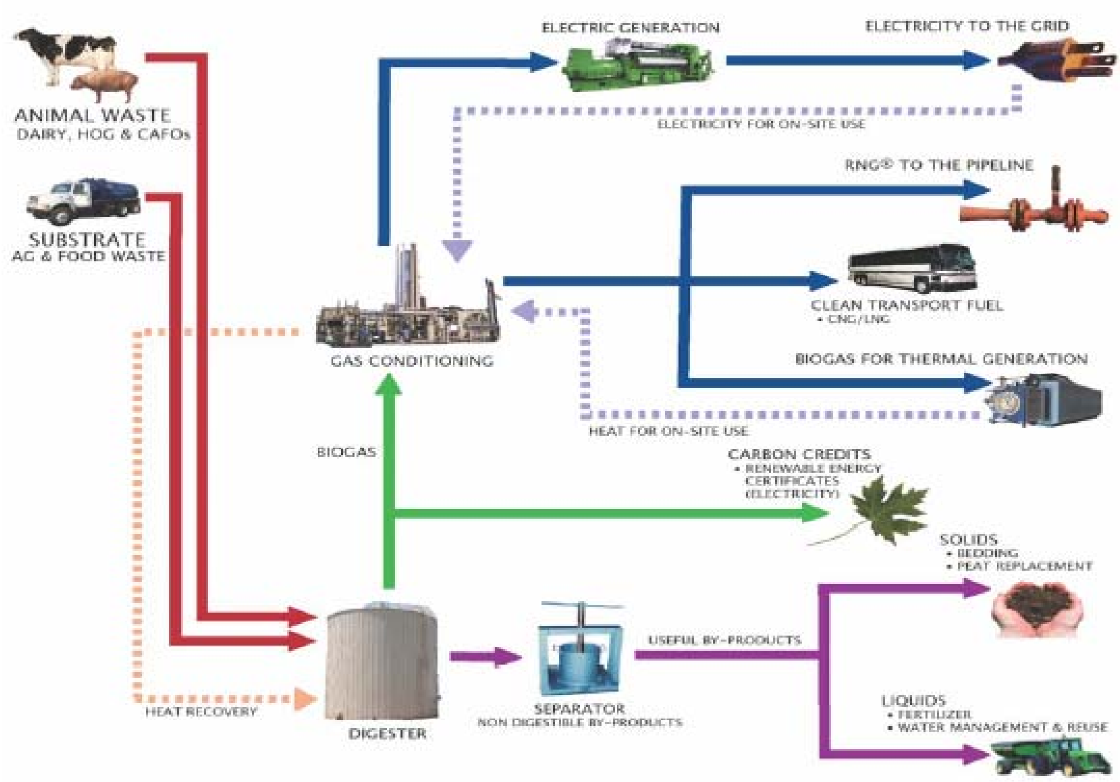


Figure 7-4 – Large-Scale Biogas Production – Process Flow
Source: Environmental Power Corporation *Company Presentation*, November 2008, p. 4

The biogas produced at the facility is further scrubbed or processed and compressed as it must meet the stringent requirements established by the pipeline companies prior to injection into their system. The injection of gas into the pipeline system requires this AD system to utilize more sophisticated scrubbing and pressurizing equipment than typical AD systems to assure consistent gas quality as biogas with low methane or other impurities would contaminate the natural gas in the pipeline system. Table 7-2 is a summary of the technical and economic characteristics associated with a large-scale biogas facility.

Table 7-2
Technical and Economic Requirements
for a Large-Scale Digester Installation

Description	Large-Scale Digester
Project Characteristics	
Biogas (mmBtu)	635,000
Typical Duty Cycle	Base Load
Unit Life (years)	30
Construction Period	> 1 year
Technology Status	Mature
Economic Characteristics (2009$)[1]	
Capital Cost ($/MMBtu)	$35
Non-Fuel Variable O&M ($/MMBtu)	$4
Estimated Cost of Biogas ($/MMBtu)	$9

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).

Project Characteristics

The following system description is based on EPC's Huckabay Ridge facility which is an upright mix digester that produces biogas in Stephenville, Texas. The plant's design calls for eight 916,000 gallon digesters which will process waste from approximately 10,000 cows plus organic matter and is expected to produce approximately 635,000 mmBtu of biogas per year. The system includes the eight digester tanks, a 700,000 gallon substitute tank, and a gas scrubber which removes carbon dioxide, water vapor, and hydrogen sulfide. The gas is then pressurized to approximately 1,000 psi using a natural gas compressor.

Economic Characteristics

This biogas production facility is estimated to cost approximately $22 million, or $35/MMBtu of biogas production capacity. The estimated annual operating expenses for the facility are approximately $4/MMBtu, or approximately $2.5 million.[42] The cost of biogas from the facility is estimated at approximately $9/MMBtu based on discussions with EPC and a review of the project's capital and operating costs.

[42] Environmental Power Corporation SEC Form FWP, 12/04.08.

This large-scale digester is estimated to produce approximately 635,000 mmBtu/year. Assuming this was utilized in a generator with an 8,000 Btu/kWh heat rate, it would result in enough gas for approximately 10 MW of capacity operating 90% of the year.

7.6 Theoretical and Technical Potential Conclusion for the use of Biogas in the CCSF

As previously stated, there is little additional biogas production potential within the CCSF due to the lack of organic matter which could be used as a feedstock. A recent study by the CEC for the State indicates a total technical potential by 2010 of approximately 538 MW with less than 1%, or 3 MW of potential in the CCSF.[43] This figure is considered reasonable given the lack of agricultural activity in the CCSF and the current capture and utilization of biogas at the existing WWTPs. Therefore, it is reasonable to assume that there is a total theoretical and technical potential of approximately 3 to 5 MW within the CCSF, including the existing WWTP digesters. The potential for out-of-city biogas production with delivery to the CCSF is much higher.

Several statewide studies have been undertaken to assess the potential for generating capacity using biomass and biogas resources. A recent study performed for the CEC and published in 2008 indicates that by 2010 the theoretical potential from biomass could be approximately 5,000 MW which includes approximately 4,500 MW of thermal conversion and 500 MW of landfill and biogas production.

In addition to this report, the CEC's website identified the potential for 105 MW of biogas production using farm-based organic matter. Therefore, it is reasonable to assume that there is approximately 100 to 150 MW of biogas potential in the State.

The estimated 150 MW of biogas potential includes three projects permitted within the State that are in various forms of pre-development activity. These projects will be developed using the same technology set forth in Figure 7.4 and are estimated to have potential biogas production capability of 1,954,000 mmBtu/year. Table 7-3 is a summary of these projects.

[43] CEC *An Assessment of Biomass Resources in California, 2007*, March 2008, p. 103.

Table 7-3
Biogas Production Capacity Permitted in California

Facility	Location	Type	Annual Energy Production (MMBtu/year)	Notes
Hanford Cluster	CA	RNG	732,000	Project Debt Financing obtained; Permitted
Bar 20	CA	RNG	601,000	Permitted; In Financing
Riverdale Cluster	CA	RNG	621,000	Project Debt Financing obtained: Permitted
		Total	**1,954,000**	

Source: Environmental Power Corporation *Company Presentation* , November, 2008, p. 14.

The combined capacity of the projects equals approximately 26 MW assuming a generating unit with a 10,000 Btu/kWh heat rate, or 38 MW assuming a unit with a 7,000 Btu/kWh heat rate.[44] In estimating the technical potential for biogas-fired generation in the CCSF jurisdiction, it is reasonable to assume that resources in the range of 26 to 38 MW are technically available to serve the CCA program, and based on discussions with EPC, the technical potential may be double this figure.

The theoretical and technical potential for the production of biogas within the CCSF is minimal and, for purposes of supplying the CCA program, is considered zero. However, 50 to 60 MW of biogas production was identified outside of the CCSF that could be transported into the CCSF for use in a variety of electric generating resources.

Therefore, a technical potential estimate of approximately 50 to 60 MW of biogas production capability is considered reasonable for use in the CCA program supply mix prior to economic considerations. Assuming that there are 55 MW of additional capacity operating at an annual capacity factor of 90% would result in the production of 435,000 MWh per year.

7.7 Data Sources

The following sources have been used in compiling data for this section.

- EPA *AgSTAR Handbook*, Second Edition
- Mark A. Moser *Resource Potential and Barriers Facing the Development of Anaerobic Digestion of Animal Waste in California*, December 1997

[44] Calculation based on: $\frac{MMBtu/yr}{Wh/Btu} \; / \; 7{,}446 \; hrs/yr = kW \; capacity$

- RIS International Ltd. *Feasibility of Generating Green Power through Anaerobic Digestion of Garden Refuse from the Sacramento Area*, April 2005
- Douglas W. Williams *Microturbine Operation with Biogas from a Covered Dairy Manure Lagoon*, 2001
- Environmental Power Corporation *Company Presentation*, November 17, 2008
- Securities and Exchange Commission *Environmental Power Corp. SEC Form FWP*, 12/31/08
- Zhiqin Zhang, Ph.D. *Existing Practices and Prospective Development of Wastes to Energy in California Presentation*, July 12-14, 2006
- Western United Resource Development, Inc. *Dairy Power Production Program Dairy Methane Digester System Program Evaluation Report*, August 2006
- Western United Resource Development, Inc. *Dairy Power Production Program Dairy Methane Digester System 90-Day Evaluation Report - Inland Empire Utilities Agency RP-5 Solids Handling Facility*, December 2006
- Natural Resources Conservation Service *An Analysis of Energy Production Costs from Anaerobic Digestion Systems on U.S. Livestock Production Facilities*, October 2007
- Department of Applied Economics *Staff Paper Series, Review of the Literature on the Economics of Central Anaerobic Digesters*, October 2008
- William F. Lazarus *Farm-Based Anaerobic Digesters as an Energy and Odor Control Technology, Background and Policy Issues*, February 2008
- Zhiqin Zhang and Gerry Braun *Cost of Electricity & Pipeline Quality Natural Gas from Biogas Presentation*, April 14-16, 2008
- Joe Kramer *Wisconsin Agricultural Biogas Casebook*, July 2008 Edition.
- California Biomass Collaborative *Biomass Resource Assessment in California in Support of the 2005 Integrated Energy Policy Report*, CEC-500-2005-066-D, April 2005

The following interview was conducted in connection with this section.

- Micky Thomas, Chief Financial Officer, Environmental Power Corporation

8.1 Fuel Cell Introduction

Fuel cells are similar to batteries in that each produces direct current (DC) through an electrochemical process without direct combustion of a fuel source. However, unlike a battery which stores previously produced electricity, a fuel cell produces DC electricity through the introduction of a fuel source. Fuel cells are based on an electrochemical process that converts the chemical energy of hydrogen into water and electricity. The hydrogen fuel source is typically derived from a hydrocarbon fuel such as biogas or natural gas. Since fuel cells do not combust hydrocarbon fuels, they have extremely low emissions.

Fuel cells are currently being developed for a number of stationary applications that include units as small as 3 kW up to 2,800 kW. The largest fuel cell installation in the U.S. includes a single installation with a capacity of approximately 2,000 kW located in Terre Haute, Indiana at the Wabash River Energy Facility. However, several large-scale installations are planned that could reach as high as 7,000 kW.

Fuel Cell Facts

- 17± MW of fuel cell capacity in California
- 0.25± MW of fuel cell capacity in the CCSF

Three systems considered for supply mix:

- 400 kW PAFC fuel cell (see Section 8.5.1)
- 1,400 and 2,800 kW MCFC fuel cells (see Section 8.5.2)

There is an estimated technical potential of 10± MW in the CCSF with an annual energy production of 43,800± MWh.

Resource type: Base Load to Peaking

8.2 Fuel Cell Project Characteristics

Most fuel cells are comprised of three primary systems which are 1) the fuel cell stack that generates DC electricity, 2) the fuel processor that converts the hydrocarbon fuel into a hydrogen rich feed stream, and 3) the power conditioner that provides reliable AC electricity or regulated DC.

There are four general fuel cell technologies which include 1) phosphoric acid fuel cells (PAFC), 2) molten carbonate fuel cells (MCFC), 3) solid oxide fuel cells (SOFC), and 4) proton exchange membrane fuel cells (PEMFC). These various types of fuel cells are at varying stages of commercial availability.

The electrolyte in each type of fuel cell is sandwiched between a positive and negative electrode which are then further stacked for the desired voltage. Figure 8-1 illustrates a generic fuel cell.

The hydrocarbon-based fuel enters the fuel cell and is mixed with air which causes the fuel to become oxidized.

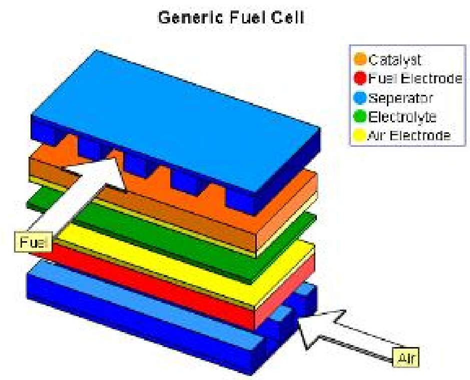


Figure 8-1 Generic Fuel Cell

In the case of PEMFC and PAFC, positively charged ions move through the electrolyte across a voltage to produce electricity. The protons and electrons are then mixed with oxygen to make water, and as this water is removed, the reaction continues.

In SOFC, oxygen radicals are moved through the electrolyte and protons.

In MCFC, carbon dioxide is required to combine with oxygen and electrons to form carbonate ions which are moved through the electrolyte.[45]

While fuel cells are still an emerging source of electric power, several have been installed throughout California. Figure 8-2 shows the four FuelCell Energy DFC300 250 kW cogeneration fuel cell units installed at the Sierra Nevada Brewing Company in Chico, California.

.

Figure 8-2 – Fuel Cells at the Sierra Nevada Brewing Company

[45] http://www.energy.ca.gov/distgen/equipment/fuel_cells/fuel_cells.html

Fuel cells can follow a wide range of electric loads and be deployed to serve a full range of electric demands. However, these units have a limited number of starts and have the greatest economic potential in a CHP application. Since these technologies utilize fuel which can be stored, their capacity can be used to meet peak demands.

8.3 Geographic Considerations for Fuel Cell Installations

The advantage of fuel cells is that they typically do not have geographic considerations like those encountered with other renewable resources and/or generating facilities. Depending on the size and application, they typically require only natural gas or biogas in order to operate. The drawback to fuel cells is their large footprint. While a 1,000 kW internal combustion engine may require approximately 350 square feet, a 1,200 kW fuel cell will require closer to 7,000 square feet. This size requirement makes the siting of these units difficult in densely developed settings like the CCSF.

8.4 Existing Fuel Cell Installations in the CCSF

The CCSF currently is host to approximately 255 kW of fuel cell capacity. The two facilities in the CCSF where fuel cells have been deployed are in conjunction with the U.S. Department of Defense Climate Change Fuel Cell Program.[46] Table 8-1 sets forth the details of the units within the CCSF.

Table 8-1
Fuel Cell Facilities in San Francisco

Location	Fuel Cell Type	Fuel Source	Power (kW)	Year Deployed
U.S. Postal Service Embarcadero Postal Center	MCFC	Natural Gas	250	2005
Presidio Trust Building	SOFC	Natural Gas	5	2002
		Total	**255**	

Source: http://www.fuelcells.org/dbs/projects.php

The 255 kW of fuel cell capacity in the CCSF is only a small fraction of the approximately 17± MW located at approximately 57 sites in the State.[47] This low historic penetration of fuel cell units is attributed to several factors including the developing nature of the technology, the high cost of the fuel cells, the relatively large footprint necessary for installation, and reliance on primarily natural gas. These factors

[46] http://www.fuelcells.org/dbs/project.php?id=112 and http://www.fuelcells.org/dbs/project.php?id=271
[47] http://www.fuelcells.org/dbs/projects.php

have limited the number of fuel cell units in the state, even with relatively high incentives from the State.[48]

8.5 Narrative Description of Generic Fuel Cell Characteristics

The fuel cell systems in this report are based on a review of available technologies that could be deployed in the CCSF and the existing type of installations in the State. This review identified a wide range of options available to market participants. Generic installations include a 400 kW PAFC and 1,400 and 2,800 kW MCFC systems[49] which were selected as being representative potential installations in the CCSF. Table 8-2 provides a summary of the operating characteristics associated with each of the units. In order to maximize efficiency, the units were assumed to be installed in CHP application with waste heat being used to produce hot water.

[48] The Self-Generation Incentive Program provides rebates of up to $4,500/kW for fuel cell installations of more than 30 kW using renewable fuels and $2,500/kW for non-renewable fuels.
[49] These units are similar to those proposed by the SFPUC for installation in close proximity to its wastewater treatment plant.

Table 8-2
Technical and Economic Requirements of Fuel Cells

Description	PAFC 400 kW	MCFC 1,400 kW	MCFC 2,800 kW
Project Characteristics			
Plant Capacity (kW)	400	1,400	2,800
Typical Duty Cycle	Base Load	Base Load	Base Load
Unit Life (years)	20	20	20
Typical Area Required (sq.ft.)	1,000±	7,000±	9,000±
Availability Factor	95%	95%	95%
Capacity Factor	90%	90%	90%
MWh/yr	3,153	11,038	22,075
Construction Period	< 1 year ±	> 1 year ±	> 1 year ±
Technology Status	Evolving	Evolving	Evolving
Economic Characteristics (2009$)[1]			
Capital Cost ($/kW)	$7,000	$6,000	$5,500
Fixed O&M ($/kW-year)	N/A	N/A	N/A
Non-Fuel Variable O&M ($/MWh)	$70	$70	$70
Capital Replacements ($/kW)	N/A	N/A	N/A
Applicable Incentives	CA Self-Gen 5 yr. MACRS	CA Self-Gen 30% ITC 5 yr. MACRS	CA Self-Gen 30% ITC 5 yr. MACRS
Performance Characteristics			
Electrical Heat Rate (Btu/kWh), HHV[2]	9,500	8,100	8,100
Electrical Efficency (%), HHV[3]	35%	42%	42%
Fuel Input (MMBtu/hr)	3.79	10.1	20.2
Heat Output (MMBtu/hr)	1.7	2.2	4.4
Heat Output (kW equivalent)	498	644	1,290
Total CHP Efficency (%) HHV[4]	81%	69%	69%
Power/Heat Ratio[5]	0.80	2.18	2.17
Effective Elec. Efficiency (%) HHV[6]	82%	65%	65%
Emissions Charcteristics			
NOx (lbs/MWh)	0.035	0.01	0.01
SOx (lbs/MWh)	Negligible	Negligible	Negligible
CO2 (lbs/MWh)[7]	1,120	600	600

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).

[2] Equipment manufacturers quote Heat Rate in terms of the lower heating value (LHV) of the fuel. Usable energy content of fuel is typically measured on a higher heating value (HHV) basis. Electric generating facility heat rates are typically quoted in HHV. The difference between LHV and HHV for plants utilizing natural gas is 11%.

[3] Electric efficiency is quoted net of parasitic and conversion losses.

[4] Total Efficiency equals (net electric generated + net heat produced) divided by total system fuel input.

[5] Power/Heat Ratio equals CHP electric power output (Btu) divided by useful heat output (Btu).

[6] Effective Electric Efficiency equals (CHP electric power output times 3,412) divided by (total fuel into CHP system minus total heat recovered divided by 0.8) electric equivalent equal to 3,412 Btu/kWh/net heat rate).

[7] CO2 assumes natural gas fuel.

8.5.1 Narrative Description of 400 kW Phosphoric Acid Fuel Cells

Project Characteristics

There are several manufacturers of fuel cells with units in the 400 kW size range utilizing various chemical, electrochemical, and electric subsystems.

For purposes of this report, a UTC Power PureCell 400, pictured in Figure 8-3, was considered to represent a reasonable technology for deployment within the CCSF considering its size and operating history. This fuel cell utilizes phosphoric acid technology and is considered commercially available.

Figure 8-3 – UTC Power PureCell 400

A 400 kW fuel cell is expected to operate approximately 90% of the year and have availabilities of 95%. The unit is expected to have a service life of 20 years with a stack[50] replacement every 5 to 10 years, depending on operation. The construction period estimate is less than one year and includes both permitting and siting of the unit. The footprint is relatively large at 1,000 square feet.

Economic Characteristics

The capital cost estimate is $7,000/kW or approximately $2.8 million plus an annual operating cost of approximately $70/MWh which includes the maintenance, labor, consumables, and major overhauls which would include a catalyst replacement every 3 to 5 years, a reformer catalyst replacement every 5 years, and a stack replacement every 4 to 6 years.

The unit's electrical heat rate is approximately 9,500 and overall efficiency utilizing the heat produced by the system is just over 80%. Emissions are very low.

[50] A fuel cell stack refers to the group of cells within the unit used to produce electricity.

8.5.2 Narrative Description of 1,400 and 2,800 kW Molten Carbonate Fuel Cells

Project Characteristics

Comparing Fuel Cell Emissions to Conventional Generation		
	DFC 3000 Fuel Cell	**Average U.S. Plant**
Fuel	Natural Gas	Natural Gas
Emissions:		
NOx (lbs/MWh)	.01	1.7
CO2 (lbs/MWh)	600	1,135

These large-scale fuel cell projects represent installations of 1,400 and 2,800 kW units offered by FuelCell Energy and are some of the largest single unit designs on the market. A picture of a FuelCell Energy DFC3000 is presented in Figure 8-4.

The units are expected to operate approximately 90% of the time with availability of 95%. The units require large footprints relative to the output with the 1,400 kW unit requiring approximately 7,000 square feet and the 2,800 kW unit 9,000 square feet. The units are estimated to have 20 year service lives with a stack replacement in 5 to 10 years.

Figure 8-4 – FuelCell Energy DFC3000

Economic Characteristics

The overnight cost is estimated at $5,500/kW and $6,000/kW for the 2,800 kW and 1,400 kW units, respectively. Both units have operating costs of approximately $70/MWh which includes the maintenance, labor, consumables, and major overhauls. Overhauls include a catalyst replacement every 3 to 5 years, a reformer catalyst replacement every 5 years, and a stack replacement every 4 to 6 years.

The units have heat rates of approximately 8,100 Btu/kW and overall efficiency utilizing the heat produced by the system is approximately 70%. Emissions are very low for units that utilize fossil fuels.

8.6 Theoretical and Technical Potential Conclusion for the use of Fuel Cells in the CCSF

The theoretical and technical potential for fuel cell deployment within the CCSF is dependent on whether the system is utilized in a CHP mode or as an electric-only installation. In a CHP application, the fuel cells will compete for customer load with other CHP units and have a potential of approximately 130 MW. This potential is discussed in Section 9.

If the units are assumed to operate in an electric-only mode, then the theoretical potential is considered to equal the CCSF's electrical load of approximately 750 MW as units could be configured and installed to replace grid-based electricity. This theoretical potential is considered to greatly overstate the true technical potential based on both the ability to site units and the historic penetration of fuel cells in the CCSF.

Therefore, the technical potential for fuel cell installation was assumed to include only customers with greater than a 200 kW load which, according to a presentation by PG&E, represents approximately 250 MW of demand associated with approximately 370 customers.[51] These installations are considered to be large enough to utilize a fuel cell in some configuration. Therefore, the technical potential prior to economic considerations is 250 MW.

Since it is unrealistic to completely ignore economic considerations, even in assessing the theoretical and technical potential, the historic statewide fuel cell installation is less than 1% of the total installed generation and includes units used for power-only and in CHP applications. A 1% penetration is considered to represent the high-end of possible deployment within the CCSF based on past experience with these units. This is due to the unit's large footprint, value of real estate in the CCSF, and cost of the fuel cells. Therefore, a 10 MW fuel cell potential is considered reasonable for installation prior to economic considerations. The units could serve loads ranging from base load to peak energy needs and have capacity factors from a few percent to as high as 90%. Assuming a mid-point of 50%, the 10 MW of fuel cells could provide approximately 43,800 MWh per year.

[51] PG&E *Meeting San Francisdo's Load Requirements*, May 5, 2008, pp. 15-16.

8.7 Data Sources

The following sources have been used in compiling data for this section.

- http://www.energy.ca.gov/distgen/equipment/fuel_cells/
- http://www.fuelcells.org/dbs/projects.php
- EPA Combined Heat and Power Partnership *Catalog of CHP Technologies*, December 2008

The following interviews were conducted in connection with this section.

- John Doyle, Manager Energy Generation Projects, SFPUC
- George Brandt, Sales Operation Manager, UTC Power

9.1 Combined Heat and Power Introduction

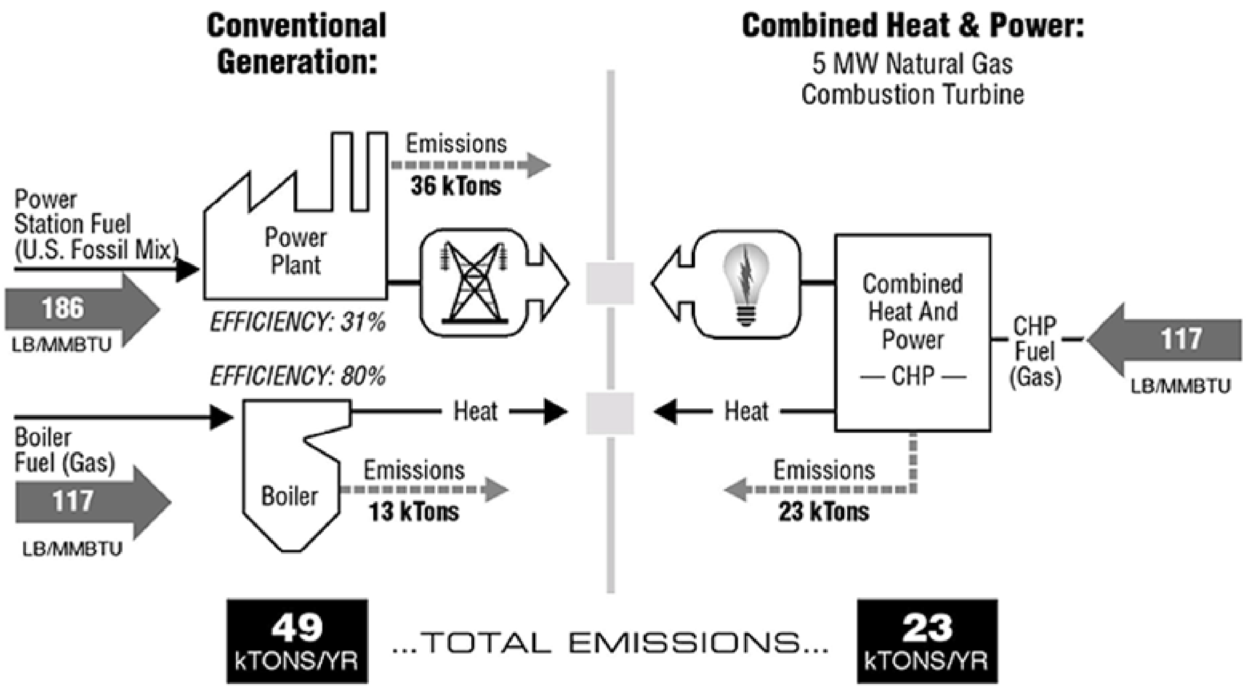
> **CHP Facts**
>
> - 9,000± MW of CHP in California
> - 30± MW of CHP in the CCSF
>
> Three systems considered for supply mix:
>
> - 65 kW microturbine operating on natural gas or biogas (see Section 9.5.1)
> - 1,000 kW reciprocating engine operating on natural gas or biogas (see Section 9.5.2)
> - 50 MW combustion turbine associated with downtown steam loop (see Section 9.5.5)
>
> There is an estimated technical potential of 130± MW in the CCSF with an annual energy production of approximately 1 million MWh.
>
> Resource type: Base Load

Combined heat and power (CHP) systems, also referred to as cogeneration systems, generate electricity and useful thermal energy in a single integrated system. CHP systems differ from conventional generating facilities or boilers which are designed to perform a single function and, unlike conventional generating facilities, the thermal energy recovered in a CHP system can be used for heating or cooling in residential, commercial, or industrial applications. Because CHP systems capture the thermal energy associated with the generation of electricity that would normally be rejected in traditional generation of electric power, the total efficiency of CHP systems is typically much greater than individual power or heat systems with efficiencies of approximately 80% while the most efficient power generating facilities are in the range of 60%.

While CHP can be operated utilizing renewable fuels, most CHP installations use natural gas but create environmental benefits due to the amount of energy extracted from each unit of fuel. The use of both centralized and distributed CHP infrastructure results in a reduction of greenhouse gas (GHG) emissions and is considered a reasonable technology for inclusion in the CCA program supply mix due to these benefits. Figure 9-1 illustrates a comparison of the GHG emissions associated with traditional single building energy systems and electricity delivered from the electric grid for a building utilizing 5 MW of electricity.[52]

[52] A 5 MW load would be similar to a large hospital or campus of buildings.

Figure 9-1
Comparison of Emissions
for 5 MW Electric Output



Source: http://www.epa.gov/chp/basic/environmental.html

Figure 9-1 illustrates the CO2 emissions output from electricity generation and thermal energy generation from the two systems, 1) a separate heat and power system with a fossil fuel-fired power plant (emissions based on the U.S. fossil mix) and a natural gas-fired boiler and 2) a 5 MW combustion turbine CHP system powered by natural gas. The separate electric and power systems emit a total of 49 kilotons/year of CO2 while the CHP system only emits 23 kilotons/year.

Traditional CHP systems can range in size from 100 kW up to systems as large as 1,500 MW. Installations are typically sized for the energy load of a single building, multiple buildings such as a campus, or an industrial application. In addition, CHP systems may be used in steam loops like the downtown steam system owned by NRG Thermal LLC (NRG) in the CCSF. The largest cogeneration facility in the U.S. is the Midland Cogeneration Venture facility in Midland, Michigan which is currently rated at 1,500± MW. There are approximately 9,000 MW of CHP capacity installed statewide.

9.2 Combined Heat and Power Project Characteristics

CHP systems can utilize a variety of technologies, the most common of those are gas turbines, microturbines, reciprocating engines, and fuel cells. Fuel cell technology was discussed previously in Section 8 and is not included in this discussion of conventional CHP systems.

9.2.1 Description of Gas Turbines

Gas turbine installations are typically associated with industrial applications or large commercial installations. Gas turbine technologies range in size from approximately 500 kW to 200 MW and generally operate on natural gas due to the size of the units. Combustion turbines have poor efficiencies at low loads and produce more emissions. Figure 9-2 shows the inside of a GE LM6000 Sprint gas turbine which is a 50± MW unit.

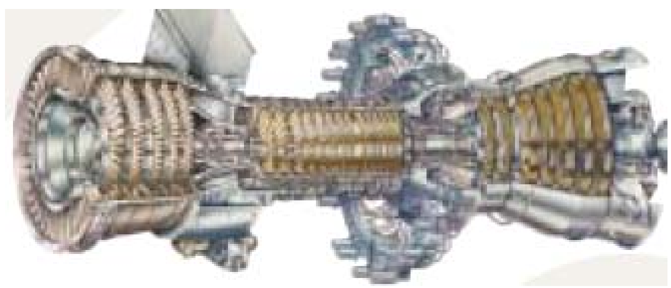


Figure 9-2 - Gas Turbine

9.2.2 Description of Microturbines

Microturbines are small in nature, ranging in size from 30 to 250 kW. These units have relatively high costs and are limited to low temperature cogeneration applications. The benefit of microturbines is that they are simple units and typically require no cooling or other specialized equipment for operation. Figure 9-3 shows the 60 kW Capstone microturbines at the Ritz-Carlton hotel in San Francisco.

Figure 9-3 – Microturbine

9.2.3 Description of Internal Combustion Engines

Internal combustion engines are typically less than 5 MW. These units are less sophisticated than microturbines and have a wider range of power efficiency operating at partial or minimal load. Internal combustion engines are the most flexible types of CHP units. Figure 9-4 shows a Waukesha APG series internal combustion engine.

Figure 9-4 - Internal Combustion Engine

CHP resources are typically base load and operate at very high capacity factors. These systems can be used as a compliment to intermittent resources such as wind or solar which only produce electricity when the resource permits.

9.3 Geographic Considerations for Combined Heat and Power Installations

The advantage of CHP systems is that location and size are typically not a factor as the units utilize biogas or natural gas as a fuel and have relatively small footprints relative to electrical output. The ability to transmit biogas to a CHP facility from a resource outside the city makes them particularly attractive in the CCA program's goal of seeking renewable generation within the CCSF jurisdiction.

The only geographic consideration is the existence of a heat or chilled water host and the availability of natural gas or biogas at sufficient pressures to fuel the facility. Since most of the CCSF has sufficient levels of natural gas to currently operate the heat source at existing infrastructure, it is considered feasible to site typical CHP facilities throughout the CCSF.

9.4 Existing Combined Heat and Power Installations in the CCSF

The CCSF currently is host to approximately 60 MW of CHP capacity if the 30 MW unit at the San Francisco International Airport is included, with 13.5 MW located at the University of San Francisco campus which hosts a natural gas-fired combined cycle unit. The remaining capacity located in the CCSF is comprised of smaller units ranging in size from 14 kW to the combined 3 MW of cogeneration capacity located at the CCSF's wastewater treatment plants which utilize biogas fuel. Table 9-1 is a summary of existing CHP units within the CCSF and at the San Francisco International Airport. These units are utilized for a variety of applications ranging from base load heat and power to peaking system only operated for a few hours of the year.

Table 9-1
Cogeneration Facilities in San Francisco
and San Francisco International Airport

Industry	Location	Technology	Fuel	Power (kW)	Began Operating
AirTransportation	United Cogen, Inc., SFO	CombCycle	NatGas	30,000	1985
College/Hospital	University of California, SF	CombCycle	NatGas	13,500	1998
College/University	University of San Francisco	Recip Engine	NatGas	1,500	1988
College/University	San Francisco State University	Recip Engine	NatGas	725	1984
		Recip Engine	DualFuel	1,250	1998
Schools	High School	Recip Engine	NatGas	300	2005
Schools	High School	MicroTurbine	NatGas	240	2005
Printing/Publishing	Arden Wood Benevolent Assoc.	Recip Engine	NatGas	90	1987
Residential Highrise	1080 Chestnut Street	Recip Engine	NatGas	60	1988
Residential Highrise	Nihonmachi Terrace	Recip Engine	NatGas	75	1992
Residential Highrise	Pacific Height Towers	MicroTurbine	NatGas	60	2005
Office Buildings	One Market Street	Recip Engine	NatGas	1,500	2003
Office Buildings	595 Market Street	Recip Engine	NatGas	1,130	2004
Office Buildings	DG Energy Solutions	Recip Engine	NatGas	1,200	2002
Office Buildings	201 Mission Street	Recip Engine	NatGas	750	2005
Office Buildings	TransAmerica Building	Recip Engine	NatGas	1,100	2007
Office Buildings	California Public Utilities Commission	Recip Engine	NatGas	400	2003
Office Buildings	Civic Center	Recip Engine	NatGas	800	
Office Buildings	Fremont Group	Recip Engine	NatGas	800	
Laundries	Fulton Fabricare Center	Recip Engine	NatGas	14	1991
Nursing Homes	Northern California Presbyterian Homes	Recip Engine	NatGas	240	1997
Postal Center	U.S. Postal Service	FuelCell	NatGas	250	2005
Hotels	Ritz Carlton	MicroTurbine	NatGas	240	2005
Waste Treatment	Oceanside Waste Management Facility	Recip Engine	BioGas	1,160	
Waste Treatment	Southeast Waste Management Facility	Recip Engine	BioGas	1,950	
Hospital	St. Francis Memorial	Recip Engine	NatGas	240	1996
Hospital	St. Mary's Medical Center	Recip Engine	NatGas	750	2006
			Total	**60,324**	

Source: Dr. Philip M. Perea A*n Assessment of Cogeneration for the City of San Francisco, Department of the Environment City and County of San Francisco* , June 2007, p. 10.

The 60 MW of CHP capacity in the CCSF and at the San Francisco International Airport is only a small fraction of the approximately 9,000 MW of CHP located at over 900 sites in the State.[53] The low historic penetration of CHP units in the CCSF is attributed to several factors including the ability of buildings to connect to the downtown steam loop, the high cost of construction in the CCSF, and the absence of industrial development which accounts for over half of the CHP capacity in California.

In addition, not-for-profit entities in the CCSF have the option of purchasing low cost electricity from the SFPUC which makes the economies of CHP more difficult to justify in institutional or city-owned buildings.

9.5 Generic Combined Heat and Power Characteristics

Generic installations included in this report are a 65 kW microturbine and a 1,000 kW reciprocating engine. In addition, a large-scale 50 MW combustion turbine installed at the NRG steam production facility was identified as an opportunity unique to the CCSF. These technologies were selected as representing the potential installations in the CCSF and are discussed below.

9.5.1 Narrative Description of Microturbines

Microturbines range in size from 30 to 250 kW and can be located inside or outside of enclosures or buildings. The basic components of microturbines include a compressor, turbine generator, recuperator, and heat exchanger. The compressor turbine package is typically comprised of a single shaft which is linked to a generator for the production of electricity. This shaft typically turns at a speed of more than 80,000 RPM. The recuperator is a heat exchanger that utilizes exhaust gas, typically at temperatures greater than 1,000°F, to preheat combustion air.

In a CHP application, there is a second heat exchanger that transforms the remaining energy from the microturbine exhaust into hot water. This hot water can then be utilized in a variety of applications which include:

- Process or space heating
- Potable water heating
- Drive or absorption chilling
- Other on-site building uses

[53] Pacific Region Combined Heat and Power Application Center *2008 Combined Heat and Power Baseline Assessment and Action Plan for the California Market*, September 30, 2009.

There are several manufacturers of microturbines which provide a range of sizes and designs. A Capstone C65 was considered to represent a reasonable technology for deployment within the CCSF considering its size and ability to be located within existing infrastructure. Several larger microturbines were considered which have lower costs per unit and better electrical efficiencies, but required a substantial footprint and vertical clearance for installation. While the Capstone model was selected, there are several units produced by other vendors that could be substituted in this size range.

Figure 9-5 shows the internal components of a microturbine.

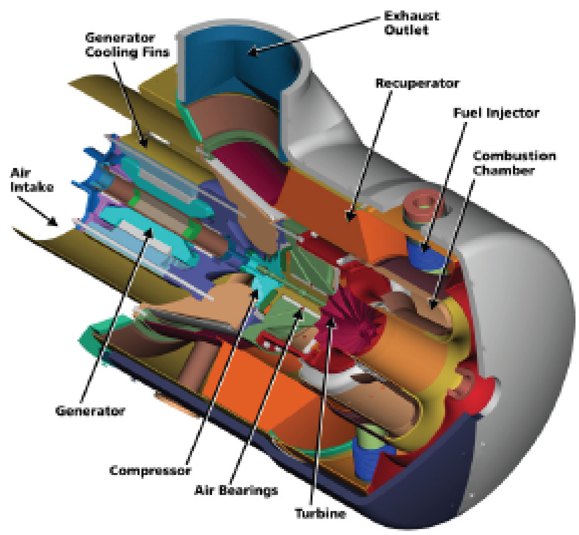


Figure 9-5 - Internal Components of a Microturbine

In addition to a single unit, several microturbines could be installed to meet large electric and heat loads. An example of this type of application is the four 60 kW microturbines at the Ritz-Carlton in San Francisco that total approximately 240 kW.

Table 9-2 is a summary of the characteristics of a 65 kW microturbine which is considered to operate in a CHP mode utilizing biogas or natural gas and provide hot water from the exhaust heat.

Table 9-2
Technical and Economic Characteristics
of a 65 kW Microturbine

Description	Microturbine 65 kW
Project Characteristics	
Plant Capacity (kW)	65
Typical Duty Cycle	Base Load
Unit Life (years)	10
Typical Area Required (sq.ft.)	110
Availability Factor	98%
Capacity Factor	95%
MWh/yr	541
Construction Period	<1 year
Technology Status	Mature
Economic Characteristics (2009$)[1]	
Capital Cost ($/kW)	$3,000
Fixed O&M ($/kW-year)	N/A
Non-Fuel Variable O&M ($/MWh)	$40
Capital Replacements ($/kW)	N/A
Applicable Incentives	CA Self-Gen 10% ITC 5 yr. MACRS
Performance Characteristics	
Electrical Heat Rate (Btu/kWh), HHV[2]	13,650
Electrical Efficency (%), HHV[3]	25%
Fuel Input (MMBtu/hr)	0.889
Required Fuel Gas Pressure (psig)	75
Exhuast Flow (lbs/sec)	1.12
Exhuast Temp (degrees F)	592
Heat Output (MMBtu/hr)	0.408
Heat Output (kW equivalent)	120
Total CHP Efficency (%) HHV[4]	71.0%
Power/Heat Ratio[5]	0.54
Effective Elec. Efficiency (%) HHV[6]	59%
Emissions Charcteristics	
NOx (lbs/MWh)	<.07
SOx (lbs/MWh)	0.3
CO2 (lbs/MWh)[7]	1,597

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).

[2] Equipment manufacturers quote Heat Rate in terms of the lower heating value (LHV) of the fuel. Usable energy content of fuel is typically measured on a higher heating value (HHV) basis. Electric generating facility heat rates are typically quoted in HHV. The difference between LHV and HHV for plants utilizing natural gas is 11%.

[3] Electric efficiency is quoted net of parasitic and conversion losses.

[4] Total Efficiency equals (net electric generated + net heat produced) divided by total system fuel input.

[5] Power/Heat Ratio equals CHP electric power output (Btu) divided by useful heat output (Btu).

[6] Effective Electric Efficiency equals (CHP electric power output times 3,412) divided by (total fuel into CHP system minus total heat recovered divided by 0.8) electric equivalent equal to 3,412 Btu/kWh/net heat rate).

[7] CO2 assumes natural gas fuel.

Project Characteristics

The unit is expected to have a 10-year life or 80,000 hours of operation. The availability is expected to be high at approximately 98% of the year with a capacity factor estimate of 95%. The unit is considered to be a mature technology and take less than one year to install.

Economic Characteristics

The unit is estimated to cost $3,000/kW installed based on vendor quotes and a review of EPA studies. The $40/MWh maintenance cost includes fixed O&M. The maintenance schedule for the microturbine is similar to that of combustion turbines and includes:

- After each 8,000 hours of operation – replace air and fuel filters
- After each 16,000-20,000 hours of operation – inspect/replace fuel injectors, igniters, and thermo couplers
- After each 20,000 hours of operation – replace battery
- After each 40,000 hours of operation – major overhaul and core turbine replacement

The major overhaul after 40,000 hours of operation consists of replacing the main shaft with the compressor and turbine and inspecting and/or replacing the combustor. This overhaul is estimated at $800/kW.

Performance Characteristics

The unit is expected to have a heat rate of approximately 13,600 Btu/kWh and a heat output of 0.408 mmBtu/hr. This results in an electric efficiency of approximately 60% HHV and an overall efficiency of approximately 70%. The electric efficiency compares favorably to alternative sources of electric generators using fossil fuel which range from 30 to 60%, depending on technology and fuel.

9.5.2 Narrative Description of Reciprocating Engines

Reciprocating engines are among the most widely used or type of technology for distributed power and CHP applications. Reciprocating engines can range from a few kilowatts to 5 MW. There are two basic types of engines, spark ignition and compression ignition engines. Spark ignition engines, like those found in most automobiles, use primarily natural gas but can also use biogas, propane, or gasoline. Compression ignition engines, or diesel engines, typically operate on diesel or kerosene but can be configured to burn gas-based fuels.

In a CHP application, spark ignition engines are typically utilized with natural gas. These units are relatively inexpensive, have a long operating history, and offer efficiencies of between 60 and 70%. This high efficiency is produced by the capture of waste heat from four sources that include 1) exhaust gas, 2) engine water jacket cooling water, 3) lube oil cooling water, and 4) turbo charger cooling.

The recovered heat is typically in the form of hot water which can be used for the following:

- Process or space heating
- Potable water heating
- The driver for absorption chilling
- Other on-site building uses

Figure 9-6 is a typical illustration of a reciprocating engine in CHP operation.

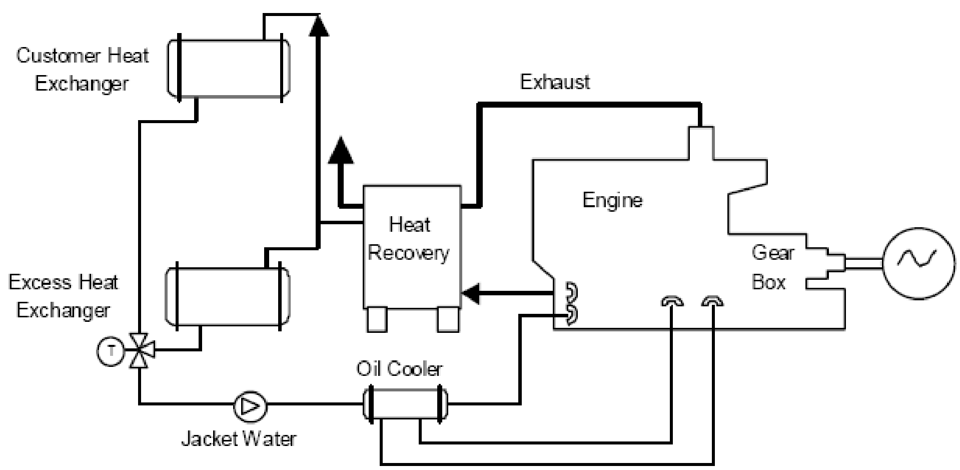


Figure 9-6 - Illustration of Reciprocating Engine

There are several manufacturers of reciprocating engines that could be used as CHP units. However, like the microturbines large units all require a greater footprint and hinder the ability to effectively deploy those systems in the CCSF. Therefore, units in the 1,000 kW range were considered for inclusion in this report, such as the Waukesha APG1000.

The Waukesha engine has been used in several CCSF applications and includes the 1.5 MW installation at One Market Street and the 1.1 MW installation at the Transamerica building.

Table 9-3 is a summary of the characteristics of a 1,000 kW reciprocating engine operating on natural gas or biogas in a base load mode of operation and providing hot water from the exhaust heat.

Table 9-3
Technical and Economic Characteristics
of a 1,000 kW Reciprocating Engine

Description	Reciprocating Engine 1,000 kW
Project Characteristics	
Plant Capacity (kW)	1,000
Typical Duty Cycle	Base Load
Unit Life (years)	20
Typical Area Required (sq.ft.)	350
Availability Factor	92%
Capacity Factor	90%
MWh/yr	7,884
Construction Period	< 1 year
Technology Status	Mature
Economic Characteristics (2009$)[1]	
Capital Cost ($/kW)	$2,200
Fixed O&M ($/kW-year)	$25
Non-Fuel Variable O&M ($/MWh)	$15
Capital Replacements ($/kW)	N/A
Applicable Incentives	CA Self-Gen 10% ITC 5 yr. MACRS
Performance Characteristics	
Electrical Heat Rate (Btu/kWh), HHV[2]	10,429
Electrical Effecincy (%), HHV[3]	33%
Fuel Input (MMBtu/hr)	10.4
Heat Output (MMBtu/hr)	4.657
Heat Output (kW equivalent)	1,365
Total CHP Efficency (%) HHV[4]	77%
Power/Heat Ratio[5]	73%
Effective Elec. Efficiency (%) HHV[6]	75%
Emissions Charcteristics	
NOx (lbs/MWh)	< 0.07
SOx (lbs/MWh)	< 0.09
CO2 (lbs/MWh)[7]	1,150±

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These incentives are addressed in the economic potential report (Task 2).
[2] Equipment manufacturers quote Heat Rate in terms of the lower heating value (LHV) of the fuel. Usable energy content of fuel is typically measured on a higher heating value (HHV) basis. Electric generating facility heat rates are typically quoted in HHV. The difference between LHV and HHV for plants utilizing natural gas is 11%.
[3] Electric efficiency is quoted net of parasitic and conversion losses.
[4] Total Efficiency equals (net electric generated + net heat produced) divided by total system fuel input.
[5] Power/Heat Ratio equals CHP electric power output (Btu) divided by useful heat output (Btu).
[6] Effective Electric Efficiency equals (CHP electric power output times 3,412) divided by (total fuel into CHP system minus total heat recovered divided by 0.8) electric equivalent equal to 3,412 Btu/kWh/net heat rate).
[7] CO2 assumes natural gas fuel.

Project Characteristics

The unit is expected to have a 20-year life with an availability of 92%. The capacity factor is estimated at 90%. The unit is considered to be a mature technology and take less than one year to install.

Economic Characteristics

The unit is estimated to cost $2,200/kW installed based on vendor quotes and a review of EPA studies. The unit is estimated to require $25/kW-yr in fixed operating and maintenance, insurance, and other expenses. The variable operating and maintenance is estimated at approximately $15/MWh and includes consumables and a maintenance service contract. The contract will include routine short interval inspections to the unit, periodic engine oil and filter replacements. A top-end overhaul is recommended at approximately 10,000 hours and a major rebuild is performed at between 30,000 and 35,000 hours.

Performance Characteristics

The unit is expected to have a heat rate of approximately 10,500 Btu/kWh and a heat output of approximately 4.5 mmBtu/hr. This results in an electric efficiency of approximately 75% HHV and an overall efficiency of approximately 80%. The electric efficiency compares very favorably to alternative sources of electric generators using fossil fuel.

9.5.3 Narrative Description of Large-Scale Combustion Turbine Installation of Steam Loop

Large-scale gas turbine technology has advanced rapidly since the 1990s and is currently one of the most widely deployed technologies utilized in new generating applications for use with liquid or gas-based fuels. Gas turbines range in size from a 500 kW to 200 MW and can be utilized in electric-only or CHP applications.

There are two general types of gas turbines which include aero derivative and frame type units. Aero derivative turbines are used for stationary power and are adapted from jet or turbo shaft turbine engines. These units are used for peaking applications where quick starts are necessary as well as for base load applications. Typical units range in size from 40 to 50 MW.

Frame type units are typically large units and designed exclusively for stationary power. These units typically are large in nature and require longer periods of time to reach full operation. In a CHP application, gas turbines form the primary driver with the exhaust gas which reach temperatures as high as 1,100°F and are utilized in a heat recovery steam generator (HRSG) to produce steam or hot water. If steam is produced, additional electricity can be produced in this application.

While it is possible to utilize combustion turbines in either a peaking or combined cycle mode, in the CCSF with the appropriate permits, this type of installation is considered beyond the scope of this report. However, one project that could potentially supply up to 50 MW was considered as it utilizes combustion turbine technology in a CHP mode by supplying waste heat to the downtown steam loop and does not propose a new fossil fuel-fired plant. Instead, this project would be the replacement of an existing boiler with a combustion turbine which would produce electricity and the waste heat would be used for the production of steam.

The downtown steam loop owned by NRG serves approximately 180 buildings in the Market Street area. The steam is produced utilizing a conventional boiler. In looking to expand its steam production capability and increase its thermal efficiency, NRG prepared engineering and feasibility studies that propose the incorporation of a 50 MW General Electric LM 6000 combustion turbine into its existing steam production facility. This turbine would replace one of its existing boilers and increase both steam production for its growing system and the efficiency of the system. The new turbine is expected to be 30-40% more efficient than the existing boiler and provide positive environmental and reliability benefits to the CCSF.

The repowering of the steam production facility would be done with the installation of an LM 6000 PF and a 10 MW steam turbine to provide approximately 53 MW of electricity in addition to the steam.

Table 9-4 provides a summary of the project's technical and economic characteristics.

Table 9-4
Technical and Economic Characteristics
of a Large-Scale Combustion Turbine
Associated with the Steam Loop

Description	LM 6000 Installation on Steam Loop (Phase 1)
Project Characteristics	
Plant Capacity (MW)	50
Typical Duty Cycle	Base Load
Unit Life (years)	30
Typical Area Required (sq.ft.)	10,000
Availability Factor	98%
Capacity Factor	90 - 92%
MWh/yr	315,360
Construction Period	> 1 year
Technology Status	Mature
Economic Characteristics (2009$)[1]	
Capital Cost ($/kW)	$2,500
Fixed O&M ($/kW-year)	$10
Non-Fuel Variable O&M ($/MWh)	$25
Capital Replacements ($/kW)	Included in Variable
Performance Characteristics	
Electrical Heat Rate (Btu/kWh), HHV	8,000
Electrical Efficency (%), HHV	43%
Fuel Input (MMBtu/hr)	430
Heat Output (MMBtu/hr)	69.3
Heat Output (kW equivalent)	20,300
Total CHP Efficency (%) HHV	56%
Power/Heat Ratio	2.4
Emissions Charcteristics @ 53.6 MW	
NOx (lbs/MWh)	0.057
SOx (lbs/MWh)	0.06
CO2 (lbs/MWh)[2]	931

[1] The Economic Characteristics do not include any federal, state, or local incentives for the development of renewable resources. These
[2] CO2 assumes natural gas fuel.
Note: Figures provided by NRG Thermal

Project Characteristics

The unit is expected to have a 30-year life with an availability of approximately 98%. The capacity factor is estimated at 90%. The unit is considered to be a mature technology. Construction is considered to require more than one year due to a constrained footprint and limited construction lay down area.

Economic Characteristics

The unit is estimated to cost $2,500/kW based on discussions with NRG. The maintenance cost includes fixed O&M. Fixed operating and maintenance costs include staffing, insurance, and administrative costs which are estimated at approximately $10/kW-yr for the project. These costs may be lower for the unit installed as part of the existing steam loop but are considered reasonable.

In addition, variable costs will include consumables as well as the cost of future maintenance that accrues relative to stops and starts and hours operated. These expenses are estimated at $25/MWh and include the following maintenance schedule:

- After each 4,000 hours of operation - inspection using boroscopes and other visual maintenance techniques
- After each 25,000 hours of operation - hot gas path inspection and rebuild
- After each 50,000 hours of operation - major overhaul of both the hot and cold gas paths

These costs are typically included in a maintenance service agreement.

9.6 Theoretical and Technical Potential Conclusion for the use of Combined Heat and Power in the CCSF

The potential for CHP installation, measured in megawatts of capacity, is dependent on a corresponding host for the additional thermal energy generated in the CHP process. The excess thermal energy can be used for a number of different applications such as space or process heaters, domestic hot water, or evaporative cooling and dependent on user-specific thermal loads.

In assessing the theoretical and technical potential for CHP in the CCSF, several sources of information were reviewed and considered. One of these was a report prepared for the SF Environment which assessed CHP potential in the CCSF. This report concluded that there is approximately 106 MW of CHP potential within the

CCSF based on a review of likely candidates for this type of application. The conclusions from the study are set forth in Table 9-5 by identifiable market segments.

Table 9-5
Cogeneration Potential in San Francisco

Market	Power (MW)
Office Buildings	> 80
Hotels	~ 20
Residential Highrises	> 2
Hospitals	~ 4
Other (Commercial Retail and Misc., Data Centers, Schools/Fitness Centers with pools, Warehouses)	several MW (to be studied)
Total:	**> 106**

Source: Dr. Philip M. Perea *An Assessment of Cogeneration for the City of San Francisco, Department of the Environment City and County of San Francisco*, June 2007, p. 14.

The conclusions from this report are considered consistent with the theoretical potential of CHP units in the CCSF, but may overstate the technical or reasonable potential penetration of CHP units in the downtown area due to the existence of the downtown steam loop.

A review of the candidate buildings that comprise the 106 MW of potential indicates that several buildings currently served by steam from the loop were also considered candidates for CHP application. While it may be possible to attract customers from the existing steam loop with CHP application, it is unlikely that this will occur in the near-term. According to NRG, only one customer on its loop has installed a CHP unit and it still receives backup steam from the system. Therefore, it is more reasonable to assume that existing customers of the steam loop will continue to utilize this steam and are not reasonable candidates for CHP application. In addition, since the repowering of the steam production facility with an LM 6000 is considered as a significant supply source in this report, it is important to avoid double-counting steam customers that could install CHP units and also benefit from the repowering of the steam facility. Therefore, a review of candidates for CHP from the SF Environment report was undertaken to avoid double-counting of the candidates in the downtown area.

In analyzing the revised potential for CHP candidate buildings, a diagram of the downtown steam loop which identifies the general location of the existing steam lines and buildings was reviewed along with information provided by NRG relative to their customers. Figure 9-7 sets forth the NRG system map.

Figure 9-7 – NRG San Francisco Area
Source: http://www.nrgthermal.com/Centers/Sanfran/index.htm

This review of the system map and discussions with NRG indicated a theoretical potential of 57 MW in this office building market as opposed to the 80 MW cited in the original SF Environment report. The difference between the figures is the result of eliminating those candidate buildings that are current steam loop customers or have existing CHP.

In addition to the candidates that are currently served by the steam loop, there are approximately 36 million square feet within one block of a steam line or that could be served by the steam loop, according to NRG. If the candidate buildings within one block of the steam loop are eliminated as potential candidates for CHP application, the result is approximately 20 MW of potential in the downtown area.

Therefore, after reviewing the potential candidates for CHP throughout the CCSF, it is more reasonable to assume that there is a theoretical potential of approximately 80 MW of distributed CHP throughout the CCSF and another 50 MW associated with the repowering of the steam production facility. This total of 130 MW is considered to be a reasonable estimate for near-term potential, especially considering that just under half is attributable to an identifiable project. The 130 MW technical potential for CHP is considered reasonable and over four times more CHP than currently installed in the CCSF. This figure is considered to reflect a reasonable penetration for CHP and includes projects such as the University of California, San Francisco complex and other buildings currently considering CHP installations even though these projects have not been specifically addressed in the totals. These units are considered to be based loaded with capacity factors of approximately 90% and result in an annual energy potential of approximately 1 million MWh per year.

9.7 Data Sources

The following sources have been used in compiling data for this section.

- Dr. Philip M. Perea *An Assessment of Cogeneration for the City of San Francisco, Department of the Environment City and County of San Francisco*, June 2007
- ONSITE SYSCOM Energy Corp. *Market Assessment of Combined Heat and Power in the State of California*, December 22, 1999
- EPRI *Assessment of California CHP Market and Policy Options for Increased Penetration*, July 2005
- U.S. EPA Combined Heat and Power Partnership *Catalog of CHP Technologies*, December 2008
- ICF International *CHP Market Analysis*, December 16, 2008
- Pacific Regional Combined Heat and Power Application Center *2008 Combined Heat and Power Baseline Assessment and Action Plan for the California Market*, September 30, 2008

The following interview was conducted in connection with this section.

- Jerry Pittman, LEED AP, NRG Thermal LLC

Economic Potential for Renewable Energy Resource Development in the City and County of San Francisco as part of the CCA Program (Task 2 of 5)

(DRAFT REPORT)

Prepared for the
San Francisco
Public Utilities Commission

June 29, 2009

Contract No.: **CS No.: CS-920R-A**

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Appendices

1.1 Overview of Economic Potential

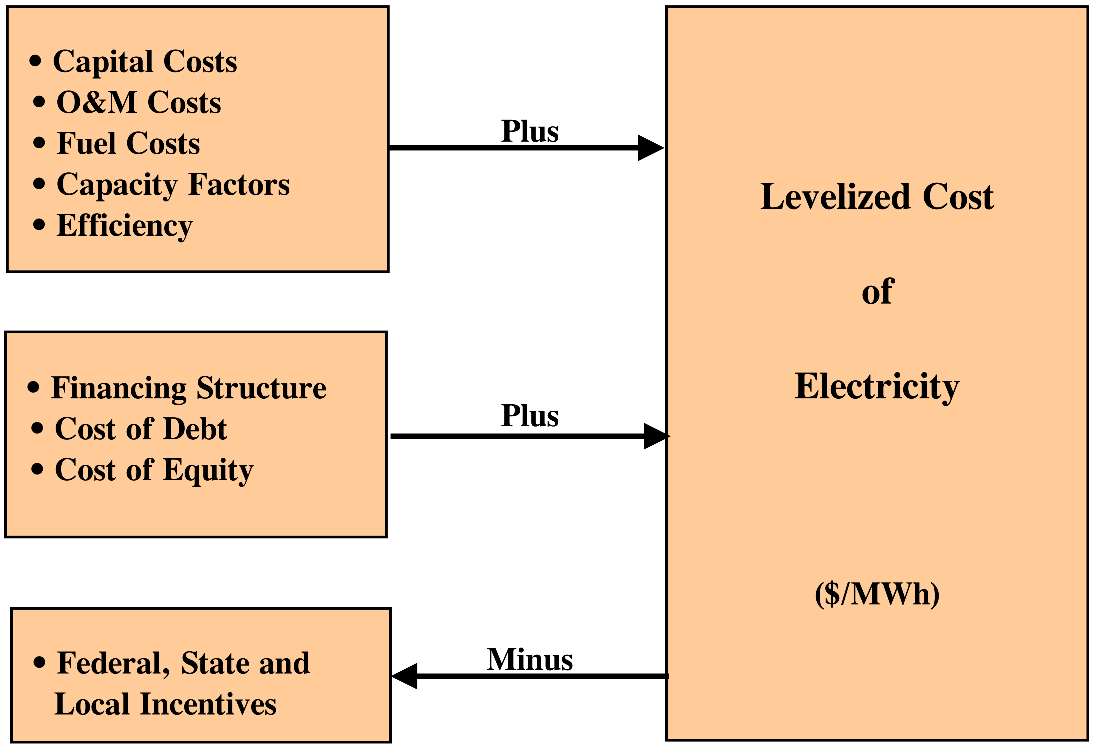
George E. Sansoucy, P.E., LLC (GES) was retained by the San Francisco Public Utilities Commission (SFPUC) to prepare a report on the economic potential for renewable energy resource development in the City and County of San Francisco (CCSF) as part of its Community Choice Aggregation (CCA) program.

> **Levelized Cost of Electricity (LCOE)**
>
> • The LCOE, for the purposes of this analysis, is defined as the cost per unit of electricity required to recover the invested capital, cover annual operating and maintenance (O&M) expenses, and provide debt and equity investors their respective rates of return.
>
> • The LCOE represents the level or constant price over a specified time period that electricity must be sold for so that a project can break even based on a specific assumption about the project's cost of capital and is a standard unit of measure used to assess the life cycle cost of various competing resources.

The purpose of this Task 2 report is to analyze the economic potential of those resources considered theoretically and technically possible within the CCSF. The economic potential is based on the Levelized Cost of Electricity (LCOE) associated with each technology identified in the Theoretical and Technical Potential (Task 1) Report under two ownership scenarios. The first scenario assumes for-profit ownership with the electricity being delivered to the CCA program via a power purchase agreement (PPA). The second scenario assumes the renewable resource is owned by a not-for-profit entity such as the CCSF or quasi-governmental entity created to own the generation on behalf of the CCA program using H Bonds or other forms of tax exempt revenue bonds to finance these projects. The for-profit scenario allows the owner/developer to utilize all incentives available at the federal level through the U.S. Tax Code. The LCOE, for the purposes of this analysis, is defined as the cost per unit of electricity required to recover the invested capital, cover annual operating and maintenance (O&M) expenses, and provide debt and equity investors their respective rates of return.

Figure 1-1 is an illustration of the LCOE components relative to the annual costs associated with each increment of electricity as measured in dollars per megawatt-hour ($/MWh). The LCOE includes all the fixed and variable costs of operation, taking into consideration the effect of federal, State, and local tax incentives and revenue required to support the capital investment.

Figure 1-1
Levelized Cost of Electricity (LCOE) Components



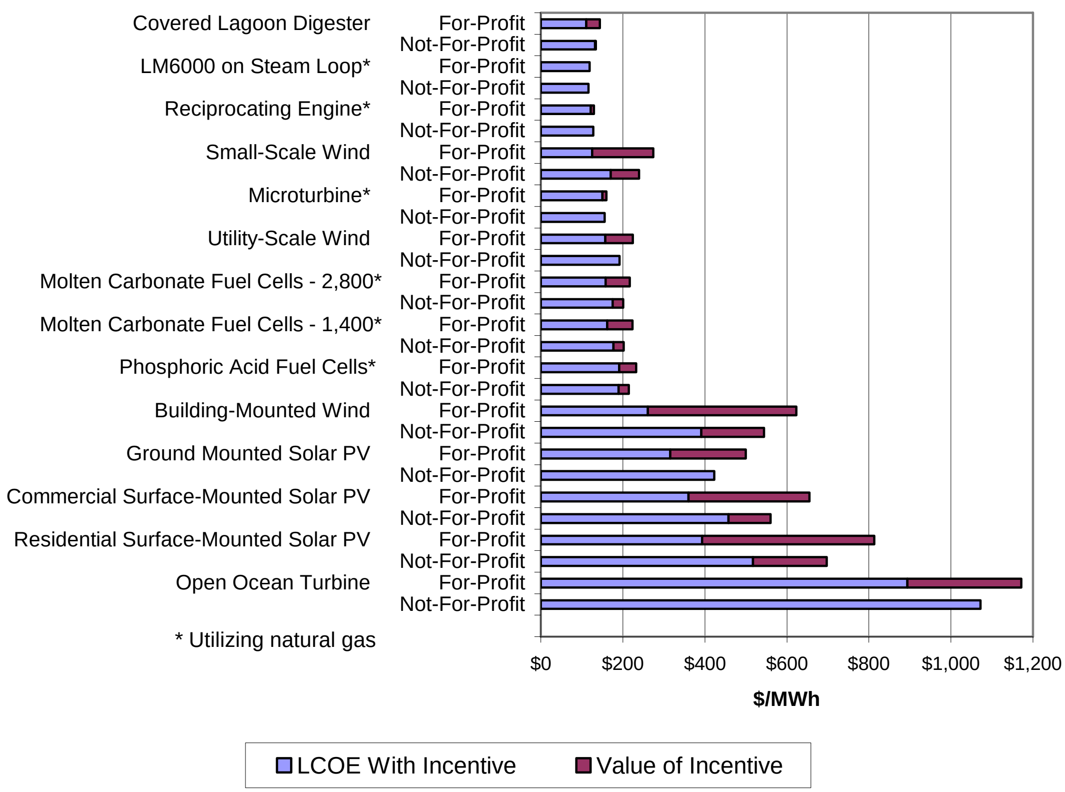
The levelized costs set forth in this report correspond to the levelized cost model set forth in Figure 1-1. A full discussion of these components and the scenarios under which the LCOE was calculated is provided in Section 3.

1.2 Levelized Cost of Electricity

The LCOE of the theoretically and technically possible renewable energy resources identified in the Task 1 report was developed using the spreadsheet models developed by GES. A separate model was developed for each ownership structure that addresses the capital structure and ability of each ownership type to take advantage of incentives available to renewable resources. The model calculates the LCOE of each renewable resource over a 20-year period, which is a typical period for this type of analysis, based on resource-specific cost and operating data and market-based assumptions about financing, federal and State tax liability or benefits, and other incentives available to each technology. The 20-year period is selected to reflect typical useful lives of projects, debt financing periods which typically do not exceed 20 years, and is a long enough period to reflect future costs associated with each unit relative to other market alternatives. The for-profit model minimizes the LCOE over a 20-year period while maintaining debt financing requirements and equity returns necessary to satisfy investor requirements. The not-for-profit model develops the LCOE over a 20-year period by calculating the revenue requirements associated with each project assuming 100% debt financing and no federal or State income tax benefits or liability.

The results of each analysis are set forth in Figure 1-2. A general discussion of these results is provided below along with a summary of the assumptions and results for each resource category.

Figure 1-2
Levelized Cost of Electricity (LCOE)
Including Incentives and LCOE Without Incentives
(in ascending order by For-Profit)



The LCOEs shown in Figure 1-2 illustrate the total cost of each resource with and without incentives utilizing an LCOE spreadsheet model designed to minimize the cost of electricity. The LCOE for each resource is presented based on for- and not-for-profit ownership structures and takes into account the value of the various federal, state, and local incentives. The LCOE with incentives represents the price at which these resources could provide power to the CCA program utilizing the existing incentives. The total LCOE is presented to measure the total cost of the resources absent any incentives.

An example of how the incentives lower the LCOE is illustrated in the small wind category which has a total LCOE under both the for- and not-for-profit scenarios of over $200/MWh. After inclusion of various incentives, the LCOE under both scenarios is less than $200/MWh with the unit's LCOE being reduced significantly by the current incentives available to this resource. Since a significant number of the incentives are administered through the Federal Tax Code, for-profit entities have a cost advantage over not-for-profit entities in the development and ownership of most renewables as illustrated in Figure 1-2.

The overall LCOEs offer deductions for the incentives and range from a low of approximately $120/MWh to a high of over $1,000/MWh and indicate that the fuel cell and CHP units utilizing natural gas as a fuel provide the lowest LCOE while solar PV and wind are among the highest. The primary reason for the high cost of solar PV, wind, and tidal power is the high capital cost of each project on a $/kW basis relative to the anticipated low output associated with less than optimum conditions for those resources in the CCSF. Even after significant incentives for their resources, as shown in Figure 1-2, the poor conditions for solar PV and wind may make these resources more suited for deployment in locations outside the CCSF, which is addressed in our Task 3 report.

The lowest LCOE is typically accomplished utilizing a for-profit ownership structure with energy sold to the CCA program via a PPA. This type of structure typically provides the lowest price of electricity because the subject resource qualifies for federal incentives provided through the U.S. Tax Code. This is clearly the case for most of the resources addressed in this report. The exceptions are a fuel cell which is too small to qualify for federal incentives and the downtown steam loop LM6000 which is too large to take advantage of the incentives.

2.1 Economic Potential Introduction

> **Purpose and Use of Report**
>
> • This report investigates the economic potential for in-city resources as a component of the 360 MW roll-out and 51% Renewable Portfolio Standards.
>
> • Subsequent reports will address out-of-city renewable resources and the potential economic impact on CCA program rates relative to various mixes of in-city renewable resources.

The San Francisco Public Utilities Commission (SFPUC) has retained George E. Sansoucy, P.E., LLC (GES) to prepare this Task 2 report on the economic potential of renewable energy resources that could be developed within the City and County of San Francisco (CCSF). This report is intended to assist the SFPUC in assessing the potential resources that could be deployed in the CCSF and included as supply resources for its Community Choice Aggregation (CCA) program. This program calls for either the CCSF or its Energy Service Provider (ESP)[1] to develop 360 megawatts (MW) of renewable, distributed generation or energy efficiency measures to be included as part of the supply mix serving customer loads, with approximately 210 of the total 360 MW preferred within the jurisdictional boundaries of the CCSF. The 210 MW of in-city resources include 31 MW of solar, 72 MW of local renewable resources, and 107 MW of local energy efficiency.

This report (Task 2) is the second in a series of five reports that will address the feasibility, cost, and rate consequences of the in-city renewable roll-out and the 51% renewable energy requirements by 2017. The previous and subsequent tasks are summarized as follows:

- Task 1 included the theoretical and technical potential for renewable resources within the CCSF.

- Task 3 includes an analysis of out-of-city renewable resources and the cost to CCA program customers relative to the in-city resources identified in Tasks 1 and 2. This task assesses the cost of those resources in a manner identical to that used in Task 2.

- Task 4 is a comparison of the information and costs developed in Tasks 1 through 3 relative to whether these resources are cost effective and allow the CCA program to “meet or beat” Pacific Gas and Electric Company’s (PG&E) expected rates for CCA program customers.

[1] An ESP is an individual or company that contracts directly with its customers to provide electric supplies. ESPs may serve only selected markets, such as large commercial and industrial customers, or all customers including residential.

- Task 5 is a report setting forth any recommendations that could enhance the CCA program based on the investigations and analyses set forth in Tasks 1 through 4.

2.2 CCA Program Resource Requirement

The implementation of the CCA program will require that, among other things, sufficient electric resources are available to serve the program customers. PG&E will no longer be responsible for supplying the resources necessary to serve the customers that are part of the CCA program, but will be responsible for the transmission and distribution of the electricity as well as meter reading and billing. The expectation is that the CCA program supply mix will utilize a wide range of renewable and non-renewable resource options to ensure that the electrical supply is cost effective, reliable, and meets the criteria set forth by the CCA program directives.

2.3 Scope of Economic Potential Analysis

The scope of this analysis is to provide the economic potential of renewable energy resources that could be deployed in the CCSF jurisdiction as part of the CCA program utilizing the Levelized Cost of Electricity (LCOE) associated with each resource. This report analyzes the LCOE for the resources identified in the Task 1 report as both theoretically and technically feasible for deployment in the CCSF. The economic potential of each resource is developed using an LCOE which will be gauged against market prices for a portfolio of resources available to CCA program participants in the Task 4 report. The LCOE for each resource under for- and not-for-profit ownership structures was used to identify the LCOE necessary to justify deployment of the resources in the CCSF under various types of ownership and financing structures.

The use of these two ownership structures is consistent with the CCA program goal of utilizing some combination of PPAs and owned resources to satisfy CCA customer demand. The economics of each ownership structure are discussed below and are dependent, among other things, on the level of federal, State, and local incentives available to for-profit entities relative to comparable incentives for not-for-profit entities. As the level of incentives provided through the U.S. Tax Code increase, the ability for not-for-profit owners to provide equally economic electric prices diminishes as only tax paying entities benefit from these incentives.

The LCOE for each resource is calculated using a Microsoft Excel spreadsheet model that identifies the revenues necessary to recover invested capital, cover annual operating and maintenance (O&M) expenses, and provide debt and equity investors their respective rates of return. The models are different for each ownership type to account for the financing structure and incentives available. Over a 20-year period, the LCOE associated with each ownership structure is used to assess the economic potential of the renewable resources in the CCSF. The 20-year period is selected to reflect typical useful lives of projects, debt financing periods which typically do not exceed 20 years, and is a long enough period to reflect future costs associated with each unit relative to other market price levels. The 20-year LCOE model is appropriate and consistent with those used by industry professionals in assessing the LCOE of various projects and used by the CPUC to establish the capital recovery component of its Market Price Reference (MPR).[2]

In performing the LCOE calculations under both ownership structures, current market and resource assumptions were utilized as inputs for items such as inflation, current federal, State, and local incentives, and cost of debt and equity. These assumptions, along with those developed for each technology in the Task 1 report, are set forth in Section 3 of this report.

2.4 Report Organization

The report is organized into the following sections.

- Section 3.0 Methodology and Assumptions

  This section describes the general approach employed in this report, the extent of the information gathered, technologies analyzed, and methodology and general assumptions. This section provides the initial resource screening and a discussion of generic characteristics and assumptions relative to each of the selected resources.

- Section 4.0 Levelized Cost of Electricity Model

  The LCOE for each resource is set forth in this section along with a least cost ranking of the various renewable resources.

- Appendix A and Appendix B

  The appendices to this report set forth the calculations utilized to develop a 20-year LCOE for each resource identified in the Task 1 report for both ownership structures.

[2] The MPR is a key component of the RPS program. Pursuant to Legislation, the MPR has three functions. The first, expressed in § 399.14(g), is to deem reasonable per se and allow to be recovered in rates those "[p]rocurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15..." The second function of the MPR is to establish the basis for the use of Above-Market Funds (AMFs) which are awarded by the Commission pursuant to SB 1036, Statutes 2007, ch. 685. The third function of the MPR is to set limits on the procurement obligations of retail sellers under the RPS program. That is, if the amount of AMFs available to an electrical corporation is insufficient to support the total costs expended above the market price, then the Commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available AMFs. CPUC Resolution E-4214, 12/31/08, p. 21.

3.1 Methodology and Assumptions Introduction

The renewable energy resources identified in the Task 1 report have three primary economic drivers that determine the cost competitiveness of each relative to alternatives in the marketplace. These include 1) the capital necessary to install the resource and the associated cost of this capital, 2) the O&M costs, including fuel, necessary for the resource to produce electricity, and 3) federal and State tax credits or other incentives that promote development of renewable resources. In addition to these primary drivers, renewable resources are subject to the same market forces as other electric resources which include the availability of credit, demand for new capacity, and availability of technology and resources.

These economic drivers were incorporated into an analysis for each renewable resource and used to calculate a 20-year LCOE. The LCOE estimates are typical calculations used to assess electric resources and provide a first level of screening among several technologies or unit sizes in the economic selection of supply resources. The constant price each resource must receive over a 20-year period to justify the resource economics can be compared against the 20-year LCOE of other resources or against market prices to determine the economic potential of a particular resource.

3.2 Overnight Costs versus Installed Costs

Overnight cost reflects a reasonable estimate of the cost necessary to instantaneously install a particular technology. Overnight cost is the initial expenditure required to construct a particular technology and does not include the cost incurred for owner's Administrative and General (A&G) expenses and Interest During Construction (IDC) or changes in construction costs due to inflation. Installed cost is the total cost of constructing a resource once the owner's A&G expenses, IDC, and inflation are taken into consideration.

The owner/developer's costs are estimated at 5% of overnight costs and reimburse the owner for the costs associated with planning and managing, and bringing the resource to commercial operation. The owner's A&G expenses are estimated at 5% which is considered reasonable since most of the resources selected are mature and reflect off-the-shelf installations. Therefore, a significant amount of the construction risk and management is reflected in the contractor's direct costs. In those instances where the projects are more complex, these 5% cost adders may understate true costs but are not considered to dramatically alter the results of the analysis or position of various resources on a supply curve.

In addition to these soft costs, an IDC factor was developed to account for the cost of money used to fund the project during construction. The IDC factor was only applied to resources that are anticipated to take more than one year to complete. In calculating the IDC factor, the inflation rate used is 3% and the interest rate used is based on the project's debt rate. The cost of debt is discussed in greater detail below and is estimated at 7% and 5% to reflect reasonable costs associated with each type of ownership structure addressed in this report. Table 3-1 develops factors for both types of ownership structure for projects anticipated to take greater than one year to construct but less than three years. These factors are used to convert overnight costs to installed costs.

Table 3-1
Calculation of IDC Factor

Line		For-Profit		Total	Not-For-Profit		Total
1	Year	0	+1		0	+1	
2	Draw	50%	50%		50%	50%	
3	Construction Requirement ($/Yr)	$0.5000	$0.5000	$1.0000	$0.5000	$0.5000	$1.0000
4	Inflation Rate	0.0%	3.0%		0.0%	3.0%	
5	Inflation Factor	1.00	1.03		1.00	1.03	
6	Inflation Adj. Cost (line 3 x line 5)	$0.5000	$0.5150		$0.5000	$0.5150	
7	Annual Rate	7.0%	7.0%		5.0%	5.0%	
8	Years of IDC	0.5	1.5		0.5	1.5	
9	IDC	3.44%	10.75%		2.47%	7.63%	
10	Annual IDC (line 6 x line 9)	$0.01720	$0.05536	$0.07256	$0.01235	$0.03930	$0.05165
11	IDC Factor as % of Loan Requirement (rounded)			1.07			1.05

Notes:
Line 1: Year reflects period prior to in-service date.
Line 2: Draw reflects amount of funding expended in each period.
Line 3: Construction Requirement reflects dollars of expenditures based on construction schedule and Draw amount.
Line 4: Inflation Rate reflects the amount of inflation experienced prior to construction and deflates overnight costs.
Line 6: Inflation Adj. Cost reflects deflated construction expenditures
Line 8: Years of IDC reflects period over which IDC is accrued and is based on funding occuring mid-year.
Line 9: IDC reflects interest rate that accrues during construction period.
Line 10: Annual IDC reflects percent of inflation-adjusted costs.
Line 11: IDC Factor reflects percent of construction cost expressed as a factor.

The installed cost includes an IDC component which is calculated by assuming that construction expenditures are drawn down evenly over two years and that payments are made mid-year. Construction is estimated to start in the summer of 2009 and be completed within two years. Therefore, construction costs have been escalated to account for changes in price levels using an inflation rate of 3%.

Interest is applied to the inflation-adjusted construction costs to arrive at the estimated IDC factor. The factor is applied to the overnight costs developed in the Task 1 report to arrive at the installed cost of each project under for- and not-for-profit ownership structures. Table 3-2 is a summary of the overnight costs adjusted for IDC and inflation to arrive at an installed cost of each technology.

Table 3-2
Calculation of Installed Costs

A	B	C	D	E		
Technology	Net Capacity (AC kW)	Overnight Cost ($/kW)	Overnight Cost with A&G and Contingencies (@ 5%)	Construction Period (years)	Installed Cost ($/kW) For-Profit (1.07)	Installed Cost ($/kW) Not-For-Profit (1.05)
			[C × 1.05]		[(D × 1.07) if E is > 1]	[(D × 1.05) if E is > 1]
Solar PV						
Residential Surface-Mounted	4.2	$10,000	$10,500	1	$10,500	$10,500
Commercial Surface-Mounted	84.2	$8,300	$8,715	1	$8,715	$8,715
Ground Mounted	4,194.0	$8,000	$8,400	2	$8,988	$8,820
Wind Power						
Building-Mounted	3.0	$6,400	$6,720	1	$6,720	$6,720
Small-Scale	500.0	$3,260	$3,423	1	$3,423	$3,423
Utility-Scale	7,500.0	$2,500	$2,625	2	$2,809	$2,756
Tidal Power						
Open Ocean Turbine	2,400.0	$7,700	$8,085	2	$8,651	$8,489
Anaerobic Digestion						
Covered Lagoon Digester	250.0	$5,500	$5,775	1	$5,775	$5,775
Fuel Cells						
PAFC	400.0	$7,000	$7,350	1	$7,350	$7,350
MCFC	1,400.0	$6,000	$6,300	1	$6,300	$6,300
MCFC	2,800.0	$5,500	$5,775	1	$5,775	$5,775
Cogeneration or CHP						
Microturbine	65.0	$3,000	$3,150	1	$3,150	$3,150
Reciprocating Engine	1,000.0	$2,200	$2,310	1	$2,310	$2,310
LM6000 on Steam Loop	50,000.0	$2,500	$2,625	2	$2,809	$2,756

3.3 Operating Costs for Selected Resources

The O&M costs for each technology are estimated based on both the fixed and variable operating costs of the technology. The annual fixed expense is expressed in 2009$ per kilowatt-year ($/kW-yr) and the variable expense is expressed in 2009$ per megawatt-hour ($/MWh).

The fixed or variable expenses for each technology are set forth in Table 3-3 and are based on information set forth in the Task 1 report. These costs are considered sufficient to operate the project and assume that it operates at its maximum efficiency.

In addition to the direct O&M costs, certain technologies require either annual capital replacements or a lump sum replacement in a particular period. These are set forth in this table as well, either on a $/kW-yr basis or as a lump sum at Year 10 for inverter replacements associated with solar PV and wind installations. If the figures are set forth in a lump sum, a formula is used on the pro forma to annualize this expense so that costs are spread over the useful life of the capital replacements.

Table 3-3
Calculation of Fixed and Variable Expenses

Technology	Net Capacity (AC kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Replacement ($/kW-yr)	Lump Sum Replacement ($/kW)
Solar PV					
Residential Surface-Mounted	4.2	$75	N/A	N/A	$1,200
Commercial Surface-Mounted	84.2	$45	N/A	N/A	$800
Ground Mounted	4,194.0	$25	N/A	N/A	$600
Wind Power					
Building-Mounted	3.0	$50	N/A	N/A	$1,000
Small-Scale	500.0	$50	N/A	N/A	$800
Utility-Scale	7,500.0	$30	N/A	N/A	$800
Tidal Power					
Open Ocean Turbine	2,400.0	$385	N/A	$125	N/A
Anaerobic Digestion					
Covered Lagoon Digester	250.0	$200	$30	N/A	N/A
Fuel Cells					
PAFC	400.0	N/A	$70	N/A	N/A
MCFC	1,400.0	N/A	$70	N/A	N/A
MCFC	2,800.0	N/A	$70	N/A	N/A
Cogeneration or CHP					
Microturbine	65.0	N/A	$40	N/A	N/A
Reciprocating Engine	1,000.0	$25	$15	N/A	N/A
LM6000 on Steam Loop	50,000.0	$10	$25	N/A	N/A

3.4 Incentives for Renewable Resources

There are a number of economic incentives available for the installation and operation of renewable energy technologies. These incentives and rebates are offered by federal, State, and local government to promote the construction of renewable technologies that otherwise would not be viable in a competitive market. The following discussion provides a brief overview of the incentives and rebates available to developers and owners.

There are three levels of incentives available that include federal, State, and local. In calculating the LCOE for each resource, it is assumed that the resource ownership structure would qualify the resource to take advantage of these incentives. The specific program and benefits available are set forth below along with a table of the benefits applied to each resource in the pro forma models.

Incentives

Resources benefit from three levels of incentives, depending on ownership structure and type of resource which include:

- Federal incentives provided through the U.S. Tax Code.
- State incentives provided by the State agencies.
- Local incentive provided by the CCSF.

3.4.1 Federal Incentives Specific to Renewables

The federal incentives for renewable energy are primarily offered through the Internal Revenue Codes in the form of tax deductions such as accelerated depreciation, tax credits, or more recently the ability to receive grants and loans for renewable energy. The major incentives include 26 USC § 45 - Production Tax Credits (PTC), § 48 Investment Tax Credits (ITC), and § 168 Accelerated Depreciation.

Investment Tax Credits and Grants

The American Recovery and Reinvestment Act of 2009 (ARRA-2009) provides for the expansion and extension of several tax-related renewable energy provisions. In lieu of taking the PTC or ITC, eligible taxpayers may apply for grants to the Secretary of the Treasury for a non-discretionary grant of between 10 and 30% of the cost associated with an eligible project. The grant is not subject to federal tax, but the basis of the project is reduced by 15%. Construction must commence during 2009 and 2010 and the project must be in commercial operation before the date the eligible ITC expires.[3]

[3] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US53F&State=federal&currentpageid=1&ee=1&re=1

These grants are in lieu of PTC available under § 45, which allows for an income tax credit ranging from 1 to 2.1¢/kWh for eligible renewable energy resources. These payments escalate and are for a period of 10 years after the date the facility is placed in service. The in-service deadlines are as follows:[4]

- January 1, 2013 for wind
- January 1, 2014 for biomass, landfill gas, trash, qualified hydropower, marine and hydrokinetic
- January 1, 2017 for fuel cells, small wind, solar, geothermal, microturbines, CHP, and geothermal heat pumps

Accelerated Depreciation

Section 168 contains a provision for Modified Accelerated Cost Recovery System (MACRS) which allows for the investment in eligible resources to be recovered through accelerated depreciation deductions. The program has no expiration and eligible resources qualify for 5-year 200% declining-balance depreciation.[5]

Clean Renewable Energy Bonds (CREBs)

CREBs may be used by certain entities in primarily the public sector to finance renewable resources. The resources are generally the same as those which qualify for PTCs. CREBs may be issued to governmental entities, electric cooperatives, and certain lenders. The loan is issued with a zero percent interest rate and the bond holder receives federal tax credits in lieu of interest.

Participation in the program is limited by the volume of bonds allocated by Congress for the program. Participants must file with the IRS for a CREB allocation and then issue the bonds within a specified time period.

Other Incentives

The ARRA-2009 incentives discussed above are those most likely to benefit the projects identified in this report. There are other programs and incentives that provide loans and other benefits to taxpayers for measures associated with non-electric energy efficiency and reduction and improvements such as weatherization or modernization of utility systems.

[4] Ibid.
[5] Ibid.

In addition to the incentives provided by the ARRA-2009, there are additional incentives associated with renewable resources provided at the federal level. A summary of the most relevant are discussed below.

- New Markets Tax Credits (NMTC) – The NMTC Program permits taxpayers to receive a credit against federal income taxes for making qualified equity investments in designated Community Development Entities (CDEs). Substantially all of the qualified equity investment must in turn be used by the CDE to provide investments in low-income communities. The credit provided to the investor totals 39% of the cost of the investment and is claimed over a seven-year credit allowance period. In each of the first three years, the investor receives a credit equal to 5% of the total amount paid for the stock or capital interest at the time of purchase. For the final four years the value of the credit is 6% annually. Investors may not redeem their investments in CDEs prior to the conclusion of the seven-year period. An organization wishing to receive awards under the NMTC Program must be certified as a CDE by the Community Development Financial Instituti9ons Fund (the Fund) of the U.S. Department of the Treasury.
- Community Reinvestment Act (CRA) Credits – Enacted by Congress in 1977, the CRA program is intended to encourage banks to help meet the credit needs of the communities in which they operate, including low- and moderate-income neighborhoods, consistent with safe and sound banking operations. The CRA requires that each insured depository institution's record in helping meet the credit needs of its entire community be evaluated periodically, and this record is taken into account in considering an institution's application for deposit facilities, mergers and acquisitions. Banks are constantly looking for ways to meet their CRA requirements; therefore, solar PPAs for businesses in low- and moderate-income neighborhoods in their service territories may be very attractive. While CRA credits may not provide additional financial incentives for solar projects, they may increase banks' appetites to invest in such projects.

3.4.2 State Incentives

California offers additional incentives to promote the development of renewable resources that include programs for solar, wind, and other resources. A summary of these incentives is provided below.

- California Solar Initiative (CSI) – The CSI program offers monetary incentives for systems up to the first 1,000 kW of an eligible solar energy system. The effective dates for the program are 1/1/2007 –

12/31/2016 or until the CSI budget has been reached. These rebates apply to electric distribution customers in California.[6]

- California Energy Commission Emerging Renewable Program (ERP) – The ERP provides electric customers with a financial incentive to develop renewable energy systems and utilize an emerging renewable technology such as wind, fuel cells, or anaerobic digestion systems. The consumer and the energy system must satisfy a number of requirements. The customer must receive electricity distribution service at the site of installation from an existing in-state electric corporation such at PG&E, and the customer must generate electricity to offset on-site load. The program provides rebates of $2,500/kW for the first 7.5 kW and $1,500/kW for the second increment up to 30 kW for wind turbines. Fuel cell and other systems would receive $3,000/kW for up to 30 kW. These rebates will decline over time pursuant to program guidelines.[7]

- California Self-Generation Incentive Program (SGIP) – This program provides incentives to qualified distributed generation projects under 5 MW. The incentive is a function of type of installation and fuel utilized. In addition, incentives decline relative to unit size. The incentives range from $2,625 to $4,500/kW.[8]

3.4.3 Local Incentives

- San Francisco Incentives – The GoSolarSF program provides additional funds for residential and commercial solar installations. The range of the incentive varies depending on type of host site and installer utilized. A summary of the program and applicable incentives is provided below.

[6] http://www.consumerenergycenter.org/erprebate/index.html
[7] http://www.gosolarcalifornia.org/csi/index.html
[8] SGIP and your company, Center for Sustainable Energy California at http://www.cpuc.ca.gov

Type	Residential Incentive Levels	Amount
Basic	Any SF property owner	$2,000
Environmental Justice	CARE customers, CALHome enrollees & residences in 94107 & 94124 zip codes	$3,500
Workforce Development	Installer hires City's Workforce Development Program graduates	$4,000
Additional Payments (To an incentive above)	Low-income: Applications received on or after Feb. 1, 2009	$7,000
	City Installer: Using an installer with principal place of business in San Francisco	$1,000
	Business Incentive Level	
Basic	$1,500/kW of installed solar capacity (Installer must be Workforce-Development Certified)	up to $10,000
	Non-Profit Incentive Levels	
Non-Residential	Non-residential buildings owned and occupied by non-profits, or owned by government entities and occupied by non-profits	$1,500/kW no cap
Multi-Unit, Residential	Multi-unit residential buildings owned and operated by non-profits (for-profit, multi-unit residential buildings can qualify if 75% of the units are designated as affordable housing for a period of no less than 30 years) • Up to $150,000 • Additional $100,000 incentive available on a matching-fund basis • Total Limit: $250,000	$4,500/kW

Source: GoSolarSF Brochure at http://sfwater.org/detail.cfm/MC_ID/17/MSC_ID/400/C_ID/3910

The incentives associated with each of the renewable technologies considered in this report will be used to analyze the economic potential of each supply resource.

The incentives associated with each of the technologies considered in this report will be used to analyze the economic potential of each supply resource and are summarized in Table 3-4 and reflect a reasonable estimate of the incentives available to each resource. However, the use of the assumptions set forth in Table 3-4 should not be considered a guarantee that a resource or technology will qualify for each program as several of the incentives and programs may require additional federal or State appropriations to continue to provide the level of benefits assumed in the table. In addition, in cases where there are declining benefits, the current incentives are used in the models for purposes of calculating the LCOE.

Table 3-4
Federal, State and Local Incentives

Technology	Net Capacity (AC kW)	Federal Incentives: ITC %	Federal Incentives: PTC (2009 $/kWh)	Federal Incentives: MACRS	State Incentives: Capacity-Based Incentives ($/kW) Non-Govt.	State Incentives: Capacity-Based Incentives ($/kW) Govt.	State Incentives: Production-Based Incentives ($/kW) Non-Govt.	State Incentives: Production-Based Incentives ($/kW) Govt.	Local Incentive: GoSolarSF For-Profit	Local Incentive: GoSolarSF Not-For-Profit
Solar PV[1]										
Residential Surface-Mounted	4.2	30%	0.021	5 yrs.	$1,550	$2,300	0.22	0.32	$5,000	$5,000
Commercial Surface-Mounted	84.2	30%	0.021	5 yrs.	$1,100	$1,850	0.15	0.26	$10,000	$10,000
Ground Mounted	4,194.0	30%	0.021	5 yrs.	N/A	N/A	N/A	N/A	N/A	N/A
Wind Power[2]										
Building-Mounted	3.0	30%	0.021	5 yrs.	$2,500	$2,500	N/A	N/A	N/A	N/A
Small-Scale	500.0	30%	0.021	5 yrs.	$1,500	$1,500	N/A	N/A	N/A	N/A
Utility-Scale	7,500.0	30%	0.021	5 yrs.	N/A	N/A	N/A	N/A	N/A	N/A
Tidal Power										
Open Ocean Turbine	2,400.0	30%	0.021	5 yrs.	N/A	N/A	N/A	N/A	N/A	N/A
Anaerobic Digestion[3]										
Covered Lagoon Digester	250.0	30%	0.021	5 yrs.	$210	$210	N/A	N/A	N/A	N/A
Fuel Cells[4]										
PAFC - capped @ $3,000/kW	400.0	N/A	N/A	5 yrs.	$2,500	$2,500	N/A	N/A	N/A	N/A
MCFC	1,400.0	30%	N/A	5 yrs.	$2,500	$2,500	N/A	N/A	N/A	N/A
MCFC	2,800.0	30%	N/A	5 yrs.	$2,500	$2,500	N/A	N/A	N/A	N/A
Cogeneration or CHP[5]										
Microturbine	65.0	10%	N/A	5 yrs.	N/A	N/A	N/A	N/A	N/A	N/A
Reciprocating Engine	1,000.0	10%	N/A	5 yrs.	N/A	N/A	N/A	N/A	N/A	N/A
LM6000 on Steam Loop	50,000.0	10%	N/A	20 yrs.	N/A	N/A	N/A	N/A	N/A	N/A

[1] The GoSolarSF incentive was applied to all projects under the assumption that each will qualify as a supply resource in the CCA program.
[2] The residential wind turbine is assumed to qualify under the ERP with an installed capacity of less than 30 kW. The 500 kW community wind project qualified under the California SGIP. Utility wind exceeds the 5 MW limit.
[3] The rebate for the first 7.5 kW is $2,500/kW, the next 22.5 kW is $1,500/kW for a total of (7.5 x $2,500) plus (22.5 x $1,500) $52,500 divided by 250 kW = $210/kW of installed capacity.
[4] Fuel cell rebates assume natural gas. Using biogas results in a State incentive of $4,500/kW and the ability to use the federal PTC.
[5] CHP units do not currently qualify for State incentives.

3.5 Efficiency of Technology at Producing Electricity

The efficiency of various technologies will vary and is typically dependent on the resource's ability to convert kinetic or potential energy into electricity. Resources that convert solar or kinetic energy are measured based on the system's efficiency at which these resources convert this energy into electricity.

In the case of units that utilize biogas or natural gas, the system efficiency represents the amount of fuel which is converted to electricity. These figures are expressed in the unit's heat rate or Btu/kWh produced on an HHV[9] basis. A heat rate reflects the Btus required for producing one kilowatt-hour of electricity. Electric generating facilities with low heat rates are more efficient than units with high heat rates.

The most efficient electric generating systems, typically combined cycle units, have operating heat rates of 7,000 to 8,000 and reflect efficiencies approaching 60%. The technologies that utilize fuel in the generation of electricity are shown in Table 3-5, along with the corresponding heat rate on an HHV basis.

Table 3-5
Heat Rate of Each Technology

Technology	Net Capacity (AC kW)	Capacity Factor (%)	HHV Heat Rate (Btu/kWh)
Fuel Cells			
PAFC	400.0	90.0%	9,500
MCFC	1,400.0	90.0%	8,100
MCFC	2,800.0	90.0%	8,100
Cogeneration or CHP			
Microturbine	65.0	95.0%	13,650
Reciprocating Engine	1,000.0	90.0%	10,429
LM6000 on Steam Loop	50,000.0	92.0%	8,000

3.6 Insurance Costs

The installation of renewable resources typically requires that the units be insured for both catastrophic failure and loss of revenue. The LCOE calculation was estimated at one-half percent of the installed cost for year one. The year one estimate is then escalated at the rate of inflation and is considered to reflect the cost of insuring each technology. This insurance cost estimate is typical of premiums for other projects.

[9] HHV stands for higher heating value of a fuel and is defined as the amount of heat released by a specific quantity once it is combusted and the product has returned to a temperature of 25°C.

3.7 Royalty Payments

A royalty payment has been included in the LCOE calculation to reflect the cost of securing or leasing a location for the proposed project. This payment was applied to all resources that are anticipated to supply only CCA customers with benefits such as solar PV, wind, and tidal projects.

Royalty or lease payments vary based on scarcity of sites, size of installation and terms of the agreement. For example, typical wind royalty payments can be based on either a per turbine rate or a percentage of gross revenue. These prices range from $1,000 per turbine where units have good symbiotic relationships with existing agricultural uses to figures as high as $7,000 per turbine. In the case of royalties based on a percentage of revenue, these figures can vary from a few percent to figures as high as 10% of gross revenue. In estimating the royalty payments for installations in the CCSF, a figure of $15/kW-yr was used to reflect an annual payment that fell within this matrix of potential rates as the ultimate payments will be a function of negotiations between an energy supplier and property owner.

For example, the host of a two turbine 500 kW installation would receive $7,500 for the first year assuming a $15/kW-yr royalty payment. This translates into approximately $3,750 per turbine, or 8% of the project's first year revenue, and illustrates how the $15/kW-yr is reflective of typical royalty or lease payment requirements associated with a renewable resource.

The payment was estimated at $15/kW-yr escalated at the rate of inflation. The LCOE calculation for the covered lagoon digester, fuel cells, and CHP units that provide additional on-site benefits did not include a royalty payment as the units provide more than just electrical benefits to the site host.

3.8 Income Taxes

The income generated by the project is taxable at the federal and State levels. As much of the federal support for renewable energy facilities is concentrated within the U.S. Tax Code, in the forming of ITCs, PTCs, and accelerated depreciation, the income tax liability in some instances produces a tax benefit to the project owner. The following is a general discussion of the federal and State income tax liabilities and benefits associated with renewable energy projects and the income tax rate applicable to the projects.

Federal and State Income Tax Issues

The for-profit owners of renewable resources are subject to federal and State income taxes associated with after-tax cash flows. In most instances, losses or tax credits associated with the project generate a substantial amount of the resource economic benefits and typically result in for-profit ownership structure having lower LCOE than not-for-profit structures. A discussion of the tax benefits and liabilities is provided below.

Federal Taxes

As discussed previously, a significant number of the federal incentives associated with renewable resources are available through the U.S. Tax Code. Therefore, most of the for-profit pro formas show tax benefits versus liability. The benefits are typically a function of ITCs and five years MACRS depreciation. These two incentives generate a significant number of the pro forma federal tax benefits for each project. The federal income tax rate of 35% is considered to reflect the federal tax bracket of typical project owners. In calculating tax benefits and liability, it was assumed that the project owner or participant could utilize 100% of the tax benefits in the year incurred by the project's pro forma.

State Taxes

In developing the pro forma estimates, it is assumed that the entities owning or developing the resource will be corporate and not individuals. Therefore, the California corporate tax will apply to any after-tax cash flows produced by the project. California does not follow the federal guidelines for renewable energy projects with respect to depreciation and other benefits. In particular, the State does not grant accelerated depreciation associated with renewable resources and relies on a depreciating schedule that reflects the unit's estimated life in calculating depreciation for State purposes, and the State taxable income is calculated using depreciation estimates that are consistent with the assumptions in the pro formas. In all instances, other than building-mounted wind, a 20-year life was used to estimate depreciation for State purposes.

The State's corporate tax rate varies by entity from a low of 8.84% to a high of 10.84% of taxable income. The higher 10.84% relates to banks and financial institutions which are the most likely tax equity partners associated with the resources addressed in this report. Therefore, a 10.84% State income tax was selected for use in the for-profit pro formas.

3.9 Natural Gas Fuel Prices

The natural gas price forecast used to calculate the LCOE of the resources utilized was based on a 20-year forecast prepared for GES by Platts Power Outlook Research Service.[10] The forecast is based on natural gas delivered to San Francisco city gate plus a distribution adder and was developed based on market conditions that existed as of May 29, 2009. These gas forecasts are considered to reflect a reasonable cost of providing natural gas to resources within the CCSF based on current fuel prices. The gas prices used in this report are set forth in Table 3-6.

These gas prices may change based on future economic conditions and result in actual natural gas prices being more or less than those expressed in this report and the LCOE of resources utilizing natural gas as a fuel source. However, for purposes of calculating a current LCOE, these prices are considered to reflect the current market conditions and price of natural gas in the CCSF.

[10] Platts is a division of The McGraw-Hill Companies, Inc. and is the world's largest provider of energy information and research.

Table 3-6
Natural Gas Price Forecast
as of 5/29/09

Year	Natural Gas Prices ($/mmBtu)
2009	$5.69
2010	$6.53
2011	$7.44
2012	$7.73
2013	$7.83
2014	$7.96
2015	$8.11
2016	$8.22
2017	$8.33
2018	$8.45
2019	$8.56
2020	$8.66
2021	$8.70
2022	$8.84
2023	$8.96
2024	$9.07
2025	$9.18
2026	$9.30
2027	$9.41
2028	$9.53
2029	$9.72

Note: Natural gas price forecast is based on price forecast prepared for GES as of 5/29/09.

3.10 Capital Structure and Financing Assumptions

The capital structure and financing assumptions are unique to each form of ownership and renewable resource. The capital structure refers to the amount of debt and equity utilized to fund ownership of the project. The cost of each type of capital is market-based and reflects current market requirements for attracting each type of capital. The estimates used take into consideration the resource's use as part of the CCA program which is anticipated to lower the overall risk. The capital structure and associated cost of financing each type of capital is dependent on several factors that include 1) ownership structure, 2) cash flow available for debt service, and 3) risk of the project.

3.10.1 For-Profit Capital Structure

The for-profit capital structure includes the use of both debt and equity capital to finance the ownership of renewable resources. In both instances, these financing options are taxable and require higher returns than under not-for-profit ownership.

In financing the project with debt, the cash flows available to satisfy these obligations must meet requirements set forth by various financial institutions. In general, entities providing debt financing will require debt service coverage ratios (DSCR)[11] of between 1.2x and 1.8x cash flow. This range is based on a review of the financing term for several renewable energy projects and our experience with the valuation of resources for financing and other purposes.

The financial models in this report structure the debt to reflect the project's ability to satisfy a specified DSCR in each year of the analyses. The remainder of the project is financed utilizing equity. The 1.2x DSCR selected was the lowest possible ratio that could be used for financing purposes without additional guarantees or additional funds established to assure debt service payments.

Typical equity rates for use in financing renewable resources are 12 to 18% after-tax without situations which lower the risk of the project. An after-tax rate of 12% was selected as representing a reasonable project rate of return for equity invested in this type of project.

The 1.2x DSCR and the 12% cost of equity are both at the low end of the range for merchant generating facilities. This is considered reasonable due to the use of the resources in the CCSF CCA program which lower the project's risk and increases its ability to receive attractive financing. Therefore, if the financing was for merchant purposes with a sale into the California electric market, the DSCR and cost of equity would most likely be higher to reflect this additional risk.

3.10.2 Not-For-Profit Capital Structure

In estimating the LCOE for a not-for-profit entity such as the CCSF, the CCA program, public utility, or similar quasi-governmental entity created to own the generation on behalf of the CCA program, a financing structure of 100% debt is used, which is typical for this type of ownership as long as the use of the project meets the public purpose provisions of the IRS rules. The cost of not-for-profit debt is typically lower than for-profit debt as it is tax exempt. In the case of the potential CCA resources, a tax exempt debt rate of 5% is considered reasonable and used in the pro forma models to estimate the debt costs and the LCOE. This cost of debt assumes H Bonds or similar forms of financing and that the project meets the financing requirements necessary to utilize tax exempt financing.

[11] Debt Service Coverage Ratio (DSCR) is the ratio of net operating income to annual debt service and measures the ability of a property to meet its debt service obligation out of operating income.

In addition to the use of the H Bonds, the models were run utilizing CREBs which are a competitive source of financing which the project owner would have to apply for to the IRS and the amount of awards for this type of financing are limited by Congress. However, the interest rate on the bonds is zero as the bond holder receives federal tax credits in lieu of interest.

Table 3-7 summarizes the financial assumptions utilized in calculating levelized costs of energy. These financing assumptions are consistent with current market expectations and assume typical developer and/or merchant ownership credit worthiness and project finance with a contact to the CCA program.

Table 3-7
Capital and Financing Assumptions

	For-Profit	Not-For-Profit
% Debt	40-60%	100%
% Equity	60-40%	0%
Cost of Debt	7.0%	5.0%
Cost of Equity	12%	N/A
Debt Term (years)	20	20

3.11 Ownership Structure Model

3.11.1 For-Profit Ownership Structure

The for-profit ownership structure assumes that the project will be owned and operated by one or more for-profit entities that utilize a PPA to provide power to the CCA program. The three ownership structures consist of 1) a sole corporate owner, 2) a partnership “flip” structure, or 3) operating lease of same kind. The benefits of each structure will vary by project, but each is designed to maximize benefits while lowering the LCOE.[12]

In calculating the LCOE, no particular structure was assumed but the benefits that arise from each was incorporated into the LCOE by assuming that the owner could utilize all the benefits which flow from the U.S. Tax Code and that the credit worthiness of both the CCA program and the developer assured reasonable debt and equity rates for the projects.

[12] In addition to these structures, there are several more that utilize one or more of these general structures to create complex ownership and financing arrangements which may include municipal prepayment for power, certain guarantees or other entities providing debt and equity to the deal in order to lower borrowing costs and improve the economics. However, for purposes of calculating the LCOE, those additional structures were not analyzed as each would be both project- and owner-specific.

The for-profit model used to calculate the LCOE for each project was developed in Microsoft Excel. The model utilizes user-defined inputs, internal formulas, and the Excel Solver function to minimize the 20-year LCOE for each renewable energy project while satisfying the targeted Internal Rate of Return (IRR) for equity investors and the minimum DSCR necessary to finance each resource based on available cash flows generated through the sale of power. The model assumes equity investors can utilize all associated tax benefits and calculates the amount of project leverage based upon a predetermined DSCR typically required to obtain financing. The inability of the owner to utilize all of the tax benefits in the year incurred has the potential of changing the results and increasing the LCOE associated with each project. In addition, changes in the level of benefits available through the U.S. Tax Code, or other incentives, will result in a different LCOE than those presented in this report.

The assumptions for each project are set forth on the first page of the spreadsheet and consist of three general categories which include 1) Project, 2) Financial/Economic, and 3) Incentive assumptions. These assumptions are shown in the shaded cells and require user inputs. The LCOE estimates for each resource are based on information in the Task 1 report and general market assumptions that relate to all projects set forth in Section 3 of this report.

The pro forma for each project is shown on the second page of the spreadsheet and shows the financial calculations that determine the LCOE. These figures are developed by the model utilizing the underlying formulas and Excel Solver function which minimize the LCOE while satisfying the project's debt and equity requirement. The worksheet for each project was developed by using reasonable assumptions. Input assumptions that exceed reasonable market expectation may result in the model failing to find a solution or require that the user manually change the first year PPA price until an optimum solution is found that satisfies all of the project's financial assumptions. This was not necessary for any of the resources in this report, but may occur for less mature technologies or assumptions that exceed reasonable parameters.

3.11.2 Not-For-Profit Ownership Structure

The not-for-profit structure assumes a tax-exempt entity owns the resource and utilizes H Bonds or other forms of revenue bonds to finance the capital costs. The structure assumes that the owner is capable of gaining access to low cost financing at the project level and that no other funds or obligations are utilized to lower the interest rate. In addition, no income taxes are paid at the federal or State level.

The not-for-profit model is a standard revenue requirement model and assumes 100% tax exempt debt financing. The model calculates the annual revenue necessary to satisfy the debt obligations as well as the O&M expenses associated with each project and conforms to typical not-for-profit financing principles. The model reflects the annual Cost of Electricity (COE) or revenue requirement per MWh that would be required to own and operate the project. The LCOE is then calculated from the annual revenue requirements.

4.1 Introduction

The LCOE of the theoretically and technically possible renewable energy resources identified in the Task 1 report was developed using the spreadsheet models developed by GES. A separate model was developed for each ownership structure that addresses the capital structure and ability of each ownership type to take advantage of incentives available to renewable resources. The model calculates the LCOE of each resource technology based on resource-specific cost and operating data and market-based assumptions about financing, federal and State tax liability or benefits, and other incentives available to each technology. The for-profit model minimizes the LCOE over a 20-year period while maintaining debt financing requirements and equity returns necessary to satisfy investor requirements. The not-for-profit model develops the LCOE by calculating the revenue requirements associated with each project assuming 100% debt financing and no federal or State income tax benefits or liability over a 20-year period.

The results of each analysis are set forth in Table 4-1 and Figure 4-1 and show both the LCOE and first year price of each resource. A discussion of these results and specific assumptions is provided below for each resource category.

LCOE v. First Year Price

• The LCOE, for the purposes of this analysis, is defined as the cost per unit of electricity required to recover the invested capital, cover annual operating and maintenance (O&M) expenses, and provide debt and equity investors their respective rates of return. The LCOE is a standard unit of measure used to assess the life cycle cost of various generating resources.

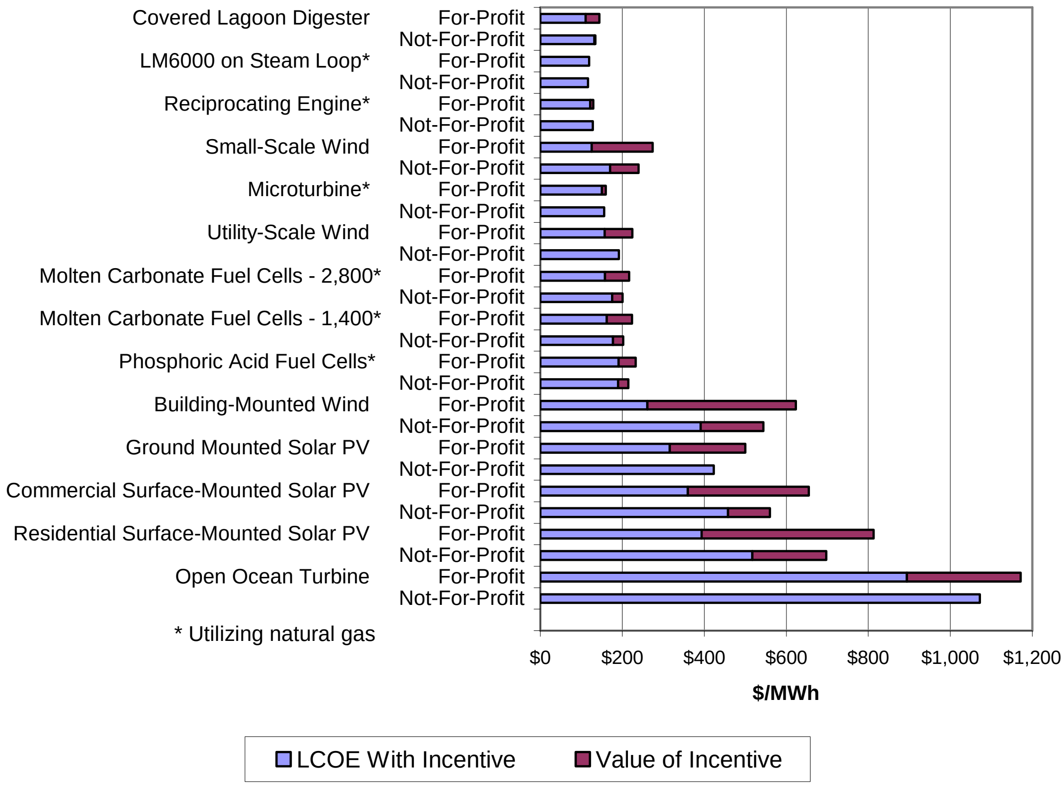
• First year price represents the current cost of producing electricity from a specific resource but does not address future price increases or costs associated with the project. While this price can be more reasonably compared with contemporary prices, it is typically not a useful measure of comparing different generating resources or long-term costs.

Table 4-1
Summary of Levelized Cost of Electricity (LCOE)
($/MWh)

	For-Profit		Not-For-Profit @ 5% Interest Rate	
	LCOE	**First Year**	**LCOE**	**First Year**
Residential Surface-Mounted Solar PV	$393	$321	$517	$435
Commercial Surface-Mounted Solar PV	$360	$293	$459	$398
Ground Mounted Solar PV	$316	$256	$423	$377
Building-Mounted Wind	$261	$214	$391	$333
Small-Scale Wind	$125	$103	$171	$135
Utility-Scale Wind	$157	$128	$192	$160
Open Ocean Turbine	$894	$725	$1,072	$950
Covered Lagoon Digester	$111	$90	$132	$116
PAFC	$192	$155	$190	$155
MCFC - 1,400	$162	$133	$177	$143
MCFC - 2,800	$158	$130	$175	$141
Microturbine	$150	$121	$156	$123
Reciprocating Engine	$122	$98	$128	$100
LM6000 on Steam Loop	$119	$95	$116	$93

Note: The LCOE for CHP units is based on Platts natural gas price forecast as of 5/29/09.

Figure 4-1
Levelized Cost of Electricity (LCOE)
Including Incentives and LCOE Without Incentives
(in ascending order by For-Profit)



4.2 Solar PV LCOE Range from $316 to $517/MWh

The for- and not-for-profit LCOE for various solar PV installations considered technically feasible in the CCSF was calculated for each type of ownership and ranged from a low of $316/MWh to a high of $517/MWh. The results of the LCOE models are set forth in Table 4-2.

Table 4-2
Solar PV Resources
($/MWh)

	For-Profit			Not-For-Profit @ 5% Interest Rate		
	LCOE	**First Year**	**Value of Incentive**	**LCOE**	**First Year**	**Value of Incentive**
Residential Surface-Mounted Solar PV	$393	$321	$420	$517	$435	$180
Commercial Surface-Mounted Solar PV	$360	$293	$295	$459	$398	$102
Ground Mounted Solar PV	$316	$256	$184	$423	$377	$0

The LCOE indicates that in each instance, the use of a for-profit ownership structure and sales of electricity to the CCA program using a PPA results in the lowest LCOE due to the high level of federal and State incentives available to for-profit owners of solar installations. The ground-mounted installation had the lowest LCOE followed by a commercial surface-mounted solar PV unit.

The solar units owned by both for- and not-for-profit entities are typically eligible for incentives which lower the LCOE. In the instance of for-profit entities, these incentives allow for lower LCOE due to a substantial number of the incentives being provided at the federal level through the U.S. Tax Code. These include 5-year accelerated depreciation and a 30% ITC or grant for the project owner.

The not-for-profit LCOE calculations are higher in all instances due to the inability of the owner to utilize federal incentives provided through the U.S. Tax Code. The not-for-profit model was run assuming that the project received a 0% interest Clean Renewable Energy Bond (CREB) from the federal government. The use of the CREB lowers the LCOE to be competitive or lower than the for-profit estimate assuming that the project continued to qualify for State and local incentives.

The results of the analysis are consistent with current market conditions and are considered reasonable estimates based on the previously discussed assumptions. The LCOEs indicated that absent significant incentives, none of the solar PV resources would be cost competitive with market prices or non-renewable resources.

4.3 Wind LCOE Range from $125 to $391/MWh

The for- and not-for-profit LCOE for the various wind installations ranged from a low of $125/MWh to a high of $391/MWh. The results of the LCOE models are set forth in Table 4-3.

Table 4-3
Wind Resources
($/MWh)

	For-Profit			Not-For-Profit @ 5% Interest Rate		
	LCOE	**First Year**	**Value of Incentive**	**LCOE**	**First Year**	**Value of Incentive**
Building-Mounted Wind	$261	$214	$362	$391	$333	$153
Small-Scale Wind	$125	$103	$149	$171	$135	$69
Utility-Scale Wind	$157	$128	$67	$192	$160	$0

As with solar, the PPA approach to procuring renewable resources results in the lowest LCOE due to the high level of incentives tied to the U.S. Tax Code. The most attractive project would be a small-scale wind farm that receives California capacity-based incentives at $1,500/kW, or approximately $750,000 for a 500 kW project. This level of incentive is not available to projects over 5 MW and results in the small-scale wind project having a lowest LCOE. Irrespective of the economics, the lack of a site for the larger wind turbine makes this option technically impossible in the CCSF though it was considered for purposes of comparison to the other options. The use of CREBs provides similar results to those found for the solar projects with LCOEs associated with not-for-profit ownership being comparable to the for-profit ownership structure.

4.4 Tidal Power LCOE Range from $894 to $1,072/MWh

The LCOE for the tidal power installation is $894 and $1,072/MWh for the for- and not-for-profit ownership structures, respectively. These high capital costs relative to the other renewable alternatives make this type of installation economically impractical, which is consistent with prior tidal power studies performed on the San Francisco Bay tidal potential. These resources are considered to be uneconomic at this time due to high capital costs relative to low output levels and other alternatives in the market.

4.5 Covered Lagoon Digester LCOE Range from $111 to $132/MWh

A covered lagoon digester was considered in the LCOE estimate even though this installation would be located outside of the CCSF. This technology was included to support calculations related to other biogas production facilities that could support in-city generation and also to consider the cost of biogas that could be delivered to the CCSF either in the form of gas or electricity. The LCOE for a covered lagoon digester is estimated at $111 and $132/MWh for the for- and not-for-profit ownership structures, respectively. These are among the lowest LCOEs developed and demonstrate the attractiveness of biogas resources. Additional costs would be required to deliver this product to the CCSF, putting this option in the $125 to $150/MWh range, depending on transmission costs. The use of CREBs would lower the LCOE of the not-for-profit option to that of the for-profit ownership structure.

4.6 Fuel Cell LCOE Range from $158 to $192/MWh

The LCOE for various fuel cell options considered in the Task 1 report is based on the estimated cost of the electricity after credit is given for the waste heat recovered from the system and ranged from a low of $158/MWh to a high of $192/MWh. The LCOE presented below assumes natural gas as a fuel. Biogas options are discussed below along with estimated LCOEs for selected units. The results of the LCOE models for fuel cells are set forth in Table 4-4.

Table 4-4
Fuel Cell Resources
($/MWh)

	For-Profit			Not-For-Profit @ 5% Interest Rate		
	LCOE	First Year	Value of Incentive	LCOE	First Year	Value of Incentive
PAFC	$192	$155	$41	$190	$155	$25
MCFC - 1,400	$162	$133	$62	$177	$143	$25
MCFC - 2,800	$158	$130	$59	$175	$141	$26

The fuel cell LCOE assumes that waste heat is provided to a host site and that approximately 60% of this is put to a beneficial use. The remaining 40% is considered unbeneficial as a host site is typically unable to utilize 100% of this resource. The use of a 60% factor is considered reasonable given the anticipated heating, cooling, and process heat associated with typical host sites in the CCSF. In certain instances, hosts can utilize a great level of this waste heat and improve the project economics and potentially lower the LCOE. The use of CREBs financing would lower the LCOE of the not-for-profit ownership scenarios and be comparable with for-profit financing.

4.7 CHP LCOE Range from $116 to $156/MWh

The LCOE for various CHP options considered in the Task 1 report is based on the estimated cost of the electricity after credit is given for the waste heat recovered from the system and ranged from a low of $116/MWh to a high of $156/MWh. The results of the LCOE models for CHP units are set forth in Table 4-5.

Table 4-5
CHP Resources
($/MWh)

	For-Profit			Not-For-Profit @ 5% Interest Rate		
	LCOE	**First Year**	**Value of Incentive**	**LCOE**	**First Year**	**Value of Incentive**
Microturbine	$150	$121	$10	$156	$123	$0
Reciprocating Engine	$122	$98	$7	$128	$100	$0
LM6000 on Steam Loop	$119	$95	$0	$116	$93	$0

The CHP LCOE assumes that waste heat is provided to a host site and that approximately 60% of this is put to a beneficial use, similar to the assumptions for the fuel cells. The exception to this is the NRG LM6000 associated with the steam loop which is assumed to utilize 90% of the waste heat as it has multiple hosts that could accept this waste heat. The for- and not-for-profit ownership structures are more similar due to the lack of 30% ITCs for these resources.

4.8 CHP Biogas Options

An out-of-city biogas source was identified in the Task 1 report that could be utilized by in-city resources if the gas was delivered via the interstate pipeline. The estimated cost of the biogas at its source is $9/mmBtu which is expected to escalate more closely with the rate of inflation than fossil fuel as the cost of the product is based on fixed costs and O&M expenses.

Selected in-city CHP and fuel cell options were modeled assuming the use of biogas delivered to the CCSF at a cost of approximately $10/mmBtu to estimate the LCOE of renewable in-city resources utilizing this biogas.

The units selected included the MCFC 1,500 fuel cell, the internal combustion engine, and the LM6000 steam loop repowering project. The results of the analysis shown in Table 4-6 are based on the estimated cost of biofuel and the additional incentives available to the resource.

Table 4-6
Summary of Biogas Option LCOE
($/MWh)

	For-Profit	Not-For-Profit
MCFC 1,500 Fuel Cell	$172	$181
Internal Combustion	$143	$166
LM6000 on Steam Loop	$114	$146

The use of biogas associated with in-city resources results in prices that ranged from approximately $114 to $181/MWh and is typically more expensive than if the resource burns natural gas. The exception is the LM6000 associated with the steam loop that would qualify for federal PTCs which lowers the LCOE.

Pro Forma Notes – For-Profit

Note #

1. Year 1 Annual Generation reflects the estimated kWh produced by the Project and is calculated by multiplying the Installed Capacity by the Project Capacity Factor by 8,760hr/yr. Year 2 through 20 based on Capacity less Degradation Factor.

2. First year Cost of Electricity (COE) is calculated using the Excel Solver Function and is the variable that determines the minimum Levelized Cost of Electricity (LCOE). Years 2 through 20 are based on the Year 1 electricity adjusted by the PPA Escalation Rate.

3. Power Sales are calculated by multiplying Line 3 by Line 4 divided by 1 million to convert kWh to MWh and dollars into thousands of dollars.

4. If the Project is eligible for a State Capacity-Based Incentive (CBI), it is calculated in Year 1 by multiplying the Project's Installed Capacity by the CBI amount set forth in under State Incentives divided by 1,000.

5. If the Project is eligible for a State Performance-Based Incentive (PBI), it is calculated by multiplying the PBI amount by the amount of generation (Line 3) for the term of the PBI divided by 1,000.

6. Other Revenues are specific to certain projects and are identified, where appropriate, in each model. Should it say its Other Incentives divided by 1,000?

7. Fixed O&M is calculated by multiplying the Fixed O&M ($/kW) by the Project Capacity and dividing it by 1,000 to convert kWh to MWh and dollars into thousands of dollars. Years 2 through 20 are calculated in a similar manner except the Fixed O&M Escalation Rate is applied to the Year 1 Fixed O&M.

8. Variable O&M is calculated by multiplying the Variable O&M by the Annual Generation (Line 3) divided by 1 million to convert kWh to MWh and dollars into thousands of dollars. Years 2 through 20 are calculated in a similar manner except the Variable O&M Escalation Rate is applied to the Year 1 Variable O&M.

9. If applicable, Fuel Costs are calculated by multiplying the Fuel Cost per MMBtu by the Annual Generation (Line 3) by the Project's Heat Rate.

10. Insurance costs are calculated by multiplying Total Capital Cost by the Insurance Cost divided by 1,000 to convert dollars into thousands. Years 2 through 20 are based on the Year 1 Insurance Cost escalated by using the Insurance Escalation.

11. Royalty Payment reflects use of a host site. The Year 1 Royalty Payment is calculated by multiplying the Royalty Payment ($/kW) by Project Capacity (kW) divided by 1,000.

12. Total Expenses are the sum of Lines 13 through 17.

13. EBITDA is calculated by subtracting Line 19 from Line 7.

Pro Forma Notes – For-Profit

14. Federal Investment Tax Credit is calculated by multiplying the % allowed under the IRS rules and the Total Capital Cost.

15. Federal Production Tax Credit is calculated by multiplying the Annual Generation (Line 3) by the PTC ($/kWh) divided by 1,000.

16. The State Depreciation Rate is that allowed under California Law for Renewable energy Projects.

17. State Depreciation is calculated by multiplying the Total Capital Cost by the State Depreciation Rate.

18. The Federal Depreciation Rate is that allowed under the IRS Code for Renewable Energy Projects.

19. Federal Depreciation is calculated by multiplying the Total Capital Cost by the Federal Depreciation Rate less one half of the ITC Line 24.

20. State Taxable Income is calculated by subtracting the State Depreciation (Line 28) and Interest (Line 69) from the EBITDA.

21. State Income Tax is calculated by multiplying the State Taxable Income by the State Income Tax Rate of 10.84% which is the highest California Income Tax Rate and is applicable to the types of financial institutions most likely to invest in this type of Project.

22. State Tax Benefit (Liability) is the sum of the Line 34.

23. Federal Taxable Income is calculated by subtracting the State Income Tax (Line 34), Federal Depreciation (Line 30) and Interest (Line 69) from the EBITDA.

24. Federal Income Tax is calculated by multiplying the Federal Taxable Income by the Federal Income Tax Rate of 35%.

25. Federal Tax Benefit (Liability) is the sum of Federal Income Tax and Federal ITC.

26. Total Tax Benefit (Liability) is the sum of Lines 25, 35 and 38.

27. Equity Contribution represents the amount of Equity in the Project and is a function of cash flow and Project Economics. The amount of equity is calculated by subtracting the State Capacity Based Incentives (Line 8) and Debt (Line 65) from the Total Capital Cost. The figure is expressed as a negative to reflect cash out flow in the spreadsheet.

28. Cash Distribution reflects cash available to the equity investor. This figure is calculated by subtracting Debt Service Payment (Line 68) from EBITDA (Line 21).

29. Tax Benefits (Liability) equals Line 41.

Pro Forma Notes – For-Profit

30. Total is the sum of Lines 48 and 49.

31. Interest Rate reflects the Projects anticipated Debt Rate.

32. EBITDA Scaling Factor is calculated in the first year as (1/(1+interest rate)). In Years 2 through 20 it is calculated as (prior year factor/(1+interest rate)).

33. Adjusted EBITDA is calculated by multiplying Line 54 by Line 56.

34. Period DSCR represents the required DSCR for the Project and is used to size the amount of Debt the Project can support.

35. Debt Sizing is used to determine the amount of Debt and Leverage for the Project based on the ability of the EBITDA to satisfy the selected DSCR. The calculation is based on the sum of the Debt sizing calculation for each year which is calculated by dividing the Adjusted EBITDA (Line 57) by the DSCR (Line 58).

36. Beginning Balance reflects the amount of Debt outstanding at the beginning of each period and is equal to the Ending Balance (Line 65) of the prior period.

37. Draw downs reflect cash outflows, if applicable.

38. Repayment reflects the amount of Debt repaid each period and is sculpted to reflect project cash flows. The Repayment is based on Line 70.

39. Ending Balance is calculated by subtracting Repayments (Line 64) from the Beginning Balance (Line 62).

40. Debt Service is the annual debt payment and includes both principal and interest. The Debt Service is calculated by dividing the EBITDA (Line 21 or Line 56) by the DSCR.

41. Interest is calculated by multiplying the Beginning Balance (Line 62) by the Interest Rate (Line 53).

42. Principal is the Difference between Debt Service Payments (Line 68) and the Interest (Line 69).

43. DSCR is calculated by dividing the EBITDA (Line 21 or Line 56) by the Debt Service Payment (Line 68).

44. Leverage reflects the amount of debt used to finance the project and is calculated by dividing Debt Size (Line 59) by total Capital. The difference reflects the equity requirement.

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	4.2
Installed Cost ($/kW)	$10,500
Fixed O&M ($/kW)	$75
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	18.5%
Degradation	0.5%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$1,200
Replacement Term (years)	10
Cost of Equity (Target IRR)	12.0%
Discount Rate	10.39%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$1,550
PBI Amount	$0.22
PBI Term	5
Other Incentives	
GOSOLARSF	$ 5,000

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$44
Debt Requirement ($ in 000)	$14
Equity Requirement ($ in 000)	$30
Financial Results	
Leverage	32%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$392.53
First Year PPA Price ($/MWH)	$320.75

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		6,807	6,772	6,739	6,705	6,671	6,638	6,605	6,572	6,539	6,506	6,474	6,441	6,409	6,377	6,345	6,314	6,282	6,251	6,219	6,188
4	Cost of Electricty ($/MWh) (Note 2)		$320.75	$330.38	$340.29	$350.50	$361.01	$371.84	$383.00	$394.49	$406.32	$418.51	$431.07	$444.00	$457.32	$471.04	$485.17	$499.72	$514.72	$530.16	$546.06	$562.44
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$2	$2	$2	$2	$2	$2	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
8	State Capacity Based Incentive (CBI) (Note 4)		$7																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
14	Variable O&M (Note 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 10)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
17	Royalty Payment (Note 11)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
19	**Total Expenses (Note 12)**		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
20																						
21	**EBITDA (Note 13)**		$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$1	$1	$1	$2	$2	$2	$2	$2
22																						
23	**Tax Credits**																					
24	Federal Investment Tax Credit (Note 14)		$13																			
25	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Depreciation**																					
27	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
28	State Depreciation (Note 17)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
29	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30	Federal Depreciation (Note 19)		($7)	($12)	($7)	($4)	($4)	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31																						
32	**Income Taxes**																					
33	State Taxable Income (Note 20)		($2)	($2)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
34	State Income Tax (Note 21)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	State Tax Benefit (Liability) (Note 22)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Federal Taxable Income (Note 23)		$5	($11)	($6)	($3)	($3)	($1)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2
37	Federal Income Tax (Note 24)		($2)	$4	$2	$1	$1	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)
38	Federal Tax Benefit (Liability) (Note 25)		$12	$4	$2	$1	$1	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)
39																						
40																						
41	**Total Tax Benefit (Liability) (Note 26)**		$12	$4	$2	$1	$1	$1	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)
42																						
43																						
44																						
45	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
46																						
47	Equity Contribution (Note 27)	($18)																				
48	Cash Distribution (Note 28)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
49	Tax Benefits (Liability) (Note 29)		$12	$4	$2	$1	$1	$1	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)
50	**Total (Note 30)**	($18)	$12	$4	$3	$2	$2	$1	$0	($0)	($0)	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)
51																						
52	**Debt**																					
53	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
54	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
55																						
56	EBITDA		$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$1	$1	$1	$2	$2	$2	$2	$2
57	Adjusted EBITDA (Note 33)		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$0	$0	$0	$0
58	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
59	Debt Sizing (Note 35)	**$14**	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0
60																						
61	Repayment/Amortization																					
62	Beginning Balance (Note 36)		$14	$14	$13	$13	$13	$12	$11	$11	$10	$9	$9	$8	$8	$7	$6	$5	$5	$4	$3	$1
63	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Repayments (Note 38)		($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
65	Ending Blance (Note 39)	$14	$14	$13	$13	$13	$12	$11	$11	$10	$9	$9	$8	$8	$7	$6	$5	$5	$4	$3	$1	($0)
66																						
67	Calculation of Repayments																					
68	Debt Service Payment (Note 40)		($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
69	Interest (Note 41)		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
70	Principal (Note 42)		($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
71	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
72	**Leverage (Note 44)**		32%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	84.2
Installed Cost ($/kW)	$8,715
Fixed O&M ($/kW)	$45
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	18.5%
Degradation	0.5%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$800
Replacement Term (years)	10
Cost of Equity (Target IRR)	12.0%
Discount Rate	9.97%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$1,100
PBI Amount	$0.15
PBI Term	5
Other Incentives	
GOSOLARSF	$ 10,000

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$734
Debt Requirement ($ in 000)	$297
Equity Requirement ($ in 000)	$436
Financial Results	
Leverage	41%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$360.16
First Year PPA Price ($/MWH)	$293.35

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
3	Annual Generation (kWh) (Note 1)		136,455	135,772	135,093	134,418	133,746	133,077	132,412	131,750	131,091	130,435	129,783	129,134	128,489	127,846	127,207	126,571	125,938	125,308	124,682	124,058
4	Cost of Electricty ($/MWh) (Note 2)		$293.35	$302.15	$311.21	$320.55	$330.17	$340.07	$350.27	$360.78	$371.61	$382.75	$394.24	$406.06	$418.25	$430.79	$443.72	$457.03	$470.74	$484.86	$499.41	$514.39
6	**Revenues**																					
7	Power Sales (Note 3)		$40	$41	$42	$43	$44	$45	$46	$48	$49	$50	$51	$52	$54	$55	$56	$58	$59	$61	$62	$64
8	State Capacity Based Incentive (CBI) (Note 4)		$93																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$10	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	**Expenses**																					
13	Fixed O&M (Note 7)		($4)	($4)	($4)	($4)	($4)	($4)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($7)
14	Variable O&M (Note 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 10)		($4)	($4)	($4)	($4)	($4)	($4)	($4)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)
17	Royalty Payment (Note 11)		($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)
19	**Total Expenses (Note 12)**		($9)	($9)	($9)	($10)	($10)	($10)	($10)	($11)	($11)	($21)	($21)	($22)	($22)	($22)	($23)	($23)	($24)	($24)	($24)	($25)
21	**EBITDA (Note 13)**		$31	$32	$33	$34	$34	$35	$36	$37	$38	$29	$30	$31	$32	$33	$34	$35	$36	$37	$38	$39
23	**Tax Credits**																					
24	Federal Investment Tax Credit (Note 14)		$220																			
25	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Depreciation**																					
27	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
28	State Depreciation (Note 17)		($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)	($37)
29	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30	Federal Depreciation (Note 19)		($125)	($200)	($120)	($72)	($72)	($36)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	**Income Taxes**																					
33	State Taxable Income (Note 20)		($26)	($25)	($24)	($23)	($21)	($20)	($18)	($16)	($15)	($22)	($21)	($19)	($17)	($15)	($13)	($11)	($8)	($6)	($3)	$0
34	State Income Tax (Note 21)		$3	$3	$3	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$1	$0	($0)
35	State Tax Benefit (Liability) (Note 22)		$3	$3	$3	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$1	$0	($0)
36	Federal Taxable Income (Note 23)		($9)	($185)	($104)	($55)	($54)	($17)	$20	$22	$24	$17	$18	$20	$21	$23	$25	$27	$29	$32	$34	$37
37	Federal Income Tax (Note 24)		$3	$65	$37	$19	$19	$6	($7)	($8)	($8)	($6)	($6)	($7)	($7)	($8)	($9)	($9)	($10)	($11)	($12)	($13)
38	Federal Tax Benefit (Liability) (Note 25)		$223	$65	$37	$19	$19	$6	($7)	($8)	($8)	($6)	($6)	($7)	($7)	($8)	($9)	($9)	($10)	($11)	($12)	($13)
41	**Total Tax Benefit (Liability) (Note 26)**		$226	$68	$39	$22	$21	$8	($5)	($6)	($7)	($4)	($4)	($5)	($6)	($6)	($7)	($8)	($9)	($10)	($12)	($13)
45	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
47	Equity Contribution (Note 27)	($334)																				
48	Cash Distribution (Note 28)		$5	$5	$5	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$6	$6	$6	$6	$6	$6
49	Tax Benefits (Liability) (Note 29)		$226	$68	$39	$22	$21	$8	($5)	($6)	($7)	($4)	($4)	($5)	($6)	($6)	($7)	($8)	($9)	($10)	($12)	($13)
50	**Total (Note 30)**	($334)	$231	$73	$45	$27	$27	$14	$1	$0	($0)	$1	$1	$0	($0)	($1)	($2)	($3)	($3)	($4)	($5)	($6)
52	**Debt**																					
53	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
54	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
56	EBITDA		$31	$32	$33	$34	$34	$35	$36	$37	$38	$29	$30	$31	$32	$33	$34	$35	$36	$37	$38	$39
57	Adjusted EBITDA (Note 33)		$29	$28	$27	$26	$24	$23	$22	$21	$20	$15	$14	$14	$13	$13	$12	$12	$11	$11	$10	$10
58	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
59	Debt Sizing (Note 35)	**$297**	$24	$23	$22	$21	$20	$20	$19	$18	$17	$12	$12	$11	$11	$11	$10	$10	$9	$9	$9	$8
61	Repayment/Amortization																					
62	Beginning Balance (Note 36)		$297	$292	$286	$279	$270	$260	$249	$237	$223	$207	$197	$186	$174	$159	$143	$125	$105	$83	$58	$30
63	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Repayments (Note 38)		($5)	($6)	($7)	($8)	($10)	($11)	($13)	($14)	($16)	($10)	($11)	($13)	($14)	($16)	($18)	($20)	($22)	($25)	($27)	($30)
65	Ending Blance (Note 39)	$297	$292	$286	$279	$270	$260	$249	$237	$223	$207	$197	$186	$174	$159	$143	$125	$105	$83	$58	$30	($0)
67	Calculation of Repayments																					
68	Debt Service Payment (Note 40)		($26)	($27)	($27)	($28)	($29)	($29)	($30)	($31)	($31)	($24)	($25)	($26)	($26)	($27)	($28)	($29)	($30)	($31)	($32)	($32)
69	Interest (Note 41)		($21)	($20)	($20)	($19)	($19)	($18)	($17)	($17)	($16)	($14)	($14)	($13)	($12)	($11)	($10)	($9)	($7)	($6)	($4)	($2)
70	Principal (Note 42)		($5)	($6)	($7)	($8)	($10)	($11)	($13)	($14)	($16)	($10)	($11)	($13)	($14)	($16)	($18)	($20)	($22)	($25)	($27)	($30)
71	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
72	**Leverage (Note 44)**		41%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	4,194.0
Installed Cost ($/kW)	$8,988
Fixed O&M ($/kW)	$25
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	24.0%
Degradation	0.5%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$600
Replacement Term (years)	10
Cost of Equity (Target IRR)	12.0%
Discount Rate	9.49%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$0
PBI Amount	$0.00
PBI Term	0
Other Incentives	
GOSOLARSF	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$37,696
Debt Requirement ($ in 000)	$18,908
Equity Requirement ($ in 000)	$18,788
Financial Results	
Leverage	50%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$315.66
First Year PPA Price ($/MWH)	$256.12

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

($ in 1000 unless noted otherwise)

Year		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Annual Generation (kWh) (Note 1)		8,817,466	8,773,378	8,729,511	8,685,864	8,642,435	8,599,222	8,556,226	8,513,445	8,470,878	8,428,523	8,386,381	8,344,449	8,302,727	8,261,213	8,219,907	8,178,807	8,137,913	8,097,224	8,056,738	8,016,454
Cost of Electricty ($/MWh) (Note 2)		$256.12	$263.80	$271.72	$279.87	$288.26	$296.91	$305.82	$314.99	$324.44	$334.18	$344.20	$354.53	$365.16	$376.12	$387.40	$399.02	$410.99	$423.32	$436.02	$449.10
Revenues																					
Power Sales (Note 3)		$2,258	$2,314	$2,372	$2,431	$2,491	$2,553	$2,617	$2,682	$2,748	$2,817	$2,887	$2,958	$3,032	$3,107	$3,184	$3,264	$3,345	$3,428	$3,513	$3,600
State Capacity Based Incentive (CBI) (Note 4)		$0																			
State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Expenses																					
Fixed O&M (Note 7)		($105)	($108)	($111)	($115)	($118)	($122)	($125)	($129)	($133)	($137)	($141)	($145)	($149)	($154)	($159)	($163)	($168)	($173)	($179)	($184)
Variable O&M (Note 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Insurance (Note 10)		($188)	($194)	($200)	($206)	($212)	($218)	($225)	($232)	($239)	($246)	($253)	($261)	($269)	($277)	($285)	($294)	($302)	($312)	($321)	($330)
Royalty Payment (Note 11)		($63)	($65)	($67)	($69)	($71)	($73)	($75)	($77)	($80)	($82)	($85)	($87)	($90)	($92)	($95)	($98)	($101)	($104)	($107)	($110)
Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	($358)	($358)	($358)	($358)	($358)	($358)	($358)	($358)	($358)	($358)	($358)
Total Expenses (Note 12)		($356)	($367)	($378)	($389)	($401)	($413)	($425)	($438)	($451)	($823)	($837)	($851)	($866)	($881)	($897)	($913)	($930)	($947)	($965)	($983)
EBITDA (Note 13)		$1,902	$1,948	$1,994	$2,042	$2,090	$2,140	$2,191	$2,244	$2,297	$1,994	$2,050	$2,107	$2,166	$2,226	$2,287	$2,350	$2,415	$2,481	$2,548	$2,617
Tax Credits																					
Federal Investment Tax Credit (Note 14)		$11,309																			
Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation																					
State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
State Depreciation (Note 17)		($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)	($1,885)
Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Federal Depreciation (Note 19)		($6,408)	($10,253)	($6,152)	($3,691)	($3,691)	($1,846)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Income Taxes																					
State Taxable Income (Note 20)		($1,306)	($1,243)	($1,174)	($1,100)	($1,020)	($934)	($841)	($741)	($634)	($877)	($773)	($662)	($542)	($414)	($275)	($126)	$34	$206	$391	$590
State Income Tax (Note 21)		$142	$135	$127	$119	$111	$101	$91	$80	$69	$95	$84	$72	$59	$45	$30	$14	($4)	($22)	($42)	($64)
State Tax Benefit (Liability) (Note 22)		$142	$135	$127	$119	$111	$101	$91	$80	$69	$95	$84	$72	$59	$45	$30	$14	($4)	($22)	($42)	($64)
Federal Taxable Income (Note 23)		($5,688)	($9,476)	($5,314)	($2,787)	($2,716)	($793)	$1,135	$1,224	$1,320	$1,103	$1,195	$1,294	$1,401	$1,516	$1,640	$1,772	$1,915	$2,069	$2,234	$2,411
Federal Income Tax (Note 24)		$1,991	$3,317	$1,860	$975	$950	$278	($397)	($428)	($462)	($386)	($418)	($453)	($490)	($531)	($574)	($620)	($670)	($724)	($782)	($844)
Federal Tax Benefit (Liability) (Note 25)		$13,300	$3,317	$1,860	$975	$950	$278	($397)	($428)	($462)	($386)	($418)	($453)	($490)	($531)	($574)	($620)	($670)	($724)	($782)	($844)
Total Tax Benefit (Liability) (Note 26)		$13,441	$3,451	$1,987	$1,095	$1,061	$379	($306)	($348)	($393)	($291)	($335)	($381)	($432)	($486)	($544)	($607)	($674)	($746)	($824)	($908)
Project Equity Returns Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Equity Contribution (Note 27)	($18,788)																				
Cash Distribution (Note 28)		$317	$325	$332	$340	$348	$357	$365	$374	$383	$332	$342	$351	$361	$371	$381	$392	$402	$413	$425	$436
Tax Benefits (Liability) (Note 29)		$13,441	$3,451	$1,987	$1,095	$1,061	$379	($306)	($348)	($393)	($291)	($335)	($381)	($432)	($486)	($544)	($607)	($674)	($746)	($824)	($908)
Total (Note 30)	($18,788)	$13,758	$3,776	$2,319	$1,435	$1,409	$736	$59	$26	($10)	$41	$7	($30)	($71)	($115)	($163)	($215)	($272)	($333)	($399)	($471)
Debt																					
Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
EBITDA		$1,902	$1,948	$1,994	$2,042	$2,090	$2,140	$2,191	$2,244	$2,297	$1,994	$2,050	$2,107	$2,166	$2,226	$2,287	$2,350	$2,415	$2,481	$2,548	$2,617
Adjusted EBITDA (Note 33)		$1,778	$1,701	$1,628	$1,558	$1,490	$1,426	$1,365	$1,306	$1,249	$1,013	$974	$936	$899	$863	$829	$796	$764	$734	$705	$676
Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Debt Sizing (Note 35)	**$18,908**	$1,481	$1,418	$1,356	$1,298	$1,242	$1,188	$1,137	$1,088	$1,041	$845	$811	$780	$749	$719	$691	$663	$637	$612	$587	$564
Repayment/Amortization																					
Beginning Balance (Note 36)		$18,908	$18,646	$18,328	$17,950	$17,505	$16,988	$16,394	$15,715	$14,946	$14,078	$13,402	$12,632	$11,761	$10,779	$9,679	$8,451	$7,084	$5,567	$3,890	$2,038
Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Repayments (Note 38)		($262)	($318)	($379)	($445)	($517)	($594)	($678)	($770)	($868)	($676)	($770)	($872)	($981)	($1,100)	($1,229)	($1,367)	($1,516)	($1,678)	($1,851)	($2,038)
Ending Blance (Note 39)	$18,908	$18,646	$18,328	$17,950	$17,505	$16,988	$16,394	$15,715	$14,946	$14,078	$13,402	$12,632	$11,761	$10,779	$9,679	$8,451	$7,084	$5,567	$3,890	$2,038	$0
Calculation of Repayments																					
Debt Service Payment (Note 40)		($1,585)	($1,623)	($1,662)	($1,701)	($1,742)	($1,784)	($1,826)	($1,870)	($1,914)	($1,661)	($1,708)	($1,756)	($1,805)	($1,855)	($1,906)	($1,959)	($2,012)	($2,067)	($2,123)	($2,181)
Interest (Note 41)		($1,324)	($1,305)	($1,283)	($1,256)	($1,225)	($1,189)	($1,148)	($1,100)	($1,046)	($985)	($938)	($884)	($823)	($755)	($678)	($592)	($496)	($390)	($272)	($143)
Principal (Note 42)		($262)	($318)	($379)	($445)	($517)	($594)	($678)	($770)	($868)	($676)	($770)	($872)	($981)	($1,100)	($1,229)	($1,367)	($1,516)	($1,678)	($1,851)	($2,038)
DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Leverage (Note 44)		50%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	3.0
Installed Cost ($/kW)	$6,720
Fixed O&M ($/kW)	$50
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	15.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$1,000
Replacement Term (years)	10
Cost of Equity (Target IRR)	12.0%
Discount Rate	10.85%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$2,500
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$20
Debt Requirement ($ in 000)	$5
Equity Requirement ($ in 000)	$16
Financial Results	
Leverage	23%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$261.36
First Year PPA Price ($/MWH)	$214.32

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942
4	Cost of Electricty ($/MWh) (Note 2)		$214.32	$220.75	$227.38	$234.20	$241.22	$248.46	$255.91	$263.59	$271.50	$279.64	$288.03	$296.67	$305.57	$314.74	$324.18	$333.91	$343.93	$354.24	$364.87	$375.82
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
8	State Capacity Based Incentive (CBI) (Note 4)		$8																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
14	Variable O&M (Note 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 10)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
17	Royalty Payment (Note 11)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
19	**Total Expenses (Note 12)**		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
20																						
21	**EBITDA (Note 13)**		$1	$1	$1	$1	$1	$1	$1	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1
22																						
23	**Tax Credits**																					
24	Federal Investment Tax Credit (Note 14)		$6																			
25	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Depreciation**																					
27	State Depreciation Rate (Note 16)		0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
28	State Depreciation (Note 17)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30	Federal Depreciation (Note 19)		($3)	($5)	($3)	($2)	($2)	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31																						
32	**Income Taxes**																					
33	State Taxable Income (Note 20)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
34	State Income Tax (Note 21)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
35	State Tax Benefit (Liability) (Note 22)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
36	Federal Taxable Income (Note 23)		$4	($5)	($3)	($1)	($1)	($0)	$1	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Federal Income Tax (Note 24)		($2)	$2	$1	$1	$1	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
38	Federal Tax Benefit (Liability) (Note 25)		$4	$2	$1	$1	$1	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
39																						
40																						
41	**Total Tax Benefit (Liability) (Note 26)**		$5	$2	$1	$1	$1	$0	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
42																						
43																						
44																						
45	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
46																						
47	Equity Contribution (Note 27)	($8)																				
48	Cash Distribution (Note 28)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
49	Tax Benefits (Liability) (Note 29)		$5	$2	$1	$1	$1	$0	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
50	**Total (Note 30)**	($8)	$5	$2	$1	$1	$1	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
51																						
52	**Debt**																					
53	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
54	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
55																						
56	EBITDA		$1	$1	$1	$1	$1	$1	$1	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1
57	Adjusted EBITDA (Note 33)		$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
58	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
59	Debt Sizing (Note 35)	**$5**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
60																						
61	Repayment/Amortization																					
62	Beginning Balance (Note 36)		$5	$5	$4	$4	$4	$4	$3	$3	$3	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$0
63	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Repayments (Note 38)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
65	Ending Blance (Note 39)	$5	$5	$4	$4	$4	$4	$3	$3	$3	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$0	($0)
66																						
67	Calculation of Repayments																					
68	Debt Service Payment (Note 40)		($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
69	Interest (Note 41)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
70	Principal (Note 42)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
71	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
72	**Leverage (Note 44)**		23%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	500.0
Installed Cost ($/kW)	$3,423
Fixed O&M ($/kW)	$50
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	20.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$800
Replacement Term (years)	10
Cost of Equity (Target IRR)	12.0%
Discount Rate	10.98%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$1,500
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$1,712
Debt Requirement ($ in 000)	$349
Equity Requirement ($ in 000)	$1,363
Financial Results	
Leverage	20%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$124.97
First Year PPA Price ($/MWH)	$102.58

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000
4	Cost of Electricty ($/MWh) (Note 2)		$102.58	$105.66	$108.83	$112.10	$115.46	$118.92	$122.49	$126.17	$129.95	$133.85	$137.87	$142.00	$146.26	$150.65	$155.17	$159.82	$164.62	$169.56	$174.64	$179.88
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$90	$93	$95	$98	$101	$104	$107	$111	$114	$117	$121	$124	$128	$132	$136	$140	$144	$149	$153	$158
8	State Capacity Based Incentive (CBI) (Note 4)		$750																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($25)	($26)	($27)	($27)	($28)	($29)	($30)	($31)	($32)	($33)	($34)	($35)	($36)	($37)	($38)	($39)	($40)	($41)	($43)	($44)
14	Variable O&M (Note 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 10)		($9)	($9)	($9)	($9)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)	($13)	($13)	($14)	($14)	($15)	($15)
17	Royalty Payment (Note 11)		($8)	($8)	($8)	($8)	($8)	($9)	($9)	($9)	($10)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)	($13)
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	($57)	($57)	($57)	($57)	($57)	($57)	($57)	($57)	($57)	($57)	($57)
19	**Total Expenses (Note 12)**		($41)	($42)	($44)	($45)	($46)	($48)	($49)	($50)	($52)	($111)	($112)	($114)	($115)	($117)	($119)	($121)	($123)	($125)	($127)	($129)
20																						
21	**EBITDA (Note 13)**		$49	$50	$52	$53	$55	$57	$58	$60	$62	$7	$9	$11	$13	$15	$17	$19	$21	$24	$26	$29
22																						
23	**Tax Credits**																					
24	Federal Investment Tax Credit (Note 14)		$513																			
25	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Depreciation**																					
27	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
28	State Depreciation (Note 17)		($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)	($86)
29	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30	Federal Depreciation (Note 19)		($291)	($466)	($279)	($168)	($168)	($84)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31																						
32	**Income Taxes**																					
33	State Taxable Income (Note 20)		($61)	($59)	($56)	($53)	($49)	($46)	($42)	($38)	($34)	($86)	($84)	($82)	($80)	($77)	($75)	($72)	($69)	($66)	($62)	($59)
34	State Income Tax (Note 21)		$7	$6	$6	$6	$5	$5	$5	$4	$4	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$6
35	State Tax Benefit (Liability) (Note 22)		$7	$6	$6	$6	$5	$5	$5	$4	$4	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$6
36	Federal Taxable Income (Note 23)		$490	($432)	($243)	($129)	($126)	($39)	$48	$52	$56	$9	$11	$13	$14	$17	$19	$21	$24	$27	$30	$33
37	Federal Income Tax (Note 24)		($172)	$151	$85	$45	$44	$14	($17)	($18)	($19)	($3)	($4)	($4)	($5)	($6)	($7)	($7)	($8)	($9)	($11)	($12)
38	Federal Tax Benefit (Liability) (Note 25)		$342	$151	$85	$45	$44	$14	($17)	($18)	($19)	($3)	($4)	($4)	($5)	($6)	($7)	($7)	($8)	($9)	($11)	($12)
39																						
40																						
41	**Total Tax Benefit (Liability) (Note 26**		$349	$158	$91	$51	$49	$19	($12)	($14)	($16)	$6	$5	$4	$4	$3	$2	$0	($1)	($2)	($4)	($5)
42																						
43																						
44																						
45	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
46																						
47	Equity Contribution (Note 27)	($613)																				
48	Cash Distribution (Note 28)		$8	$8	$9	$9	$9	$9	$10	$10	$10	$1	$1	$2	$2	$2	$3	$3	$4	$4	$4	$5
49	Tax Benefits (Liability) (Note 29)		$349	$158	$91	$51	$49	$19	($12)	($14)	($16)	$6	$5	$4	$4	$3	$2	$0	($1)	($2)	($4)	($5)
50	**Total (Note 30)**	($613)	$357	$166	$100	$60	$59	$28	($3)	($4)	($6)	$7	$7	$6	$6	$5	$4	$4	$3	$2	$1	($1)
51																						
52	**Debt**																					
53	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
54	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
55																						
56	EBITDA		$49	$50	$52	$53	$55	$57	$58	$60	$62	$7	$9	$11	$13	$15	$17	$19	$21	$24	$26	$29
57	Adjusted EBITDA (Note 33)		$46	$44	$42	$41	$39	$38	$36	$35	$34	$3	$4	$5	$5	$6	$6	$6	$7	$7	$7	$7
58	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
59	Debt Sizing (Note 35)	**$349**	$38	$37	$35	$34	$33	$31	$30	$29	$28	$3	$3	$4	$4	$5	$5	$5	$6	$6	$6	$6
60																						
61	Repayment/Amortization																					
62	Beginning Balance (Note 36)		$349	$332	$314	$293	$269	$242	$211	$178	$140	$98	$100	$99	$97	$94	$88	$80	$70	$57	$41	$22
63	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Repayments (Note 38)		($16)	($19)	($21)	($24)	($27)	($30)	($34)	($38)	($42)	$1	($0)	($2)	($4)	($6)	($8)	($10)	($13)	($16)	($19)	($22)
65	Ending Blance (Note 39)	$349	$332	$314	$293	$269	$242	$211	$178	$140	$98	$100	$99	$97	$94	$88	$80	$70	$57	$41	$22	($0)
66																						
67	Calculation of Repayments																					
68	Debt Service Payment (Note 40)		($41)	($42)	($43)	($44)	($46)	($47)	($49)	($50)	($52)	($6)	($7)	($9)	($11)	($12)	($14)	($16)	($18)	($20)	($22)	($24)
69	Interest (Note 41)		($24)	($23)	($22)	($20)	($19)	($17)	($15)	($12)	($10)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($5)	($4)	($3)	($2)
70	Principal (Note 42)		($16)	($19)	($21)	($24)	($27)	($30)	($34)	($38)	($42)	$1	($0)	($2)	($4)	($6)	($8)	($10)	($13)	($16)	($19)	($22)
71	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
72	**Leverage (Note 44)**		20%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	7,500.0
Installed Cost ($/kW)	$2,809
Fixed O&M ($/kW)	$30
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	20.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$800
Replacement Term (years)	10
Cost of Equity (Target IRR)	12.0%
Discount Rate	9.43%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$0
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$21,068
Debt Requirement ($ in 000)	$10,817
Equity Requirement ($ in 000)	$10,251
Financial Results	
Leverage	51%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$157.45
First Year PPA Price ($/MWH)	$127.69

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000
4	Cost of Electricty ($/MWh) (Note 2)		$127.69	$131.52	$135.46	$139.53	$143.71	$148.02	$152.47	$157.04	$161.75	$166.60	$171.60	$176.75	$182.05	$187.51	$193.14	$198.93	$204.90	$211.05	$217.38	$223.90
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$1,678	$1,728	$1,780	$1,833	$1,888	$1,945	$2,003	$2,063	$2,125	$2,189	$2,255	$2,322	$2,392	$2,464	$2,538	$2,614	$2,692	$2,773	$2,856	$2,942
8	State Capacity Based Incentive (CBI) (Note 4)		$0																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($225)	($232)	($239)	($246)	($253)	($261)	($269)	($277)	($285)	($294)	($302)	($311)	($321)	($330)	($340)	($351)	($361)	($372)	($383)	($395)
14	Variable O&M (Note 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 10)		($105)	($108)	($112)	($115)	($119)	($122)	($126)	($130)	($133)	($137)	($142)	($146)	($150)	($155)	($159)	($164)	($169)	($174)	($179)	($185)
17	Royalty Payment (Note 11)		($113)	($116)	($119)	($123)	($127)	($130)	($134)	($138)	($143)	($147)	($151)	($156)	($160)	($165)	($170)	($175)	($181)	($186)	($192)	($197)
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	($854)	($854)	($854)	($854)	($854)	($854)	($854)	($854)	($854)	($854)	($854)
19	**Total Expenses (Note 12)**		($443)	($456)	($470)	($484)	($498)	($513)	($529)	($545)	($561)	($1,432)	($1,449)	($1,467)	($1,486)	($1,505)	($1,524)	($1,544)	($1,565)	($1,586)	($1,608)	($1,631)
20																						
21	**EBITDA (Note 13)**		$1,235	$1,272	$1,310	$1,349	$1,390	$1,432	$1,475	$1,519	$1,564	$757	$805	$855	$907	$959	$1,014	$1,070	$1,128	$1,187	$1,248	$1,311
22																						
23	**Tax Credits**																					
24	Federal Investment Tax Credit (Note 14)		$6,320																			
25	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Depreciation**																					
27	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
28	State Depreciation (Note 17)		($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)	($1,053)
29	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30	Federal Depreciation (Note 19)		($3,581)	($5,730)	($3,438)	($2,063)	($2,063)	($1,031)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31																						
32	**Income Taxes**																					
33	State Taxable Income (Note 20)		($576)	($519)	($459)	($393)	($322)	($246)	($163)	($73)	$23	($727)	($665)	($597)	($524)	($445)	($359)	($266)	($166)	($57)	$60	$186
34	State Income Tax (Note 21)		$62	$56	$50	$43	$35	$27	$18	$8	($3)	$79	$72	$65	$57	$48	$39	$29	$18	$6	($7)	($20)
35	State Tax Benefit (Liability) (Note 22)		$62	$56	$50	$43	$35	$27	$18	$8	($3)	$79	$72	$65	$57	$48	$39	$29	$18	$6	($7)	($20)
36	Federal Taxable Income (Note 23)		($3,041)	($5,140)	($2,794)	($1,360)	($1,297)	($197)	$908	$988	$1,074	$405	$461	$521	$586	$657	$733	$816	$906	$1,002	$1,107	$1,220
37	Federal Income Tax (Note 24)		$1,064	$1,799	$978	$476	$454	$69	($318)	($346)	($376)	($142)	($161)	($182)	($205)	($230)	($257)	($286)	($317)	($351)	($387)	($427)
38	Federal Tax Benefit (Liability) (Note 25)		$7,385	$1,799	$978	$476	$454	$69	($318)	($346)	($376)	($142)	($161)	($182)	($205)	($230)	($257)	($286)	($317)	($351)	($387)	($427)
39																						
40																						
41	**Total Tax Benefit (Liability) (Note 26)**		$7,447	$1,855	$1,028	$519	$489	$96	($300)	($338)	($378)	($63)	($89)	($118)	($148)	($182)	($218)	($257)	($299)	($345)	($394)	($447)
42																						
43																						
44																						
45	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
46																						
47	Equity Contribution (Note 27)	($10,251)																				
48	Cash Distribution (Note 28)		$206	$212	$218	$225	$232	$239	$246	$253	$261	$126	$134	$143	$151	$160	$169	$178	$188	$198	$208	$219
49	Tax Benefits (Liability) (Note 29)		$7,447	$1,855	$1,028	$519	$489	$96	($300)	($338)	($378)	($63)	($89)	($118)	($148)	($182)	($218)	($257)	($299)	($345)	($394)	($447)
50	**Total (Note 30)**	($10,251)	$7,653	$2,067	$1,246	$744	$720	$334	($54)	($85)	($118)	$63	$45	$25	$3	($22)	($49)	($79)	($111)	($147)	($186)	($229)
51																						
52	**Debt**																					
53	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
54	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
55																						
56	EBITDA		$1,235	$1,272	$1,310	$1,349	$1,390	$1,432	$1,475	$1,519	$1,564	$757	$805	$855	$907	$959	$1,014	$1,070	$1,128	$1,187	$1,248	$1,311
57	Adjusted EBITDA (Note 33)		$1,154	$1,111	$1,070	$1,030	$991	$954	$918	$884	$851	$385	$383	$380	$376	$372	$367	$362	$357	$351	$345	$339
58	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
59	Debt Sizing (Note 35)	**$10,817**	$962	$926	$891	$858	$826	$795	$765	$737	$709	$321	$319	$316	$313	$310	$306	$302	$297	$293	$288	$282
60																						
61	Repayment/Amortization																					
62	Beginning Balance (Note 36)		$10,817	$10,545	$10,223	$9,846	$9,411	$8,912	$8,342	$7,697	$6,971	$6,155	$5,955	$5,700	$5,387	$5,008	$4,560	$4,034	$3,425	$2,725	$1,927	$1,021
63	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Repayments (Note 38)		($272)	($322)	($376)	($435)	($500)	($569)	($645)	($727)	($816)	($200)	($254)	($314)	($378)	($449)	($526)	($609)	($700)	($798)	($905)	($1,021)
65	Ending Blance (Note 39)	$10,817	$10,545	$10,223	$9,846	$9,411	$8,912	$8,342	$7,697	$6,971	$6,155	$5,955	$5,700	$5,387	$5,008	$4,560	$4,034	$3,425	$2,725	$1,927	$1,021	($0)
66																						
67	Calculation of Repayments																					
68	Debt Service Payment (Note 40)		($1,029)	($1,060)	($1,092)	($1,125)	($1,158)	($1,193)	($1,229)	($1,266)	($1,304)	($631)	($671)	($713)	($755)	($799)	($845)	($891)	($940)	($989)	($1,040)	($1,093)
69	Interest (Note 41)		($757)	($738)	($716)	($689)	($659)	($624)	($584)	($539)	($488)	($431)	($417)	($399)	($377)	($351)	($319)	($282)	($240)	($191)	($135)	($71)
70	Principal (Note 42)		($272)	($322)	($376)	($435)	($500)	($569)	($645)	($727)	($816)	($200)	($254)	($314)	($378)	($449)	($526)	($609)	($700)	($798)	($905)	($1,021)
71	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
72	**Leverage (Note 44)**		51%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	2,400.0
Installed Cost ($/kW)	$8,651
Fixed O&M ($/kW)	$510
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	15.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Cost of Equity (Target IRR)	12.0%
Discount Rate	9.53%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$0
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$20,762
Debt Requirement ($ in 000)	$10,264
Equity Requirement ($ in 000)	$10,499
Financial Results	
Leverage	49%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$893.80
First Year PPA Price ($/MWH)	$725.42

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600
4	Cost of Electricty ($/MWh) (Note 2)		$725.42	$747.18	$769.60	$792.68	$816.46	$840.96	$866.19	$892.17	$918.94	$946.50	$974.90	$1,004.15	$1,034.27	$1,065.30	$1,097.26	$1,130.18	$1,164.08	$1,199.00	$1,234.97	$1,272.02
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$2,288	$2,356	$2,427	$2,500	$2,575	$2,652	$2,732	$2,814	$2,898	$2,985	$3,074	$3,167	$3,262	$3,360	$3,460	$3,564	$3,671	$3,781	$3,895	$4,011
8	State Capacity Based Incentive (CBI) (Note 4)		$0																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($1,224)	($1,261)	($1,299)	($1,337)	($1,378)	($1,419)	($1,462)	($1,505)	($1,551)	($1,597)	($1,645)	($1,694)	($1,745)	($1,797)	($1,851)	($1,907)	($1,964)	($2,023)	($2,084)	($2,146)
14	Variable O&M (Note 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 10)		($104)	($107)	($110)	($113)	($117)	($120)	($124)	($128)	($132)	($135)	($140)	($144)	($148)	($152)	($157)	($162)	($167)	($172)	($177)	($182)
17	Royalty Payment (Note 11)		($36)	($37)	($38)	($39)	($41)	($42)	($43)	($44)	($46)	($47)	($48)	($50)	($51)	($53)	($54)	($56)	($58)	($60)	($61)	($63)
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($1,364)	($1,405)	($1,447)	($1,490)	($1,535)	($1,581)	($1,628)	($1,677)	($1,728)	($1,779)	($1,833)	($1,888)	($1,944)	($2,003)	($2,063)	($2,125)	($2,189)	($2,254)	($2,322)	($2,391)
20																						
21	**EBITDA (Note 13)**		$924	$952	$980	$1,010	$1,040	$1,071	$1,103	$1,136	$1,170	$1,205	$1,242	$1,279	$1,317	$1,357	$1,397	$1,439	$1,483	$1,527	$1,573	$1,620
22																						
23	**Tax Credits**																					
24	Federal Investment Tax Credit (Note 14)		$6,229																			
25	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Depreciation**																					
27	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
28	State Depreciation (Note 17)		($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)	($1,038)
29	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30	Federal Depreciation (Note 19)		($3,530)	($5,647)	($3,388)	($2,033)	($2,033)	($1,017)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31																						
32	**Income Taxes**																					
33	State Taxable Income (Note 20)		($833)	($801)	($767)	($730)	($690)	($647)	($600)	($549)	($494)	($435)	($370)	($301)	($226)	($145)	($57)	$37	$139	$248	$366	$494
34	State Income Tax (Note 21)		$90	$87	$83	$79	$75	$70	$65	$60	$54	$47	$40	$33	$24	$16	$6	($4)	($15)	($27)	($40)	($54)
35	State Tax Benefit (Liability) (Note 22)		$90	$87	$83	$79	$75	$70	$65	$60	$54	$47	$40	$33	$24	$16	$6	($4)	($15)	($27)	($40)	($54)
36	Federal Taxable Income (Note 23)		($3,234)	($5,324)	($3,035)	($1,646)	($1,611)	($555)	$503	$549	$598	$651	$708	$770	$837	$909	$987	$1,071	$1,162	$1,260	$1,365	$1,478
37	Federal Income Tax (Note 24)		$1,132	$1,863	$1,062	$576	$564	$194	($176)	($192)	($209)	($228)	($248)	($270)	($293)	($318)	($346)	($375)	($407)	($441)	($478)	($517)
38	Federal Tax Benefit (Liability) (Note 25)		$7,361	$1,863	$1,062	$576	$564	$194	($176)	($192)	($209)	($228)	($248)	($270)	($293)	($318)	($346)	($375)	($407)	($441)	($478)	($517)
39																						
40																						
41	**Total Tax Benefit (Liability) (Note 26)**		$7,451	$1,950	$1,145	$655	$639	$264	($111)	($132)	($156)	($181)	($208)	($237)	($268)	($303)	($339)	($379)	($422)	($468)	($517)	($571)
42																						
43																						
44																						
45	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
46																						
47	Equity Contribution (Note 27)	($10,499)																				
48	Cash Distribution (Note 28)		$154	$159	$163	$168	$173	$179	$184	$189	$195	$201	$207	$213	$220	$226	$233	$240	$247	$255	$262	$270
49	Tax Benefits (Liability) (Note 29)		$7,451	$1,950	$1,145	$655	$639	$264	($111)	($132)	($156)	($181)	($208)	($237)	($268)	($303)	($339)	($379)	($422)	($468)	($517)	($571)
50	**Total (Note 30)**	($10,499)	$7,605	$2,109	$1,309	$824	$812	$443	$73	$57	$39	$20	($1)	($24)	($49)	($76)	($106)	($139)	($175)	($213)	($255)	($301)
51																						
52	**Debt**																					
53	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
54	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
55																						
56	EBITDA		$924	$952	$980	$1,010	$1,040	$1,071	$1,103	$1,136	$1,170	$1,205	$1,242	$1,279	$1,317	$1,357	$1,397	$1,439	$1,483	$1,527	$1,573	$1,620
57	Adjusted EBITDA (Note 33)		$863	$831	$800	$770	$741	$714	$687	$661	$637	$613	$590	$568	$547	$526	$506	$488	$469	$452	$435	$419
58	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
59	Debt Sizing (Note 35)	**$10,264**	$720	$693	$667	$642	$618	$595	$572	$551	$530	$511	$492	$473	$455	$438	$422	$406	$391	$376	$362	$349
60																						
61	Repayment/Amortization																					
62	Beginning Balance (Note 36)		$10,264	$10,212	$10,134	$10,027	$9,888	$9,713	$9,501	$9,246	$8,947	$8,598	$8,195	$7,734	$7,210	$6,617	$5,949	$5,201	$4,366	$3,436	$2,404	$1,262
63	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Repayments (Note 38)		($51)	($78)	($107)	($139)	($174)	($213)	($254)	($300)	($349)	($403)	($461)	($524)	($593)	($667)	($748)	($835)	($930)	($1,032)	($1,142)	($1,262)
65	Ending Blance (Note 39)	$10,264	$10,212	$10,134	$10,027	$9,888	$9,713	$9,501	$9,246	$8,947	$8,598	$8,195	$7,734	$7,210	$6,617	$5,949	$5,201	$4,366	$3,436	$2,404	$1,262	($0)
66																						
67	Calculation of Repayments																					
68	Debt Service Payment (Note 40)		($770)	($793)	($817)	($841)	($867)	($893)	($919)	($947)	($975)	($1,005)	($1,035)	($1,066)	($1,098)	($1,131)	($1,165)	($1,199)	($1,235)	($1,273)	($1,311)	($1,350)
69	Interest (Note 41)		($718)	($715)	($709)	($702)	($692)	($680)	($665)	($647)	($626)	($602)	($574)	($541)	($505)	($463)	($416)	($364)	($306)	($241)	($168)	($88)
70	Principal (Note 42)		($51)	($78)	($107)	($139)	($174)	($213)	($254)	($300)	($349)	($403)	($461)	($524)	($593)	($667)	($748)	($835)	($930)	($1,032)	($1,142)	($1,262)
71	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
72	**Leverage (Note 44)**		49%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	250.0
Installed Cost ($/kW)	$5,775
Fixed O&M ($/kW)	$200
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$30
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Cost of Equity (Target IRR)	12.0%
Discount Rate	9.66%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$210
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$1,444
Debt Requirement ($ in 000)	$677
Equity Requirement ($ in 000)	$767
Financial Results	
Leverage	47%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$110.71
First Year PPA Price ($/MWH)	$89.95

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000
4	Cost of Electricty ($/MWh) (Note 2)		$89.95	$92.65	$95.43	$98.29	$101.24	$104.27	$107.40	$110.62	$113.94	$117.36	$120.88	$124.51	$128.24	$132.09	$136.05	$140.14	$144.34	$148.67	$153.13	$157.72
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$177	$183	$188	$194	$200	$206	$212	$218	$225	$231	$238	$245	$253	$260	$268	$276	$284	$293	$302	$311
8	State Capacity Based Incentive (CBI) (Note 4)		$53																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($50)	($52)	($53)	($55)	($56)	($58)	($60)	($61)	($63)	($65)	($67)	($69)	($71)	($73)	($76)	($78)	($80)	($83)	($85)	($88)
14	Variable O&M (Note 8)		($59)	($61)	($63)	($65)	($67)	($69)	($71)	($73)	($75)	($77)	($79)	($82)	($84)	($87)	($89)	($92)	($95)	($98)	($101)	($104)
15	Fuel Cost (Note 9)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 10)		($7)	($7)	($8)	($8)	($8)	($8)	($9)	($9)	($9)	($9)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)
17	Royalty Payment (Note 11)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($116)	($120)	($123)	($127)	($131)	($135)	($139)	($143)	($147)	($152)	($156)	($161)	($166)	($171)	($176)	($181)	($187)	($192)	($198)	($204)
20																						
21	**EBITDA (Note 13)**		$61	$63	$65	$67	$69	$71	$73	$75	$77	$80	$82	$84	$87	$89	$92	$95	$98	$101	$104	$107
22																						
23	**Tax Credits**																					
24	Federal Investment Tax Credit (Note 14)		$433																			
25	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Depreciation**																					
27	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
28	State Depreciation (Note 17)		($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)	($72)
29	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30	Federal Depreciation (Note 19)		($245)	($393)	($236)	($141)	($141)	($71)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31																						
32	**Income Taxes**																					
33	State Taxable Income (Note 20)		($59)	($57)	($54)	($52)	($49)	($46)	($43)	($40)	($36)	($32)	($28)	($24)	($19)	($13)	($7)	($1)	$5	$13	$20	$29
34	State Income Tax (Note 21)		$6	$6	$6	$6	$5	$5	$5	$4	$4	$4	$3	$3	$2	$1	$1	$0	($1)	($1)	($2)	($3)
35	State Tax Benefit (Liability) (Note 22)		$6	$6	$6	$6	$5	$5	$5	$4	$4	$4	$3	$3	$2	$1	$1	$0	($1)	($1)	($2)	($3)
36	Federal Taxable Income (Note 23)		($173)	($371)	($212)	($115)	($113)	($40)	$34	$37	$40	$43	$47	$51	$56	$60	$66	$71	$77	$83	$90	$98
37	Federal Income Tax (Note 24)		$61	$130	$74	$40	$40	$14	($12)	($13)	($14)	($15)	($16)	($18)	($19)	($21)	($23)	($25)	($27)	($29)	($32)	($34)
38	Federal Tax Benefit (Liability) (Note 25)		$494	$130	$74	$40	$40	$14	($12)	($13)	($14)	($15)	($16)	($18)	($19)	($21)	($23)	($25)	($27)	($29)	($32)	($34)
39																						
40																						
41	**Total Tax Benefit (Liability) (Note 26**		$500	$136	$80	$46	$45	$19	($7)	($8)	($10)	($12)	($13)	($15)	($17)	($20)	($22)	($25)	($28)	($31)	($34)	($37)
42																						
43																						
44																						
45	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
46																						
47	Equity Contribution (Note 27)	($714)																				
48	Cash Distribution (Note 28)		$10	$10	$11	$11	$11	$12	$12	$12	$13	$13	$14	$14	$14	$15	$15	$16	$16	$17	$17	$18
49	Tax Benefits (Liability) (Note 29)		$500	$136	$80	$46	$45	$19	($7)	($8)	($10)	($12)	($13)	($15)	($17)	($20)	($22)	($25)	($28)	($31)	($34)	($37)
50	**Total (Note 30)**	($714)	$510	$146	$91	$57	$56	$31	$5	$4	$3	$2	$0	($1)	($3)	($5)	($7)	($9)	($11)	($14)	($17)	($20)
51																						
52	**Debt**																					
53	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
54	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
55																						
56	EBITDA		$61	$63	$65	$67	$69	$71	$73	$75	$77	$80	$82	$84	$87	$89	$92	$95	$98	$101	$104	$107
57	Adjusted EBITDA (Note 33)		$57	$55	$53	$51	$49	$47	$45	$44	$42	$40	$39	$37	$36	$35	$33	$32	$31	$30	$29	$28
58	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
59	Debt Sizing (Note 35)	**$677**	$47	$46	$44	$42	$41	$39	$38	$36	$35	$34	$32	$31	$30	$29	$28	$27	$26	$25	$24	$23
60																						
61	Repayment/Amortization																					
62	Beginning Balance (Note 36)		$677	$674	$668	$661	$652	$641	$627	$610	$590	$567	$541	$510	$476	$436	$392	$343	$288	$227	$159	$83
63	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Repayments (Note 38)		($3)	($5)	($7)	($9)	($12)	($14)	($17)	($20)	($23)	($27)	($30)	($35)	($39)	($44)	($49)	($55)	($61)	($68)	($75)	($83)
65	Ending Blance (Note 39)	$677	$674	$668	$661	$652	$641	$627	$610	$590	$567	$541	$510	$476	$436	$392	$343	$288	$227	$159	$83	($0)
66																						
67	Calculation of Repayments																					
68	Debt Service Payment (Note 40)		($51)	($52)	($54)	($55)	($57)	($59)	($61)	($62)	($64)	($66)	($68)	($70)	($72)	($75)	($77)	($79)	($81)	($84)	($86)	($89)
69	Interest (Note 41)		($47)	($47)	($47)	($46)	($46)	($45)	($44)	($43)	($41)	($40)	($38)	($36)	($33)	($31)	($27)	($24)	($20)	($16)	($11)	($6)
70	Principal (Note 42)		($3)	($5)	($7)	($9)	($12)	($14)	($17)	($20)	($23)	($27)	($30)	($35)	($39)	($44)	($49)	($55)	($61)	($68)	($75)	($83)
71	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
72	**Leverage (Note 44)**		47%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	400.0
Installed Cost ($/kW)	$7,350
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$70
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	9,500
Heat Recovery (mmBTU/hr)	1.70
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Replacement Escalation %	0.0%
Cost of Equity (Target IRR)	12.0%
Discount Rate	9.57%

Federal Incentives	N/A
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	0%
State Incentives	
State Incentive Type	CBI
CBI Amount	$2,500
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$2,940
Debt Requirement ($ in 000)	$1,429
Equity Requirement ($ in 000)	$1,511
Financial Results	
Leverage	49%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$191.51
First Year PPA Price ($/MWH)	$155.48

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600
4	Cost of Electricty ($/MWh) (Note 2)		$155.48	$160.15	$164.95	$169.90	$175.00	$180.25	$185.66	$191.23	$196.96	$202.87	$208.96	$215.23	$221.68	$228.33	$235.18	$242.24	$249.51	$256.99	$264.70	$272.64
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$490	$505	$520	$536	$552	$568	$585	$603	$621	$640	$659	$679	$699	$720	$742	$764	$787	$810	$835	$860
8	State Capacity Based Incentive (CBI) (Note 4)		$1,000																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 8)		($221)	($227)	($234)	($241)	($248)	($256)	($264)	($271)	($280)	($288)	($297)	($306)	($315)	($324)	($334)	($344)	($354)	($365)	($376)	($387)
15	Fuel Cost (Note 9)		($170)	($195)	($223)	($232)	($235)	($238)	($243)	($246)	($250)	($253)	($256)	($259)	($261)	($265)	($268)	($272)	($275)	($279)	($282)	($286)
16	Insurance (Note 10)		($15)	($15)	($16)	($16)	($17)	($17)	($18)	($18)	($19)	($19)	($20)	($20)	($21)	($22)	($22)	($23)	($24)	($24)	($25)	($26)
17	Royalty Payment (Note 11)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($406)	($438)	($473)	($489)	($500)	($511)	($524)	($536)	($548)	($560)	($573)	($585)	($596)	($611)	($625)	($639)	($653)	($668)	($683)	($698)
20	**Beneficial Energy Recapture**		$57	$66	$75	$78	$79	$80	$82	$83	$84	$85	$86	$87	$87	$89	$90	$91	$92	$93	$95	$96
21	**Total Expenses after Recapture**		($349)	($372)	($398)	($411)	($421)	($431)	($443)	($453)	($464)	($475)	($487)	($498)	($509)	($522)	($535)	($547)	($561)	($574)	($588)	($603)
22																						
23	**EBITDA (Note 13)**		$142	$133	$122	$125	$131	$137	$143	$150	$157	$164	$172	$180	$190	$198	$207	$217	$226	$236	$247	$257
24																						
25	**Tax Credits**																					
26	Federal Investment Tax Credit (Note 14)		$0																			
27	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Depreciation**																					
29	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
30	State Depreciation (Note 17)		($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)	($147)
31	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
32	Federal Depreciation (Note 19)		($588)	($941)	($564)	($339)	($339)	($169)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33																						
34	**Income Taxes**																					
35	State Taxable Income (Note 20)		($105)	($113)	($123)	($120)	($113)	($106)	($99)	($91)	($81)	($71)	($60)	($48)	($33)	($19)	($4)	$13	$32	$51	$73	$96
36	State Income Tax (Note 21)		$11	$12	$13	$13	$12	$12	$11	$10	$9	$8	$7	$5	$4	$2	$0	($1)	($3)	($6)	($8)	($10)
37	State Tax Benefit (Liability) (Note 22)		$11	$12	$13	$13	$12	$12	$11	$10	$9	$8	$7	$5	$4	$2	$0	($1)	($3)	($6)	($8)	($10)
38	Federal Taxable Income (Note 23)		$465	($895)	($527)	($299)	($293)	($117)	$58	$66	$75	$84	$93	$104	$118	$130	$144	$159	$175	$193	$212	$233
39	Federal Income Tax (Note 24)		($163)	$313	$184	$105	$102	$41	($20)	($23)	($26)	($29)	($33)	($37)	($41)	($45)	($50)	($56)	($61)	($68)	($74)	($81)
40	Federal Tax Benefit (Liability) (Note 25)		($163)	$313	$184	$105	$102	$41	($20)	($23)	($26)	($29)	($33)	($37)	($41)	($45)	($50)	($56)	($61)	($68)	($74)	($81)
41																						
42																						
43	**Total Tax Benefit (Liability) (Note 26)**		($151)	$325	$198	$118	$115	$53	($10)	($13)	($17)	($22)	($26)	($31)	($38)	($43)	($50)	($57)	($65)	($73)	($82)	($92)
44																						
45																						
46																						
47	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
48																						
49	Equity Contribution (Note 27)	($511)																				
50	Cash Distribution (Note 28)		$24	$22	$20	$21	$22	$23	$24	$25	$26	$27	$29	$30	$32	$33	$35	$36	$38	$39	$41	$43
51	Tax Benefits (Liability) (Note 29)		($151)	$325	$198	$118	$115	$53	($10)	($13)	($17)	($22)	($26)	($31)	($38)	($43)	($50)	($57)	($65)	($73)	($82)	($92)
52	**Total (Note 30)**	($511)	($128)	$348	$218	$138	$137	$75	$14	$12	$9	$6	$2	($1)	($6)	($10)	($15)	($21)	($27)	($34)	($41)	($49)
53																						
54	**Debt**																					
55	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
56	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
57																						
58	EBITDA		$142	$133	$122	$125	$131	$137	$143	$150	$157	$164	$172	$180	$190	$198	$207	$217	$226	$236	$247	$257
59	Adjusted EBITDA (Note 33)		$132	$116	$100	$95	$93	$91	$89	$87	$85	$84	$82	$80	$79	$77	$75	$73	$72	$70	$68	$66
60	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
61	Debt Sizing (Note 35)	**$1,429**	$110	$97	$83	$79	$78	$76	$74	$73	$71	$70	$68	$67	$66	$64	$63	$61	$60	$58	$57	$55
62																						
63	Repayment/Amortization																					
64	Beginning Balance (Note 36)		$1,429	$1,411	$1,400	$1,396	$1,390	$1,378	$1,360	$1,336	$1,305	$1,265	$1,217	$1,159	$1,089	$1,007	$912	$804	$679	$538	$379	$200
65	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
66	Repayments (Note 38)		($18)	($12)	($4)	($6)	($12)	($18)	($24)	($31)	($40)	($48)	($58)	($69)	($82)	($95)	($109)	($124)	($141)	($159)	($179)	($200)
67	Ending Blance (Note 39)	$1,429	$1,411	$1,400	$1,396	$1,390	$1,378	$1,360	$1,336	$1,305	$1,265	$1,217	$1,159	$1,089	$1,007	$912	$804	$679	$538	$379	$200	($0)
68																						
69	Calculation of Repayments																					
70	Debt Service Payment (Note 40)		($118)	($111)	($102)	($104)	($109)	($114)	($119)	($125)	($131)	($137)	($143)	($150)	($159)	($165)	($173)	($180)	($189)	($197)	($205)	($214)
71	Interest (Note 41)		($100)	($99)	($98)	($98)	($97)	($96)	($95)	($94)	($91)	($89)	($85)	($81)	($76)	($70)	($64)	($56)	($48)	($38)	($27)	($14)
72	Principal (Note 42)		($18)	($12)	($4)	($6)	($12)	($18)	($24)	($31)	($40)	($48)	($58)	($69)	($82)	($95)	($109)	($124)	($141)	($159)	($179)	($200)
73	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
74	**Leverage (Note 44)**		49%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	1,400.0
Installed Cost ($/kW)	$6,300
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$70
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	8,100
Heat Recovery (mmBTU/hr)	2.20
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Replacement Escalation %	0.0%
Cost of Equity (Target IRR)	12.0%
Discount Rate	10.94%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$2,500
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$8,820
Debt Requirement ($ in 000)	$1,876
Equity Requirement ($ in 000)	$6,944
Financial Results	
Leverage	21%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$162.30
First Year PPA Price ($/MWH)	$133.18

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

($ in 1000 unless noted otherwise)

Line #			1	2	3	4	5	6	7	8	9	10
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2												
3	Annual Generation (kWh) (Note 1)		11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600
4	Cost of Electricty ($/MWh) (Note 2)		$133.18	$137.18	$141.29	$145.53	$149.90	$154.39	$159.02	$163.79	$168.71	$173.77
5												
6	**Revenues**											
7	Power Sales (Note 3)		$1,470	$1,514	$1,560	$1,606	$1,654	$1,704	$1,755	$1,808	$1,862	$1,918
8	State Capacity Based Incentive (CBI) (Note 4)		$3,500									
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11												
12	**Expenses**											
13	Fixed O&M (Note 7)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 8)		($773)	($796)	($820)	($844)	($870)	($896)	($923)	($950)	($979)	($1,008)
15	Fuel Cost (Note 9)		($509)	($583)	($665)	($691)	($700)	($712)	($725)	($735)	($745)	($755)
16	Insurance (Note 10)		($44)	($45)	($47)	($48)	($50)	($51)	($53)	($54)	($56)	($58)
17	Royalty Payment (Note 11)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($1,325)	($1,425)	($1,532)	($1,584)	($1,619)	($1,658)	($1,700)	($1,739)	($1,779)	($1,821)
20	**Beneficial Energy Recapture**		$74	$85	$97	$101	$102	$104	$105	$107	$108	$110
21	**Total Expenses after Recapture**		($1,251)	($1,340)	($1,435)	($1,483)	($1,517)	($1,555)	($1,595)	($1,632)	($1,671)	($1,711)
22												
23	**EBITDA (Note 13)**		$219	$174	$125	$123	$137	$149	$160	$175	$191	$207
24												
25	**Tax Credits**											
26	Federal Investment Tax Credit (Note 14)		$2,646									
27	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Depreciation**											
29	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
30	State Depreciation (Note 17)		($441)	($441)	($441)	($441)	($441)	($441)	($441)	($441)	($441)	($441)
31	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000
32	Federal Depreciation (Note 19)		($1,499)	($2,399)	($1,439)	($864)	($864)	($432)	$0	$0	$0	$0
33												
34	**Income Taxes**											
35	State Taxable Income (Note 20)		($354)	($394)	($443)	($446)	($434)	($423)	($412)	($397)	($380)	($362)
36	State Income Tax (Note 21)		$38	$43	$48	$48	$47	$46	$45	$43	$41	$39
37	State Tax Benefit (Liability) (Note 22)		$38	$43	$48	$48	$47	$46	$45	$43	$41	$39
38	Federal Taxable Income (Note 23)		$2,126	($2,310)	($1,393)	($820)	($809)	($368)	$74	$87	$102	$118
39	Federal Income Tax (Note 24)		($744)	$808	$488	$287	$283	$129	($26)	($31)	($36)	($41)
40	Federal Tax Benefit (Liability) (Note 25)		$1,902	$808	$488	$287	$283	$129	($26)	($31)	($36)	($41)
41												
42												
43	**Total Tax Benefit (Liability) (Note 26**		$1,940	$851	$536	$335	$330	$175	$19	$13	$5	($2)
44												
45												
46												
47	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10
48												
49	Equity Contribution (Note 27)	($3,444)										
50	Cash Distribution (Note 28)		$36	$29	$21	$21	$23	$25	$27	$29	$32	$34
51	Tax Benefits (Liability) (Note 29)		$1,940	$851	$536	$335	$330	$175	$19	$13	$5	($2)
52	**Total (Note 30)**	($3,444)	$1,977	$880	$556	$356	$353	$199	$46	$42	$37	$33
53												
54	**Debt**											
55	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
56	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835
57												
58	EBITDA		$219	$174	$125	$123	$137	$149	$160	$175	$191	$207
59	Adjusted EBITDA (Note 33)		$204	$152	$102	$94	$98	$99	$100	$102	$104	$105
60	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
61	Debt Sizing (Note 35)	**$1,876**	$170	$127	$85	$78	$81	$83	$83	$85	$87	$88
62												
63	Repayment/Amortization											
64	Beginning Balance (Note 36)		$1,876	$1,825	$1,808	$1,831	$1,856	$1,872	$1,878	$1,876	$1,861	$1,832
65	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
66	Repayments (Note 38)		($51)	($18)	$23	$25	$16	$7	($2)	($15)	($29)	($44)
67	Ending Blance (Note 39)	$1,876	$1,825	$1,808	$1,831	$1,856	$1,872	$1,878	$1,876	$1,861	$1,832	$1,788
68												
69	Calculation of Repayments											
70	Debt Service Payment (Note 40)		($182)	($145)	($104)	($103)	($114)	($124)	($134)	($146)	($159)	($172)
71	Interest (Note 41)		($131)	($128)	($127)	($128)	($130)	($131)	($131)	($131)	($130)	($128)
72	Principal (Note 42)		($51)	($18)	$23	$25	$16	$7	($2)	($15)	($29)	($44)
73	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
74	**Leverage (Note 44)**		21%									

Line #		11	12	13	14	15	16	17	18	19	20
1	**Year**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2											
3	Annual Generation (kWh) (Note 1)	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600
4	Cost of Electricty ($/MWh) (Note 2)	$178.98	$184.35	$189.88	$195.58	$201.45	$207.49	$213.72	$220.13	$226.73	$233.53
5											
6	**Revenues**										
7	Power Sales (Note 3)	$1,976	$2,035	$2,096	$2,159	$2,223	$2,290	$2,359	$2,430	$2,503	$2,578
8	State Capacity Based Incentive (CBI) (Note 4)										
9	State Performanced Based Incentive (PBI) (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11											
12	**Expenses**										
13	Fixed O&M (Note 7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 8)	($1,038)	($1,070)	($1,102)	($1,135)	($1,169)	($1,204)	($1,240)	($1,277)	($1,315)	($1,355)
15	Fuel Cost (Note 9)	($765)	($774)	($778)	($790)	($801)	($811)	($821)	($831)	($841)	($852)
16	Insurance (Note 10)	($59)	($61)	($63)	($65)	($67)	($69)	($71)	($73)	($75)	($77)
17	Royalty Payment (Note 11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**	($1,863)	($1,905)	($1,942)	($1,990)	($2,036)	($2,083)	($2,131)	($2,181)	($2,232)	($2,284)
20	**Beneficial Energy Recapture**	$111	$113	$113	$115	$117	$118	$119	$121	$122	$124
21	**Total Expenses after Recapture**	($1,752)	($1,792)	($1,829)	($1,875)	($1,920)	($1,965)	($2,012)	($2,060)	($2,109)	($2,160)
22											
23	**EBITDA (Note 13)**	$224	$243	$267	$284	$304	$325	$347	$369	$393	$417
24											
25	**Tax Credits**										
26	Federal Investment Tax Credit (Note 14)										
27	Federal Production Tax Credit (Note 15)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Depreciation**										
29	State Depreciation Rate (Note 16)	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
30	State Depreciation (Note 17)	($441)	($441)	($441)	($441)	($441)	($441)	($441)	($441)	($441)	($441)
31	Federal Depreciation Rate (Note 18)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
32	Federal Depreciation (Note 19)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33											
34	**Income Taxes**										
35	State Taxable Income (Note 20)	($342)	($319)	($289)	($265)	($236)	($204)	($169)	($132)	($90)	($46)
36	State Income Tax (Note 21)	$37	$35	$31	$29	$26	$22	$18	$14	$10	$5
37	State Tax Benefit (Liability) (Note 22)	$37	$35	$31	$29	$26	$22	$18	$14	$10	$5
38	Federal Taxable Income (Note 23)	$136	$156	$183	$205	$231	$259	$290	$323	$360	$400
39	Federal Income Tax (Note 24)	($48)	($55)	($64)	($72)	($81)	($91)	($102)	($113)	($126)	($140)
40	Federal Tax Benefit (Liability) (Note 25)	($48)	($55)	($64)	($72)	($81)	($91)	($102)	($113)	($126)	($140)
41											
42											
43	**Total Tax Benefit (Liability) (Note 26**	($10)	($20)	($33)	($43)	($55)	($69)	($83)	($99)	($116)	($135)
44											
45											
46											
47	**Project Equity Returns** Year	11	12	13	14	15	16	17	18	19	20
48											
49	Equity Contribution (Note 27)										
50	Cash Distribution (Note 28)	$37	$40	$44	$47	$51	$54	$58	$62	$66	$70
51	Tax Benefits (Liability) (Note 29)	($10)	($20)	($33)	($43)	($55)	($69)	($83)	($99)	($116)	($135)
52	**Total (Note 30)**	$27	$20	$12	$4	($5)	($14)	($25)	($37)	($51)	($65)
53											
54	**Debt**										
55	Interest Rate (Note 31)	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
56	EBITDA Scaling Factor (Note 32)	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
57											
58	EBITDA	$224	$243	$267	$284	$304	$325	$347	$369	$393	$417
59	Adjusted EBITDA (Note 33)	$106	$108	$111	$110	$110	$110	$110	$109	$109	$108
60	Period DSCR (Note 34)	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
61	Debt Sizing (Note 35)	$89	$90	$92	$92	$92	$92	$92	$91	$91	$90
62											
63	Repayment/Amortization										
64	Beginning Balance (Note 36)	$1,788	$1,727	$1,645	$1,538	$1,409	$1,255	$1,072	$858	$610	$325
65	Drawdowns (Note 37)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
66	Repayments (Note 38)	($61)	($81)	($107)	($129)	($154)	($183)	($214)	($248)	($285)	($325)
67	Ending Blance (Note 39)	$1,727	$1,645	$1,538	$1,409	$1,255	$1,072	$858	$610	$325	($0)
68											
69	Calculation of Repayments										
70	Debt Service Payment (Note 40)	($187)	($202)	($222)	($237)	($253)	($271)	($289)	($308)	($328)	($348)
71	Interest (Note 41)	($125)	($121)	($115)	($108)	($99)	($88)	($75)	($60)	($43)	($23)
72	Principal (Note 42)	($61)	($81)	($107)	($129)	($154)	($183)	($214)	($248)	($285)	($325)
73	DSCR (Note 43)	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
74	**Leverage (Note 44)**										

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	2,800.0
Installed Cost ($/kW)	$5,775
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$70
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	8,100
Heat Recovery (mmBTU/hr)	4.40
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Replacement Escalation %	0.0%
Cost of Equity (Target IRR)	12.0%
Discount Rate	11.06%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	30%
State Incentives	
State Incentive Type	CBI
CBI Amount	$2,500
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$16,170
Debt Requirement ($ in 000)	$3,026
Equity Requirement ($ in 000)	$13,144
Financial Results	
Leverage	19%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$158.13
First Year PPA Price ($/MWH)	$129.88

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200
4	Cost of Electricty ($/MWh) (Note 2)		$129.88	$133.78	$137.79	$141.93	$146.19	$150.57	$155.09	$159.74	$164.53	$169.47	$174.55	$179.79	$185.18	$190.74	$196.46	$202.36	$208.43	$214.68	$221.12	$227.75
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$2,867	$2,953	$3,042	$3,133	$3,227	$3,324	$3,424	$3,526	$3,632	$3,741	$3,853	$3,969	$4,088	$4,211	$4,337	$4,467	$4,601	$4,739	$4,881	$5,028
8	State Capacity Based Incentive (CBI) (Note 4)		$7,000																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 8)		($1,545)	($1,592)	($1,639)	($1,689)	($1,739)	($1,791)	($1,845)	($1,900)	($1,957)	($2,016)	($2,077)	($2,139)	($2,203)	($2,269)	($2,337)	($2,407)	($2,480)	($2,554)	($2,631)	($2,710)
15	Fuel Cost (Note 9)		($1,017)	($1,167)	($1,330)	($1,382)	($1,400)	($1,423)	($1,450)	($1,470)	($1,489)	($1,511)	($1,531)	($1,548)	($1,556)	($1,581)	($1,602)	($1,622)	($1,641)	($1,663)	($1,683)	($1,704)
16	Insurance (Note 10)		($81)	($83)	($86)	($88)	($91)	($94)	($97)	($99)	($102)	($105)	($109)	($112)	($115)	($119)	($122)	($126)	($130)	($134)	($138)	($142)
17	Royalty Payment (Note 11)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($2,644)	($2,842)	($3,055)	($3,159)	($3,230)	($3,308)	($3,392)	($3,470)	($3,549)	($3,633)	($3,716)	($3,799)	($3,874)	($3,969)	($4,062)	($4,155)	($4,251)	($4,351)	($4,451)	($4,555)
20	**Beneficial Energy Recapture**		$148	$170	$194	$201	$204	$207	$211	$214	$217	$220	$223	$225	$226	$230	$233	$236	$239	$242	$245	$248
21	**Total Expenses after Recapture**		($2,496)	($2,672)	($2,862)	($2,958)	($3,027)	($3,101)	($3,181)	($3,256)	($3,333)	($3,413)	($3,493)	($3,574)	($3,648)	($3,739)	($3,829)	($3,919)	($4,012)	($4,109)	($4,206)	($4,308)
22																						
23	**EBITDA (Note 13)**		$372	$281	$180	$175	$201	$223	$243	$270	$299	$328	$360	$395	$440	$472	$508	$548	$589	$630	$675	$720
24																						
25	**Tax Credits**																					
26	Federal Investment Tax Credit (Note 14)		$4,851																			
27	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Depreciation**																					
29	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
30	State Depreciation (Note 17)		($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)	($809)
31	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
32	Federal Depreciation (Note 19)		($2,749)	($4,398)	($2,639)	($1,583)	($1,583)	($792)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33																						
34	**Income Taxes**																					
35	State Taxable Income (Note 20)		($649)	($732)	($831)	($840)	($819)	($800)	($782)	($755)	($725)	($694)	($658)	($617)	($563)	($519)	($468)	($411)	($348)	($281)	($207)	($128)
36	State Income Tax (Note 21)		$70	$79	$90	$91	$89	$87	$85	$82	$79	$75	$71	$67	$61	$56	$51	$45	$38	$30	$22	$14
37	State Tax Benefit (Liability) (Note 22)		$70	$79	$90	$91	$89	$87	$85	$82	$79	$75	$71	$67	$61	$56	$51	$45	$38	$30	$22	$14
38	Federal Taxable Income (Note 23)		$4,481	($4,242)	($2,572)	($1,524)	($1,505)	($696)	$112	$135	$162	$190	$222	$258	$307	$346	$391	$442	$498	$558	$624	$695
39	Federal Income Tax (Note 24)		($1,568)	$1,485	$900	$533	$527	$244	($39)	($47)	($57)	($66)	($78)	($90)	($107)	($121)	($137)	($155)	($174)	($195)	($218)	($243)
40	Federal Tax Benefit (Liability) (Note 25)		$3,283	$1,485	$900	$533	$527	$244	($39)	($47)	($57)	($66)	($78)	($90)	($107)	($121)	($137)	($155)	($174)	($195)	($218)	($243)
41																						
42																						
43	**Total Tax Benefit (Liability) (Note 26)**		$3,353	$1,564	$990	$624	$615	$330	$46	$34	$22	$9	($6)	($24)	($46)	($65)	($86)	($110)	($137)	($165)	($196)	($229)
44																						
45																						
46																						
47	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
48																						
49	Equity Contribution (Note 27)	($6,144)																				
50	Cash Distribution (Note 28)		$62	$47	$30	$29	$33	$37	$40	$45	$50	$55	$60	$66	$73	$79	$85	$91	$98	$105	$113	$120
51	Tax Benefits (Liability) (Note 29)		$3,353	$1,564	$990	$624	$615	$330	$46	$34	$22	$9	($6)	($24)	($46)	($65)	($86)	($110)	($137)	($165)	($196)	($229)
52	**Total (Note 30)**	($6,144)	$3,415	$1,611	$1,020	$654	$649	$368	$86	$79	$72	$64	$54	$42	$27	$14	($1)	($19)	($39)	($60)	($83)	($109)
53																						
54	**Debt**																					
55	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
56	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
57																						
58	EBITDA		$372	$281	$180	$175	$201	$223	$243	$270	$299	$328	$360	$395	$440	$472	$508	$548	$589	$630	$675	$720
59	Adjusted EBITDA (Note 33)		$347	$246	$147	$134	$143	$148	$151	$157	$163	$167	$171	$175	$183	$183	$184	$186	$186	$187	$187	$186
60	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
61	Debt Sizing (Note 35)	**$3,026**	$290	$205	$122	$111	$119	$124	$126	$131	$136	$139	$143	$146	$152	$153	$154	$155	$155	$155	$156	$155
62																						
63	Repayment/Amortization																					
64	Beginning Balance (Note 36)		$3,026	$2,928	$2,898	$2,951	$3,012	$3,055	$3,084	$3,097	$3,089	$3,056	$2,996	$2,906	$2,780	$2,608	$2,397	$2,141	$1,835	$1,472	$1,050	$561
65	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
66	Repayments (Note 38)		($98)	($30)	$53	$61	$44	$28	$14	($9)	($33)	($60)	($90)	($126)	($172)	($211)	($256)	($307)	($362)	($422)	($489)	($561)
67	Ending Blance (Note 39)	$3,026	$2,928	$2,898	$2,951	$3,012	$3,055	$3,084	$3,097	$3,089	$3,056	$2,996	$2,906	$2,780	$2,608	$2,397	$2,141	$1,835	$1,472	$1,050	$561	($0)
68																						
69	Calculation of Repayments																					
70	Debt Service Payment (Note 40)		($310)	($234)	($150)	($146)	($167)	($185)	($202)	($225)	($250)	($274)	($300)	($329)	($367)	($393)	($424)	($456)	($491)	($525)	($563)	($600)
71	Interest (Note 41)		($212)	($205)	($203)	($207)	($211)	($214)	($216)	($217)	($216)	($214)	($210)	($203)	($195)	($183)	($168)	($150)	($128)	($103)	($73)	($39)
72	Principal (Note 42)		($98)	($30)	$53	$61	$44	$28	$14	($9)	($33)	($60)	($90)	($126)	($172)	($211)	($256)	($307)	($362)	($422)	($489)	($561)
73	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
74	**Leverage (Note 44)**		19%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	65.0
Installed Cost ($/kW)	$3,150
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$40
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	13,650
Heat Recovery (mmBTU/hr)	0.40
Capacity Factor	95.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Replacement Escalation %	0.0%
Cost of Equity (Target IRR)	12.0%
Discount Rate	8.81%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	2.5%
PTC Term (years)	10
ITC (10% of 30%)	10%
State Incentives	
State Incentive Type	CBI
CBI Amount	$0
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$205
Debt Requirement ($ in 000)	$131
Equity Requirement ($ in 000)	$74
Financial Results	
Leverage	64%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$149.84
First Year PPA Price ($/MWH)	$120.91

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930
4	Cost of Electricty ($/MWh) (Note 2)		$120.91	$124.54	$128.27	$132.12	$136.08	$140.17	$144.37	$148.70	$153.16	$157.76	$162.49	$167.37	$172.39	$177.56	$182.89	$188.37	$194.02	$199.84	$205.84	$212.01
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$65	$67	$69	$71	$74	$76	$78	$80	$83	$85	$88	$91	$93	$96	$99	$102	$105	$108	$111	$115
8	State Capacity Based Incentive (CBI) (Note 4)		$0																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 8)		($22)	($22)	($23)	($24)	($24)	($25)	($26)	($27)	($27)	($28)	($29)	($30)	($31)	($32)	($33)	($34)	($35)	($36)	($37)	($38)
15	Fuel Cost (Note 9)		($42)	($48)	($55)	($57)	($58)	($59)	($60)	($61)	($62)	($62)	($63)	($64)	($64)	($65)	($66)	($67)	($68)	($69)	($69)	($70)
16	Insurance (Note 10)		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
17	Royalty Payment (Note 11)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($65)	($72)	($79)	($82)	($83)	($85)	($87)	($89)	($90)	($92)	($94)	($95)	($97)	($99)	($100)	($102)	($104)	($106)	($108)	($110)
20	**Beneficial Energy Recapture**		$14	$16	$19	$19	$20	$20	$20	$21	$21	$21	$21	$22	$22	$22	$22	$23	$23	$23	$23	$24
21	**Total Expenses after Recapture**		($50)	($55)	($60)	($63)	($64)	($65)	($67)	($68)	($69)	($71)	($72)	($74)	($75)	($76)	($78)	($80)	($81)	($83)	($85)	($86)
22																						
23	**EBITDA (Note 13)**		$15	$12	$9	$9	$10	$11	$11	$12	$13	$14	$16	$17	$18	$20	$21	$22	$24	$25	$27	$28
24																						
25	**Tax Credits**																					
26	Federal Investment Tax Credit (Note 14)		$20																			
27	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Depreciation**																					
29	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
30	State Depreciation (Note 17)		($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)	($10)
31	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
32	Federal Depreciation (Note 19)		($39)	($62)	($37)	($22)	($22)	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33																						
34	**Income Taxes**																					
35	State Taxable Income (Note 20)		($4)	($7)	($10)	($10)	($9)	($9)	($8)	($7)	($6)	($5)	($3)	($2)	$0	$2	$4	$6	$8	$11	$14	$17
36	State Income Tax (Note 21)		$0	$1	$1	$1	$1	$1	$1	$1	$1	$0	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($2)
37	State Tax Benefit (Liability) (Note 22)		$0	$1	$1	$1	$1	$1	$1	$1	$1	$0	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($2)
38	Federal Taxable Income (Note 23)		($33)	($58)	($36)	($21)	($21)	($9)	$3	$4	$5	$6	$7	$9	$11	$12	$14	$16	$18	$20	$22	$25
39	Federal Income Tax (Note 24)		$11	$20	$13	$7	$7	$3	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($5)	($6)	($7)	($8)	($9)
40	Federal Tax Benefit (Liability) (Note 25)		$32	$20	$13	$7	$7	$3	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($5)	($6)	($7)	($8)	($9)
41																						
42																						
43	**Total Tax Benefit (Liability) (Note 26**		$32	$21	$14	$9	$8	$4	($0)	($1)	($1)	($2)	($2)	($3)	($4)	($4)	($5)	($6)	($7)	($8)	($9)	($11)
44																						
45																						
46																						
47	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
48																						
49	Equity Contribution (Note 27)	($74)																				
50	Cash Distribution (Note 28)		$2	$2	$1	$1	$2	$2	$2	$2	$2	$2	$3	$3	$3	$3	$3	$4	$4	$4	$4	$5
51	Tax Benefits (Liability) (Note 29)		$32	$21	$14	$9	$8	$4	($0)	($1)	($1)	($2)	($2)	($3)	($4)	($4)	($5)	($6)	($7)	($8)	($9)	($11)
52	**Total (Note 30)**	($74)	$35	$23	$15	$10	$10	$6	$2	$1	$1	$1	$0	($0)	($1)	($1)	($2)	($2)	($3)	($4)	($5)	($6)
53																						
54	**Debt**																					
55	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
56	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
57																						
58	EBITDA		$15	$12	$9	$9	$10	$11	$11	$12	$13	$14	$16	$17	$18	$20	$21	$22	$24	$25	$27	$28
59	Adjusted EBITDA (Note 33)		$14	$11	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8	$8	$8	$7	$7	$7
60	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
61	Debt Sizing (Note 35)	**$131**	$12	$9	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6
62																						
63	Repayment/Amortization																					
64	Beginning Balance (Note 36)		$131	$127	$126	$127	$129	$130	$130	$130	$128	$126	$123	$118	$113	$105	$96	$86	$73	$58	$42	$22
65	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
66	Repayments (Note 38)		($3)	($1)	$1	$1	$1	$0	($0)	($1)	($2)	($3)	($4)	($6)	($7)	($9)	($11)	($13)	($15)	($17)	($19)	($22)
67	Ending Blance (Note 39)	$131	$127	$126	$127	$129	$130	$130	$130	$128	$126	$123	$118	$113	$105	$96	$86	$73	$58	$42	$22	($0)
68																						
69	Calculation of Repayments																					
70	Debt Service Payment (Note 40)		($12)	($10)	($7)	($7)	($8)	($9)	($10)	($10)	($11)	($12)	($13)	($14)	($15)	($16)	($17)	($19)	($20)	($21)	($22)	($24)
71	Interest (Note 41)		($9)	($9)	($9)	($9)	($9)	($9)	($9)	($9)	($9)	($9)	($9)	($8)	($8)	($7)	($7)	($6)	($5)	($4)	($3)	($2)
72	Principal (Note 42)		($3)	($1)	$1	$1	$1	$0	($0)	($1)	($2)	($3)	($4)	($6)	($7)	($9)	($11)	($13)	($15)	($17)	($19)	($22)
73	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
74	**Leverage (Note 44)**		64%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	1,000.0
Installed Cost ($/kW)	$2,310
Fixed O&M ($/kW)	$25
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$25
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	10,429
Heat Recovery (mmBTU/hr)	3.00
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	5
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Replacement Escalation %	0.0%
Cost of Equity (Target IRR)	12.0%
Discount Rate	8.82%

Federal Incentives	ITC
PTC ($/kWh)	$0.021
PTC Escalation	3.0%
PTC Term (years)	10
ITC (10% of 30%)	10%
State Incentives	
State Incentive Type	CBI
CBI Amount	$0
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$2,310
Debt Requirement ($ in 000)	$1,469
Equity Requirement ($ in 000)	$841
Financial Results	
Leverage	64%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$121.77
First Year PPA Price ($/MWH)	$98.26

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																					
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000
4	Cost of Electricty ($/MWh) (Note 2)		$98.26	$101.21	$104.25	$107.38	$110.60	$113.92	$117.33	$120.85	$124.48	$128.21	$132.06	$136.02	$140.10	$144.30	$148.63	$153.09	$157.69	$162.42	$167.29	$172.31
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$775	$798	$822	$847	$872	$898	$925	$953	$981	$1,011	$1,041	$1,072	$1,105	$1,138	$1,172	$1,207	$1,243	$1,280	$1,319	$1,358
8	State Capacity Based Incentive (CBI) (Note 4)		$0																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($25)	($26)	($27)	($27)	($28)	($29)	($30)	($31)	($32)	($33)	($34)	($35)	($36)	($37)	($38)	($39)	($40)	($41)	($43)	($44)
14	Variable O&M (Note 8)		($197)	($203)	($209)	($215)	($222)	($228)	($235)	($242)	($250)	($257)	($265)	($273)	($281)	($289)	($298)	($307)	($316)	($326)	($336)	($346)
15	Fuel Cost (Note 9)		($468)	($537)	($612)	($636)	($644)	($654)	($667)	($676)	($685)	($695)	($704)	($712)	($715)	($727)	($737)	($746)	($755)	($765)	($774)	($784)
16	Insurance (Note 10)		($12)	($12)	($12)	($13)	($13)	($13)	($14)	($14)	($15)	($15)	($16)	($16)	($16)	($17)	($17)	($18)	($19)	($19)	($20)	($20)
17	Royalty Payment (Note 11)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($701)	($777)	($860)	($891)	($907)	($925)	($946)	($963)	($981)	($1,000)	($1,018)	($1,035)	($1,048)	($1,070)	($1,090)	($1,110)	($1,130)	($1,151)	($1,171)	($1,193)
20	**Beneficial Energy Recapture**		$101	$116	$132	$137	$139	$141	$144	$146	$148	$150	$152	$154	$154	$157	$159	$161	$163	$165	$167	$169
21	**Total Expenses after Recapture**		($601)	($661)	($728)	($754)	($768)	($784)	($802)	($817)	($833)	($850)	($866)	($882)	($894)	($913)	($931)	($949)	($967)	($986)	($1,005)	($1,024)
22																						
23	**EBITDA (Note 13)**		$174	$137	$94	$93	$104	$114	$123	$135	$148	$161	$175	$191	$210	$225	$241	$258	$276	$295	$314	$334
24																						
25	**Tax Credits**																					
26	Federal Investment Tax Credit (Note 14)		$231																			
27	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Depreciation**																					
29	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
30	State Depreciation (Note 17)		($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)	($116)
31	Federal Depreciation Rate (Note 18)		0.20000	0.32000	0.19200	0.11520	0.11520	0.05760	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
32	Federal Depreciation (Note 19)		($439)	($702)	($421)	($253)	($253)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33																						
34	**Income Taxes**																					
35	State Taxable Income (Note 20)		($44)	($79)	($120)	($123)	($113)	($105)	($96)	($84)	($70)	($56)	($40)	($21)	$3	$23	$47	$73	$101	$131	$165	$201
36	State Income Tax (Note 21)		$5	$9	$13	$13	$12	$11	$10	$9	$8	$6	$4	$2	($0)	($3)	($5)	($8)	($11)	($14)	($18)	($22)
37	State Tax Benefit (Liability) (Note 22)		$5	$9	$13	$13	$12	$11	$10	$9	$8	$6	$4	$2	($0)	($3)	($5)	($8)	($11)	($14)	($18)	($22)
38	Federal Taxable Income (Note 23)		($363)	($657)	($413)	($247)	($238)	($104)	$30	$41	$53	$66	$80	$97	$118	$136	$157	$180	$205	$232	$262	$294
39	Federal Income Tax (Note 24)		$127	$230	$145	$86	$83	$36	($10)	($14)	($19)	($23)	($28)	($34)	($41)	($48)	($55)	($63)	($72)	($81)	($92)	($103)
40	Federal Tax Benefit (Liability) (Note 25)		$358	$230	$145	$86	$83	$36	($10)	($14)	($19)	($23)	($28)	($34)	($41)	($48)	($55)	($63)	($72)	($81)	($92)	($103)
41																						
42																						
43	**Total Tax Benefit (Liability) (Note 26)**		$363	$238	$158	$100	$96	$48	($0)	($5)	($11)	($17)	($24)	($32)	($42)	($50)	($60)	($71)	($83)	($96)	($110)	($125)
44																						
45																						
46																						
47	**Project Equity Returns**	Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
48																						
49	Equity Contribution (Note 27)	($841)																				
50	Cash Distribution (Note 28)		$29	$23	$16	$15	$17	$19	$21	$23	$25	$27	$29	$32	$35	$37	$40	$43	$46	$49	$52	$56
51	Tax Benefits (Liability) (Note 29)		$363	$238	$158	$100	$96	$48	($0)	($5)	($11)	($17)	($24)	($32)	($42)	($50)	($60)	($71)	($83)	($96)	($110)	($125)
52	**Total (Note 30)**	($841)	$392	$261	$173	$115	$113	$67	$20	$17	$14	$10	$5	$0	($7)	($13)	($20)	($28)	($37)	($46)	($57)	($69)
53																						
54	**Debt**																					
55	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
56	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
57																						
58	EBITDA		$174	$137	$94	$93	$104	$114	$123	$135	$148	$161	$175	$191	$210	$225	$241	$258	$276	$295	$314	$334
59	Adjusted EBITDA (Note 33)		$163	$119	$77	$71	$74	$76	$77	$79	$81	$82	$83	$85	$87	$87	$87	$87	$87	$87	$87	$86
60	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
61	Debt Sizing (Note 35)	**$1,469**	$136	$99	$64	$59	$62	$63	$64	$66	$67	$68	$69	$71	$73	$73	$73	$73	$73	$73	$72	$72
62																						
63	Repayment/Amortization																					
64	Beginning Balance (Note 36)		$1,469	$1,427	$1,413	$1,433	$1,456	$1,471	$1,479	$1,480	$1,471	$1,450	$1,418	$1,371	$1,308	$1,224	$1,123	$1,001	$856	$686	$488	$260
65	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
66	Repayments (Note 38)		($42)	($14)	$20	$23	$15	$8	$1	($9)	($21)	($33)	($47)	($63)	($84)	($101)	($122)	($145)	($170)	($198)	($228)	($260)
67	Ending Blance (Note 39)	$1,469	$1,427	$1,413	$1,433	$1,456	$1,471	$1,479	$1,480	$1,471	$1,450	$1,418	$1,371	$1,308	$1,224	$1,123	$1,001	$856	$686	$488	$260	($0)
68																						
69	Calculation of Repayments																					
70	Debt Service Payment (Note 40)		($145)	($114)	($79)	($77)	($87)	($95)	($103)	($113)	($124)	($134)	($146)	($159)	($175)	($187)	($201)	($215)	($230)	($246)	($262)	($279)
71	Interest (Note 41)		($103)	($100)	($99)	($100)	($102)	($103)	($104)	($104)	($103)	($102)	($99)	($96)	($92)	($86)	($79)	($70)	($60)	($48)	($34)	($18)
72	Principal (Note 42)		($42)	($14)	$20	$23	$15	$8	$1	($9)	($21)	($33)	($47)	($63)	($84)	($101)	($122)	($145)	($170)	($198)	($228)	($260)
73	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
74	**Leverage (Note 44)**		64%																			

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	50,000.0
Installed Cost ($/kW)	$2,809
Fixed O&M ($/kW)	$10
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$25
Variable O&M Escalation	3.0%
Fuel Cost ($/MMbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payment ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	8,000
Heat Recovery (mmBTU/hr)	69.30
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Project Debt Service Coverage Ratio (DSCR)	1.20
Debt Rate	7.00%
Debt Term (years)	20
Economic Life (years)	20
Depreciation Term (years)	20
Percent Depreciated	100%
PPA Escalation Rate	3.0%
State Tax Rate	10.84%
Federal Tax Rate	35.0%
Replacement Capital (2009$/kW)	$0
Replacement Term (years)	-
Replacement Escalation %	0.0%
Cost of Equity (Target IRR)	12.0%
Discount Rate	7.91%

Federal Incentives	ITC
PTC ($/kWh)	$0.000
PTC Escalation	0.0%
PTC Term (years)	0
ITC (10% of 30%)	10%
State Incentives	
State Incentive Type	N/A
CBI Amount	$0
PBI Amount	$0.00
PBI Term	0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital Costs	
Total Capital Costs ($ in 000)	$140,450
Debt Requirement ($ in 000)	$114,810
Equity Requirement ($ in 000)	$25,640
Financial Results	
Leverage	82%
Target IRR	12%
Proforma IRR	12%
Electric Price Results	
LCOE ($/MWh)	$118.75
First Year PPA Price ($/MWH)	$95.10

FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	**Year**		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																						
3	Annual Generation (kWh) (Note 1)		394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000
4	Cost of Electricty ($/MWh) (Note 2)		$95.10	$97.96	$100.89	$103.92	$107.04	$110.25	$113.56	$116.96	$120.47	$124.09	$127.81	$131.64	$135.59	$139.66	$143.85	$148.17	$152.61	$157.19	$161.91	$166.76
5																						
6	**Revenues**																					
7	Power Sales (Note 3)		$37,489	$38,614	$39,772	$40,966	$42,195	$43,460	$44,764	$46,107	$47,490	$48,915	$50,383	$51,894	$53,451	$55,054	$56,706	$58,407	$60,159	$61,964	$63,823	$65,738
8	State Capacity Based Incentive (CBI) (Note 4)		$0																			
9	State Performanced Based Incentive (PBI) (Note 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Other Revenues (Note 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																						
12	**Expenses**																					
13	Fixed O&M (Note 7)		($500)	($515)	($530)	($546)	($563)	($580)	($597)	($615)	($633)	($652)	($672)	($692)	($713)	($734)	($756)	($779)	($802)	($826)	($851)	($877)
14	Variable O&M (Note 8)		($9,855)	($10,151)	($10,455)	($10,769)	($11,092)	($11,425)	($11,767)	($12,120)	($12,484)	($12,859)	($13,244)	($13,642)	($14,051)	($14,472)	($14,907)	($15,354)	($15,814)	($16,289)	($16,777)	($17,281)
15	Fuel Cost (Note 9)		($17,944)	($20,577)	($23,463)	($24,377)	($24,693)	($25,103)	($25,576)	($25,923)	($26,269)	($26,648)	($26,995)	($27,310)	($27,436)	($27,878)	($28,256)	($28,603)	($28,950)	($29,328)	($29,675)	($30,054)
16	Insurance (Note 10)		($702)	($723)	($745)	($767)	($790)	($814)	($839)	($864)	($890)	($916)	($944)	($972)	($1,001)	($1,031)	($1,062)	($1,094)	($1,127)	($1,161)	($1,196)	($1,231)
17	Royalty Payment (Note 11)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 12)**		($29,001)	($31,966)	($35,193)	($36,460)	($37,138)	($37,921)	($38,779)	($39,522)	($40,276)	($41,075)	($41,855)	($42,616)	($43,201)	($44,116)	($44,981)	($45,830)	($46,694)	($47,604)	($48,500)	($49,443)
20	**Beneficial Energy Recapture**		$3,497	$4,011	$4,573	$4,751	$4,813	$4,893	$4,985	$5,052	$5,120	$5,194	$5,261	$5,323	$5,348	$5,434	$5,507	$5,575	$5,643	$5,716	$5,784	$5,858
21	**Total Expenses after Recapture**		($25,504)	($27,956)	($30,620)	($31,709)	($32,325)	($33,028)	($33,794)	($34,469)	($35,156)	($35,881)	($36,593)	($37,293)	($37,854)	($38,682)	($39,474)	($40,255)	($41,051)	($41,888)	($42,716)	($43,585)
22																						
23	**EBITDA (Note 13)**		$11,986	$10,658	$9,152	$9,257	$9,870	$10,432	$10,971	$11,638	$12,334	$13,034	$13,789	$14,601	$15,597	$16,372	$17,232	$18,152	$19,108	$20,076	$21,107	$22,153
24																						
25	**Tax Credits**																					
26	Federal Investment Tax Credit (Note 14)		$4,214																			
27	Federal Production Tax Credit (Note 15)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Depreciation**																					
29	State Depreciation Rate (Note 16)		0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
30	State Depreciation (Note 17)		($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)	($7,023)
31	Federal Depreciation Rate (Note 18)		0.03750	0.07219	0.06677	0.06177	0.05713	0.05285	0.04888	0.04522	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461	0.04462	0.04461
32	Federal Depreciation (Note 19)		($5,188)	($9,987)	($9,237)	($8,545)	($7,904)	($7,311)	($6,762)	($6,256)	($6,173)	($6,171)	($6,173)	($6,171)	($6,173)	($6,171)	($6,173)	($6,171)	($6,173)	($6,171)	($6,173)	($6,171)
33																						
34	**Income Taxes**																					
35	State Taxable Income (Note 20)		($3,074)	($4,264)	($5,702)	($5,611)	($5,008)	($4,419)	($3,821)	($3,057)	($2,219)	($1,327)	($325)	$795	$2,168	$3,404	$4,803	$6,350	$8,030	$9,829	$11,806	$13,923
36	State Income Tax (Note 21)		$333	$462	$618	$608	$543	$479	$414	$331	$241	$144	$35	($86)	($235)	($369)	($521)	($688)	($870)	($1,065)	($1,280)	($1,509)
37	State Tax Benefit (Liability) (Note 22)		$333	$462	$618	$608	$543	$479	$414	$331	$241	$144	$35	($86)	($235)	($369)	($521)	($688)	($870)	($1,065)	($1,280)	($1,509)
38	Federal Taxable Income (Note 23)		($906)	($6,766)	($7,298)	($6,526)	($5,346)	($4,229)	($3,146)	($1,959)	($1,129)	($332)	$560	$1,560	$2,782	$3,886	$5,132	$6,513	$8,009	$9,614	$11,375	$13,264
39	Federal Income Tax (Note 24)		$317	$2,368	$2,554	$2,284	$1,871	$1,480	$1,101	$686	$395	$116	($196)	($546)	($974)	($1,360)	($1,796)	($2,279)	($2,803)	($3,365)	($3,981)	($4,643)
40	Federal Tax Benefit (Liability) (Note 25)		$4,531	$2,368	$2,554	$2,284	$1,871	$1,480	$1,101	$686	$395	$116	($196)	($546)	($974)	($1,360)	($1,796)	($2,279)	($2,803)	($3,365)	($3,981)	($4,643)
41																						
42																						
43	**Total Tax Benefit (Liability) (Note 26)**		$4,864	$2,830	$3,173	$2,892	$2,414	$1,959	$1,515	$1,017	$636	$260	($161)	($632)	($1,209)	($1,729)	($2,317)	($2,968)	($3,674)	($4,430)	($5,261)	($6,152)
44																						
45																						
46																						
47	**Project Equity Returns** Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
48																						
49	Equity Contribution (Note 27)	($25,640)																				
50	Cash Distribution (Note 28)		$1,998	$1,776	$1,525	$1,543	$1,645	$1,739	$1,828	$1,940	$2,056	$2,172	$2,298	$2,433	$2,600	$2,729	$2,872	$3,025	$3,185	$3,346	$3,518	$3,692
51	Tax Benefits (Liability) (Note 29)		$4,864	$2,830	$3,173	$2,892	$2,414	$1,959	$1,515	$1,017	$636	$260	($161)	($632)	($1,209)	($1,729)	($2,317)	($2,968)	($3,674)	($4,430)	($5,261)	($6,152)
52	**Total (Note 30)**	($25,640)	$6,861	$4,607	$4,698	$4,435	$4,059	$3,698	$3,344	$2,957	$2,691	$2,432	$2,137	$1,801	$1,391	$999	$555	$58	($489)	($1,084)	($1,743)	($2,460)
53																						
54	**Debt**																					
55	Interest Rate (Note 31)		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
56	EBITDA Scaling Factor (Note 32)		0.93458	0.87344	0.81630	0.76290	0.71299	0.66634	0.62275	0.58201	0.54393	0.50835	0.47509	0.44401	0.41496	0.38782	0.36245	0.33873	0.31657	0.29586	0.27651	0.25842
57																						
58	EBITDA		$11,986	$10,658	$9,152	$9,257	$9,870	$10,432	$10,971	$11,638	$12,334	$13,034	$13,789	$14,601	$15,597	$16,372	$17,232	$18,152	$19,108	$20,076	$21,107	$22,153
59	Adjusted EBITDA (Note 33)		$11,201	$9,310	$7,471	$7,062	$7,037	$6,951	$6,832	$6,773	$6,709	$6,626	$6,551	$6,483	$6,472	$6,349	$6,246	$6,149	$6,049	$5,940	$5,836	$5,725
60	Period DSCR (Note 34)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
61	Debt Sizing (Note 35)	**$114,810**	$9,335	$7,758	$6,226	$5,885	$5,864	$5,793	$5,693	$5,645	$5,591	$5,521	$5,459	$5,403	$5,394	$5,291	$5,205	$5,124	$5,041	$4,950	$4,864	$4,771
62																						
63	Repayment/Amortization																					
64	Beginning Balance (Note 36)		$114,810	$112,859	$111,877	$112,082	$112,213	$111,844	$110,979	$109,606	$107,580	$104,832	$101,309	$96,909	$91,526	$84,935	$77,237	$68,283	$57,936	$46,068	$32,563	$17,253
65	Drawdowns (Note 37)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
66	Repayments (Note 38)		($1,951)	($982)	$205	$132	($370)	($864)	($1,374)	($2,026)	($2,748)	($3,523)	($4,399)	($5,384)	($6,591)	($7,698)	($8,953)	($10,347)	($11,868)	($13,505)	($15,310)	($17,253)
67	Ending Blance (Note 39)	$114,810	$112,859	$111,877	$112,082	$112,213	$111,844	$110,979	$109,606	$107,580	$104,832	$101,309	$96,909	$91,526	$84,935	$77,237	$68,283	$57,936	$46,068	$32,563	$17,253	($0)
68																						
69	Calculation of Repayments																					
70	Debt Service Payment (Note 40)		($9,988)	($8,882)	($7,627)	($7,714)	($8,225)	($8,693)	($9,142)	($9,698)	($10,278)	($10,862)	($11,491)	($12,167)	($12,998)	($13,643)	($14,360)	($15,127)	($15,924)	($16,730)	($17,590)	($18,461)
71	Interest (Note 41)		($8,037)	($7,900)	($7,831)	($7,846)	($7,855)	($7,829)	($7,769)	($7,672)	($7,531)	($7,338)	($7,092)	($6,784)	($6,407)	($5,945)	($5,407)	($4,780)	($4,056)	($3,225)	($2,279)	($1,208)
72	Principal (Note 42)		($1,951)	($982)	$205	$132	($370)	($864)	($1,374)	($2,026)	($2,748)	($3,523)	($4,399)	($5,384)	($6,591)	($7,698)	($8,953)	($10,347)	($11,868)	($13,505)	($15,310)	($17,253)
73	DSCR (Note 43)		1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
74	**Leverage (Note 44)**		82%																			

Pro Forma Notes – Not-For-Profit

Note #

1. Year 1 Annual Generation reflects the estimated kWh produced by the Project and is calculated by multiplying the Installed Capacity by the Project Capacity Factor by 8,760hr/yr. Year 2 through 20 based on Capacity less Degradation Factor.

2. Revenue Requirement (kWh) (Line 4) reflect Revenue Requirement (Line 10) divided by Annual Generation (kWh) multiplied by 1,000,000.

3. Revenue Requirement (Line 10) reflects the $/MWh necessary to satisfy the project Debt (Line 28 and Line 29) and Total Expenses (Line 19).

4. Fixed O&M is calculated by multiplying the Fixed O&M ($/kW) by the Project Capacity divided by 1,000 to convert kWh to MWh and dollars into thousands of dollars. Years 2 through 20 are calculated in a similar manner except the Fixed O&M Escalation Rate is applied to the Year 1 Fixed O&M.

5. Variable O&M is calculated by multiplying the Variable O&M by the Annual Generation (Line 3) divided by 1 million to convert kWh to MWh and dollars into thousands of dollars. Years 2 through 20 are calculated in a similar manner except the Variable O&M Escalation Rate is applied to the Year 1 Variable O&M.

6. If applicable, Fuel Costs are calculated by multiplying the Fuel Cost per MMBtu by the Annual Generation (Line 3) by the Project's Heat Rate.

7. Insurance costs are calculated by multiplying Total Capital Cost by the Insurance Cost. Years 2 through 20 are based on the Year 1 Insurance Cost escalated by using the Insurance Escalation.

8. Royalty Payment reflects use of a host site. The Year 1 Royalty Payment is calculated by multiplying the Royalty Payment ($/kW) by Project Capacity (kW) divided by 1,000.

9. Total Expenses are the sum of Lines 13 through 17.

10. Interest Rate reflects the Projects anticipated Debt Rate.

11. Beginning Balance reflects the amount of Debt outstanding at the beginning of each period and is equal to the Ending Balance (Line 30) of the prior period.

12. Interest is calculated by multiplying the Beginning Balance (Line 27) by the Interest Rate (Line 25).

13. Repayment is calculated using the PPMT function of Excel to calculate the principal Repayment amount.

14. Ending Balance reflects the Beginning Balance (Line 27) less the Repayment (Line 29).

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	4.2
Capital Cost ($/kW)	$10,500
Fixed O&M ($/kW)	$75
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance Cost (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	18.5%
Degradation	0.5%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$1,200
Replacement Term	10
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$2,300
Other Incentives	
GOSOLARSF	$ 5,000

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$44
Less: State Incentives	$10
Less: GOSOLARSF	$5
Total	$29
Electric Price Results	
LCOE ($/MWh)	$517.21
First Year PPA Price ($/MWH)	$435.00

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #																					
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																					
3	Annual Generation (kWh) (Note 1)	6,807	6,772	6,739	6,705	6,671	6,638	6,605	6,572	6,539	6,506	6,474	6,441	6,409	6,377	6,345	6,314	6,282	6,251	6,219	6,188
4	Revenue Requirement ($/MWh) (Note 2)	$435.00	$439.84	$444.79	$449.87	$455.07	$460.40	$465.87	$471.47	$477.22	$1,257.75	$489.16	$495.36	$501.73	$508.26	$514.97	$521.86	$528.94	$536.21	$543.67	$551.34
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$3	$3	$3	$3	$3	$3	$3	$3	$3	$8	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
17	Royalty Payment (Note 8)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($6)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
20																					
21																					
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$29	$29	$28	$27	$26	$25	$23	$22	$21	$20	$18	$17	$15	$14	$12	$10	$8	$6	$4	$2
28	Interest (Note 12)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($0)	($0)	($0)
29	Repayments (Note 13)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
30	Ending Balance (Note 14)	$29	$28	$27	$26	$25	$23	$22	$21	$20	$18	$17	$15	$14	$12	$10	$8	$6	$4	$2	$0

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	84.2
Capital Cost ($/kW)	$8,715
Fixed O&M ($/kW)	$45
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	18.5%
Degradation	0.5%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$800
Replacement Term	10
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$1,850
Other Incentives	
GOSOLARSF	$ 10,000

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$734
Less: State Incentives	$156
Less: GOSOLARSF	$10
Total	$568
Electric Price Results	
LCOE ($/MWh)	$458.74
First Year PPA Price ($/MWH)	$397.95

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																				
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																					
3	Annual Generation (kWh) (Note 1)	136,455	135,772	135,093	134,418	133,746	133,077	132,412	131,750	131,091	130,435	129,783	129,134	128,489	127,846	127,207	126,571	125,938	125,308	124,682	124,058
4	Revenue Requirement ($/MWh) (Note 2)	$397.95	$401.87	$405.89	$409.99	$414.19	$418.48	$422.88	$427.37	$431.97	$953.11	$441.51	$446.45	$451.51	$456.70	$462.02	$467.46	$473.05	$478.78	$484.65	$490.68
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$54	$55	$55	$55	$55	$56	$56	$56	$57	$124	$57	$58	$58	$58	$59	$59	$60	$60	$60	$61
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	($4)	($4)	($4)	($4)	($4)	($4)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($7)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)
17	Royalty Payment (Note 8)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	($67)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($9)	($9)	($9)	($10)	($10)	($10)	($10)	($11)	($11)	($79)	($12)	($12)	($12)	($13)	($13)	($14)	($14)	($14)	($15)	($15)
20																					
21																					
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$568	$551	$533	$514	$494	$473	$451	$428	$404	$379	$352	$324	$295	$264	$231	$197	$162	$124	$85	$43
28	Interest (Note 12)	($28)	($28)	($27)	($26)	($25)	($24)	($23)	($21)	($20)	($19)	($18)	($16)	($15)	($13)	($12)	($10)	($8)	($6)	($4)	($2)
29	Repayments (Note 13)	($17)	($18)	($19)	($20)	($21)	($22)	($23)	($24)	($25)	($27)	($28)	($29)	($31)	($32)	($34)	($36)	($37)	($39)	($41)	($43)
30	Ending Balance (Note 14)	$551	$533	$514	$494	$473	$451	$428	$404	$379	$352	$324	$295	$264	$231	$197	$162	$124	$85	$43	($0)

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	4,194
Capital Cost ($/kW)	$8,820
Fixed O&M ($/kW)	$25
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	24.0%
Degradation	0.5%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$600
Replacement Term	10
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$0
Other Incentives	
GOSOLARSF	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$36,991
Less: State Incentives	$0
Less: GOSOLARSF	$0
Total	$36,991
Electric Price Results	
LCOE ($/MWh)	$423.16
First Year PPA Price ($/MWH)	$376.64

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2											
3	Annual Generation (kWh) (Note 1)	8,817,466	8,773,378	8,729,511	8,685,864	8,642,435	8,599,222	8,556,226	8,513,445	8,470,878	8,428,523
4	Revenue Requirement ($/MWh) (Note 2)	$376.64	$379.73	$382.89	$386.11	$389.39	$392.73	$396.13	$399.61	$403.15	$796.32
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$3,321	$3,332	$3,342	$3,354	$3,365	$3,377	$3,389	$3,402	$3,415	$6,712
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($105)	($108)	($111)	($115)	($118)	($122)	($125)	($129)	($133)	($137)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($185)	($191)	($196)	($202)	($208)	($214)	($221)	($227)	($234)	($241)
17	Royalty Payment (Note 8)	($63)	($65)	($67)	($69)	($71)	($73)	($75)	($77)	($80)	($82)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,283)
19	**Total Expenses (Note 9)**	($353)	($363)	($374)	($385)	($397)	($409)	($421)	($434)	($447)	($3,744)
20											
21											
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$36,991	$35,872	$34,698	$33,464	$32,169	$30,810	$29,382	$27,883	$26,308	$24,656
28	Interest (Note 12)	($1,850)	($1,794)	($1,735)	($1,673)	($1,608)	($1,540)	($1,469)	($1,394)	($1,315)	($1,233)
29	Repayments (Note 13)	($1,119)	($1,175)	($1,233)	($1,295)	($1,360)	($1,428)	($1,499)	($1,574)	($1,653)	($1,735)
30	Ending Balance (Note 14)	$35,872	$34,698	$33,464	$32,169	$30,810	$29,382	$27,883	$26,308	$24,656	$22,920

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2											
3	Annual Generation (kWh) (Note 1)	8,386,381	8,344,449	8,302,727	8,261,213	8,219,907	8,178,807	8,137,913	8,097,224	8,056,738	8,016,454
4	Revenue Requirement ($/MWh) (Note 2)	$410.46	$414.23	$418.07	$422.00	$426.01	$430.11	$434.30	$438.58	$442.95	$447.42
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$3,442	$3,457	$3,471	$3,486	$3,502	$3,518	$3,534	$3,551	$3,569	$3,587
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($141)	($145)	($149)	($154)	($159)	($163)	($168)	($173)	($179)	($184)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($249)	($256)	($264)	($272)	($280)	($288)	($297)	($306)	($315)	($324)
17	Royalty Payment (Note 8)	($85)	($87)	($90)	($92)	($95)	($98)	($101)	($104)	($107)	($110)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($474)	($488)	($503)	($518)	($534)	($550)	($566)	($583)	($600)	($618)
20											
21											
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$22,920	$21,098	$19,184	$17,175	$15,066	$12,851	$10,525	$8,083	$5,519	$2,827
28	Interest (Note 12)	($1,146)	($1,055)	($959)	($859)	($753)	($643)	($526)	($404)	($276)	($141)
29	Repayments (Note 13)	($1,822)	($1,913)	($2,009)	($2,109)	($2,215)	($2,326)	($2,442)	($2,564)	($2,692)	($2,827)
30	Ending Balance (Note 14)	$21,098	$19,184	$17,175	$15,066	$12,851	$10,525	$8,083	$5,519	$2,827	$0

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	3
Capital Cost ($/kW)	$6,720
Fixed O&M ($/kW)	$50
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	15.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$1,000
Replacement Term	10
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$2,500
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$20
Less: State Incentives	$8
Total	$13
Electric Price Results	
LCOE ($/MWh)	$391.32
First Year PPA Price ($/MWH)	$332.74

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																				
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																					
3	Annual Generation (kWh) (Note 1)	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942	3,942
4	Revenue Requirement ($/MWh) (Note 2)	$332.74	$334.99	$337.31	$339.70	$342.16	$344.69	$347.30	$349.99	$352.76	$1,116.65	$358.55	$361.57	$364.69	$367.90	$371.21	$374.61	$378.12	$381.73	$385.45	$389.28
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$4	$1	$1	$1	$1	$1	$1	$1	$2	$2	$2
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
17	Royalty Payment (Note 8)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($3)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)
20																					
21																					
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$13	$12	$12	$11	$11	$11	$10	$10	$9	$8	$8	$7	$7	$6	$5	$4	$4	$3	$2	$1
28	Interest (Note 12)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
29	Repayments (Note 13)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
30	Ending Balance (Note 14)	$12	$12	$11	$11	$11	$10	$10	$9	$8	$8	$7	$7	$6	$5	$4	$4	$3	$2	$1	$0

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	500
Capital Cost ($/kW)	$3,423
Fixed O&M ($/kW)	$50
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	20.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$800
Replacement Term	10
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$1,500
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$1,712
Less: State Incentives	$750
Total	$962
Electric Price Results	
LCOE ($/MWh)	$170.61
First Year PPA Price ($/MWH)	$134.94

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																				
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																					
3	Annual Generation (kWh) (Note 1)	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000	876,000
4	Revenue Requirement ($/MWh) (Note 2)	$134.94	$136.35	$137.80	$139.29	$140.83	$142.41	$144.04	$145.72	$147.45	$605.85	$151.06	$152.95	$154.90	$156.90	$158.97	$161.10	$163.29	$165.54	$167.87	$170.26
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$118	$119	$121	$122	$123	$125	$126	$128	$129	$531	$132	$134	$136	$137	$139	$141	$143	$145	$147	$149
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	($25)	($26)	($27)	($27)	($28)	($29)	($30)	($31)	($32)	($33)	($34)	($35)	($36)	($37)	($38)	($39)	($40)	($41)	($43)	($44)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($9)	($9)	($9)	($9)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)	($13)	($13)	($14)	($14)	($15)	($15)
17	Royalty Payment (Note 8)	($8)	($8)	($8)	($8)	($8)	($9)	($9)	($9)	($10)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)	($13)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	($400)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($41)	($42)	($44)	($45)	($46)	($48)	($49)	($50)	($52)	($454)	($55)	($57)	($59)	($60)	($62)	($64)	($66)	($68)	($70)	($72)
20																					
21																					
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$962	$932	$902	$870	$836	$801	$764	$725	$684	$641	$596	$548	$499	$446	$392	$334	$274	$210	$143	$73
28	Interest (Note 12)	($48)	($47)	($45)	($43)	($42)	($40)	($38)	($36)	($34)	($32)	($30)	($27)	($25)	($22)	($20)	($17)	($14)	($11)	($7)	($4)
29	Repayments (Note 13)	($29)	($31)	($32)	($34)	($35)	($37)	($39)	($41)	($43)	($45)	($47)	($50)	($52)	($55)	($58)	($60)	($63)	($67)	($70)	($73)
30	Ending Balance (Note 14)	$932	$902	$870	$836	$801	$764	$725	$684	$641	$596	$548	$499	$446	$392	$334	$274	$210	$143	$73	($0)

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	7,500
Capital Cost ($/kW)	$2,756
Fixed O&M ($/kW)	$30
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	20.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$800
Replacement Term	10
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	0
Other Incentives	0

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$20,670
Less: State Incentives	$0
Total	$20,670
Electric Price Results	
LCOE ($/MWh)	$191.70
First Year PPA Price ($/MWH)	$159.78

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																				
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																					
3	Annual Generation (kWh) (Note 1)	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000	13,140,000
4	Revenue Requirement ($/MWh) (Note 2)	$159.78	$160.78	$161.82	$162.89	$163.99	$165.12	$166.29	$167.49	$168.73	$626.62	$171.32	$172.67	$174.06	$175.50	$176.97	$178.50	$180.06	$181.68	$183.34	$185.06
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$2,099	$2,113	$2,126	$2,140	$2,155	$2,170	$2,185	$2,201	$2,217	$8,234	$2,251	$2,269	$2,287	$2,306	$2,325	$2,345	$2,366	$2,387	$2,409	$2,432
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	($225)	($232)	($239)	($246)	($253)	($261)	($269)	($277)	($285)	($294)	($302)	($311)	($321)	($330)	($340)	($351)	($361)	($372)	($383)	($395)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($103)	($106)	($110)	($113)	($116)	($120)	($123)	($127)	($131)	($135)	($139)	($143)	($147)	($152)	($156)	($161)	($166)	($171)	($176)	($181)
17	Royalty Payment (Note 8)	($113)	($116)	($119)	($123)	($127)	($130)	($134)	($138)	($143)	($147)	($151)	($156)	($160)	($165)	($170)	($175)	($181)	($186)	($192)	($197)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($441)	($454)	($468)	($482)	($496)	($511)	($526)	($542)	($558)	($6,575)	($592)	($610)	($629)	($647)	($667)	($687)	($707)	($729)	($751)	($773)
20																					
21																					
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$20,670	$20,045	$19,389	$18,699	$17,976	$17,216	$16,418	$15,580	$14,701	$13,777	$12,807	$11,789	$10,720	$9,597	$8,419	$7,181	$5,881	$4,517	$3,084	$1,580
28	Interest (Note 12)	($1,034)	($1,002)	($969)	($935)	($899)	($861)	($821)	($779)	($735)	($689)	($640)	($589)	($536)	($480)	($421)	($359)	($294)	($226)	($154)	($79)
29	Repayments (Note 13)	($625)	($656)	($689)	($724)	($760)	($798)	($838)	($880)	($924)	($970)	($1,018)	($1,069)	($1,123)	($1,179)	($1,238)	($1,300)	($1,365)	($1,433)	($1,504)	($1,580)
30	Ending Balance (Note 14)	$20,045	$19,389	$18,699	$17,976	$17,216	$16,418	$15,580	$14,701	$13,777	$12,807	$11,789	$10,720	$9,597	$8,419	$7,181	$5,881	$4,517	$3,084	$1,580	$0

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	2,400
Capital Cost ($/kW)	$8,489
Fixed O&M ($/kW)	$510
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$0
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$15
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	15.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$20,374
Less: State Incentives	$0
Total	$20,374
Electric Price Results	
LCOE ($/MWh)	$1,071.62
First Year PPA Price ($/MWH)	$950.25

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

($ in 1000 unless noted otherwise)

Line #	Year	1	2	3	4	5	6	7	8	9	10
2											
3	Annual Generation (kWh) (Note 1)	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600
4	Revenue Requirement ($/MWh) (Note 2)	$950.25	$963.20	$976.55	$990.29	$1,004.45	$1,019.03	$1,034.05	$1,049.52	$1,065.45	$1,081.86
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$2,997	$3,038	$3,080	$3,123	$3,168	$3,214	$3,261	$3,310	$3,360	$3,412
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($1,224)	($1,261)	($1,299)	($1,337)	($1,378)	($1,419)	($1,462)	($1,505)	($1,551)	($1,597)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($102)	($105)	($108)	($111)	($115)	($118)	($122)	($125)	($129)	($133)
17	Royalty Payment (Note 8)	($36)	($37)	($38)	($39)	($41)	($42)	($43)	($44)	($46)	($47)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($1,362)	($1,403)	($1,445)	($1,488)	($1,533)	($1,579)	($1,626)	($1,675)	($1,725)	($1,777)
20											
21											
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$20,374	$19,757	$19,110	$18,431	$17,718	$16,969	$16,183	$15,357	$14,490	$13,580
28	Interest (Note 12)	($1,019)	($988)	($956)	($922)	($886)	($848)	($809)	($768)	($724)	($679)
29	Repayments (Note 13)	($616)	($647)	($679)	($713)	($749)	($786)	($826)	($867)	($910)	($956)
30	Ending Balance (Note 14)	$19,757	$19,110	$18,431	$17,718	$16,969	$16,183	$15,357	$14,490	$13,580	$12,624

Line #	Year	11	12	13	14	15	16	17	18	19	20
2											
3	Annual Generation (kWh) (Note 1)	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600
4	Revenue Requirement ($/MWh) (Note 2)	$1,098.77	$1,116.18	$1,134.11	$1,152.58	$1,171.61	$1,191.20	$1,211.39	$1,232.18	$1,253.59	$1,275.65
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$3,465	$3,520	$3,577	$3,635	$3,695	$3,757	$3,820	$3,886	$3,953	$4,023
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($1,645)	($1,694)	($1,745)	($1,797)	($1,851)	($1,907)	($1,964)	($2,023)	($2,084)	($2,146)
14	Variable O&M (Note 5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($137)	($141)	($145)	($150)	($154)	($159)	($163)	($168)	($173)	($179)
17	Royalty Payment (Note 8)	($48)	($50)	($51)	($53)	($54)	($56)	($58)	($60)	($61)	($63)
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($1,830)	($1,885)	($1,942)	($2,000)	($2,060)	($2,122)	($2,185)	($2,251)	($2,318)	($2,388)
20											
21											
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$12,624	$11,620	$10,566	$9,460	$8,298	$7,078	$5,797	$4,452	$3,040	$1,557
28	Interest (Note 12)	($631)	($581)	($528)	($473)	($415)	($354)	($290)	($223)	($152)	($78)
29	Repayments (Note 13)	($1,004)	($1,054)	($1,107)	($1,162)	($1,220)	($1,281)	($1,345)	($1,412)	($1,483)	($1,557)
30	Ending Balance (Note 14)	$11,620	$10,566	$9,460	$8,298	$7,078	$5,797	$4,452	$3,040	$1,557	($0)

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	250
Capital Cost ($/kW)	$5,775
Fixed O&M ($/kW)	$200
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$30
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	$0
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	0
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$210
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$1,444
Less: State Incentives	$53
Total	$1,391
Electric Price Results	
LCOE ($/MWh)	$132.26
First Year PPA Price ($/MWH)	$115.67

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																				
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2																					
3	Annual Generation (kWh) (Note 1)	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000	1,971,000
4	Revenue Requirement ($/MWh) (Note 2)	$115.67	$117.44	$119.27	$121.14	$123.08	$125.07	$127.13	$129.24	$131.42	$133.66	$135.97	$138.35	$140.80	$143.33	$145.93	$148.61	$151.37	$154.21	$157.14	$160.15
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$228	$231	$235	$239	$243	$247	$251	$255	$259	$263	$268	$273	$278	$282	$288	$293	$298	$304	$310	$316
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	($50)	($52)	($53)	($55)	($56)	($58)	($60)	($61)	($63)	($65)	($67)	($69)	($71)	($73)	($76)	($78)	($80)	($83)	($85)	($88)
14	Variable O&M (Note 5)	($59)	($61)	($63)	($65)	($67)	($69)	($71)	($73)	($75)	($77)	($79)	($82)	($84)	($87)	($89)	($92)	($95)	($98)	($101)	($104)
15	Fuel Cost (Note 6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Insurance (Note 7)	($7)	($7)	($8)	($8)	($8)	($8)	($9)	($9)	($9)	($9)	($10)	($10)	($10)	($11)	($11)	($11)	($12)	($12)	($12)	($13)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($116)	($120)	($123)	($127)	($131)	($135)	($139)	($143)	($147)	($152)	($156)	($161)	($166)	($171)	($176)	($181)	($187)	($192)	($198)	($204)
20																					
21																					
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$1,391	$1,349	$1,305	$1,259	$1,210	$1,159	$1,105	$1,049	$989	$927	$862	$793	$722	$646	$567	$483	$396	$304	$208	$106
28	Interest (Note 12)	($70)	($67)	($65)	($63)	($60)	($58)	($55)	($52)	($49)	($46)	($43)	($40)	($36)	($32)	($28)	($24)	($20)	($15)	($10)	($5)
29	Repayments (Note 13)	($42)	($44)	($46)	($49)	($51)	($54)	($56)	($59)	($62)	($65)	($69)	($72)	($76)	($79)	($83)	($87)	($92)	($96)	($101)	($106)
30	Ending Balance (Note 14)	$1,349	$1,305	$1,259	$1,210	$1,159	$1,105	$1,049	$989	$927	$862	$793	$722	$646	$567	$483	$396	$304	$208	$106	$0

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	400
Capital Cost ($/kW)	$7,350
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$70
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	9,500
Heat Recovery (mmBTU/hr)	1.70
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$2,500
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$2,940
Less: State Incentives	$1,000
Total	$1,940
Electric Price Results	
LCOE ($/MWh)	$189.55
First Year PPA Price ($/MWH)	$155.41

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																				
1	**Year**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
2																					
3	Annual Generation (kWh) (Note 1)	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600	3,153,600
4	Revenue Requirement ($/MWh) (Note 2)	$155.41	$162.25	$169.61	$173.58	$176.58	$179.82	$183.24	$186.53	$189.89	$193.39	$196.92	$200.48	$203.80	$207.76	$211.71	$215.71	$219.81	$224.06	$228.37	$232.85
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$490	$512	$535	$547	$557	$567	$578	$588	$599	$610	$621	$632	$643	$655	$668	$680	$693	$707	$720	$734
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 5)	($221)	($227)	($234)	($241)	($248)	($256)	($264)	($271)	($280)	($288)	($297)	($306)	($315)	($324)	($334)	($344)	($354)	($365)	($376)	($387)
15	Fuel Cost (Note 6)	($170)	($195)	($223)	($232)	($235)	($238)	($243)	($246)	($250)	($253)	($256)	($259)	($261)	($265)	($268)	($272)	($275)	($279)	($282)	($286)
16	Insurance (Note 7)	($15)	($15)	($16)	($16)	($17)	($17)	($18)	($18)	($19)	($19)	($20)	($20)	($21)	($22)	($22)	($23)	($24)	($24)	($25)	($26)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($406)	($438)	($473)	($489)	($500)	($511)	($524)	($536)	($548)	($560)	($573)	($585)	($596)	($611)	($625)	($639)	($653)	($668)	($683)	($698)
20		$71	$82	$93	$97	$98	$100	$102	$103	$105	$106	$108	$109	$109	$111	$113	$114	$115	$117	$118	$120
21		($334)	($356)	($379)	($392)	($401)	($411)	($422)	($433)	($443)	($454)	($465)	($477)	($487)	($500)	($512)	($525)	($538)	($551)	($565)	($579)
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$1,940	$1,881	$1,820	$1,755	$1,687	$1,616	$1,541	$1,462	$1,380	$1,293	$1,202	$1,106	$1,006	$901	$790	$674	$552	$424	$289	$148
28	Interest (Note 12)	($97)	($94)	($91)	($88)	($84)	($81)	($77)	($73)	($69)	($65)	($60)	($55)	($50)	($45)	($40)	($34)	($28)	($21)	($14)	($7)
29	Repayments (Note 13)	($59)	($62)	($65)	($68)	($71)	($75)	($79)	($83)	($87)	($91)	($96)	($100)	($105)	($111)	($116)	($122)	($128)	($134)	($141)	($148)
30	Ending Balance (Note 14)	$1,881	$1,820	$1,755	$1,687	$1,616	$1,541	$1,462	$1,380	$1,293	$1,202	$1,106	$1,006	$901	$790	$674	$552	$424	$289	$148	$0
31																					

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	1,400
Capital Cost ($/kW)	$6,300
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$70
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	8,100
Heat Recovery (mmBTU/hr)	4.08
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	2500
Other Incentives	0

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$8,820
Less: State Incentives	$3,500
Total	$5,320
Electric Price Results	
LCOE ($/MWh)	$176.82
First Year PPA Price ($/MWH)	$143.21

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	1	2	3	4	5	6	7	8	9	10
2											
3	Annual Generation (kWh) (Note 1)	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600
4	Revenue Requirement ($/MWh) (Note 2)	$143.21	$149.92	$157.11	$161.03	$163.99	$167.19	$170.56	$173.80	$177.13	$180.58
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$1,581	$1,655	$1,734	$1,777	$1,810	$1,845	$1,883	$1,918	$1,955	$1,993
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 5)	($773)	($796)	($820)	($844)	($870)	($896)	($923)	($950)	($979)	($1,008)
15	Fuel Cost (Note 6)	($509)	($583)	($665)	($691)	($700)	($712)	($725)	($735)	($745)	($755)
16	Insurance (Note 7)	($44)	($45)	($47)	($48)	($50)	($51)	($53)	($54)	($56)	($58)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($1,325)	($1,425)	($1,532)	($1,584)	($1,619)	($1,658)	($1,700)	($1,739)	($1,779)	($1,821)
20		$172	$197	$224	$233	$236	$240	$245	$248	$251	$255
21		($1,154)	($1,228)	($1,307)	($1,350)	($1,383)	($1,418)	($1,456)	($1,491)	($1,528)	($1,566)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$5,320	$5,159	$4,990	$4,813	$4,627	$4,431	$4,226	$4,010	$3,784	$3,546
28	Interest (Note 12)	($266)	($258)	($250)	($241)	($231)	($222)	($211)	($201)	($189)	($177)
29	Repayments (Note 13)	($161)	($169)	($177)	($186)	($196)	($205)	($216)	($226)	($238)	($250)
30	Ending Balance (Note 14)	$5,159	$4,990	$4,813	$4,627	$4,431	$4,226	$4,010	$3,784	$3,546	$3,296
31											

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	11	12	13	14	15	16	17	18	19	20
2											
3	Annual Generation (kWh) (Note 1)	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600	11,037,600
4	Revenue Requirement ($/MWh) (Note 2)	$184.07	$187.59	$190.88	$194.79	$198.70	$202.64	$206.69	$210.90	$215.16	$219.58
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$2,032	$2,071	$2,107	$2,150	$2,193	$2,237	$2,281	$2,328	$2,375	$2,424
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 5)	($1,038)	($1,070)	($1,102)	($1,135)	($1,169)	($1,204)	($1,240)	($1,277)	($1,315)	($1,355)
15	Fuel Cost (Note 6)	($765)	($774)	($778)	($790)	($801)	($811)	($821)	($831)	($841)	($852)
16	Insurance (Note 7)	($59)	($61)	($63)	($65)	($67)	($69)	($71)	($73)	($75)	($77)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($1,863)	($1,905)	($1,942)	($1,990)	($2,036)	($2,083)	($2,131)	($2,181)	($2,232)	($2,284)
20		$258	$261	$262	$267	$270	$274	$277	$280	$284	$287
21		($1,605)	($1,644)	($1,680)	($1,723)	($1,766)	($1,810)	($1,855)	($1,901)	($1,948)	($1,997)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$3,296	$3,034	$2,759	$2,470	$2,167	$1,848	$1,514	$1,163	$794	$407
28	Interest (Note 12)	($165)	($152)	($138)	($124)	($108)	($92)	($76)	($58)	($40)	($20)
29	Repayments (Note 13)	($262)	($275)	($289)	($303)	($319)	($334)	($351)	($369)	($387)	($407)
30	Ending Balance (Note 14)	$3,034	$2,759	$2,470	$2,167	$1,848	$1,514	$1,163	$794	$407	$0
31											

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	2,800
Capital Cost ($/kW)	$5,775
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$70
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	8,100
Heat Recovery (mmBTU/hr)	8.16
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	2500
Other Incentives	0

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$16,170
Less: State Incentives	$7,000
Total	$9,170
Electric Price Results	
LCOE ($/MWh)	$175.46
First Year PPA Price ($/MWH)	$140.65

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)																				
1	**Year**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
2																					
3	Annual Generation (kWh) (Note 1)	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200
4	Revenue Requirement ($/MWh) (Note 2)	$140.65	$147.80	$155.48	$159.54	$162.55	$165.81	$169.25	$172.54	$175.91	$179.42	$182.96	$186.52	$189.81	$193.79	$197.75	$201.74	$205.83	$210.09	$214.39	$218.86
5																					
6	**Revenues**																				
7																					
8																					
9																					
10	Revenue Requirement (Note 3)	$3,105	$3,263	$3,432	$3,522	$3,588	$3,660	$3,736	$3,809	$3,883	$3,961	$4,039	$4,117	$4,190	$4,278	$4,365	$4,453	$4,544	$4,638	$4,733	$4,831
11																					
12	**Expenses**																				
13	Fixed O&M (Note 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 5)	($1,545)	($1,592)	($1,639)	($1,689)	($1,739)	($1,791)	($1,845)	($1,900)	($1,957)	($2,016)	($2,077)	($2,139)	($2,203)	($2,269)	($2,337)	($2,407)	($2,480)	($2,554)	($2,631)	($2,710)
15	Fuel Cost (Note 6)	($1,017)	($1,167)	($1,330)	($1,382)	($1,400)	($1,423)	($1,450)	($1,470)	($1,489)	($1,511)	($1,531)	($1,548)	($1,556)	($1,581)	($1,602)	($1,622)	($1,641)	($1,663)	($1,683)	($1,704)
16	Insurance (Note 7)	($81)	($83)	($86)	($88)	($91)	($94)	($97)	($99)	($102)	($105)	($109)	($112)	($115)	($119)	($122)	($126)	($130)	($134)	($138)	($142)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($2,644)	($2,842)	($3,055)	($3,159)	($3,230)	($3,308)	($3,392)	($3,470)	($3,549)	($3,633)	($3,716)	($3,799)	($3,874)	($3,969)	($4,062)	($4,155)	($4,251)	($4,351)	($4,451)	($4,555)
20		$275	$315	$359	$373	$378	$384	$391	$397	$402	$408	$413	$418	$420	$427	$432	$438	$443	$449	$454	$460
21		($2,369)	($2,527)	($2,697)	($2,786)	($2,852)	($2,924)	($3,000)	($3,073)	($3,147)	($3,225)	($3,303)	($3,382)	($3,454)	($3,542)	($3,629)	($3,718)	($3,808)	($3,902)	($3,997)	($4,096)
22																					
23																					
24	**Debt**																				
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26																					
27	Beginning Balance (Note 11)	$9,170	$8,893	$8,601	$8,296	$7,975	$7,638	$7,284	$6,912	$6,522	$6,112	$5,682	$5,230	$4,756	$4,258	$3,735	$3,186	$2,609	$2,004	$1,368	$701
28	Interest (Note 12)	($459)	($445)	($430)	($415)	($399)	($382)	($364)	($346)	($326)	($306)	($284)	($262)	($238)	($213)	($187)	($159)	($130)	($100)	($68)	($35)
29	Repayments (Note 13)	($277)	($291)	($306)	($321)	($337)	($354)	($372)	($390)	($410)	($430)	($452)	($474)	($498)	($523)	($549)	($577)	($605)	($636)	($667)	($701)
30	Ending Balance (Note 14)	$8,893	$8,601	$8,296	$7,975	$7,638	$7,284	$6,912	$6,522	$6,112	$5,682	$5,230	$4,756	$4,258	$3,735	$3,186	$2,609	$2,004	$1,368	$701	($0)
31																					

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	65
Capital Cost ($/kW)	$3,150
Fixed O&M ($/kW)	$0
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$40
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	13,560
Heat Recovery (mmBTU/hr)	0.41
Capacity Factor	95.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$205
Less: State Incentives	$0
Total	$205
Electric Price Results	
LCOE ($/MWh)	$155.53
First Year PPA Price ($/MWH)	$122.64

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2											
3	Annual Generation (kWh) (Note 1)	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930
4	Revenue Requirement ($/MWh) (Note 2)	$122.64	$131.28	$140.68	$144.58	$146.84	$149.40	$152.19	$154.66	$157.18	$159.84
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$66	$71	$76	$78	$79	$81	$82	$84	$85	$86
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 5)	($22)	($22)	($23)	($24)	($24)	($25)	($26)	($27)	($27)	($28)
15	Fuel Cost (Note 6)	($42)	($48)	($55)	($57)	($57)	($58)	($59)	($60)	($61)	($62)
16	Insurance (Note 7)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($64)	($71)	($79)	($81)	($83)	($85)	($87)	($88)	($90)	($92)
20		$14	$17	$19	$20	$20	$20	$21	$21	$21	$22
21		($50)	($55)	($60)	($62)	($63)	($64)	($66)	($67)	($69)	($70)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$205	$199	$192	$185	$178	$171	$163	$154	$146	$136
28	Interest (Note 12)	($10)	($10)	($10)	($9)	($9)	($9)	($8)	($8)	($7)	($7)
29	Repayments (Note 13)	($6)	($7)	($7)	($7)	($8)	($8)	($8)	($9)	($9)	($10)
30	Ending Balance (Note 14)	$199	$192	$185	$178	$171	$163	$154	$146	$136	$127
31											

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2											
3	Annual Generation (kWh) (Note 1)	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930	540,930
4	Revenue Requirement ($/MWh) (Note 2)	$162.45	$165.02	$167.12	$170.15	$173.06	$175.93	$178.86	$181.94	$184.99	$188.19
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$88	$89	$90	$92	$94	$95	$97	$98	$100	$102
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Variable O&M (Note 5)	($29)	($30)	($31)	($32)	($33)	($34)	($35)	($36)	($37)	($38)
15	Fuel Cost (Note 6)	($63)	($64)	($64)	($65)	($66)	($67)	($67)	($68)	($69)	($70)
16	Insurance (Note 7)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($93)	($95)	($96)	($98)	($100)	($102)	($104)	($106)	($108)	($110)
20		$22	$22	$22	$23	$23	$23	$23	$24	$24	$24
21		($71)	($73)	($74)	($76)	($77)	($79)	($80)	($82)	($84)	($85)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$127	$117	$106	$95	$83	$71	$58	$45	$31	$16
28	Interest (Note 12)	($6)	($6)	($5)	($5)	($4)	($4)	($3)	($2)	($2)	($1)
29	Repayments (Note 13)	($10)	($11)	($11)	($12)	($12)	($13)	($14)	($14)	($15)	($16)
30	Ending Balance (Note 14)	$117	$106	$95	$83	$71	$58	$45	$31	$16	$0
31											

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	1,000
Capital Cost ($/kW)	$2,310
Fixed O&M ($/kW)	$25
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$25
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	10,429
Heat Recovery (mmBTU/hr)	3.00
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$2,310
Less: State Incentives	$0
Total	$2,310
Electric Price Results	
LCOE ($/MWh)	$127.53
First Year PPA Price ($/MWH)	$99.69

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2											
3	Annual Generation (kWh) (Note 1)	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000
4	Revenue Requirement ($/MWh) (Note 2)	$99.69	$107.40	$115.80	$119.12	$120.91	$122.97	$125.23	$127.19	$129.18	$131.29
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$786	$847	$913	$939	$953	$970	$987	$1,003	$1,018	$1,035
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($25)	($26)	($27)	($27)	($28)	($29)	($30)	($31)	($32)	($33)
14	Variable O&M (Note 5)	($197)	($203)	($209)	($215)	($222)	($228)	($235)	($242)	($250)	($257)
15	Fuel Cost (Note 6)	($468)	($537)	($612)	($636)	($644)	($654)	($667)	($676)	($685)	($695)
16	Insurance (Note 7)	($12)	($12)	($12)	($13)	($13)	($13)	($14)	($14)	($15)	($15)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($701)	($777)	($860)	($891)	($907)	($925)	($946)	($963)	($981)	($1,000)
20		$101	$116	$132	$137	$139	$141	$144	$146	$148	$150
21		($601)	($661)	($728)	($754)	($768)	($784)	($802)	($817)	($833)	($850)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$2,310	$2,240	$2,167	$2,090	$2,009	$1,924	$1,835	$1,741	$1,643	$1,540
28	Interest (Note 12)	($116)	($112)	($108)	($104)	($100)	($96)	($92)	($87)	($82)	($77)
29	Repayments (Note 13)	($70)	($73)	($77)	($81)	($85)	($89)	($94)	($98)	($103)	($108)
30	Ending Balance (Note 14)	$2,240	$2,167	$2,090	$2,009	$1,924	$1,835	$1,741	$1,643	$1,540	$1,431
31											

Line #	($ in 1000 unless noted otherwise)										
1	**Year**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2											
3	Annual Generation (kWh) (Note 1)	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000
4	Revenue Requirement ($/MWh) (Note 2)	$133.35	$135.36	$136.92	$139.33	$141.62	$143.87	$146.15	$148.56	$150.93	$153.42
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$1,051	$1,067	$1,079	$1,099	$1,117	$1,134	$1,152	$1,171	$1,190	$1,210
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($34)	($35)	($36)	($37)	($38)	($39)	($40)	($41)	($43)	($44)
14	Variable O&M (Note 5)	($265)	($273)	($281)	($289)	($298)	($307)	($316)	($326)	($336)	($346)
15	Fuel Cost (Note 6)	($704)	($712)	($715)	($727)	($737)	($746)	($755)	($765)	($774)	($784)
16	Insurance (Note 7)	($16)	($16)	($16)	($17)	($17)	($18)	($19)	($19)	($20)	($20)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($1,018)	($1,035)	($1,048)	($1,070)	($1,090)	($1,110)	($1,130)	($1,151)	($1,171)	($1,193)
20		$152	$154	$154	$157	$159	$161	$163	$165	$167	$169
21		($866)	($882)	($894)	($913)	($931)	($949)	($967)	($986)	($1,005)	($1,024)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$1,431	$1,318	$1,198	$1,073	$941	$803	$657	$505	$345	$177
28	Interest (Note 12)	($72)	($66)	($60)	($54)	($47)	($40)	($33)	($25)	($17)	($9)
29	Repayments (Note 13)	($114)	($119)	($125)	($132)	($138)	($145)	($152)	($160)	($168)	($177)
30	Ending Balance (Note 14)	$1,318	$1,198	$1,073	$941	$803	$657	$505	$345	$177	($0)
31											

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- ASSUMPTIONS

Shaded Cells are Inputs

Project Assumptions	
Project Capacity (kW)	50,000
Capital Cost ($/kW)	$2,756
Fixed O&M ($/kW)	$10
Fixed O&M Escalation	3.0%
Variable O&M ($/MWh)	$25
Variable O&M Escalation	3.0%
Fuel Cost ($/Mbtu)	
Fuel Cost Escalation	3.0%
Insurance (% of Capital)	0.5%
Insurance Escalation	3.0%
Royalty Payments ($/kW)	$0
Royalty Escalation	3.0%
Heat Rate (Btu/kWh)	8,000
Heat Recovery (mmBTU/hr)	69.30
Capacity Factor	90.0%
Degradation	0.0%

Financial/Economic Assumptions	
Debt Rate	5.00%
Debt Term (years)	20
Economic Life (years)	20
Replacement Capital	$0
Replacement Term	-
Replacement Escalation %	0.0%
	5.00%

State Incentives	
State Incentives	
CBI Incentive	$0
Other Incentives	$ -

RESULTS OF ANALYSIS	
Capital	
Total Capital Costs ($ in 000)	$137,800
Less: State Incentives	$0
Total	$137,800
Electric Price Results	
LCOE ($/MWh)	$115.95
First Year PPA Price ($/MWH)	$92.71

NOT-FOR-PROFIT LEVELIZED COST OF ELECTRICITY -- PROFORMA

Line # ($ in 1000 unless noted otherwise)

Line #		1	2	3	4	5	6	7	8	9	10
1	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
2											
3	Annual Generation (kWh) (Note 1)	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000
4	Revenue Requirement ($/MWh) (Note 2)	$92.71	$98.93	$105.69	$108.45	$110.01	$111.80	$113.74	$115.45	$117.19	$119.03
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$36,548	$38,999	$41,664	$42,752	$43,367	$44,070	$44,835	$45,510	$46,197	$46,921
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($500)	($515)	($530)	($546)	($563)	($580)	($597)	($615)	($633)	($652)
14	Variable O&M (Note 5)	($9,855)	($10,151)	($10,455)	($10,769)	($11,092)	($11,425)	($11,767)	($12,120)	($12,484)	($12,859)
15	Fuel Cost (Note 6)	($17,944)	($20,577)	($23,463)	($24,377)	($24,693)	($25,103)	($25,576)	($25,923)	($26,269)	($26,648)
16	Insurance (Note 7)	($689)	($710)	($731)	($753)	($775)	($799)	($823)	($847)	($873)	($899)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($28,988)	($31,953)	($35,179)	($36,445)	($37,123)	($37,906)	($38,763)	($39,505)	($40,260)	($41,058)
20		$3,497	$4,011	$4,573	$4,751	$4,813	$4,893	$4,985	$5,052	$5,120	$5,194
21		($25,491)	($27,942)	($30,606)	($31,694)	($32,310)	($33,013)	($33,778)	($34,453)	($35,140)	($35,864)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$137,800	$133,633	$129,257	$124,662	$119,838	$114,772	$109,454	$103,869	$98,005	$91,848
28	Interest (Note 12)	($6,890)	($6,682)	($6,463)	($6,233)	($5,992)	($5,739)	($5,473)	($5,193)	($4,900)	($4,592)
29	Repayments (Note 13)	($4,167)	($4,376)	($4,595)	($4,824)	($5,066)	($5,319)	($5,585)	($5,864)	($6,157)	($6,465)
30	Ending Balance (Note 14)	$133,633	$129,257	$124,662	$119,838	$114,772	$109,454	$103,869	$98,005	$91,848	$85,383
31											

Line #		11	12	13	14	15	16	17	18	19	20
1	**Year**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
2											
3	Annual Generation (kWh) (Note 1)	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000	394,200,000
4	Revenue Requirement ($/MWh) (Note 2)	$120.83	$122.61	$124.03	$126.13	$128.14	$130.12	$132.13	$134.26	$136.35	$138.56
5											
6	**Revenues**										
7											
8											
9											
10	Revenue Requirement (Note 3)	$47,633	$48,332	$48,892	$49,720	$50,511	$51,292	$52,087	$52,924	$53,751	$54,619
11											
12	**Expenses**										
13	Fixed O&M (Note 4)	($672)	($692)	($713)	($734)	($756)	($779)	($802)	($826)	($851)	($877)
14	Variable O&M (Note 5)	($13,244)	($13,642)	($14,051)	($14,472)	($14,907)	($15,354)	($15,814)	($16,289)	($16,777)	($17,281)
15	Fuel Cost (Note 6)	($26,995)	($27,310)	($27,436)	($27,878)	($28,256)	($28,603)	($28,950)	($29,328)	($29,675)	($30,054)
16	Insurance (Note 7)	($926)	($954)	($982)	($1,012)	($1,042)	($1,073)	($1,106)	($1,139)	($1,173)	($1,208)
17	Royalty Payment (Note 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Capital Replacements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	**Total Expenses (Note 9)**	($41,837)	($42,598)	($43,182)	($44,096)	($44,961)	($45,809)	($46,672)	($47,583)	($48,477)	($49,420)
20		$5,261	$5,323	$5,348	$5,434	$5,507	$5,575	$5,643	$5,716	$5,784	$5,858
21		($36,576)	($37,275)	($37,835)	($38,663)	($39,454)	($40,234)	($41,030)	($41,866)	($42,693)	($43,562)
22											
23											
24	**Debt**										
25	Interest Rate (Note 10)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
26											
27	Beginning Balance (Note 11)	$85,383	$78,594	$71,467	$63,982	$56,124	$47,873	$39,209	$30,112	$20,560	$10,531
28	Interest (Note 12)	($4,269)	($3,930)	($3,573)	($3,199)	($2,806)	($2,394)	($1,960)	($1,506)	($1,028)	($527)
29	Repayments (Note 13)	($6,788)	($7,128)	($7,484)	($7,858)	($8,251)	($8,664)	($9,097)	($9,552)	($10,029)	($10,531)
30	Ending Balance (Note 14)	$78,594	$71,467	$63,982	$56,124	$47,873	$39,209	$30,112	$20,560	$10,531	($0)
31											