

Appendix I: Generating Resources and Energy Storage Technologies - Background Information

Introduction.....	1
General Approach and Assumptions	2
Conventions	2
Levelized Costs.....	2
Capital Cost Estimates	3
Project Financing	7
Incentives.....	8
Transmission.....	9
Integration Cost for Variable Resources.....	11
Carbon Dioxide Allowance Prices.....	13
Carbon Dioxide Sequestration	13
Assumptions for Reference Plants.....	18
Landfill Gas	18
Animal Waste Energy Recovery.....	21
Wastewater Treatment Plant Energy Recovery	24
Woody Residue Power Plant	27
Geothermal.....	28
Hydropower	30
Solar Photovoltaic Plant.....	31
Concentrating Solar Power Plant	34
Wind.....	36
Waste Heat Energy Recovery Cogeneration.....	40
Coal-fired Steam-electric Plant.....	41
Coal-fired Gasification Combined-cycle Plant.....	41
Natural Gas Combined-Cycle Gas Turbine	41
Natural Gas Simple-Cycle Gas Turbines.....	45
Reference Aeroderivative Simple-cycle Gas Turbine Plant.....	45
Reference Heavy-duty Simple-cycle Gas Turbine Plant	49
Natural Gas Reciprocating Engine Plant	51
Advanced Nuclear Plant	51
Compressed Air Energy Storage.....	51
Pumped Storage Hydropower.....	51
Values Underlying Charts of Chapter 6.....	51
Figures 6-1A-C: Levelized Electricity Cost of Generating Options.....	51
Figure 6-2: Levelized Fixed Cost of Firm Capacity Options	53
References.....	55

INTRODUCTION

This appendix describes the development of the planning assumptions for new generating resources for use in preparing the Sixth Power Plan.

GENERAL APPROACH AND ASSUMPTIONS

Conventions

The following conventions are used in this Appendix and in Chapter 6 unless otherwise noted:

The price base year from which future changes in real costs are calculated is 2008

Costs are expressed in constant 2006 dollars

The technology base year from which future changes in technology are calculated is 2008

The scope of resource cost estimates includes the cost and losses of delivery to the wholesale receiving point of the local load-serving entity.

“Near-term” refers to the period 2010 - 2014; “Mid-term” to the period 2015-2019 and “Longer-term” to the period 2020 - 2029.

In calculating total investment cost, project costs are assumed to be fixed (in real terms) at the first year of construction.

Levelized Costs

Comparative levelized lifecycle generating resource costs are provided in several locations in this plan. These are computed using the Council’s MicroFin project revenue requirements model. MicroFin is also used to compute levelized capital costs for new resource options for the AURORA^{xmp}® Electric Market Model and for the Council’s Regional Portfolio Model. The operation of MicroFin is as follows:

Total project investment is calculated for the selected year of construction using the estimated project capital cost, plant capacity, cost escalation factors, construction cash flow estimates and the construction financing of the selected type of project developer (Consumer-owned utility, investor-owned utility and independent project developer financing options are available in MicroFin. Most resource costs reported in this plan assume investor-owned utility financing.

Annual capital-related costs (debt interest, debt principal, return on equity, recovery of equity, state and federal taxes) are calculated for the total project investment using the long-term financing characteristics and tax obligations of the selected type of developer. Financial incentives such as accelerated depreciation, investment tax credit and production tax credits are applied at this point.

Annual property tax and insurance payments are calculated based on depreciated plant value.

Annual energy production is calculated based on plant capacity and capacity factor.

Annual fixed fuel costs are calculated based on escalated fixed fuel costs and plant capacity. Annual variable fuel costs are based on escalated variable fuel costs, heat rate and energy production.

Annual fixed O&M costs are calculated based on escalated fixed O&M costs and plant capacity. Annual variable O&M costs are based on escalated variable O&M costs and energy production.

Annual emission costs are calculated based on fuel consumption, fuel carbon content, and forecast CO₂ allowance costs.

Annual transmission costs are calculated based on plant capacity and escalated unit transmission costs. Integration costs are calculated based on forecast integration costs and energy production.

The value of transmission losses is calculated based on total annual costs and the transmission loss factor.

The net present value for the initial year of service is calculated for each component of annual cost over the life of the project. The levelized annual cost stream yielding the same net present value is then calculated for each component. The discount rate used for the net present value and levelization is the weighted after-tax cost of capital for the selected type of project developer.

The resulting levelized cost components are converted to unit (per-megawatt-hour) values, discounted to the base year (2006 dollar values) and summed to yield total revenue requirements.

A copy of MicroFin, loaded with the resource, fuel financing and other assumptions used to calculate investment costs and project revenue requirements for this plan is available from the Council on request.

Capital Cost Estimates

The capital cost estimates for the reference power plants are based on published sources. These include costs reported in the media for planned projects, projects under construction and completed projects, and generic cost estimates for specific technologies and projects appearing in publically-available reports. Using this information, the Council develops an estimate of per kilowatt Total Project Costs for each reference plant. “Total Project Costs” (often referred to as “overnight” costs) are defined here as total direct and indirect costs of project development and construction and commissioning, exclusive of the costs of securing financing, and escalation and interest incurred during construction. Various financing assumptions can then be applied to the total project cost to yield total project investment costs.

The raw cost data used to develop reference plant cost estimates can represent different vintages, project scope and year dollars and may or may not include the costs of financing, escalation and interest during construction. In all cases it is necessary to normalize reported costs to common vintage, scope, year dollars and to overnight value. The information needed to make these adjustments is typically documented in technology assessments and feasibility studies. However, the needed information is often incomplete or entirely missing in media reports, necessitating assumptions. The general approach used to normalize costs is as follows; additional details regarding specific technologies are provided in the respective technology sections:

- Project capacity is adjusted to common metrics. For thermal projects this is net output under ISO conditions. Wind project costs are based on installed turbine capacity and utility-scale solar project costs are adjusted to net AC output.

- Reported estimates were screened and adjusted to represent a plant configuration broadly approximating the reference plant. Plants having configurations clearly unrepresentative of the reference plant were eliminated from the sample. For example, reported costs for simple-cycle combustion turbine plants of consisting of more than four units were omitted. In other cases, costs were increased or decreased to normalize major design characteristics. For example, the reported costs of thermal plants provided with dry cooling was adjusted down to represent the cost of plants employing evaporative cooling.
- Estimates were adjusted to include all owners' costs (project development, land, infrastructure and financing). Unless specifically noted in the reporting, cost estimates reported prior to completion are assumed to be overnight construction cost, exclusive of owner's costs. These were increased to account for owner's costs. Reported costs for completed plants are assumed to include all owners' costs.
- Costs reported for specific projects were adjusted to an average construction cost index for the Pacific Northwest states using the state adjustment factors of USACE (2008).
- Costs were adjusted to represent overnight costs. Cost estimates reported prior to completion are assumed to be overnight costs so were not adjusted other than conversion to constant (real) 2006 dollars. Reported costs for completed projects are assumed to be in as-expended (nominal) dollars including financing, and escalation and interest during construction. For these cases, the equivalent overnight total plant costs in year 2006 dollars are calculated using the Council's MicroFin project financing and levelization model.

Because of the substantial escalation in plant construction costs between 2004 and 2008 it is necessary to plot costs by vintage to gain a sense of typical 2008 base year costs and range of costs. Costs of completed plants or plants under construction are assumed to represent costs as of the initial year of construction. The vintage of costs reported for plants not yet under construction is assumed to be the year of publication. Some resources, particularly those where large sample sizes are available and plants tend to have relatively uniform characteristics yielded well-defined distributions. Figure I-14 (wind plants) is one such example. In cases with well-defined distributions, the representative 2008 base year cost was taken as the approximate average of 2008 costs and the range the range of normalized reported costs (less obvious outliers).

Other resources yielded poorly-defined distributions, because of small sample sizes, plants inherently of widely varying characteristics or for other reasons. An example is I-BIO-1, landfill gas energy recovery projects. In these cases, the selection of the reference plant base year cost was influenced by the source and apparent quality of individual samples and the shape of the HIS Cambridge Energy Research Associates Power Capital Cost Index¹ (converted to real terms).

Capital costs forecasts are based on the interaction of two factors - near-term declines resulting from contraction of the credit market and reduction in demand for goods since mid 2008, and, over the longer-term, the effect of technological improvements and economies of production, particularly for less-mature technologies. In general, capital costs (in real terms) are assumed to drop from mid-2008 highs to market equilibrium values by 2011. Market equilibrium values are

¹ <http://www.cera.com/asp/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10429>

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan assumed to be the average of 2004 and 2008 capital costs (in 2006 constant year dollar values). Further declines resulting from technological advances and economies of production are based on rates observed in the years prior to 2004. These assumptions are described below for the various reference plants. The base year capital cost assumptions and capital cost forecasts for the various reference plants are provided in Table I-1. Selected cases are plotted in Figure I-1 to illustrate the changes through time.

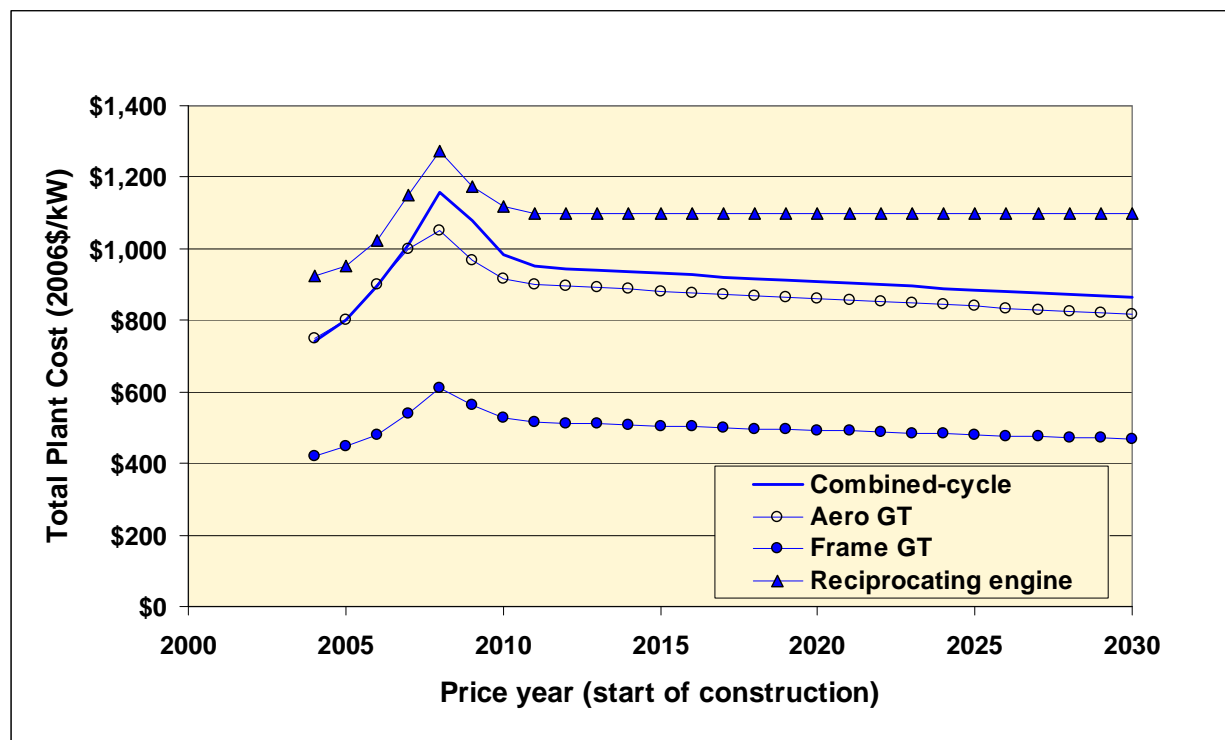
[The following table is yet to be completed]

Table I-1: Projected total plant cost (overnight, 2006 dollar values)

	Animal Waste	Combined-cycle	Geothermal	Landfill Gas	Reciprocating Engines	Wastewater Treatment	Wind
2008	\$5,000	\$1,160	\$4,800	\$2,349		\$5,000	\$2,100
2009	\$4,600	\$1,079	\$4,400	\$2,161		\$4,600	\$1,806
2010	\$4,385	\$982	\$3,988	\$2,060		\$3,963	\$1,725
2011	\$4,314	\$950	\$3,850	\$2,026		\$3,750	\$1,700
2012	\$4,314	\$945	\$3,850	\$2,026		\$3,731	\$1,692
2013	\$4,314	\$941	\$3,850	\$2,026		\$3,713	\$1,683
2014	\$4,314	\$936	\$3,850	\$2,026		\$3,694	\$1,675
2015	\$4,314	\$931	\$3,850	\$2,026		\$3,676	\$1,666
2016	\$4,314	\$927	\$3,850	\$2,026		\$3,657	\$1,658
2017	\$4,314	\$922	\$3,850	\$2,026		\$3,639	\$1,650
2018	\$4,314	\$917	\$3,850	\$2,026		\$3,621	\$1,641
2019	\$4,314	\$913	\$3,850	\$2,026		\$3,603	\$1,633
2020	\$4,314	\$908	\$3,850	\$2,026		\$3,585	\$1,625
2021	\$4,314	\$904	\$3,850	\$2,026		\$3,567	\$1,617
2022	\$4,314	\$899	\$3,850	\$2,026		\$3,549	\$1,609
2023	\$4,314	\$895	\$3,850	\$2,026		\$3,531	\$1,601
2024	\$4,314	\$890	\$3,850	\$2,026		\$3,513	\$1,593
2025	\$4,314	\$886	\$3,850	\$2,026		\$3,496	\$1,585
2026	\$4,314	\$881	\$3,850	\$2,026		\$3,478	\$1,577
2027	\$4,314	\$877	\$3,850	\$2,026		\$3,461	\$1,569
2028	\$4,314	\$873	\$3,850	\$2,026		\$3,444	\$1,561
2029	\$4,314	\$868	\$3,850	\$2,026		\$3,426	\$1,553

[The following figure is yet to be completed]

Figure I-1: Selected projections of total plant cost



Project Financing

Power plants can be constructed by investor-owned utilities, consumer-owned utilities and independent power project developers. Each of these entities uses different project financing mechanisms. The differing financing mechanisms and financial incentives available for some resources result in owner-specific total capital investment costs and annual capital service requirements for otherwise identical projects. In general, financing by consumer-owned utilities results in lower capital service requirement than financing by either investor-owned utilities or independent developers. The object of the Council's plan is to choose among types of resources rather than to recommend the development of specific resources. For this reason, a single type of resource developer is chosen to provide consistent comparisons of resource costs. Investor-owned utility financing is used as this basis in this power plan.

Plant investment costs are calculated using the Council's MicroFin model. MicroFin is a spreadsheet model used to calculate annual and levelized lifecycle minimum revenue requirements for various resource alternatives. Accelerated depreciation is normalized for investor-owned utility financing. Investment and production tax credits are credited as available against project costs. MicroFin is used by the Council to calculate levelized electricity costs for broad comparisons among resource alternatives, to calculate levelized fixed costs required to model new resource option in the AURORA^{xmp}® model and to calculate the levelized cost of the the three phases of development and construction (Option, Early Construction and Committed Construction) required for the Regional Portfolio Model. Though investor-owned utility financing is used as the standard for this plan, MicroFin can also model typical consumer-owned

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan utility financing and non-third party independent power developer financing. MicroFin is available from the Council on request.

The financing parameter values used in MicroFin are shown in Table I-2.

**Table I-2: Assumptions regarding financing and other common parameters
(Values are nominal unless stated)**

	Municipal/ PUD	Investor-Owned Utility	Independent Power Producer
Federal Income Tax Rate	--	35%	35%
Federal Investment Tax Credit	--	See Incentives	See Incentives
FIT Recovery Period	--	See Incentives	See Incentives
State Income Tax Rate	--	5.9%	5.9%
State Investment Tax Credit	--	None	None
SIT Recovery Period	--	Same as federal	Same as federal
Property Tax	1.4%	1.4%	1.4%
Insurance	0.25%	0.25%	0.25%
Debt Term	Economic life	Economic life	15 years max
Equity return	--	Economic life	15 years max
Debt fraction - Development	100%	50%	0%
Debt fraction - Construction	100%	50%	60%
Debt fraction - Term	100%	50%	60%
Debt interest - Development	5.2%	7.3%	--
Debt interest - Construction	5.2%	7.3%	6.0%
Debt interest - Term	5.2%	7.3%	7.3%
Return on Equity - Development	--	11.0%	--
Return on Equity - Construction	--	11.0%	14.5%
Return on Equity - Term	--	11.0%	14.5%
Debt Financing Fee	2.0%	2.0%	2.0%
Discount Rate	4.4%	7.3%	7.7%
General Inflation Rate	2.0%	2.0%	2.0%

Incentives

Existing federal energy production tax credit and investment tax credit are assumed to apply to qualifying resources for their currently authorized term. Existing provisions for accelerated depreciation are assumed to continue indefinitely. Numerous complexities and options are present in the tax code with respect to these incentives and simplifications are made here, for example, the “tax credit appetite” of the developing entity is constrained only by the federal income tax incurred by this specific project. No conversions to investment tax credit are taken. Assumptions regarding federal incentives are provided in Table I-3.

Table I-3: Assumptions regarding federal incentives (2006 year dollar values)

Resource	PTC2 (Alternative to ITC)	ITC3 (Alternative to PTC)	Accelerated Depreciation Recovery Period ³
Biomass (Open loop)	\$9.85/MWh thru 2013	None	7-year
CHP4 (OL Biomass)	\$9.85/MWh thru 2013 ⁵	10% thru 2016 ⁶	5-year
CHP4 (NG)	None	10% thru 2016 ⁶	5-year
Geothermal	\$19.70/MWh thru 2013	10% (no expiration date)	5-year
Hydropower⁷	\$9.85/MWh thru 2013	None	20-year
Solar	\$9.85/MWh thru 2013	30% thru 2016, 10% thereafter	5-year
Wind	\$19.70/MWh thru 2012	None	5-year

State incentives represent within-region income transfers and are not considered in calculating project costs⁸ to better represent true project costs.

Transmission

[Portions of this section are yet to be completed]

² The federal production tax credit is generally available for the first ten years of operation.

³ Investment tax credit and accelerated depreciation may be limited to only a portion of total plant investment. In this plan the credits are assumed to apply to the entire investment.

⁴ Including waste heat energy recovery.

⁵ Denied if investment tax credit is taken (26 USC ¶ 48(c)(3)).

⁶ Tests regarding size, net thermal efficiency and percentage energy to electrical and non-electrical loads apply to CHP facilities (26 USC ¶ 48(c)(3)).

⁷ Qualifications apply.

⁸ This treatment is not entirely consistent with the treatment of state taxes. These also represent within-region income transfer. Omitting state taxes, however, would eliminate a fairly significant cost that is in-theory applicable to all resources.

Table I-4: Transmission lines to access remote resources

Line	Segments	Type	Capacity	Line Miles	Capital Cost (MM\$)	Losses
MT Wind to ID	Townsend, MT - Midpoint, ID (MSTI)	Sgl ckt 500kV AC	1500 MW	415	1100	4.2%
MT Wind to OR/WA	Townsend, MT - Midpoint, ID (MSTI) Midpoint, ID - Hemmingway, ID (Gateway W. Seg 8) Hemmingway, ID - Boardman, OR (B2H)	Sgl ckt 500kV AC	1500 MW	844	2200	6.5%
AB Wind to OR/WA	Milo, AB - Grass Valley, OR (Northern Lights HVDC)	Sgl ckt +/- 500kV DC	2000 MW	615	1900	4.3%
NV Solar to ID	White R. Valley, NV - Thirtymile, NV (No proposal) Thirtymile, NV - Midpoint, ID (SWIP N.)	Sgl ckt 500kV AC	1500 MW	370	1000	4.0%
NV Solar to OR/WA	White R. Valley, NV - Thirtymile, NV (No proposal) Thirtymile, NV - Midpoint, ID (SWIP N.) Midpoint, ID - Hemmingway, ID (Gateway W. Seg 8) Hemmingway, ID - Boardman, OR (B2H)	Sgl ckt 500kV AC	1500 MW	800	2100	6.5%
WY Wind to ID	Aeolus, WY - Creston (Gateway W. Seg 2) Creston - Bridger (Gateway W. Seg 3) Bridger, WY - Populus, ID (Gateway W. Seg 4) Populus - Cedar Hill, ID (Gateway W. Seg 7)	Sgl ckt 500kV AC	1500 MW	470	1300	4.5%
WY Wind to OR/WA	Aeolus, WY - Creston (Gateway W. Seg 2) Creston - Bridger (Gateway W. Seg 3) Bridger, WY - Populus, ID (Gateway W. Seg 4) Populus - Cedar Hill (Gateway W. Seg 7) Cedar Hill - Hemmingway (Gateway W. Seg 9) Hemmingway, ID - Boardman, OR (B2H line)	Sgl ckt 500kV AC	1500 MW	930	2400	7.0%

Integration Cost for Variable Resources

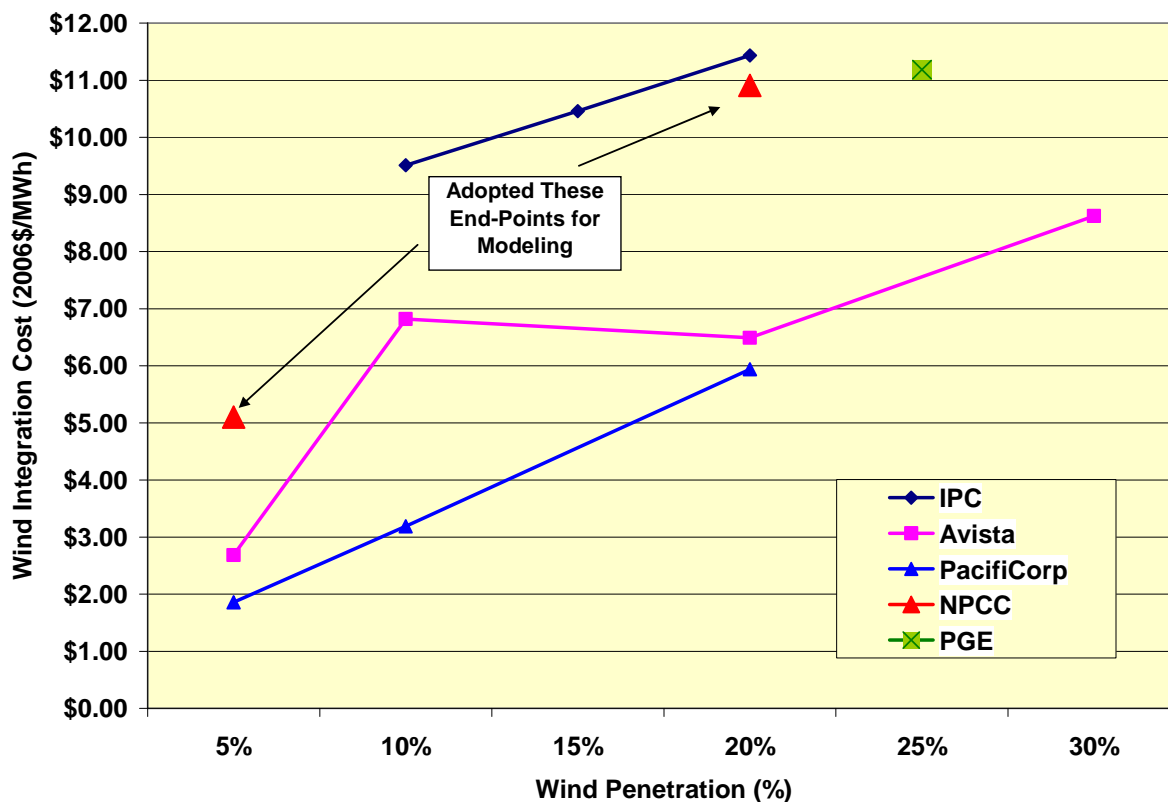
Balancing services (regulation and sub-hourly load-following) for integration of variable output renewable resources such as wind and solar are provided by reserving generating capacity for up-regulation (“up-reg”) and for down-regulation (“down-reg”). Up-regulation capability is the ability to increase generation to offset unforecasted loss of variable resource output. Down-regulation is the ability to reduce generation to offset unforecasted increases in variable resource output. Unless the variable resource is not operating, or is operating at full output, up-regulation and down-regulation must be provided simultaneously.

The provision of balancing services incurs cost because of foregone revenues or savings. Reserving capacity for up-regulation incurs foregone revenue that would have been received if the reserved capacity could have been profitably dispatched into the market. Reserving capacity for down-regulation incurs cost if the variable cost of the reserved capacity is greater than the market value of power. For these reasons, the cost of providing balancing services is sensitive to the wholesale value of power and the resource used to provide the services. Moreover, the cost of providing balancing services is a function of the penetration of installed variable resource capacity compared to peak load.

Only capacity that which is technically and environmentally capable of rapidly responding to changes in load (flexible capacity) is suitable for providing balancing services. Hydro capacity, though technically extremely flexible and frequently used to provide balancing services, can result in consumption of water, a limited energy source, during periods of low market value. An optimal balancing resource is technically and environmentally capable of flexible operation and has variable operating costs close to the market value of power.

The cost of providing balancing services is best estimated with a system impact study where the costs of operating the system with and without a given amount of variable resources are compared. This type of analysis was not performed for estimating regional variable resource integration costs because of time and modeling considerations. Rather, an approximate relationship of within-hour balancing costs to wind penetration was subjectively developed from wind integration studies undertaken by various regional utilities (Figure I-2).

Figure I-2: Wind integration cost estimates as a function of wind penetration from various wind integration studies



The lower end-point of the proposed regional cost curve represents a cost of about \$5.00 per MWh at 2% penetration (currently about 500 MW). The upper end-point represents a cost of \$10.90 at 17% system penetration (currently about 6000 MW). For purposes of the initial resource assessment, wholesale price forecasts and resource portfolio model development, penetration (and therefore integration cost) was assumed to be a linear function of time. The forecast was rebased for the 2010 - 2029 planning period based on an estimated installed regional wind capacity through 2009 of 11%. This yields a 2010 integration cost of \$8.85/MWh. The upper end of the integration cost curve (\$10.90/MWh) was assumed to be reached in 2024, and run flat in real terms thereafter (Table I-5). Because the variable resource penetration rate and final penetration level resulting from the final resource portfolio may differ from these assumptions, this curve will be revisited prior to release of the final plan.

Table I-5: Forecast regulation and load-following cost and CO₂ allowance prices

	Regulation and Load-following (\$/MWh)	CO ₂ Allowance Costs (\$/tonCO ₂)
2010	\$8.85	\$0.00
2011	\$8.99	\$0.00
2012	\$9.14	\$8.05
2013	\$9.29	\$10.39
2014	\$9.43	\$13.00
2015	\$9.58	\$15.14
2016	\$9.73	\$16.93
2017	\$9.87	\$19.15
2018	\$10.02	\$21.70
2019	\$10.17	\$24.23
2020	\$10.31	\$26.76
2021	\$10.46	\$29.15
2022	\$10.61	\$31.79
2023	\$10.75	\$34.59
2024	\$10.90	\$36.85
2025	\$10.90	\$39.32
2026	\$10.90	\$41.23
2027	\$10.90	\$43.29
2028	\$10.90	\$45.67
2029	\$10.90	\$46.72

Carbon Dioxide Allowance Prices

A deterministic forecast of CO₂ allowance (or equivalent tax) prices is used for estimating the levelized electricity costs of fossil fuel resources for broad comparisons among resource alternatives. This series is also used in the AURORA^{xmp}® model for forecasting wholesale power prices. Future carbon dioxide allowance prices are modeled as an uncertain variable in the Regional Portfolio Model (RPM), as described in Chapter 8. The deterministic forecast of CO₂ allowance prices (Table I-GEN-3) is the mean value of the probability distribution initially proposed for the RPM in late 2008. In response to comments from the Council’s Generating Resources Advisory Committee, that proposed distribution was subsequently modified to move forward the year of 50% probability of some CO₂ allowance price. However, the deterministic time series used for MicroFin and AURORA^{xmp}® studies was not updated to reflect the modified probability distribution. As a result, the values shown in Table I-GEN-3 for the mid-term period are slightly lower than the mean of the values used in the RPM for the draft plan. The difference is slight and is unlikely to significantly affect resource decisions. The forecasts will be reconciled for the final plan.

Carbon Dioxide Sequestration

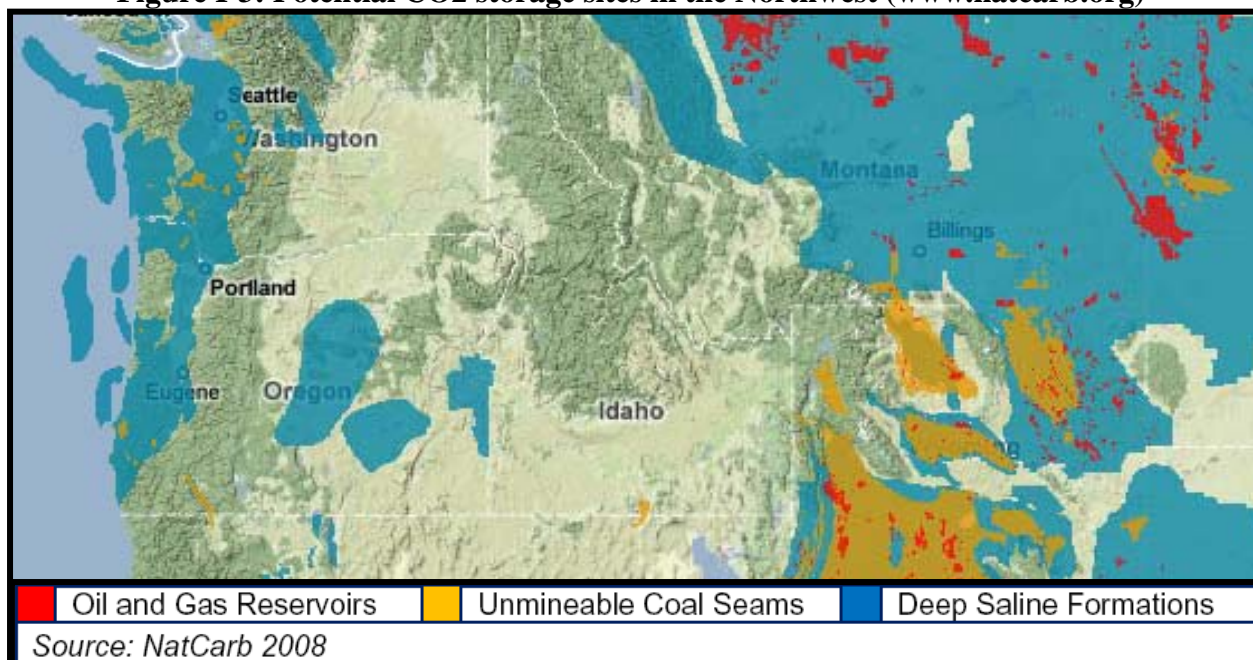
Numerous possibilities exist for isolating carbon dioxide produced by fossil fuel combustion from the atmosphere for long periods of time. The CO₂ from coal-fired power generating facilities is an attractive target for sequestration because power plants are large stationary point sources of CO₂, and many plants are located within a feasible transportation distance from potential sequestration sites.

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan
Proposals for long-term storage of CO₂ from power plant operation include deep oceanic injection and several geologic mechanisms. The general concept is to separate CO₂ at the power plant into a relatively pure form, compress the CO₂ to a liquid state and transport the liquid to the sequestration facility by pipeline for injection. The pipeline operating pressure would be sufficient for injection without further compression at the sequestration facility.

Oceanic CO₂ injection, though feasible, is controversial because of potential impacts on the ocean environment and marine life. Pilot projects in Hawaii and Norway have been cancelled as a result. Certain marine treaties now prohibit storage of CO₂ in the water column or seabed (IEA, 2008a). Geologic sequestration options with Northwest potential are described below. The following discussion is compiled from EcoSecurities (2008), IEA (2004), IEA (2008a) and the Big Sky Carbon Sequestration Partnership (<http://www.bigskyco2.org>).

CO₂-enhanced oil recovery: Carbon dioxide enhanced oil recovery (CO₂-EOR) is an established process whereby CO₂ is injected into oil fields to enhance recovery of remaining oil. The CO₂ repressurizes the reservoir and promotes release of remaining oil through viscosity reduction and other means. CO₂-EOR has been in commercial use for about three decades and about 3% of current world oil production is recovered using this technology. CO₂ sequestration is incidental to current CO₂-EOR operations, the objective of which is profitably recovering oil. EOR operations undertaken for the purpose of CO₂ sequestration would not necessarily operate at a profit though the value of the recovered oil would help offset overall costs. An added complexity of a sequestration operation is the need to ensure long-term reservoir integrity. While natural gas and oil reservoirs are inherently of great integrity, developed fields are punctured with wells, that if improperly plugged, could release sequestered CO₂. It is believed that enhanced oil recovery using CO₂ could eventually be applied to most oil fields, though the CO₂ sequestration capacity of depleted oil fields is relatively small compared to CO₂ production from power generation facilities. Scattered oilfields are found in eastern Montana (Figure I-3) and additional opportunities in Alberta, Wyoming and the Dakotas may be within feasible CO₂ transportation distance.

CO₂-enhanced natural gas recovery: Carbon dioxide enhanced natural gas recovery (CO₂-EGR) is a method of augmenting natural gas recovery and of reducing drawdown-related subsidence by repressurizing depleted natural gas fields. CO₂ is denser and more viscous than methane at reservoir conditions so the remaining methane tends to float above the injected CO₂. Methane withdrawal would continue until excessively diluted with CO₂ breaking through the overlying methane layer. A commercial-scale EGR demonstration project is underway in the North Sea, however the technology is not fully developed. As with CO₂-EOR, a major issue is ensuring long-term reservoir integrity. Though the CO₂ sequestration potential of EGR might be larger than that of EOR, the economics are less favorable because of the lower revenue from the recovered methane per ton of injected CO₂.

Figure I-3: Potential CO₂ storage sites in the Northwest (www.natcarb.org)

Depleted oil or gas fields: Carbon dioxide could be sequestered in depleted oil or gas fields using CO₂-EGR injection technology. The global theoretical potential for sequestering CO₂ in depleted oil and gas fields is of the same order of magnitude as for CO₂-EGR. Similar issues regarding resource integrity would be present and net cost would be higher because of the absence of byproduct oil or gas. Existing production wells could be repurposed for CO₂ injection.

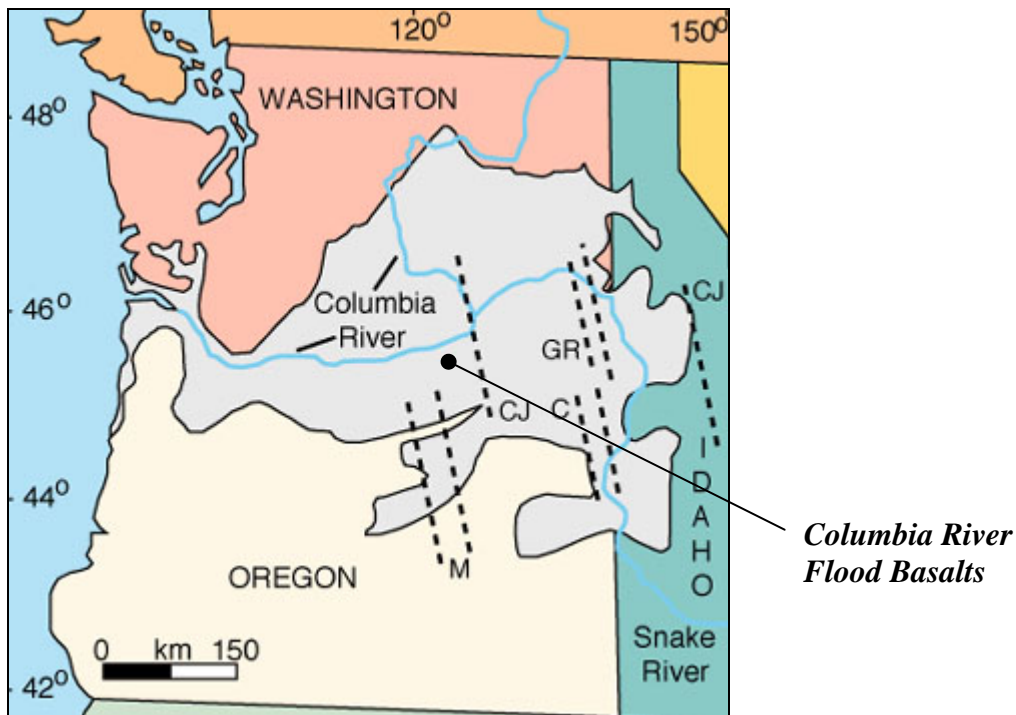
CO₂-enhanced coal bed methane recovery (ECBM): Coal beds typically contain large amounts of methane-rich gas adsorbed to the coal. Because carbon dioxide is preferentially adsorbed to coal, injection of CO₂ into deep unmineable coal seams could sequester the CO₂ and produce methane as a marketable product. CO₂ is physically adsorbed to the coal, increasing confidence in long-term storage integrity. Coal measures potentially offering ECBM potential are scattered within the four states and a substantial area of potential is present in Wyoming (Figure I-3). The effectiveness and economic feasibility of enhanced coal bed methane recovery using CO₂ injection is promising but yet to be fully demonstrated.

Deep saline aquifers: Deep saline aquifers consisting of porous rocks saturated with brine are found throughout the world, many located in the same sedimentary basins from which coal and other fossil fuels are extracted. The brines are of high salt content and typically unsuitable for agricultural use or human consumption. If confined by underlying and overlying layers of restricted permeability these formations may be suitable for long-term storage of very large quantities of CO₂. Though initially accumulating under the cap rock, the injected CO₂ is expected to eventually dissolve in the brine, promoting secure long-term storage. Deep saline formations are located below the coalfields of eastern Montana and between the Cascades and the coast (Figure I-3). The technical feasibility of CO₂ storage in deep saline aquifers has been demonstrated in the North Sea. Remaining questions relate to the amount of CO₂ that can be

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan injected into a given aquifer volume, the long-term expansion and migration of the CO₂ plume and the geochemical reactions expected to occur over time.

Flood basalt formations: The Columbia River flood basalts and possibly other basalt formations present a potential CO₂ sequestration option of particular interest to the Northwest. Flood basalts consisting of several hundred individual flows, each tens to hundreds of feet in thickness cover the central Columbia Basin and extend to the Pacific along the course of the Columbia River (Figure I-4). Many of the individual flows consist of a fractured and highly porous upper layer and a dense impermeable lower layer. Carbon dioxide could be stored in the porous upper layer, trapped between the dense lower layers of the same flow and the adjacent overlying flow. Preliminary experiments indicate that carbon dioxide would be rapidly converted to solid carbonaceous minerals in the basaltic environment, ensuring permanent storage.

Figure I-4: Columbia River Flood basalts (Oregon State University)



The U.S. DOE Regional Carbon Sequestration Partnerships and the National Carbon Sequestration Database and Geographical Information System are assessing the potential for carbon sequestration for individual U.S. states and Canadian provinces. Results are published and periodically updated in the *Carbon Sequestration Atlas of the United States and Canada* (USDOE, 2008). The top section of Table I-6 shows the current estimates of technical sequestration potential for the four Northwest states for three types of formations potentially suitable for CO₂ sequestration. The values in this section are from the *Carbon Sequestration Atlas*. To provide perspective regarding this potential, the lower section of the table expresses the technical potential in terms of the number of years of CO₂ storage potential at the estimated CO₂

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan
 production rate from Northwest coal-fired power plants in 2005. Practical storage potential is likely to be much less than the theoretical potential. This suggests that though sequestration in oil and gas reservoirs and unmineable coal seams is, in general, technically more advanced than sequestration in deep saline formations, and moreover, may yield marketable oil or gas to help offset sequestration costs, deep saline formations appear to be the principal candidate for sequestration of significant amounts of CO₂ over the long-term.

Table I-6: Theoretical storage potential of several Northwest CO₂ sequestration options

	Oil and Gas Reservoirs	Unmineable Coal Seams	Deep Saline Formations
<i>Technical Potential (MM tonsCO₂)</i>			
ID	0	Not reported	Not reported
MT	1388	322	291,948 -1,087,714
OR	0	Not reported	18,400 - 73,600
WA	0	3080-3395	99,270 -397,077
Total	1388	3402	409,617 -1,558,391
<i>Technical Potential (Years @ 2005 CO₂ production rate)</i>			
ID	0	--	--
MT	28	7	6000 - 22,000
OR	0	--	400 - 1500
WA	0	63 - 69	2000 - 8,000
Total	28	70 - 76	8300 - 32,000

The overall cost of carbon dioxide separation and sequestration includes the incremental capital and operating costs of the power plant facilities for separation and compression of CO₂, including the effects of additional electrical and steam loads on plant heat rate; the capital and operating costs of transporting the compressed, liquefied CO₂; and the capital and operating costs of the sequestration facility including long-term monitoring of reservoir integrity. The incremental costs and heat rate penalty for power plants with CO₂ separation are included in the description of the reference coal-fired power plants in the Assumptions for Reference Plants section of this Appendix.

The estimated cost of transporting CO₂ from power plant to sequestration facility ranges from \$1 - 8/tonne CO₂ (0.90 - \$7.20/ton) (EcoSecurities, 2008). The estimated cost of sequestering CO₂ in depleted oil fields ranges from \$0.50 - 4.00/tonne CO₂ (\$0.45 - \$3.30/ton) and in depleted gas fields from \$0.50 - 12.00/tonne CO₂ (\$0.45 - \$10.90/ton) (EcoSecurities, 2008). Storage in deep saline aquifers is estimated to cost from \$0.40 - 4.50/tonne CO₂ (\$0.36 - \$4.10/ton) (EcoSecurities, 2008).

For purposes of this plan, CO₂ transportation costs are assumed to average \$4.00/ton CO₂ - an approximation of the \$1 - 8/tonne CO₂ range cited in EcoSecurities (2008). CO₂ transportation is a mature technology and current cost estimates should be a reliable indicator of actual future costs. While appealing because of the potential revenue from recovered oil and gas, any serious attempt to reduce atmospheric releases of CO₂ would appear to quickly overwhelm the available capacity of partially depleted oil or gas fields in the Northwest. Sequestration in deep saline formations currently appears to be the most promising candidate for large-scale sequestration in the Northwest. The concept is in the early stages of development, however, and experience with developing technologies suggests that costs are bound to rise much higher than current estimates as the concept is commercialized. For this reason, for this plan the Council assumes CO₂ sequestration costs average \$22.50/ton CO₂, the high end of the \$15 - 25/tonne CO₂ overall North American cost range cited in IEA (2008a).

A commercial-scale deep saline sequestration facility in the Northwest is assumed to be available for operation no earlier than 2023. Given the research, development and demonstration needed to resolve remaining technical issues, the legal and institutional questions needing resolution and the development and construction time required for a commercial-scale CO₂ sequestration facility and transportation pipelines, such a facility may not be feasible within the planning period.

ASSUMPTIONS FOR REFERENCE PLANTS

Landfill Gas

A landfill gas energy recovery plant uses the methane content of the gas produced as a result of the decomposition of landfill contents to generate electric power. The complete recovery system includes an array of collection wells, collection piping, gas cleanup equipment and one or more generator sets, usually using reciprocating engines. Typically, the gas collection system is installed as a requirement of landfill operation and the raw gas sold to the operator of the power plant.

Reference Plant: The reference plant consists of two 1.6 MW reciprocating engine generating unit fuelled by landfill gas. The scope includes gas processing equipment, engine-generator sets, powerhouse and maintenance structure and power generation site infrastructure.

Availability Parameters: Plant availability parameters are as follows:

Scheduled maintenance - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

Equivalent annual availability - 88%

Capacity Factor: Landfill gas energy recovery plants are assumed to operate at an annual capacity factor of 85%, based on CEC (2007).

Unit Commitment Parameters: Landfill gas energy recovery plants operate as must-run units.

Heat rate: The heat rate of the reference plant is 10060 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

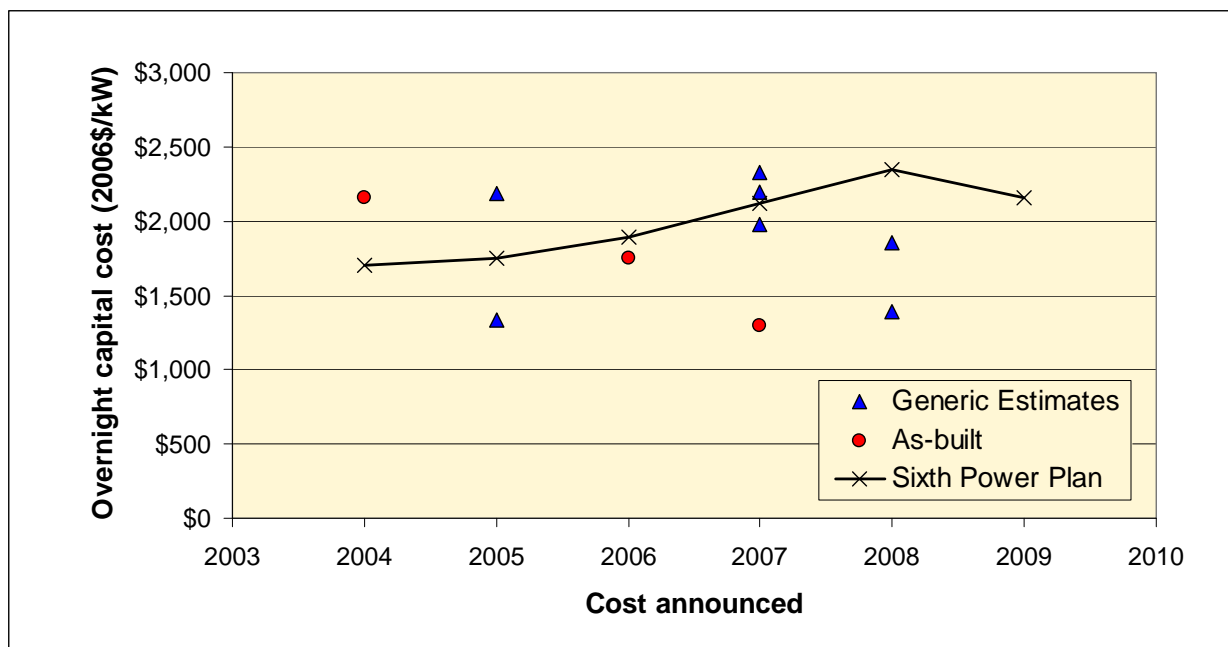
$$\text{Heat Rate (HHV)} = 10159x^{-0.0555}$$

Where x is the plant capacity in megawatts

Total Plant Cost: The “overnight” total plant cost of the reference plant is \$2350/kW installed capacity (2008 price year). This estimate is based on reported costs for three as-built plants. Four generic estimates of landfill plant development costs were also obtained. Three of these were range estimates consisting of low and high bound costs. These cost observations, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-5. The increase in capital costs from 2004 to 2008, clearly observed for most power generation technologies is not clearly evident here, particularly for the reported as-built costs. A possible reason may be that the built projects were of substantially different scopes (e.g., with or without the gas collection system) not reported. For this reason, the representative project cost estimate was based on a projection of the 2005 and 2007 generic costs cost, which together with the 2006 actual project cost seem to reasonably track observed power plant cost escalation during this period. Because landfill gas energy recovery projects were not modeled in the Regional Portfolio Model, capital cost uncertainty was not estimated.

The projected Total Plant Cost for landfill gas energy recovery plants is based on the forecast future cost of reciprocating engine generating plants. See Table I-1.

Figure I-5: Published costs of landfill gas energy recovery projects normalized to total plant costs



Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan
Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for a landfill gas energy recovery plant are those assumed for reciprocating engine power plants:

Development (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 18 mo., 3% of total plant cost

Early Construction (Final engineering, major equipment order, site preparation) - 9 mo., 9% of total plant cost

Committed Construction (Delivery of major equipment, completion of construction and testing) - 6 mo., 88% of total plant cost

Fuel Cost: A typical business arrangement is for the power plant operator to purchase the raw landfill gas from the landfill operator. The landfill operator is responsible for installing and operating the wellfield and collection system. The published sources of information regarding landfill gas prices suggest a wide range. Lazard (2008) reports landfill gas fuel costs ranging from \$1.50 to \$3.00/MMBtu. The Idaho Statesman reports that Ada County collects \$0.89/MMBtu plus 40% of REC and PTC credits for the Ada County Landfill Waste-to Energy plant. The effective fuel price (fuel plus 40% of the value of incentives) for the Ada plant 2007 was \$1.50/MMBtu. Because the Ada price lies at the low end of the range reported by Lazard, a somewhat higher expected price, \$2.00/MMBtu, is used for this plan is - higher than Ada county but towards the low end of the Lazard range.

Operating and maintenance costs: Operating and maintenance costs for landfill gas energy recovery plants were based on California Energy Commission estimates. The CEC estimates are consistent with other available estimates of the O&M costs of these plants when adjusted to comparable year dollars. Moreover, the CEC O&M costs are broken into fixed and variable components and exclude property tax and insurance, consistent with the Council's representative resource costs. Fixed O&M cost for landfill gas energy recovery (\$26/kW/yr) is estimated to be 1.1% of the overnight capital cost described above. The 1.1% is based on the ratio of fixed O&M cost to overnight cost of Appendix B ("Economic Assumptions: Landfill Gas Fuel to Energy") of CEC (2007). The variable O&M cost (\$19/MWh) was derived in a similar manner as 0.8% of total plant cost.

Economic Life: The economic lifetime of a landfill gas energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator and the productive life of a typical landfill.

Development potential: The remaining feasible development potential for landfill gas energy recovery facilities was derived from the U.S. EPA Landfill Methane Outreach Program database of candidate landfills for energy recovery⁹. EPA estimates of waste-in-place in candidate landfills in the four Northwest states were converted to estimated electricity production potential using values for gas generation potential and fuel energy content. From an assessment of landfill energy recovery potential in Oregon prepared for the Energy Trust of Oregon (ETO, 2005). The reference plant heat rate of 10,060 Btu/kWh was substituted for the more optimistic heat rate of 9000 Btu/kWh used in ETO study. This yielded a remaining undeveloped electric energy

⁹ <http://www.epa.gov/lmop/proj/index.htm>

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan potential of 69 average megawatts (Table I-7). This estimate should be viewed as having considerable uncertainty. On one hand, emplaced waste will continue to increase during the planning period, even with aggressive reuse and recycling programs. On the other, the competing alternative of direct injection of landfill-derived gas into the natural gas system is less expensive than on-site generation of electric power.

Table I-7: Derivation of estimated undeveloped landfill gas energy recovery potential

	Waste in-place (tons)	Gas Generation Potential (MMscf/yr)	Fuel Energy (TBtu/yr)	Electric Energy (MWh/yr)	Developable Potential (MWa)
Idaho	2,000,000	400	0.18	17893	2
Montana	16,956,766	3391	1.53	151701	17
Oregon	25,022,845	5005	2.25	223862	26
Washington	23,656,412	4731	2.13	211638	24
Totals	67636023	13527	6.09	605094	69

Animal Waste Energy Recovery

The energy value of certain agricultural and food wastes can be recovered by processing the waste materials in anaerobic digesters. This yields a combustible gas that be used to fuel a thermal electric power generator. Reciprocating engine-generator sets are typically used for the power production. The most widely employed anaerobic digestion technology at present, uses animal manure in liquid or slurry form. The principal source of suitable feedstock is from manure handling systems at large concentrated animal feeding operations (CAFOs).

Reference Plant: The reference plant consists of a plug flow anaerobic digester supplied by liquid or slurry manure handling system at a large (500 head, or larger) CAFO dairy. The digester produces a low-Btu methane rich-gas that supplies an 850 kW reciprocating engine generating unit. Reject heat is recovered from the engine to maintain digester operating temperatures.

Availability: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

Equivalent annual availability - 88%

Unit Commitment Parameters: Animal waste energy recovery plants operate as must-run units.

Capacity Factor: Animal waste energy recovery plants are assumed to operate at an annual capacity factor of 75%, based on CEC (2007).

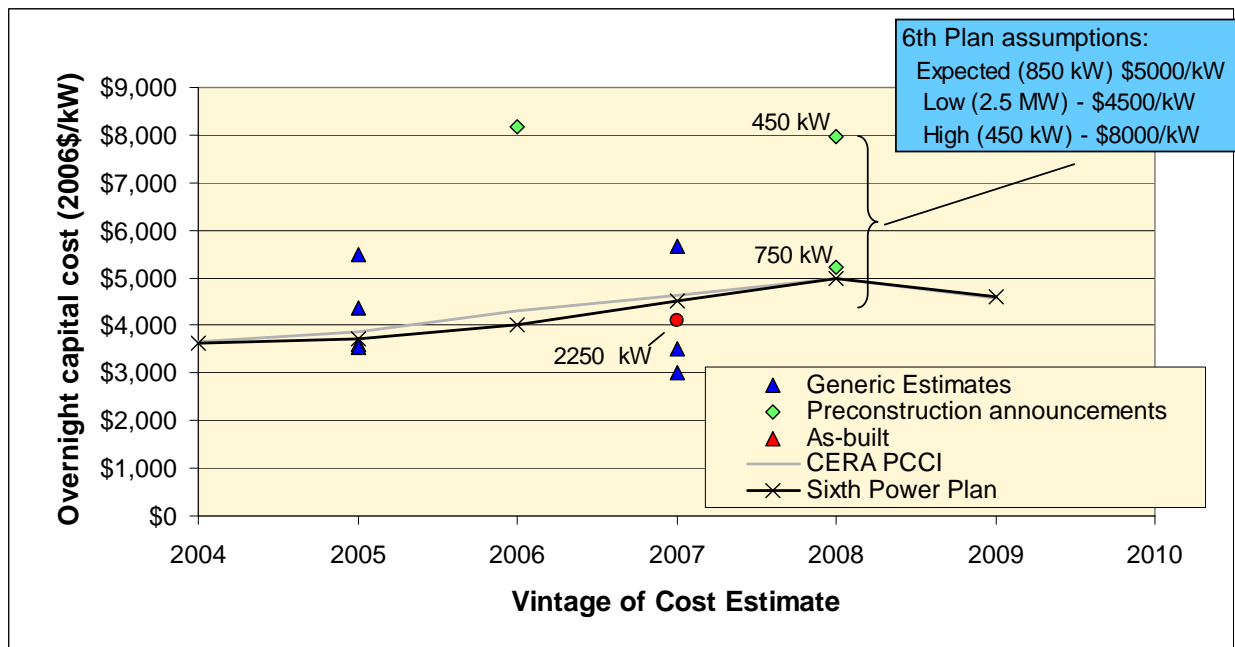
Heat rate: The heat rate of the reference plant is 10250 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

Where x is the plant capacity in megawatts

Total Plant Cost: The “overnight” total plant cost of the reference plant is \$5000/kW installed capacity (2008 price year). This estimate is based on reported costs for 3 proposed and one completed plants and generic estimates from three sources. One of the generic sources provided a range estimate consisting of low and high bound costs and a second included estimates for a range of plant sizes. These observations were normalized as described in the Capital Cost Analysis subsection of this Appendix, and are plotted by vintage in Figure I-6. If the one 2006 extreme outlier is omitted, the distribution, though based on a limited sample size, is reasonably satisfying, with a wide range appearing to be primarily driven by installed capacity and to a lesser extent by the increased cost of manure handling facilities for joint plants serving several farms compared to on-farm plants. Costs rise increasingly rapidly as plant capacity declines. \$5000/kW was chosen as the 2008 values for the reference (850 kW) plant with a range of \$4500/kW for larger units (1 - 3 MW) and \$8000 for smaller units (400 - 500kW). This resulting distribution is consistent with the general increase in power plant costs observed from 2004 through 2008 (represented by the CERA PCCI curve), the 2005 generic estimates (ETO, 2005) and the reported cost of the one completed plant from the sample (Bettencourt Dry Creek Dairy in Idaho).

The projected Total Plant Cost for is based on the forecast future cost index for reciprocating engine generating plants. See Table I-1.

Figure I-6: Published costs of animal manure energy recovery projects normalized to total plant costs



Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan
Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for an animal manure energy recovery plant are as follows:

Development (Feasibility study, permitting, engineering) - 12 mo., 3% of total plant cost

Construction (Equipment order, site preparation, delivery of equipment, completion of construction and testing) - 12 mo., 98% of total plant cost

Fuel Cost: Anaerobic digesters and associated power generation equipment serve as a solution to the challenging problem of disposing of large quantities of animal waste from large concentrated feeding operations. The value of the raw manure/fuel is assumed to be zero for this analysis. Depending on specific circumstances the raw manure might be considered to have a negative value.

Operating and Maintenance Cost: Fixed O&M cost for animal waste energy recovery is taken as 0.9% of capital cost, based on Table 6 (“AD Dairy”) of CEC (2007). This yields \$72/kW/yr for small (450 kW) facilities, \$45/kW/yr for mid-range (850 kW) facilities and \$41/kW/yr for large (2.5 MW) facilities.

Variable O&M cost for animal waste energy recovery is taken as 0.3% of capital cost, based on Table 6 (“AD Dairy”) of CEC (2007). This yields \$24/MWh for small facilities, \$15/kW/yr for mid-range facilities and \$14/kW/yr for large facilities.

Economic Life: The economic life of an animal waste energy recovery plant is assumed to be 15 years.

Development potential: The remaining feasible development potential for animal manure energy recovery facilities at dairy operations in the Northwest is estimated to be 61 MWa with a possible range of 51 to 108 MWa. The derivation of this estimate is shown in Table I-8. Potentially feasible operations and mature head are reported by EPA for the top ten states, including Idaho and Washington. These are operations of 500 head, or more and employing slurry or liquid manure handling systems. The Oregon data are from ETO, 2005, and are based on dairy farms of 500 head or more. The Oregon estimates do not appear to have been screened for use of slurry or liquid manure handling systems, so may be high. The expected energy production potential was estimated from head count using the 3 kWh per mature head per day, described as “realistic” in (ETO, 2005). The low end of the range is based on the value of 2.6 kWh/head-day assumed in EPA¹⁰ and the high end was based on “optimistic” 5 kWh/head-day of ETO (2005).

¹⁰ 38.5 ft³ methane per cow-day using plug flow digesters (EPA, p.31) x 66 kWh/1000 ft³ methane (EPA, p.32).

Table I-8: Derivation of estimated undeveloped animal manure energy recovery potential

	Feasible Operations	Mature Head at Feasible Operations (000)	Electric Generation Potential (MWa)	Operating and Committed Generation (MWa)	Developable Potential (MWa)
Idaho ¹¹	185	285	36	7.9	29
Montana ¹²	--	--	--	--	--
Oregon ¹³	32	114	14	0.5	14
Washington ¹¹	122	135	17	2.9	14
Totals	339	534	67	11.3	57

Wastewater Treatment Plant Energy Recovery

Sludge collected in the clarification stage of wastewater treatment is commonly processed to remove volatile organic materials in anaerobic digesters. Anaerobic digestion produces a low-Btu gas consisting largely of methane and carbon-dioxide. This gas can be treated to remove moisture, siloxanes, hydrogen sulfide and other impurities and used to fuel a electric generating plant. Reject heat from the engine is used to maintain optimum digester temperature.

Reference Plant: The reference plant is an 850-kilowatt reciprocating engine generating unit fuelled by gas from the anaerobic digestors of a wastewater treatment plant. Reject engine heat is captured and used to maintain optimal digester temperatures. The estimated capital cost of the installation includes engine-generator, gas processing equipment, heat recovery equipment, interconnection equipment and associated infrastructure. The anaerobic digestors are assumed to be present.

Availability: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

Equivalent annual availability - 88%

Unit Commitment Parameters: Animal waste energy recovery plants operate as must-run units.

Capacity Factor: Wastewater treatment plant energy recovery systems are assumed to operate at an annual capacity factor of 85%, based on CEC (2007)

Heat rate: The heat rate of the reference plant is 10250 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

$$\text{Heat Rate (HHV)} = 10159x^{-0.0555}$$

¹¹ U.S. Environmental Protection Agency (Undated)

¹² No estimates were located for Montana. The number of large confined dairy operations in Montana is thought to be small.

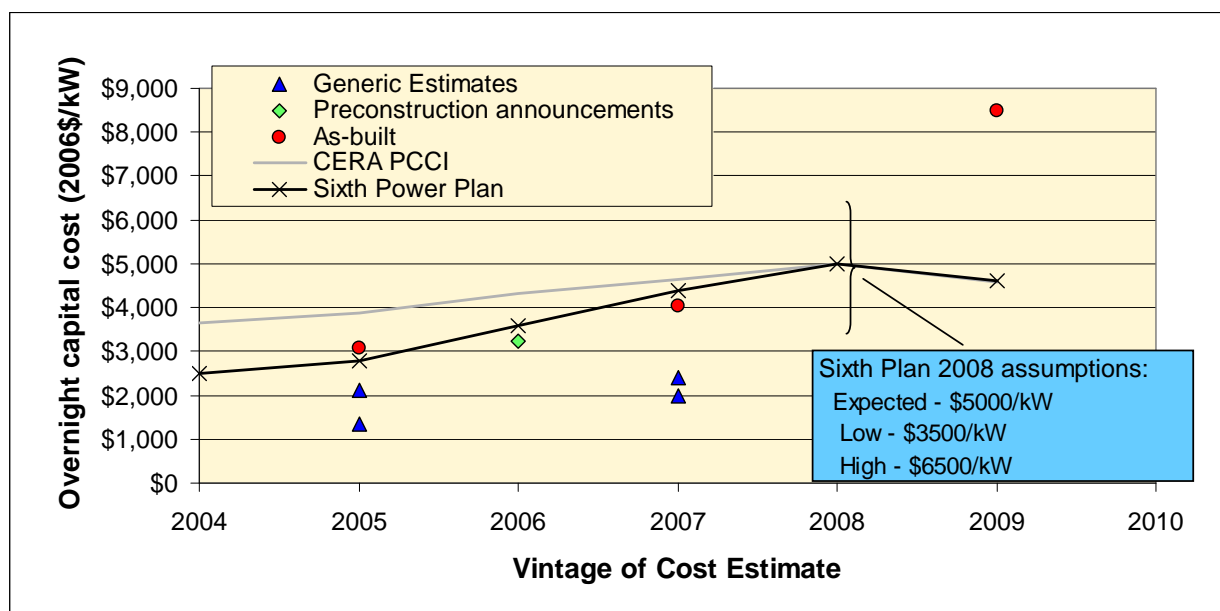
¹³ Energy Trust of Oregon (2005)

Where x is the plant capacity in megawatts

Total Plant Cost: The “overnight” total plant cost of the reference plant is \$5000/kW installed capacity (2008 price year). This estimate is based on reported costs for one proposed and two completed plants (a preconstruction and an as-built estimate is available for one of the latter). Generic estimates were obtained from three sources. One of the generic sources provided a range estimate consisting of low and high bound costs. These observations were normalized as described in the Capital Cost Analysis subsection of this Appendix, and are plotted by vintage in Figure I-7. The normalized preconstruction and as-built costs show much higher costs than do the generic estimates and much stronger escalation than do the generic costs or CERA Power Capital Cost Index. Because the underlying cost and plant configuration information is considered reliable and representative, the as-built and preconstruction estimates for 2005, 2006 and 2007 guided the development of the Sixth Power Plan 2004-09 values. The scope of the 2009 project is believed to be more extensive than a typical project hence the much higher cost. The range of uncertainty is +/- 30% of the reference 2008 cost, consistent with a “simplified” to “preliminary” quality estimate.

The projected Total Plant Cost (Table I-1) is based on the forecast future cost index for reciprocating engines.

Figure I-7: Published costs of wastewater treatment plant energy recovery projects normalized to total plant costs



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for a wastewater treatment plant energy recovery plant are those assumed for reciprocating engine power plants:

Development (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 18 mo., 3% of total plant cost

Early Construction (Final engineering, major equipment order, site preparation) - 9 mo., 9% of total plant cost

Committed Construction (Delivery of major equipment, completion of construction and testing) - 6 mo., 88% of total plant cost

Fuel Cost: The reference plant is applicable to a wastewater treatment facility already containing anaerobic sludge digesters and associated gas collection system. The fuel is therefore assumed to be free.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance for wastewater treatment plant energy recovery (\$32/kW/yr) is taken as 0.8% of capital cost, based on Table 6 (“Biomass - WWTP”) of CEC (2007). Variable O&M (\$24/MWh) is taken as 0.6% of capital cost, based on Table 6 (“Biomass - WWTP”) of CEC (2007).

Economic Life: The economic life of a wastewater treatment energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator.

Development potential: The remaining development potential for wastewater treatment energy recovery facilities in the Northwest is estimated to be about 12 MWa. This estimate is based on reported influent flow at waste treatment facilities in the four states that receive at least 5 MMgpd. (Appendix B of EPA, 2007). Total potential generation was calculated assuming production of 650 Btu/scf digester gas at a rate of 10,000 scf gas per MMgpd influent and energy conversion at a heat rate of 10,250 Btu/kWh. This yielded a total potential (developed and undeveloped) of 21 MWa, including the energy output of several facilities with operating generation not reported in EPA, 2007. Currently installed capacity at Northwest treatment facilities is capable of producing about 9 MWa. This was deducted from the total potential to yield the 12 MWa of undeveloped potential. Several trends could increase this potential. Future population growth will likely increase total regional influent production. This will increase the potential at plants included in the inventory on which the estimate is based, and may increase the number of candidate facilities (facilities receiving at least 5 MMgpd of influent, on average, and facilities using anaerobic sludge treatment). Also, larger plants will tend to employ larger power generation units which tend to be more efficient. Advances in reciprocating engine and other potentially suitable generating technologies will increase plant heat rates and therefore, the generation potential, and may also enhance the feasibility of developing energy recovery facilities at smaller treatment plants. On the other hand, some treatment facilities may choose to sell treated biogas to natural gas companies for injection into the natural gas network. However, this use of biogas, though requiring less capital investment than electric power generation, seems less likely for treatment plants, because some biogas would need to be substituted for recovered generating plant reject heat to maintain digester temperatures.

Table I-9: Derivation of estimated undeveloped wastewater treatment plant energy recovery potential

[Table to be supplied]

Woody Residue Power Plant

[Portions of this section are yet to be completed]

A woody residue steam-electric power plant converts the chemical energy of woody biomass to electric energy. Conventional plants are based on steam-electric generating technology and range in size from several to about 50 megawatts. Fluidized-bed boilers are increasingly used to provide flexibility to combust a wide variety of fuels, improve combustion efficiency and to facilitate air quality control. Small-scale modular plants are under development that could be periodically relocated to “follow the fuel” and thereby lower fuel transportation costs. Wood-fired power plants are often located at wood product plants providing both a source of residue fuel and a cogeneration steam load.

Reference Plant: The reference plant is a 25 MW steam-electric generating unit fuelled by forest thinning and other sources of woody residue. The plant includes fuel receiving, processing and storage facilities, a fluidized bed boiler, steam turbine-generator wet mechanical draft condenser cooling towers, electrical interconnection, site and supporting infrastructure. Stand-alone and cogeneration cases are described.

Availability: Plant availability parameters are as follows:

Scheduled maintenance outages - 35 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 40 hours

Equivalent annual availability - 84%

Capacity Factor: Plants serving a cogeneration load are assumed to be must-run. The default capacity factor used for must-run units is 80%. The historical energy production of woody residue plants in the Northwest indicates that annual average capacity factors of 80% or better are readily achievable for newer units.

Heat rate: The heat rate of the stand-alone plant is 15,500 Btu/kWh. The electrical heat rate (fuel charged to power) of the cogeneration plant is

Unit Commitment Parameters: Woody residue plants are assumed to operate as must-run units.

Total Plant Cost:

Figure I-8: Published costs of woody residue power generation projects normalized to total plant costs

[Table to be supplied]

Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for a woody residue steam electric plant are as follows:

Development (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 24 mo., 2% of total plant cost

Early Construction (Final engineering, major equipment order, site preparation) - 12 mo., 47% of total plant cost

Committed Construction (Delivery of major equipment, completion of construction and testing) - 12 mo., 51% of total plant cost

Fuel Cost:

Operating and maintenance costs: Economic Life: The economic life of a stand-alone steam-electric plant fuelled by woody residue is assumed to be 20 years; limited by uncertainties regarding continued fuel supply availability.

Development potential:

Table I-10: Derivation of estimated undeveloped woody residue energy recovery potential

[Table to be supplied]

Geothermal

Reference Plant: The reference plant is a 40 megawatt (nominal) binary cycle plant comprised of three 13-megawatt (net) units. The plant is assumed to use closed loop organic Rankine cycle technology suitable for low geothermal fluid temperatures. The plant includes production and injection wells, geothermal fluid piping, power block, cooling towers, step-up transformers, switchgear and interconnection facilities and security, control and maintenance facilities. Wet cooling, resulting in higher plant efficiency, greater productivity and lower cost would likely be used at sites with sufficient water. Dry cooling could be employed at sites with insufficient cooling water availability, at additional cost and some sacrifice in efficiency and productivity.

Availability Parameters: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 6.4%

Mean time to repair - 40 hours

Equivalent annual availability - 90%

Capacity Factor: The average capacity factor over the life of the facility is assumed to be 90%.

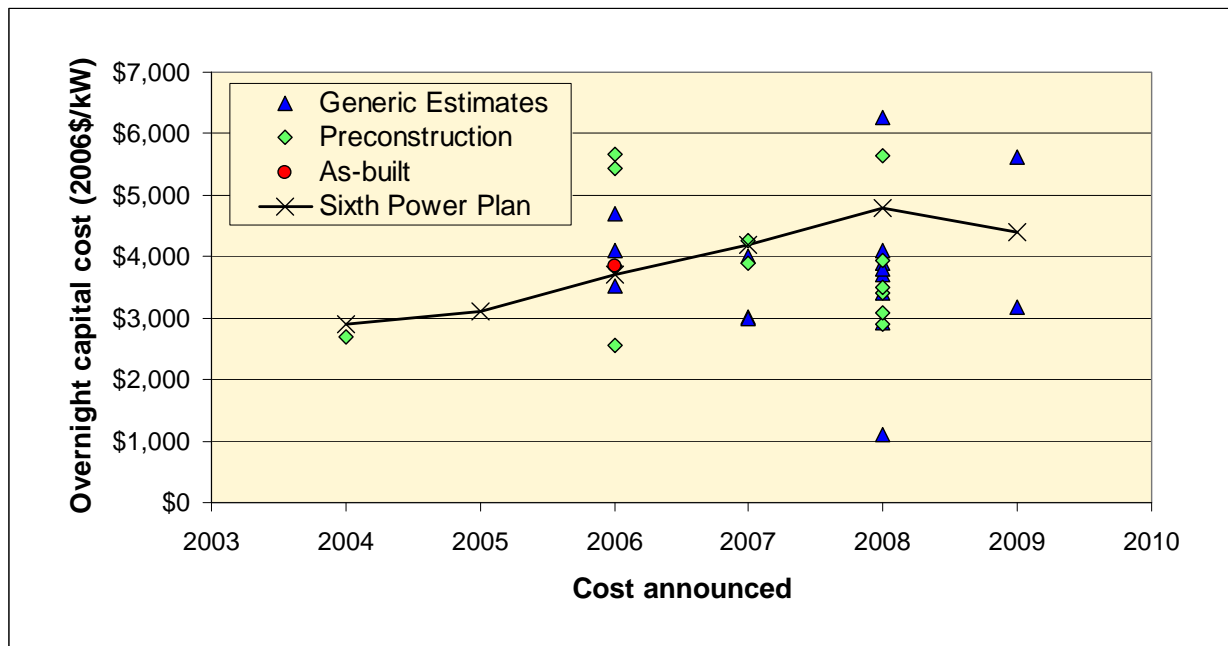
Heat Rate: The average annual full load heat rate is 28,500 Btu/kWh, typical of an ORC binary plant operating on 300°F geothermal fluid.

Unit Commitment Parameters: Geothermal plants are assumed to operate as must-run units.

Total Plant Cost: The “overnight” total plant cost of the reference geothermal plant is \$4800/kW installed capacity (2008 price year). This estimate is based on a sample of 1 as-built

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan plant costs and 12 published preconstruction estimates dating from 2004 through 2008 (including one preconstruction range estimate consisting of low and high bounded cost). Ten generic estimates of geothermal plant development costs were also obtained. Five of these were range estimates consisting of low and high bound costs and one included low, mid-range and high bound costs. Published costs, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-9. A wide range in capital cost is evident and the general increase in power plant construction costs from 2004 through mid-2008 is poorly defined. The reference plant cost estimate of \$4800/kW is based on a rough projection of average cost trends from 2004 through 2007 and lies on the high side of the 2008 cluster. The 2008 base year forecast does relate reasonably well to 2009 generic estimates (the 2009 estimates are a range estimate representing a low-temperature deep resource (high cost) and a higher temperature shallower resource (low cost)). The cost uncertainty range of -33% (\$3200) to +17% (\$5600) is based on the range of 2008 vintage costs excluding the two extreme outlying values.

Figure I-9: Published costs of binary geothermal projects normalized to total plant costs



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

Development (Site option to completion of exploration) - 36 mo., 10% of total plant cost

Early Construction (Wellfield confirmation and development) - 12 mo., 35% of total plant cost

Committed Construction (Powerplant, pipelines and infrastructure) - 24 mo., 55% of total plant cost

Operating and Maintenance Cost: Estimated operating and maintenance costs for the reference plant are \$175/kW/yr fixed plus \$4.50/MWh variable. This estimate is derived from eight

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan published sources containing estimates of geothermal plant operating and maintenance costs. Each source is associated with a capital cost estimate, allowing O&M costs to be estimated in terms of percentage of capital cost, a common approach. The O&M cost estimates were first adjusted to 2006 dollar values. Some estimates include both fixed and variable components, some are fixed only and others are in fully variable terms. Variable costs were converted to equivalent fixed values, assuming a 90% capacity factor. These were added to the fixed O&M component, if any, yielding total O&M cost in fixed terms, in 2006 year dollars. The resulting values were converted to percentages of total plant cost based on the associated normalized capital costs. This yielded an average value of 5% (omitting one extreme value associated with an unrepresentative low capital cost); \$210/kW/yr using the capital cost of the reference plant. Fixed and variable components were derived from this estimate by assuming the variable component to be \$4.50/MWh (the value from CEC, 2007). Deducting the fixed equivalent of \$4.50/MWh at 90% capacity factor from \$210/kW/yr yields the \$175/kW/yr fixed component.

Economic Life: The economic life of a geothermal plant is assumed to be 30 years; limited by wellfield viability and equipment life.

Development Potential: A recent U.S. Geological Survey assessment of moderate and high temperature hydrothermal resources¹⁴ yielded a mean total electricity generating potential with 95% confidence of 266 MWe¹⁵ of from currently identified resources and 1103 MWe from currently undiscovered resources within the four Northwest states for a total of 1369 aMW of energy potentially available with high confidence. However, factors including the limited development in the Northwest to date, the high frequency of dry holes encountered during earlier attempts to develop Northwest geothermal projects, siting resistance encountered in earlier efforts to develop Northwest geothermal resources, the high risk and long lead time associated with the confirmation of geothermal resources and the relatively few sites currently under development all suggest that the Northwest resource potential during the period of this plan will be limited by development rate rather than ultimate availability. Based on geothermal development experience in Nevada, a state with similar types of geothermal resources as the Northwest, we assume that resources can be developed at a maximum rate of 14 MW per year in from 2011 through 2014, increasing to 24 MW per year, on average for the duration of the planning period. This would yield a maximum of 416 megawatts of hydrothermal resource over the term of the plan. At 90 percent capacity factor, this capacity would yield 374 average megawatts of energy. These assumptions are believed to be conservative and should be revisited at the biennial assessment of the 6th Plan when it is expected that additional Northwest geothermal development experience will be available.

Hydropower

[This section to be supplied]

¹⁴ United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*. 2008.

¹⁵ In this study, one MWe is defined as the capability of generating 8.77 GWh (one average megawatt) continuously for a period of 30 years.

Solar Photovoltaic Plant

[Portions of this section are yet to be completed]

Photovoltaics is conversion of solar radiation to electricity by the use of solid-state electronic devices (solar cells). Though photovoltaics have been widely employed for many years to supply power to small remote loads, larger-scale and grid-connected photovoltaic installations have been few in number and capacity because of the high cost of the technology and low productivity relative to alternatives. Over the past several years, strong public and political support has led to attractive financial incentives and distributed grid-connected installations of a several kilowatts to several megawatts in installed capacity are becoming increasingly common. Utility-scale plants, 10 megawatts and larger and sited in optimal locations are appearing in Europe and the United States.

A wide variety of photovoltaic plant designs are possible with various combinations of cell, module and mounting design. A basic tradeoff is energy conversion efficiency vs. cost. Thin-film photovoltaic cells mounted on fixed racks results in a (relatively) low cost, rugged design. Conversion efficiency is low, however and thin-film cell output tends to deteriorate significantly over time. Efficiency and durability can be increased by use of single-crystalline cells mounted on single axis tracking devices. The ultimate in efficiency can be achieved by use of concentrating lenses focused on multijunction cells sensitive to a wide spectral range, mounted on fully automatic dual axis trackers. But each increase in efficiency comes at a greater cost, complexity and some sacrifice in reliability. Moreover, the most efficient designs, those employing concentrating devices, operate only on direct solar radiation so are more suitable for Southwestern locations where clear skies prevail.

Reference Plant: The reference plant is 20 megawatt (net AC output) plant using flat plate (non-concentrating) single crystalline modules mounted on automatic single-axis trackers. The 26 MW DC module output is converted to alternating current for grid interconnection using solid-state inverters. Inverter, cabling and transformer losses result in a net output of 20 MW AC. The plant also includes step-up transformers, switchgear and interconnection facilities and security, control and maintenance facilities. No storage is provided. The deployment strategy would include numerous individual plants at scattered locations within the better solar resource areas of the region. This would reduce simultaneous ramping due to cloud movement and reduce interconnection costs.

Capacity Factor: Annual and monthly average capacity factor were evaluated for five reference locations using the NREL Solar Advisor Model (<https://www.nrel.gov/analysis/sam/>). Monthly average plant output and annual average capacity factors (ac rating to net ac output) are provided in Tables I-10 and illustrated in Figure I-10. Average hourly plant output for the Boise location is provided in Table I-11 and illustrated in Figure I-11.

The plant design assumptions use for this analysis are as follows:

- Configuration - Flat plate, tracker-mounted, inverted to AC output, no storage
- Array DC power - 25.3 MW (yielding nominal 20 MW AC output)
- Modules - 12 x 10549 (126588) SunPower SPR-200-BLK(c-Si)

Mounting - Single-axis tracker

Inverters - (98) Xantrex GT250-480-POS

System degradation - 1%/yr, compounded

Internal derate factor - 84%, excluding inverter conversion efficiency

Overall performance ratio (dc rating > ac output) - 78%-79% (location-specific)

Table I-10: Estimated monthly net energy production (MWh) and annual capacity factors for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers (AC rating to net AC output)

	Billings, MT	Boise, ID	Burns, OR	Ely, NV	Yakima, WA
Jan	1722	1586	1722	2904	1255
Feb	2294	2244	2173	3083	1915
Mar	3566	3544	3323	4524	3391
Apr	3930	4404	4208	4914	3891
May	4977	5291	5180	5614	5245
Jun	5088	5656	5511	6121	5572
Jul	5837	6192	5859	6161	5941
Aug	5220	5637	5530	5461	5320
Sep	4059	4516	4421	5224	4258
Oct	2868	3389	3219	4086	2858
Nov	1905	1830	1540	2632	1279
Dec	1487	1421	1299	2579	1093
Annual	24.5%	26.4%	25.4%	30.4%	24.3%

Figure I-10: Estimated monthly net energy production for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers

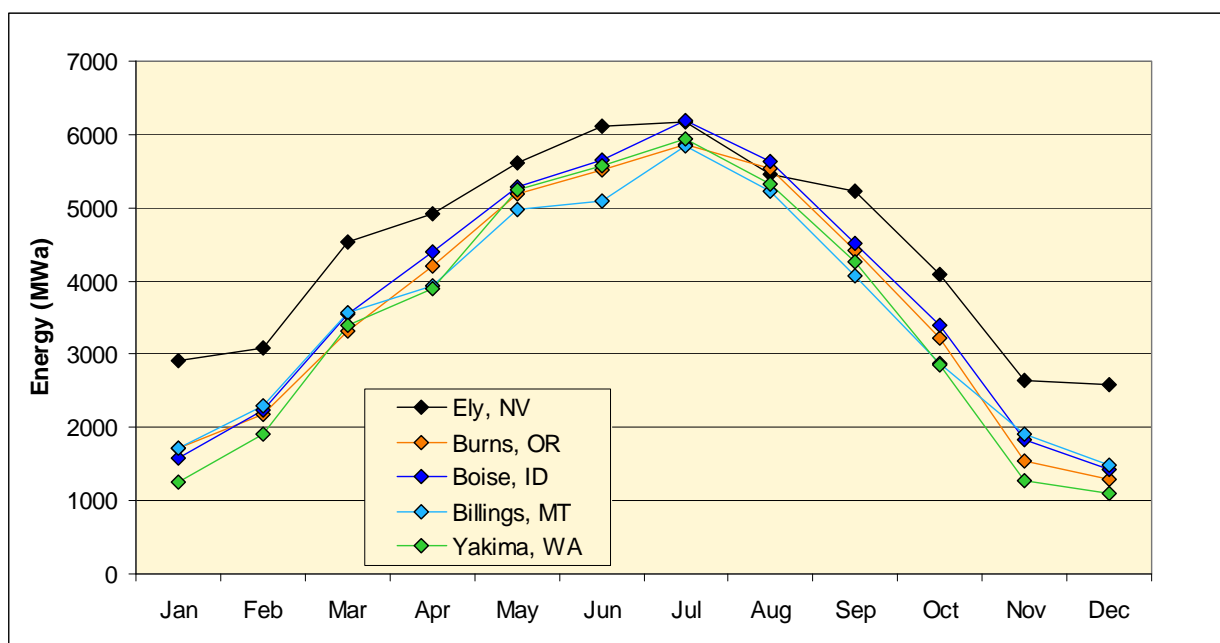
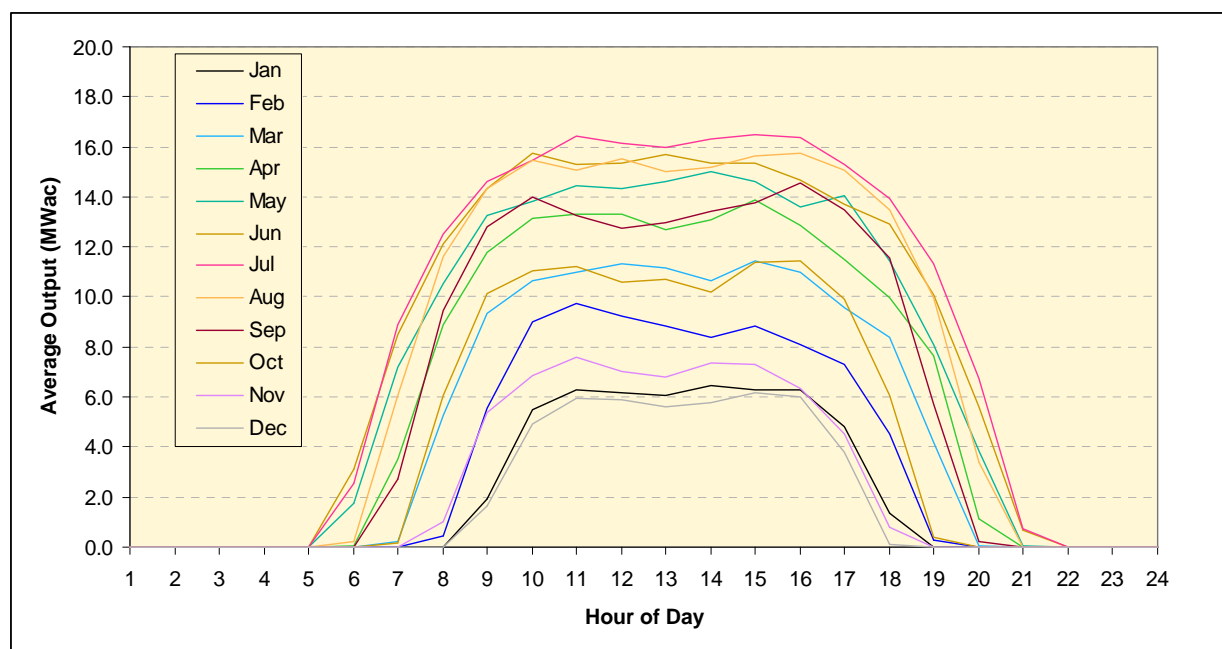


Table I-11: Estimated average hourly energy output by month (Boise location)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.08	1.78	3.10	2.54	0.22	0.00	0.00	0.00	0.00
7	0.00	0.00	0.25	3.53	7.22	8.50	8.90	6.09	2.70	0.16	0.00	0.00
8	0.00	0.47	5.29	8.90	10.55	12.15	12.50	11.61	9.45	6.09	1.02	0.00
9	1.95	5.58	9.37	11.77	13.25	14.32	14.62	14.34	12.79	10.14	5.37	1.65
10	5.52	8.99	10.63	13.16	13.81	15.73	15.46	15.46	13.98	11.06	6.85	4.92
11	6.27	9.75	11.00	13.33	14.44	15.28	16.44	15.09	13.25	11.22	7.61	5.97
12	6.20	9.24	11.35	13.30	14.33	15.34	16.17	15.54	12.76	10.61	7.03	5.89
13	6.05	8.82	11.17	12.69	14.60	15.71	15.98	15.01	12.95	10.68	6.82	5.59
14	6.45	8.37	10.65	13.11	15.00	15.33	16.33	15.17	13.41	10.19	7.36	5.77
15	6.28	8.82	11.47	13.86	14.64	15.36	16.46	15.62	13.78	11.39	7.31	6.17
16	6.32	8.08	10.97	12.88	13.58	14.70	16.37	15.76	14.54	11.46	6.37	5.99
17	4.81	7.30	9.58	11.48	14.04	13.74	15.28	15.05	13.46	9.91	4.52	3.82
18	1.36	4.52	8.39	9.97	11.46	12.94	13.92	13.51	11.55	6.06	0.79	0.11
19	0.00	0.26	4.19	7.62	8.08	10.08	11.31	9.98	5.74	0.39	0.00	0.00
20	0.00	0.00	0.03	1.13	3.86	5.63	6.76	3.40	0.22	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.05	0.66	0.74	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure I-11: Estimated average hourly energy output by month (Boise location)



Firm Capacity Value:

Unit Commitment Parameters: Solar photovoltaic plants are assumed to operate as must-run units.

Total Plant Cost: The total plant cost of the reference plant is estimated to be \$9000/kW for the 2008 price year on the basis of nominal AC plant rating (approximately \$7000/kW for the DC plant rating , as more commonly reported in the press).

Figure I-12: Published costs of utility scale solar photovoltaic projects normalized to total plant costs

Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

Development (Site acquisition, resource assessment, permitting, preliminary engineering) - 24 mo., 1% of total plant cost

Early Construction (Final engineering, major equipment order) - 12 mo., 14% of total plant cost

Committed Construction (Construction, testing) - 12 mo., 85% of total plant cost

Economic Life: The economic life of a utility-scale solar photovoltaic plant is assumed to be 25 years; limited by warranted cell lifetime. Maintenance costs are included to cover inverter replacement at 10 to 12 years.

Development Potential: The development potential for utility-scale photovoltaic plants was not assessed.

Concentrating Solar Power Plant

[Portions of this section are yet to be completed]

Parabolic trough concentrating solar thermal power plants are a commercially proven technology with over 20 years of operating history. Current plants use a synthetic oil primary heat transfer fluid and a supplementary natural gas boiler in the secondary (water) heat transfer loop for output stabilization and extended operation into the evening hours. Future plants are expected to benefit from higher collector efficiencies, higher operating temperatures (providing higher thermal efficiency and more economical storage) and economies of production.

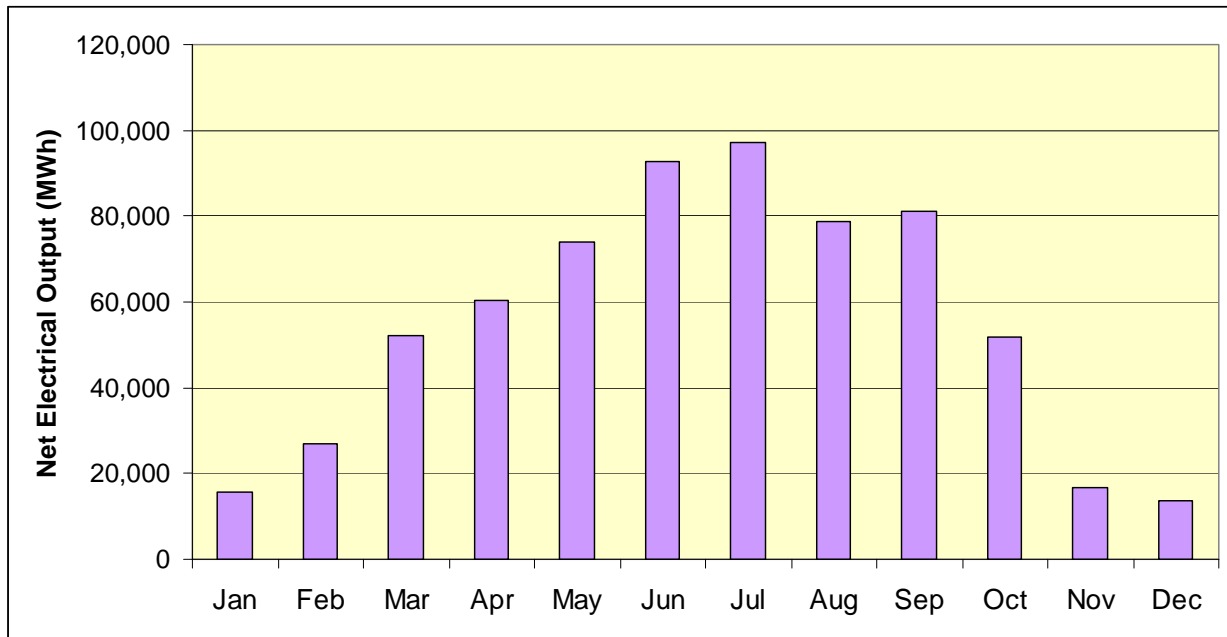
Concentrating solar technologies (thermal and photovoltaic) require high direct normal solar irradiation for efficient operation. Though the most promising sites are in the desert southwest, potentially suitable areas are found in Bonneville's Nevada service territory (http://www.nrel.gov/csp/images/3pct_csp_nv.jpg) and some evidence suggests possible sites in extreme southeastern Oregon.

Reference Plant: The reference plant is a 200-megawatt parabolic trough concentrating solar thermal plant located in east-central Nevada in the vicinity of Ely. Power would be delivered to southern Idaho via the north segment of the proposed Southwest Intertie Project and thence to

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan the Boardman area via portions of the proposed Gateway West and the Boardman-to-Hemmingway transmission projects. Higher temperature heat transfer fluids such as molten salt are expected to be available by the earliest feasible date for energization of the necessary transmission (ca. 2015). The reference plant is assumed to be equipped with thermal storage sufficient to support six to eight hours of full power operation and a 2.5x collector field. This would allowing output to be shifted to non-daylight hours, improve winter capacity factor, levelize output on intermittently cloudy days and impart some firm capacity value. No natural gas backup is provided since natural gas service is not available in the vicinity of the reference site¹⁶.

Capacity Factor: Analysis using the NREL Solar Advisor Model (<https://www.nrel.gov/analysis/sam/>) yields an annual average capacity factor of 35.5%. Output is highly seasonal, even with a collector field solar multiplier of 2.5 and eight hours of storage (Figure I -13).

Figure I-13: Estimated monthly net energy production for 200 MW parabolic trough plant with 2.5 solar multiplier and eight hours of storage located near Ely, NV



Firm Capacity Value:

Unit Commitment Parameters: Concentrating solar thermal plants are assumed to operate as must-run units.

Total Plant Cost:

¹⁶ The Ely vicinity was selected as a reference site because of the availability of reasonably favorable solar resource, suitable sites and the likelihood that the SWIP or a parallel transmission project would move forward. Subsequent analysis using the NREL Solar Advisor Model suggests possible alternatives including the Reno area with new transmission via the existing Alturas corridor. The Reno alternative may have somewhat better solar irradiation plus the advantage of natural gas service permitting use of natural gas backup.

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan
Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

Development (Site acquisition, resource assessment, permitting, preliminary engineering) - 24 mo., ___% of total plant cost

Early Construction (Final engineering, major equipment order) - 8 mo., ___% of total plant cost

Committed Construction (Construction, testing) - 20 mo., ___% of total plant cost

Economic Life:

Development Potential:

Wind

Wind power is modeled by defining a reference wind plant then applying transmission assumptions appropriate to the location of the wind resource and the load center served. Plant capacity factors are adjusted to reflect the quality of the various wind resource areas. The combinations of wind resource areas, transmission and points of delivery considered are shown in Table I-12

Table I-12: Wind resource areas, load areas and transmission assumptions

Wind Resource Area >	Columbia Basin	Southern Idaho	Central Montana	Southern Alberta	Eastern Wyoming
Oregon and Washington Load Area	Point-to-Point		500kV AC Townsend, MT > Boardman, OR + Point-to-Point	+/-500kV DC Milo, AB > Buckley, OR + Point-to-Point	500kV AC Aeolus, WY > Boardman, OR + Point-to-Point
Southern Idaho Load Area		Point-to-Point	500kV Townsend, MT > Midpoint, ID + Point-to-Point		500kV AC Aeolus, WY > Cedar Hill, ID + Point-to-Point
Montana Load Area			Point-to-Point		

Reference Plant: The reference plant consists of conventional three blade wind turbine generators, in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers and support facilities. The installed capacity is 100 MW.

Capacity Factor: The annual average capacity factor and monthly shape factors are shown in Table I-13. The annual capacity factors are from the Biennial Monitoring Report (NPCC, 2007) and the monthly shape factors were developed for the wholesale power price forecast of the Fifth Power Plan (NPCC, 2005). The capacity factors shown in Table I-13 are net at the plant interconnection and are derated for transmission losses to the point of wholesale delivery using the transmission loss factors described in the Transmission Assumptions subsection of the General Approach and Assumptions section.

Table I-13: Wind average annual capacity factors and monthly shape factors

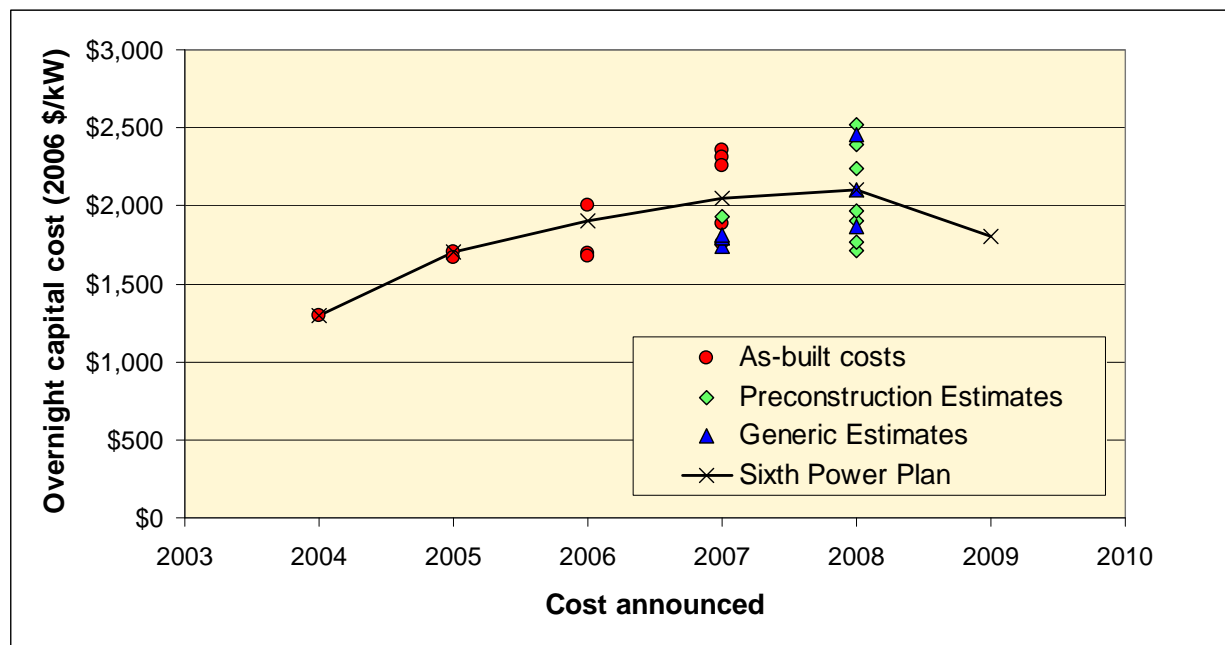
Wind Resource Area >	Columbia Basin	Southern Idaho	Central Montana	Southern Alberta	Eastern Wyoming
Average annual capacity factor (net plant output)	32%	30%	38%	38%	38%
Monthly shape factors (average monthly output as fraction of annual capacity factor)					
Jan	1.03	1.19	1.61	1.61	1.61
Feb	0.90	1.39	1.57	1.57	1.57
Mar	1.07	1.07	1.02	1.02	1.02
Apr	1.07	1.05	0.84	0.84	0.84
May	1.21	0.94	0.77	0.77	0.77
Jun	1.07	0.71	0.73	0.73	0.73
Jul	1.11	0.56	0.35	0.35	0.35
Aug	1.07	0.61	0.42	0.42	0.42
Sep	0.94	0.72	0.52	0.52	0.52
Oct	0.73	0.74	1.00	1.00	1.00
Nov	0.85	1.59	1.30	1.30	1.30
Dev	0.96	1.43	1.88	1.88	1.88

Firm Capacity Value: 5% of installed capacity as adopted by the Northwest Resource Adequacy Forum.

Unit Commitment Parameters: Wind power plants are assumed to operate as must-run units.

Total Plant Cost: The “overnight” total plant cost of the reference wind plant is \$2100/kW installed capacity (2008 price year). This estimate is based on a sample of 11 reported as-built plant costs and 8 published preconstruction estimates from 2004 through 2008. Records of these costs were obtained from the Council’s database of WECC wind plant development. Five generic estimates of wind plant development costs were also obtained. Two of these were range estimates consisting of low and high bound costs. Published costs, normalized as described in the Estimating Costs subsection of this Appendix, are plotted by vintage in Figure I-WND-1. The increase in construction costs from 2004 through mid-2008 is evident and approximated by the “Sixth Power Plan” curve. Analysis of the increase in wind plant costs during this period is provided in the Biennial Monitoring Report (NPCC, 2007).

A cost uncertainty range from -19% to +24% (\$1700 to \$2500 in 2008) is used for Regional Portfolio Model studies. The range is based on 2008 range of observations.

Figure I-14: Overnight total plant cost of wind projects

Total Plant Cost is forecast to decline 14% (real) from the 2008 price year to 2009, then to average of estimated 2004 and 2008 levels by 2011. Thereafter, TPC is assumed to decline at 0.5% per year, reflecting a 5% learning rate. See Table I- 1 and Figure I- 1.

Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a wind plant (exclusive of long-distance transmission, if any) are as follows:

Development (Site options to completion of resource assessment): - 24 mo., 5% of total plant cost

Early Construction (WTG order to first WTG shipment) - 12 mo., 16% of total plant cost

Committed Construction (WTG shipment to commercial service) - 18 mo., 79% of total plant cost

The development and construction schedule and cash flows for a wind resource requiring long-distance transmission is modeled in two phases. The first phase is coincidental development of the transmission line and 50% of the installed wind capacity potentially served by the transmission line. The transmission development schedule is controlling and the timing of wind capacity development is assumed to be such that the wind capacity enters service coincidental with the transmission line. The second phase is optional build-out of the remaining 50% of wind capacity potentially served by the transmission line in 250 MW increments.

Operating and Maintenance Cost: The variable O&M cost of \$2.00/MWh is intended to represent land rent. Land rent is reported to typically range between 2 - 4% of the gross revenue from wind turbine generator (Wind Powering America, http://www.windpoweringamerica.gov/pdfs/wpa/34600_landowners_faq.pdf). \$2.00 per MWh

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan is approximately 2% of busbar revenue requirements at the current cost of wind. Because construction costs are expected to decline and variable O&M remains constant in the analysis, the low end value was selected. Fixed O&M costs are intended to include plant operation and maintenance costs and capital replacement costs, exclusive of property taxes and insurance. The estimated fixed O&M cost of \$43/kW/yr is based on the fixed O&M cost for wind plants used for the Fifth Power Plan (\$20/kWh/yr), escalated by observed 2004 - 2008 wind plant capital cost escalation (108% nominal). The resulting value was rounded to \$40/kW/yr to yield overall annual O&M costs (including property taxes and insurance) of 2.5% of total plant cost. This percentage is within the range of 2 - 3.5% of total energy cost and 20 - 25% of total energy costs over the life of the plant cited in IEA, 2008b.

Integration cost: The forecast cost of supplying regulation and sub-hourly load-following services for operational integration is shown in Table I-GEN-3. The cost of longer-term shaping services is not included in the resource cost estimates of the plan.

Economic Life: The economic life of a wind plant is assumed to be 20 years.

Development Potential: The estimated development potential for the various blocks of wind is shown in Table I-14. Capacity and energy shown as “available” is estimated developable capacity in excess of operating and committed (under construction) capacity as of February 2009.

The Columbia Basin resource potential for delivery to western Oregon and Washington load centers is limited by new east - west transmission capacity that could be developed at current embedded transmission cost. This capacity is the sum of unconstructed projects with firm Bonneville transmission rights (estimated to be 1250 MW) and new capacity created by the West of McNary, Little Goose and I-5 Corridor reinforcements (approximately 4860 MW). This total was reduced by the capacity of unconstructed projects with announced long-term sales to California (these are assumed to hold firm transmission rights to California).

The Columbia basin potential for delivery to eastern Oregon and Washington load centers, and Idaho and Montana potential for local delivery are each assumed to be limited to a maximum penetration of 20% of forecast peak hourly load at the end of the planning period. This implies that the variable resource integration cost assumption described earlier is sufficient to cover integration costs to this level of penetration.

The remote resource blocks using new long-distance transmission were provisionally limited by the capacity of a single transmission circuit, pending initial development of the resource strategy (Chapter 9). In only one case (Low Conservation), did renewable resource development exceed the estimated availability of wind from sources not involving construction of new long-distance transmission. For this reason, further assessment of potential limits was not undertaken.

An issue needing further consideration is the prospect of additional long-term sales of Northwest wind to California utilities for compliance with California renewable portfolio standards. Various outcomes are possible, involving California renewable energy credit policy, the proposed increase in California renewable portfolio standard targets, current inertia capacity and the future competitiveness of Northwest wind vs. California and Southwestern solar from the perspective of California utilities.

Table I-14: Wind power development potential

Wind Resource Area	Load	Available Capacity (MW)	Available Energy (MWh)	Limiting Factors	Earliest Service
Columbia Basin	Westside OR/WA	4060	1300	New transmission to Westside @ embedded cost	2011
Westside OR/WA	Westside OR/WA	200	60	Allowance	2011
Columbia Basin	Eastside OR/WA	340	110	20% of 2029 peak load	2011
S. Idaho	S. Idaho	720	220	20% of 2029 peak load	2011
Montana	Montana	215	80	20% of 2029 peak load	2011
Montana	S. Idaho	1500	570	Per 500kV AC ckt	2015
Montana	OR/WA	1500	570	Per 500kV AC ckt	2015
Wyoming	S. Idaho	1500	570	Per 500kV AC ckt	2015
Wyoming	OR/WA	1500	570	Per 500kV AC ckt	2015
Alberta	OR/WA	2000	760	Per +/-500kV DC ckt	2015

Waste Heat Energy Recovery Cogeneration

Reference Plant: The reference plant is a 5 MW organic Rankine cycle (ORC) generating plant using dry cooling, operating on the gas turbine exhaust heat from a natural gas pipeline compressor station.

Capacity Factor: Energy-limited to 80%. Expected annual energy production for Trailblazer Pipeline Peetz compressor station is 27,600 MWh (3.15 MWh) (Colorado Energy News, 2009). The installed capacity at this station is 4 MW, giving a 79% capacity factor. This was rounded to 80% for the reference plant. A higher (90%) capacity factor is reported for the Northern Border Compressor Station #7 plant, though the load factor in pipelines serving the Midwestern market may be higher those of Western lines.

Development and Construction Schedule: The development and construction schedule (24 mo. Development, 12 mo. Early Construction, 12 mo. Construction) and corresponding cash flows (5% Development, 30% Early Construction, 65% Final Construction) was based on gas turbine assumptions, but with an extended development period reflecting the complexities of three-party development (third-party developer, pipeline owner and purchasing utility) and an extended early construction period including final engineering, major equipment order, site preparation and installation of compressor turbine exhaust diversion valves and ducting.

Fuel Price: Included in Operating and Maintenance cost

Heat Rate: The representative heat rate 38,000 Btu/kWh for an ORC plant operating with the reference plant assumptions (900°F GT exhaust temperature, dry cooling) is based on the average annual performance of the ORC heat recovery project at the Northern Border Pipeline Compressor Station #7 (ORNL, 2007). Because the cost of the waste heat “fuel” is assumed to be a royalty payment based on electricity production, a heat rate assumption is not required for energy production cost calculations.

Unit Commitment Parameters: Waste heat energy recovery plants are assumed to operate as must-run units.

Total Plant Cost: Typical total plant cost is based on an typical installed cost of \$2500/kW cited in Table 3 of INGAA (2008). An Owner's Cost allowance of 20% was added to the INGAA total plant cost and the resulting value adjusted to real 2006 dollars (assuming that the values in the INGAA report are 2008 dollar values). The resulting value was rounded to \$2900/kW. The range of total plant costs were derived in a similar manner from the range cited in INGAA, yielding a range of \$2300 - 2900/kW.

Total Plant Cost is forecast to decline 8% (real) from 2008 price year to 2009, then to average of estimated 2004 and 2008 levels by 2011. Thenceforth, TPC is assumed to decline at 0.5% per year, reflecting a 5% learning rate for organic Rankine cycle technology. See Figure I-1.

Operating and Maintenance Cost: Operating and maintenance costs (exclusive of property taxes and insurance) include plant O&M costs and payments to the pipeline owner for the use of the site and energy supply. INGAA, 2008 cites \$0.005/kWh (\$5/MWh) as typical pipeline company compensation and 0.002/kWh (\$2/MWh) as a typical O&M cost. A range of possible O&M costs of \$0.001 - 0.005/kWh (\$1 - 5/MWh) is cited. The O&M costs were increased by 30% to account for general and administrative costs, and rounded up to the nearest dollar, yielding an expected total O&M cost of \$8/MWh with a range of \$7 to 13/MWh.

Economic Life: The economic life of a heat recovery cogeneration plant is assumed to be 20 years; limited by uncertainty regarding host facility viability.

Coal-fired Steam-electric Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Coal-fired Gasification Combined-cycle Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Natural Gas Combined-Cycle Gas Turbine

[Portions of this section are yet to be completed]

Reference Plant: The reference plant is a single advanced “H-class” gas turbine generator and one steam turbine generator. The base-load capacity is 390 megawatts with an additional 25 megawatts of duct-firing power augmentation. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NO_x combustors and selective catalytic reduction for NO_x control and an oxidation catalyst for CO and VOC control. Condenser cooling is wet mechanical draft.

Availability: The availability parameters are those developed for the Fifth Power Plan:

Scheduled maintenance outages - 18 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 24 hours

Equivalent annual availability - 90% (of baseload rating)

The equivalent annual availability value should be reduced by 2.2% if using a “new and clean” capacity rating.

Heat Rate: The heat rate (7110 Btu/kWh) is based on the reported heat rate for the Port Westward plant (Mitsubishi MHI 501G , 6786 Btu/kWh, HHV) derated 2.1% for a maintenance-adjusted average lifecycle aging effects. The incremental heat rate of supplemental (duct fired) capacity is assumed to be 9500 Btu/kWh (Fifth Plan assumption).

Unit Commitment Parameters: Unit commitment parameters are used in the AURORA^{xmp}® Electric Power Market Model for dispatchable units. Because AURORA^{xmp}® is an hourly dispatch model, subhourly commitment capability is not modeled.

Minimum load - %

Minimum run time - hour

Minimum down time - hour

Ramp rate - greater than %/hr

Development and Construction Schedule: The development and construction schedule and associated cash flows used for the Regional Portfolio Model studies are as follows:

Phase	Definition	Duration	Cost (% of TPC)
Development (Option)	Site selection to EPC selection	24 mo	4%
Early Construction	Notice to Proceed to major foundations complete	12 mo	42%
Committed Construction	Receipt of major equipment to commercial service	18 mo	54%

These values were derived from values used in the Fifth Power Plan with the overall construction period extended to 30 months at the recommendation of the Council’s Generating Resources Advisory Committee to reflect recent construction experience.

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Economic Life: The economic lifetime of a combined-cycle plant is assumed to be 30 years.

Total Plant Cost: Total plant cost (\$1160/kW for the 2008 price year) of baseload capacity (i.e., exclusive of the incremental cost of supplemental duct firing capacity) is based on the average of four normalized reported preconstruction estimates for projects scheduled for 2008 construction (\$1100/kW). This average was adjusted upward by approximately 50% of the implied fuel savings value of advanced gas turbine technology (\$120/kW). Figure I-NG-1 illustrates the 2008 preconstruction estimates and their relationship to earlier normalized construction, preconstruction and generic estimates dating from 2002 through 2007. The increase in construction cost from 2004 through 2007 is evident and approximated by the “Sixth Power Plan” curve. In developing the analysis represented in Figure I-15, reported plant costs were normalized to equivalent overnight development and construction cost in constant 2006 dollars¹⁷. Normalization adjustments include the following:

Reported site capacity was adjusted to vendor’s nominal ISO baseload capacity as reported in Gas Turbine World (2007).

Reported costs were reduced in proportion to installed duct firing capability assuming that incremental duct firing capacity costs are 40% of incremental baseload capacity costs.

Reported costs for plants with 2x1x1¹⁸ configuration were reduced 10% to reflect the added cost of a 1x1x1 plant. Plants of 3xGT configuration and larger were excluded from the sample.

Reported costs of plants with dry cooling were reduced 6% to reflect the added cost of dry cooling.

Reported as-built costs were assumed to include all owners’ costs (development, land, infrastructure and financing). Reported preconstruction estimates were assumed to be overnight total construction cost, exclusive of owner’s costs and were increased by 29% to account for owner’s development costs. In as-built cases where specific owner’s costs were explicitly cited as excluded, these were estimated as follows: Development - 2%, Land - 2%.

¹⁷ Additional information regarding the development of the estimate of total plant cost is available on request.

¹⁸ 2x1x1 - two gas turbines, one heat recovery steam generator and one steam turbine generator.

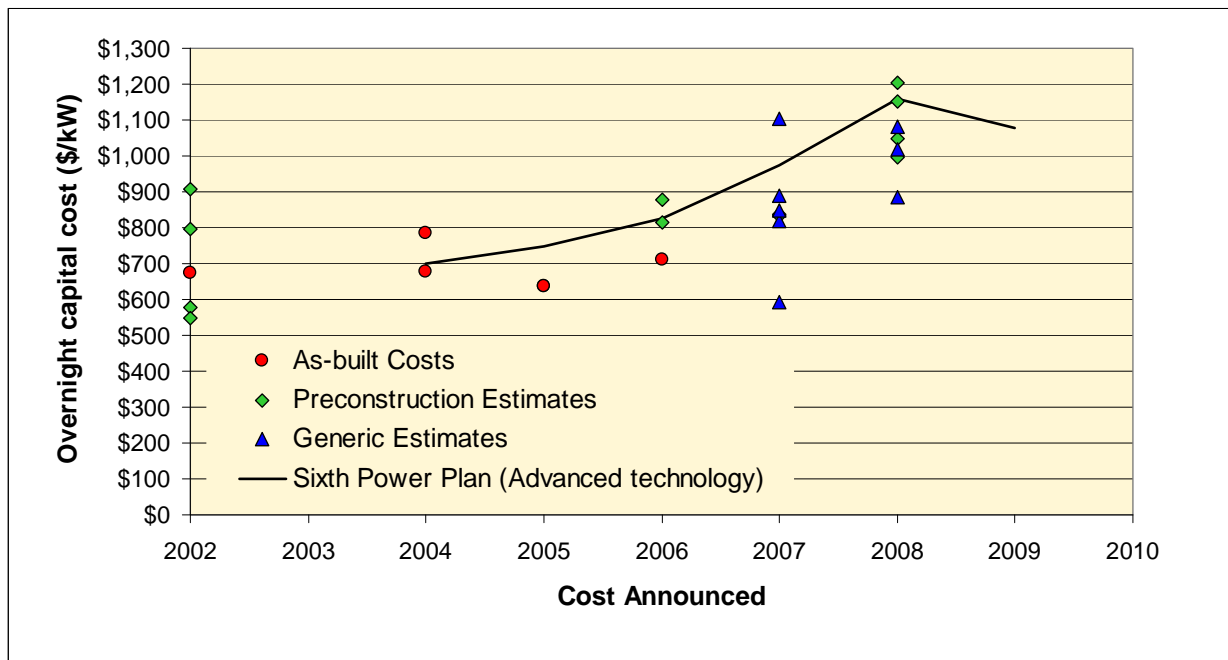
As-built costs were assumed to be nominal, including financing, and escalation and interest incurred during construction. Equivalent overnight total plant costs were back calculated, following the adjustments described above, using the Council’s MicroFin cost model. Preconstruction costs were assumed to be overnight costs so did not require further adjustment other than to 2006 dollar values.

The incremental cost of power augmentation (duct firing) is assumed to be \$465/kW for the 2008 price year assuming that the cost of incremental supplemental capacity is 40% of the incremental cost of baseload capacity.

A cost uncertainty range of +/- 30%, based on NETL (2007) is used for Regional Portfolio Model studies.

Total Plant Cost and Fixed Operating and Maintenance Costs are forecast to decline 7% (real) from the 2008 price year to 2009, then to average of estimated 2004 and 2008 levels by 2011. Thenceforth, these costs are assumed to decline at 0.5% per year, reflecting a 5% learning rate for gas turbine technology. See Table I-1 and Figure I- 1.

Figure I-15: Overnight total plant costs of combined-cycle power plants



Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance (\$14/kW/yr) and variable O&M (\$1.70/MWh) are based on values appearing in NETL (2007), escalated in proportion to the difference in the normalized combined-cycle capital cost of NETL (2007) and the Sixth Plan total plant cost described above.

Maximum Annual Development Rate: No constraints were initially placed on the regional maximum annual development rate for combined-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a potential maximum combined-cycle build rate of 415 MW (one unit) per two-year interval. This is an achievable rate, if needed.

Developable Potential: No constraints were initially placed on the cumulative development potential for combined-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 830 MW (two units) of new combined-cycle gas turbine capacity. This amount would not be constrained by gas supply, other infrastructure or air quality constraints.

Natural Gas Simple-Cycle Gas Turbines

Technology: Air is pressurized, heated by burning liquid or gas fuel then expanded through a power turbine. The power turbine drives the compressor and an electric power generator. A simple-cycle gas turbine power plant typically consists of one to several gas turbine generator units, each consisting of an air compressor, fuel combustors, and power turbine coupled to an electric generator, skid-mounted as a modular unit. The generator sets are typically equipped with inlet air filters and exhaust silencers and are installed in acoustic enclosures. Lube oil, starting, fuel forwarding, and control systems complete the basic package. Water or steam injection, intercooling¹⁹ or inlet air cooling can be used to increase power output. Basic nitrogen oxide control is accomplished by use of “low-NOx” combustors. Exhaust gas catalysts can further reduce nitrogen oxide and carbon monoxide production. Other plant components may include a switchyard, fuel gas compressors, a water treatment facility (if units are equipped with water or steam injection) and control and maintenance facilities. A fuel oil storage and supply system may be provided for backup fuel. A wide range of unit sizes is available, from less than 5 to greater than 170 megawatts.

Gas turbine designs include heavy industrial machines specifically designed for stationary applications (“frame” machines) and “aeroderivative” machines - lightweight aircraft engines adapted to stationary applications. The higher pressure (compression) ratios of aeroderivative machines result in a more efficient and compact unit than frame machines of equivalent output. Because of their lighter construction, aeroderivative machines provide superior operational flexibility including rapid black start capability, short run-up, rapid cool-down and overpower operating capability. Start times to full load of ten minutes or less allow these machines to provide “spinning” reserves without needing to be operating. Aeroderivative machines are highly modular and major maintenance is often accomplished by swapping out major components or the entire engine for a replacement, shortening maintenance outages. These attributes come at a price - industrial machines cost less on a per-kilowatt capacity basis and can be longer-lived. Both aeroderivative and industrial gas turbine technological development is strongly driven by military and aerospace gas turbine applications.

Reference Aeroderivative Simple-cycle Gas Turbine Plant

Reference Plant: The reference aeroderivative simple-cycle gas turbine plant consists of twin gas turbine generator sets of 47MW nominal capacity, ancillary equipment, a control building

¹⁹ Chilling the compressed air between air compression stages.

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan and switchyard. Cost and performance characteristics are generally based on the General Electric LM6000PD Sprint. This design uses water spray injection intercooling in the two-stage compressor to increase mass flow and reduce second-stage compressor load, thereby increasing overall power output. Lifecycle average output is 45MW per unit under ISO conditions. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control.

Availability: Availability parameters are those of the Fifth Power Plan:

Scheduled maintenance outages - 10 days/yr

Equivalent forced outage rate - 3.6%

Mean time to repair - 80 hours

Equivalent annual availability - 94%

Unit Commitment Parameters: Unit commitment parameters are used in the AURORA^{xmp}® Electric Power Market Model for dispatchable units. Because AURORA^{xmp}® is an hourly dispatch model, subhourly commitment capability is not modeled.

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - greater than 100%/hr

Development and Construction Schedule: The development and construction schedule and associated cash flows used for the Regional Portfolio Model studies are as follows:

Phase	Definition	Duration	Cost (% of TPC)
Development (Option)	Site selection to EPC selection	18 mo	5%
Early Construction	Notice to Proceed to major foundations complete	9 mo	50%
Committed Construction	Receipt of major equipment to commercial service	6 mo	45%

While the duration of the Development period and overall construction period remain at the values used for the Fifth Power Plan, the early construction period is shorted from 12 to 9 months and the Committed Construction Period extended by 3 months. Level cash flows are

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan assumed for the Development Period. Construction cash flows are based on a right-skewed cash flow from Phung, 1978, maximized at the initial month of the committed construction period.

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The lifecycle average full load heat rate (9370 Btu/kWh, HHV) is based on the new and clean full load heat rate reported for a General Electric LM6000PD Sprint (9060 Btu/kWh) in Gas Turbine World (2007). The nominal heat rate derated 3.1% for inlet, exhaust, auxiliary load and transformer losses and 0.8% for maintenance-adjusted lifecycle aging effects.

Economic Life: The economic lifetime is assumed to be 30 years.

Total Plant Cost: Total plant cost (\$1050/kW for the 2008 price year) was derived from an analysis of reported aeroderivative gas turbine costs including 13 reported preconstruction estimates, five reported costs at completion and six generic estimates dating from 2002 through 2008. The reference 2008 price year cost (representing a plant placed in-service in 2009) is an approximate average of normalized preconstruction estimates reported in 2008, exclusive of outliers. Figure I-16 illustrates the 2008 preconstruction estimates and their relationship to earlier normalized construction, preconstruction and generic estimates. The 2008 outlier is the San Francisco Potrero and SFO peaker projects. These projects have been bedeviled by delay and are proposed for challenging highly urban environments and for these reasons are not thought to be representative of future projects in the Northwest. The 2007 outlier is the average cost of five Southern California Edison peaking units - a project also confronting highly urban locations and delay. The increase in construction cost from 2004 through 2007 is evident and approximated by the “Sixth Power Plan” curve.

The values plotted in Figure I-2 are intended to represent equivalent overnight development and construction cost in constant 2006 dollars²⁰. These values were derived from “raw” reported plant costs as follows:

Reported site capacity was adjusted to vendor’s nominal ISO baseload capacity as reported in Gas Turbine World (2007).

Plants consisting of more than four units were excluded from the sample. The cost of projects consisting of a single unit were increased by 10%.

Reported as-built costs were assumed to include all owners’ costs (development, land, infrastructure and financing). Reported preconstruction estimates were assumed to be overnight total construction cost, exclusive of owner’s costs and were increased by 12% to account for owner’s development costs.

Reported as-built and preconstruction costs were adjusted to a average value for the Pacific Northwest states using the state adjustment factors of USACE (2008).

As-built costs were assumed to be nominal, including financing, and escalation and interest incurred during construction. Equivalent overnight total plant costs were back calculated, following the adjustments described above, using the Council’s MicroFin cost model.

²⁰ Additional information regarding the development of the estimate of total plant cost is available on request.

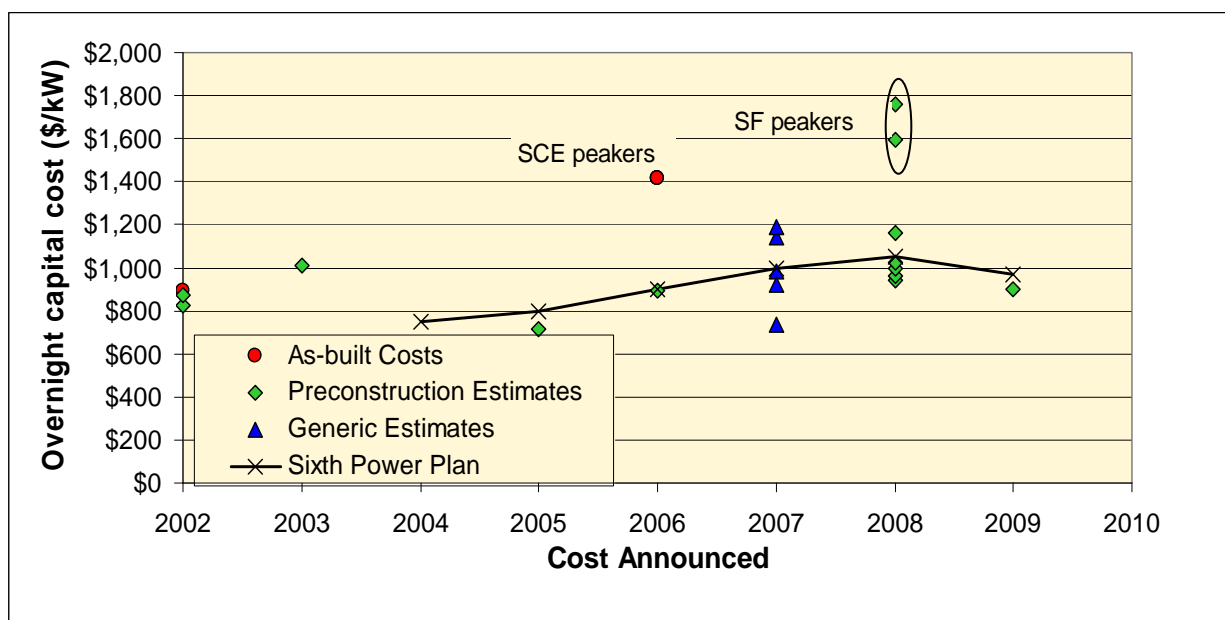
Preconstruction costs were assumed to be overnight costs so did not require further adjustment other than to 2006 dollar values.

A cost uncertainty range of +/- 30%, based on NETL (2007) is used for Regional Portfolio Model studies.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance (\$14/kW/yr) and variable O&M (\$4.00/MWh) are based on a rounded average of “Albany” and “Syracuse” GE7FA fixed O&M values (less property tax and insurance) and variable O&M values, respectively of Table A-3 of NERA (2007).

Cost Forecast: See discussion under Reference Combined-cycle Gas Turbine Plant and Figure I-3.

Figure I-16: Aero-derivative gas turbine generator total plant costs



Maximum Annual Development Rate: No constraints were initially placed on the regional maximum annual development rate for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a potential maximum simple-cycle build rate of 170 MW per two-year interval²¹. This is an achievable rate, if needed.

Developable Potential: No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that would not be constrained by gas supply, other infrastructure or air quality constraints.

²¹ The reference heavy duty simple-cycle gas turbine plant was used in the portfolio analysis, hence the capacity values of the portfolio analysis are multiples of the heavy duty reference plant capacity.

Reference Heavy-duty Simple-cycle Gas Turbine Plant

Reference Plant: The reference heavy-duty simple-cycle gas turbine plant consists of a single gas turbine generator set of 85MW nominal capacity, ancillary equipment, control building and switchyard. Cost and performance characteristics are generally based on the General Electric 7EA. Lifecycle average output is 81MW under ISO conditions. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NO_x combustors and selective catalytic reduction for NO_x control and an oxidation catalyst for CO and VOC control.

Availability: Availability parameters are those of the Fifth Power Plan:

Scheduled maintenance outages - 26 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 51 hours

Equivalent annual availability - 86%

Unit Commitment Parameters: Unit commitment parameters are used in the AURORA^{xmp}® Electric Power Market Model for dispatchable units. Because AURORA^{xmp}® is an hourly dispatch model, subhourly commitment capability is not modelled.

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - greater than 100%/hr

Development and Construction Schedule: See discussion under Reference Aero-derivative Simple-cycle Gas Turbine Plant

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The lifecycle average full load heat rate (11,960 Btu/kWh, HHV) is based on the new and clean full load heat rate reported for a General Electric MS7001EA (10,419 Btu/kWh) in Gas Turbine World (2007). The nominal heat rate derated 3.1% for inlet, exhaust, auxiliary load and transformer losses and 0.8% for maintenance-adjusted lifecycle aging effects.

Economic Life: The economic lifetime is assumed to be 30 years.

Total Plant Cost: Total plant cost (\$610/kW for the 2008 price year) was derived from an analysis of reported heavy-duty gas turbine construction costs including 9 reported preconstruction estimates, five reported costs at completion and six generic estimates dating from 2004 through 2009 (Figure I-17). Though at the high end of the range of estimates announced in 2008, the reference 2008 price year cost (representing a plant placed in-service in 2009) is at the low-end of estimates announced in 2009 (both the generic and preconstruction estimates announced in 2009 are range estimates). It is not clear if the 2009 estimates assume a

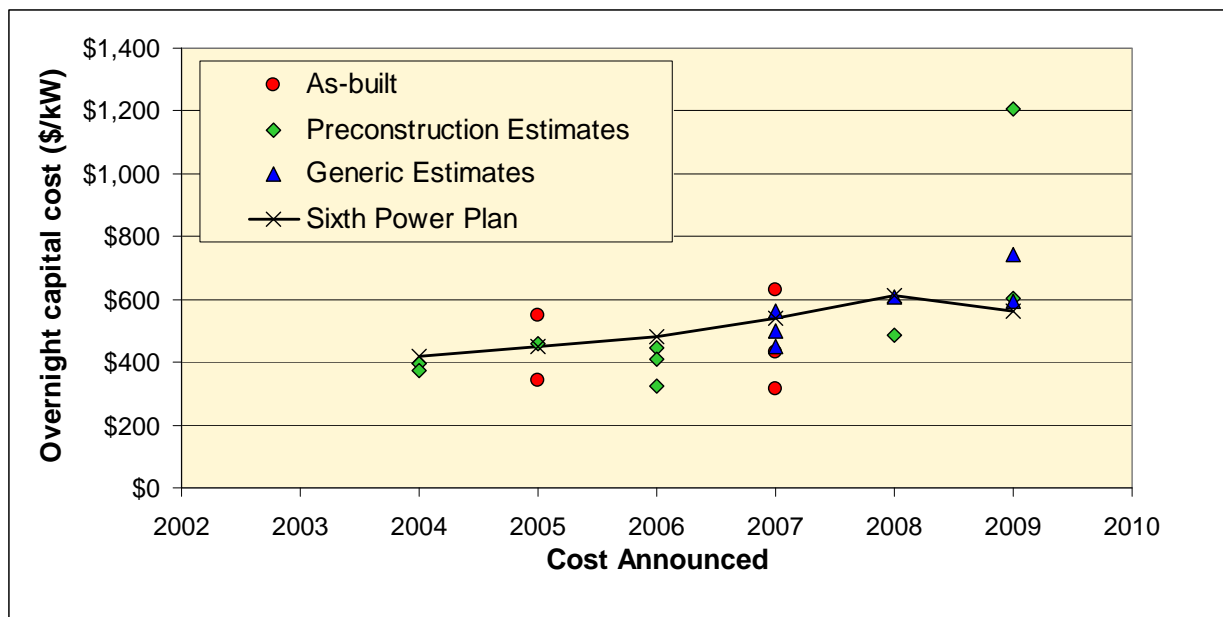
Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan continuation of the 2004 - 08 construction cost escalation trend, and as a result are unrepresentatively high, or whether the 2008 examples are low. The cost estimates will be revisited in the Biennial Assessment.

The values plotted in Figure I-17 are intended to represent equivalent overnight development and construction cost in constant 2006 dollars²². These values were derived from “raw” reported plant costs as described in the reference aeroderivative simple-cycle plant discussion.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance (\$4/kW/yr) and variable O&M (\$1.00/MWh) are based on a rounded average of “Albany” and “Syracuse” GE7FA fixed O&M values (less property tax and insurance) and variable O&M values, respectively of Table A-3 of NERA (2007).

Cost Forecast: See discussion under Combined-cycle Gas Turbine and Figure I-3.

Figure I-17: Heavy-duty gas turbine generator total plant costs



Maximum Annual Development Rate: No constraints were initially placed on the regional maximum annual development rate for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a potential maximum simple-cycle build rate of 170 MW per two-year interval. This is an achievable rate, if needed.

Developable Potential: No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that would not be constrained by gas supply, other infrastructure or air quality constraints.

²² Additional information regarding the development of the estimate of total plant cost is available on request.

Natural Gas Reciprocating Engine Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Advanced Nuclear Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Compressed Air Energy Storage

The following sources were used in the development of the discussion of compressed air energy storage:

Di Biasi (2009)

Mason (2009)

Nakhamkin (2007)

Nakhamkin, et. al. (2004)

Schainker, et. al. (2007)

Succar, Samir and Williams (2008)

Pumped Storage Hydropower

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

VALUES UNDERLYING CHARTS OF CHAPTER 6

Figures 6-1A-C: Levelized Electricity Cost of Generating Options

Figures 6-1A-C depict the levelized cost of producing and delivering electricity from resources and technologies generally used to produce electricity on a base or intermediate load basis. The technologies and resources included in Figures 6-1A-C are those assumed to be available for

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan commercial service by the respective time periods and permissible under current state law. Not included are emerging or prospective resources and technologies for which costs are speculative at this time.

The levelized costs of Figures 6-1A-C are calculated using the Council’s MicroFin levelized cost workbook. The cost calculations use the reference plant assumptions and financing assumptions described in this appendix. Natural gas and coal cases use the medium case fuel price forecasts described in Appendix B. The values reflect investor-owned utility financing, transmission to a Pacific Northwest load-serving entity wholesale delivery point, CO₂ allowance costs at the mean values of the portfolio analysis and integration cost as described in this appendix. State and federal financial incentives are excluded, except accelerated depreciation. Actual project costs may differ because of site-specific conditions and different financing and timing. MicroFin, loaded with the assumptions of this plan is available on request for those seeking more detail or the opportunity to calculate costs under varying assumptions.

The values of Figure 6-1A are based on reference plants placed in service in 2015. Figure 6-1B values are based on plants placed in service in 2020 and Figure 6-1C values are based on plants placed in service in 2025.

[These values in these tables still need to be evaluated for consistency]

Table I-15: Levelized Electricity Cost of Energy Generating Options Available in the Near-term (2010-14)

Resource	Location	Capacity Factor	Plant Busbar	Integration	Transmission and Losses	Emissions	Total
Heat Recovery	PNW	80%	\$51.49	\$0.00	\$3.54	\$0.00	\$55
Landfill Gas	PNW	85%	\$73.32	\$0.00	\$3.63	\$0.00	\$77
Geothermal	PNW	90%	\$76.28	\$0.00	\$3.57	\$0.00	\$80
Wind (MT Local)	MT	38%	\$71.69	\$9.84	\$6.53	\$0.00	\$88
Combined Cycle	PNWE	80%	\$72.52	\$0.00	\$4.02	\$13.93	\$90
New Hydro	PNW	50%	\$90.72	\$0.00	\$5.52	\$0.00	\$96
Animal/Food Waste	PNW	75%	\$97.06	\$0.00	\$4.39	\$0.00	\$100
Wind (Col Basin)	OR/WA	32%	\$84.77	\$9.84	\$7.71	\$0.00	\$101
Wind (ID Local)	ID	30%	\$90.29	\$9.84	\$8.20	\$0.00	\$102
Recip Engine	PNWE	80%	\$90.30	\$0.00	\$4.27	\$15.87	\$108
Woody Residue	PNW	80%	\$118.61	\$0.00	\$4.65	\$0.00	\$109
WWTP Biogas	PNW	85%	\$122.16	\$0.00	\$4.58	\$0.00	\$110
Utility-scale PV	S. ID/OR	26%	\$277.16	\$9.89	\$12.79	\$0.00	\$113

Table I-16: Levelized Electricity Cost of Energy Generating Options Available in the Mid-term (2015-19)

Resource	Location	Capacity Factor	Plant Busbar	Integration	Transmission and Losses	Emissions	Total
Heat Recovery	PNW	80%	\$60.97	\$0.00	\$3.53	\$0.00	\$65
Landfill Gas	PNW	85%	\$72.54	\$0.00	\$3.62	\$0.00	\$76
Geothermal	PNW	90%	\$76.32	\$0.00	\$3.57	\$0.00	\$80
Wind (MT Local)	MT	38%	\$69.97	\$10.16	\$6.50	\$0.00	\$87
Combined Cycle	PNWE	80%	\$72.42	\$0.00	\$4.07	\$16.24	\$93

New Hydro	PNW	50%	\$90.72	\$0.00	\$5.52	\$0.00	\$96
Animal/Food Waste	PNW	75%	\$95.19	\$0.00	\$4.35	\$0.00	\$100
Wind (OR/WA)	OR/WA	32%	\$82.72	\$10.16	\$7.67	\$0.00	\$101
Supercritical Coal (ID)	ID	85%	\$60.36	\$0.00	\$4.14	\$38.97	\$103
Wind (ID Local)	ID	30%	\$88.10	\$10.16	\$8.17	\$0.00	\$106
IGCC (ID)	ID	80%	\$72.02	\$0.00	\$4.46	\$36.84	\$113
MT Wind > S. ID	MT	38%	\$69.97	\$10.16	\$33.93	\$0.00	\$114
AB Wind > OR/WA	AB	38%	\$69.97	\$10.16	\$40.35	\$0.00	\$120
Woody Residue	PNW	80%	\$117.19	\$0.00	\$4.62	\$0.00	\$122
WWTP Biogas	PNW	85%	\$120.17	\$0.00	\$4.54	\$0.00	\$125
MT Wind > OR/WA	MT	38%	\$69.97	\$10.16	\$61.63	\$0.00	\$142
NV CSP > S. ID	NV	36%	\$129.23	\$0.00	\$35.36	\$0.00	\$165
NV CSP > OR/WA	NV	36%	\$129.23	\$0.00	\$73.92	\$0.00	\$203
Utility-scale PV	S. ID/OR	26%	\$219.21	\$10.18	\$11.67	\$0.00	\$241

Table I-17: Levelized Electricity Cost of Energy Generating Options Available in the Long-term (2020-29)

Resource	Location	Capacity Factor	Plant Busbar	Integration	Transmission and Losses	Emissions	Total
Heat Recovery	PNW	80%	\$59.66	\$0.00	\$3.51	\$0.00	\$63
Landfill Gas	PNW	85%	\$71.80	\$0.00	\$3.60	\$0.00	\$75
Geothermal	PNW	90%	\$76.37	\$0.00	\$3.58	\$0.00	\$80
Wind (MT Local)	MT	38%	\$68.29	\$10.27	\$6.47	\$0.00	\$85
Combined Cycle	PNWE	80%	\$71.96	\$0.00	\$4.09	\$17.44	\$93
New Hydro	PNW	50%	\$90.73	\$0.00	\$5.52	\$0.00	\$96
Animal/Food Waste	PNW	75%	\$93.38	\$0.00	\$4.32	\$0.00	\$98
Wind (OR/WA)	OR/WA	32%	\$80.73	\$10.27	\$7.64	\$0.00	\$99
MT Wind > WA/OR via CTS	MT	38%	\$68.29	\$10.27	\$21.39	\$0.00	\$100
UltraSupercritical Coal (ID)	ID	85%	\$60.04	\$0.00	\$4.13	\$38.67	\$103
Wind (ID Local)	ID	30%	\$85.98	\$10.27	\$8.13	\$0.00	\$104
IGCC (ID)	ID	80%	\$104.62	\$0.00	\$4.25	\$0.00	\$109
Advanced Nuclear	PNW	85%	\$68.29	\$10.27	\$33.88	\$0.00	\$112
MT Wind > S. ID	MT	38%	\$70.49	\$0.00	\$4.49	\$39.56	\$115
AB Wind > OR/WA	AB	38%	\$68.29	\$10.27	\$40.30	\$0.00	\$119
Woody Residue	PNW	80%	\$116.33	\$0.00	\$4.60	\$0.00	\$121
WWTP Biogas	PNW	85%	\$118.25	\$0.00	\$4.50	\$0.00	\$123
MT Wind > OR/WA	MT	38%	\$68.29	\$10.27	\$61.55	\$0.00	\$140
IGCC (CSS) via CTS	MT	80%	\$94.57	\$0.00	\$16.27	\$30.16	\$141
NV CSP > S. ID	NV	36%	\$117.30	\$0.00	\$34.93	\$0.00	\$152
NV CSP > OR/WA	NV	36%	\$117.30	\$0.00	\$73.23	\$0.00	\$191
Utility-scale PV	S. ID/OR	26%	\$183.24	\$10.29	\$11.00	\$0.00	\$205

Figure 6-2: Levelized Fixed Cost of Firm Capacity Options

Figures 6-1A-C depict the levelized fixed cost of installed capacity for resources and technologies generally used primarily to provide firm capacity or ancillary services. The technologies and resources included are those assumed to be available for commercial service

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan during the 20-year period of the plan. Not included are emerging or prospective resources and technologies for which costs are speculative at this time.

Table I-18: Levelized fixed cost of installed capacity for resources and technologies generally used primarily to provide firm capacity or ancillary services

Resource	Plant Capital & O&M	Fuel	Transmission and Losses	Total
Combined-cycle (Incremental duct firing)	\$42.59	\$31.40	\$17.90	\$92
Frame GT	\$56.53	\$52.29	\$18.58	\$127
Aeroderivative GT	\$105.67	\$40.96	\$19.31	\$166
Reciprocating Engine	\$178.07	\$35.77	\$20.61	\$234
Pumped Storage	\$288.30	\$19.24	\$44.20	\$352

REFERENCES

California Energy Commission (CEC). Comparative Costs of California Central Station Electricity Generation Technologies. December 2007.

Colorado Energy News . “Tri-State partners on heat recovered energy generation”. June 25, 2009.

Di Biasi, Victor. New solutions for energy storage and smart grid load management. *Gas Turbine World*. March - April 2009, p. 22.

EcoSecurities Consulting Limited. *CO2 Capture and Storage - An Overview of Information Available for the Western U.S.* Prepared for the Northwest Power and Conservation Council. January 2009.

Energy Trust of Oregon (ETO). Sizing and Characterizing the Market for Oregon Biopower Projects. April 2005.

Gas Turbine World. *Gas Turbine World. 2007-08 GTW Handbook*. 2007

Idaho Statesman. “In Ada county, landfill turns trash to cash.” January 1, 2009

IHS CERA. “IHS CERA Power capital costs index shows construction costs falling for all Types of new power plants” Press release June 23, 2009.

International Energy Agency. Prospects for CO2 Capture and Storage. 2004.

International Energy Agency (2008a). *CO2 Capture and Storage*. 2008.

International Energy Agency (2008b). *Energy Technology Perspectives*. 2008.

Interstate Natural Gas Association of America (INGAA). Waste Energy Recovery Opportunities for Interstate Natural Gas Pipelines. February 2008.

Lazard. Levelized Cost of Energy Analysis - Version 2.0. June 2008.

Mason, James. *Coupled Wind-CAES Power Plants: A Base Load Capacity Option*. Renewable Energy Research Institute, Farmingdale, NY. May 2009.

Nakhamkin, Michael, et. al. New Compressed Air Energy Storage Concept Improves the Profitability of Existing Simple-cycle, Combined-cycle, Wind Energy and Landfill Gas Power Plants. ASME Turbo Expo 2004.

Nakhamkin, Michael, et. al.. Available Compressed Air Energy Storage (CEAS) Plant Concepts. Power-gen. 2007.

National Energy Technology Laboratory (NETL). Cost and Performance Baseline for Fossil Energy Plants DOE/NETL-2007/1281. Revision 1, August 2007

Appendix I: Generating Resources and Energy Storage Technologies Draft Sixth Power Plan
NERA Economic Consulting. Independent Study to Establish Parameters of the ICAP Demand
Curve for the New York Independent System Operator. August 2007.

Northwest Power and Conservation Council. Fifth Northwest Electric Power and Conservation
Plan (Document 2005-7). May 2005.

Northwest Power and Conservation Council. Biennial Monitoring Report on the Fifth Power
Plan (Document 2007-4). January 2007.

Oak Ridge National Laboratory (ORNL). Subcontractor Report: National Account Energy
Alliance Final Report for the Basin Electric Project at Northern Border Pipeline Company's
Compressor Station #7, North Dakota ORNL/TM-2007/158. December 2007.

Oregon State University. Oregon-NASA Space Grant Consortium. Columbia River Flood
Basalt Province, Idaho, Washington, Oregon, USA .
http://volcano.oregonstate.edu/vwdocs/volc_images/north_america/crb.html

Phung, Duon. A Method for Estimating Escalation and Interest During Construction
ORAU/IEA-78-7(M). Oak Ridge Associated Universities Institute for Energy Analysis. 1978.

Schinker, Robert B., et. al. New Utility-scale CAES Technology: Performance and Benefits
(Including CO2 Benefits). September 2007.

Succar, Samir and Robert H. Williams. *Compressed Air Energy Storage: Theory, Resources and
Applications for Wind Power*. Princeton Environmental Institute. April 2008.

TransCanada. NorthernLights HVDC Project: WECC Comprehensive Progress Report.
November 2008.

U.S. Army Corps of Engineers (USACE). *Civil Works Construction Cost Index System
(CWCCIS) EM1110-2-1304*, Table A-3. March 2000, revised March 2008.

U.S. Department of Energy Office of Fossil Energy. 2008 Carbon Sequestration Atlas of the
United States and Canada - Second Edition. October 2008.

U.S. Environmental Protection Agency. Market Opportunities for Biogas Recovery Systems
EPA-430-8-06-004. (Undated)

U.S. Environmental Protection Agency. Opportunities for and Benefits of Combined Heat and
Power at Wastewater Treatment Facilities. April 2007.

Western Governors' Association (WGA). Clean and Diversified Energy Initiative Biomass Task
Force Report Supply Addendum. January 2006.