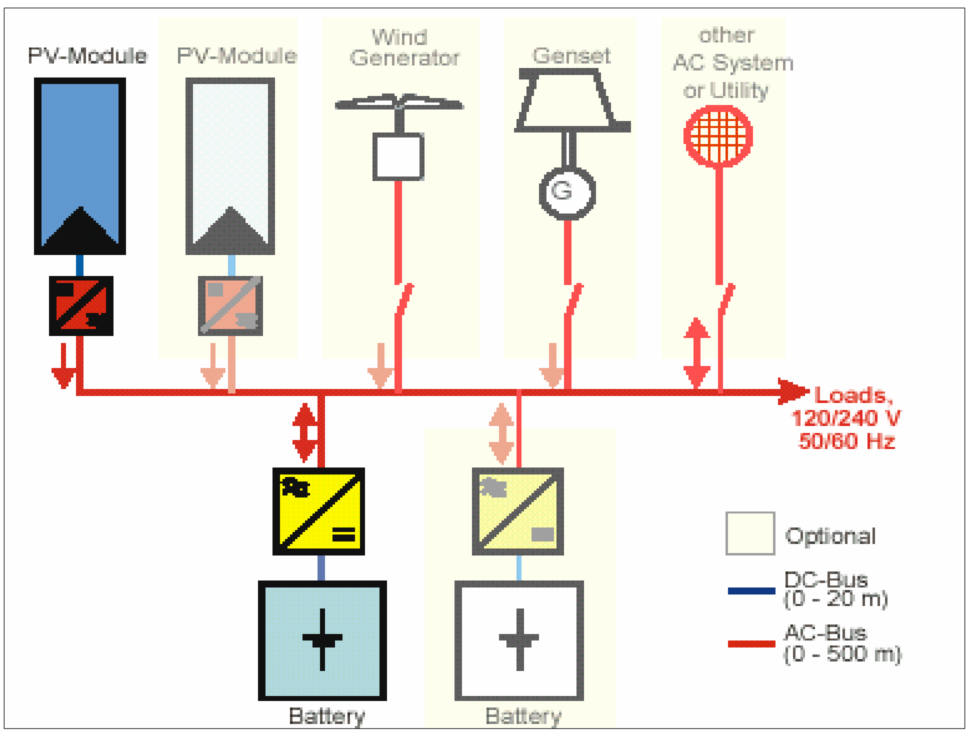
Technical and Economic Assessment of Off-Grid, Mini-Grid and Grid Electrification Technologies

Annexes



The World Bank Group
Energy Unit, Energy, Transport and Water Department

September 2006

Technical and Economic Assessment of Off-Grid, Mini-Grid and Grid Electrification Technologies
Annexes

The World Bank Group

Energy Unit, Energy, Transport and Water Department

September 2006

The International Bank for Reconstruction
and Development / The World Bank Group

1818 H Street, N.W.
Washington, D.C. 20433, U.S.A.

First printing: September 2006

Manufactured in the United States of America

Cover picture: A schematic of a hybrid wind-photovoltaics system in a min-grid configuration (Source: DOE)

Table of Contents

List of Figure and Tables

Acronyms and Abbreviations

AC	Alternating Current
ACSR	Aluminum Conductor Steel Reinforced
AD	Anaerobic Digestion
AFBC	Atmospheric Fluidized Bed Combustion
AFUDC	Allowance for Funds Used During Construction
BOS	Balance of System
CCGT	Combined Cycle Gas Turbine
CT	Combustion Turbine
DC	Direct Current
DD	Direct Drive
DFIG	Doubly-Fed Induction Generator
DSS	Direct Solar Steam
EPRI	Electric Power Research Institute
EWEA	European Wind Energy Association
FGD	Flue Gas Desulfurization
FY	Fiscal Year (July 1-June 30)
GHG	Greenhouse Gas
HRT	Hydraulic Retention Time
IC	Internal Combustion
ICB	International Competitive Bidding
IGCC	Integrated Gasification Combined Cycle
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquid Propane Gas
MENA	Middle East North Africa
NO_x	Nitrogen Oxides
O&M	Operations and Maintenance
PC	Pulverized Coal
PM	Particulate Matter
PV	Photovoltatics
SC	SuperCritical
SO_x	Sulfur Oxides
SPV	Solar Photo-voltaic
SVC	Static VAR Compensato
USC	UltraSuperCritical

Foreword

Helping power sector planners in developing economies to factor in emerging electrification technologies and configurations is essential to realizing national electrification agendas at minimum cost. New generation technologies, especially based on renewable energy, and new electrification approaches, especially based on stand-alone mini-grids or off-grid configurations, are part of the growing complexity which electrification policy makers and power system planners must be able to factor into their investment programs.

This report is part of the Energy and Water Department's commitment to providing new techniques and knowledge that complement the direct investment and other assistance to electrification as provided by the International Bank for Reconstruction and Development and the International Development Association.

Our hope is that it will stimulate discussion among practitioners both within the Bank and in the larger community of power system planners. The results provide information on the comparative cost and performance of power supply options that with additional location-specific analytic work can assist in making rational technology choice decisions and in formulating least-cost power sector development and electrification plans.

Jamal Saghir
Director
Energy and Water
Chair, Energy and Mining Sector Board
The World Bank

Acknowledgements

The electrification assessment study was undertaken by a team comprising Toyo Engineering Corporation, Chubu Electric Power Co., Inc., Princeton Energy Resources International (PERI), Energy Technologies Enterprises Corp (EnTEC), and Global Energy Associates, Inc (GEA). The report itself was prepared by several authors including K. R. Umesh (Toyo Engineering Company), Takashi Nakase, Keiichi Yoneyama and Toshiomi Sahara (Chubu Electric Power Company), Stratos Tavoulareas (EnTEC), Mahesh Vipradas (TERI), and Grayson Heffner (GEA). Chuck McGowan of EPRI and Joe Cohen and John Rezaiyan of PERI provided many helpful comments on the technical and economic assumptions underlying our assessment. The study and report preparation were managed by Masaki Takahashi of the Energy and Water Department with the assistance of Anil Cabraal.

The study team members and World Bank staff would like to dedicate this report to the memory of Dr. Tom Schweizer of Princeton Energy Resources International, who passed away last year as the assessment phase of the study was nearing completion. Tom was a dedicated and invaluable colleague always ready to cooperate and offer his services and advice.

Please address any questions or comments about this report to Masaki Takahashi (mtakahashi@worldbank.org).

A Detailed Technology Descriptions and Cost Assumptions

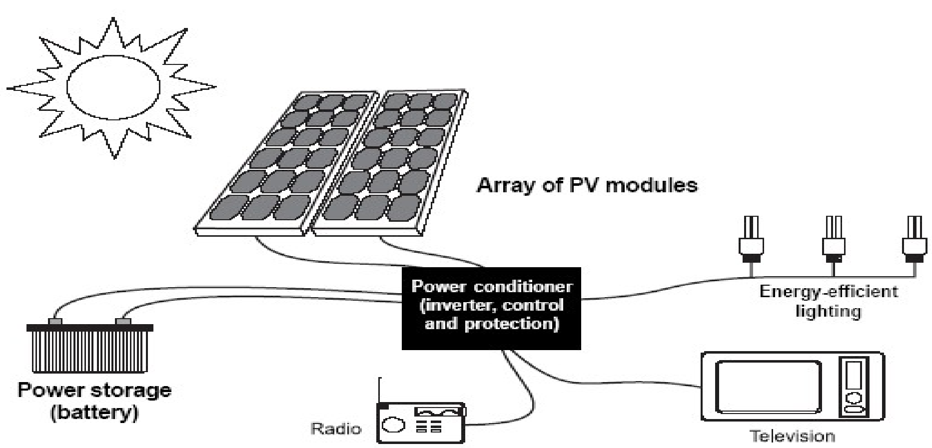
A.1 *Solar Photovoltaic Technologies*

Solar Photovoltaic (SPV) systems utilize semiconductor-based materials which directly convert solar energy into electricity. These semiconductors, called solar cells, produce an electrical charge when exposed to sunlight. Solar cells are assembled together to produce solar modules. A group of solar modules connected together to produce the desired power is called a solar array.

The first solar photovoltaic cell was developed in 1950. Very expensive at first, early applications of photovoltaic power systems were mainly for the space program. Terrestrial applications of solar photovoltaic started in late 1970's and were primarily for powering small, portable gadgets like calculators and watches. By the 1980's a number of larger-scale but still niche markets for SPV systems had emerged, mostly for remote power needs such lighting, telecommunications, and pumping. In spite of its high cost, SPV systems have steadily gained power generation market share due to their ability to produce electricity with no moving parts, no fuel requirements, zero emissions, no noise, and no need for grid connection. The modular nature of SPV, which allows systems to be configured to produce power from Watts to Mega-Watts, gives it a unique advantage over other technologies.

An SPV system typically consists of an array of solar cells, power conditioning and/or controlling device such as inverter or regulator, an electricity storage device such as battery (except in grid applications), and support structure and cabling connecting the power system to either the load or the grid. A typical SPV system arrangement is shown in Figure A-1.

Figure A-1: Typical SPV System Arrangement



Source: DOE/EPRI

A.4.1 Technology Description and Power Applications

Solar photovoltaic systems can be classified according to three principal applications:

- Stand alone solar devices purpose-built for a particular end use, such as solar HF radios, solar home lighting systems, or solar coolers. These dedicated SPV systems can either be configured to include some energy storage capacity or directly power electrical or mechanical loads, such as pumping or refrigeration.
- Stand alone solar power plants, basically small power plants designed to provide electricity from a centralized solar photovoltaic power plant to a small locality like village or a building.
- Grid connected SPV power plants, which are equivalent to any other generator supplying power to the electricity grid.

The solar photovoltaic module is the most important component of a photovoltaic system, comprising 40 – 50 % of the total system cost. As such, research and development programs have focused both on cost reduction and efficiency improvement of the solar modules. SPV cell technologies can be classified according to the materials and technology used in their manufacture. The major categories of commercial interest are:

- Silicon based solar photovoltaic cells, which are the most common solar cells in commercial use. Included in this family of solar cells are Crystalline Silicon Solar Cells (both single crystalline and poly-crystalline), which account for more than 90 % of the world's solar cell production. A well-made Crystalline Silicon Solar Cell has a theoretical photovoltaic conversion efficiency of up to 20%.
- Amorphous silicon cells, also called thin film solar cells, which are cheaper to produce and require fewer materials as compared to the crystalline silicon cells. However, these cells have lower efficiency – typically 5-10%, and tend to lose up to one-third of their efficiency levels in the first year of use. Because they can be produced as thin film of semiconductor material on a glass or plastic substrate they offer a wide variety of designs and configurations, and have found application in integrated roofing/SPV arrays.
- Compound semiconductors, which are thin film multi junction cells manufactured using other photosensitive composite solid state materials such as Cadmium/Telluride (Cd/Te) and Copper indium gallium diselenide (CGIS). This is an emerging but promising technology with high efficiency levels and light weight.

Table A.1 summarizes the characteristics of the major solar cell categories.

Table A.1: Characteristics of Solar Cells

Technology	Market share	Efficiency range	Cost range	Life	Remarks
Silicon single crystal cells	>90%	12-20 %	3- 4 $/Wp	>20 years	Mature technology
Silicon Multi crystal cells	6-7%	9-12 %	3-4 $/Wp	> 15 years	Mature technology
Amorphous silicon cell technology	3-5 %	5-10%	4-5 $/Wp	>10 years	Degradation of efficiency in first few months.
Compound semiconductors CIGS	<1%	7.5% (13.5 % at laboratory level)	Not available		Commercially available.
Cd/Te	<1%	NA(maximum16 % at laboratory level,) *(1)*			

Source: Renewable Energy Information Network

A.4.2 Technical, Environmental and Economic Assessment

For the SPV assessment we have chosen several common configurations of solar systems used in India (See Table A.2).

Table A.2: SPV System Configurations and Design Assumptions

Description	Small SPV systems		SPV mini grid power plants	Large grid connected SPV power plant
Module Capacity	50 Wp	300 W_p	25 kW	5 MW
Life span modules	20 years	20 years	25 years	25 years
Life span batteries	5 years	5 years	5 years	Not applicable
Capacity factor	20%	20%	20%	20%

Our analysis assumes a Capacity Factor of 20%, based on 4.8 hrs/day average power generation at peak level. Solar modules are rated at design operating conditions of 25^0C ambient temperature and solar insolation of 1000 W/m^2. In practice and under typical weather conditions, an average solar module on an annual basis will generate peak power for about 4-5 hours a day, equivalent to a 20 % Capacity Factor. This assumes that solar modules are deployed to face south (in Northern latitudes) and are inclined at an angle equal to latitude to achieve maximum solar energy collection throughout the year.

The environmental impact of SPV technology is nil at the point of use. Modules produce electricity silently and do not emit any harmful gases during operation. Silicon, the basic photovoltaic material used for most common solar cells, is environmentally benign. However, disposal of used batteries in environmentally safe way is important.

Table A.3 gives the capital costs for different sized solar photovoltaic systems.

Table A.3: SPV 2005 Capital Costs ($/kW)

Solar PV system capacity	50W	300W	25kW	5MW
Equipment	6,780	6,780	4,930	4,640
Civil	0	0	980	980
Engineering	0	0	200	200
Erection	0	0	700	560
Process Contingency	700	700	700	680
Total	7,480	7,480	7,510	7,060

Based on the assumed capacity factor and the life of the solar PV plant, the capital cost was annualized and the total generation cost was estimated using the formulations provided in Section 2. The generation costs for the year 2004 are given in Table A.4. Variable O & M costs include cost of battery replacement after 5 years for small systems (up to 25kW) plus replacement of electronics components for larger (25kW and 5MW) systems.

Table A.4: SPV 2005 System Generating Cost (cents/kWh)

Solar PV system capacity	50W	300W	25kW	5MW
Levelized Capital cost	45.59	45.59	42.93	40.36
Fixed O&M cost	3.00	2.50	1.50	0.97
Variable O&M cost	12.00	8.00	7.00	0.24
Fuel cost	0.0	0.0	0.0	0.0
Total	61.59	56.09	51.43	41.57

A.1.2 Future SPV costs

SPV module costs are currently about 50 to 60 % of the total system costs. We note that the cost of SPV modules on a per-W_p basis has fallen from $100 in 1970 to $5 in 1998.[1] SPV module costs continue to fall, and this drop in SPV module costs are influenced by technology advancement and growing production volume.[2]

Future costs will be driven by market growth and technology advancements, both of which can be forecast. Japan, one of the major markets for solar PV and a major manufacturer of SPV modules, is forecasting production cost reductions from 100yen/W_p today to 75 yen /W_p by 2010 and 50 yen/W_p by 2030. The solar PV industry in Europe and USA is targeting costs of $ 1.5- 2.00 /W_p within ten years, based on technological improvements as well as a growth in production volumes of 20-30 per cent (See Table A.5).

---

[1] The challenges of cold climates PV in Canada's North, Renewable Energy World, July 1998, pp36-39
[2] SPV sales have increased from 200 MW in 1999 to 427 MW in 2002 and to above 900 MW in 2004.

Table A.5: Projected SPV Module Costs

Cost	Europe	USA	Japan	India
Solar PV module costs 2004	5.71 €/W_p	5.12 $/$W_p$	100¥/ Wp	150Rs/W_p
Target cost in 2010	1.5 – 2 €/W_p	1.5 – 2 $/$W_p$	75 ¥W_p	126Rs/W_p*(@2.75/ W_p)
Expected cost in 2015	05 €/W_p	N A	50 ¥/W_p (Note - 2030 projection)	92Rs/W_p* (@$ 2/ W_p)

Sources: http://www.solarbuzz.com/ModulePrices.htm; http://www.solarbuzz.com/ModulePrices.htm
NEDO (Japan); TERI (India)

We have based SPV capital cost projections for the year 2010 and 2015 on the forecasts shown in Table A.5. Our projection assumes that, as in the past, BOS costs will come down due to improvements in the technology of electronics components and batteries, as well as increase in production volume. Thus, we assume that BOS costs will follow the same international trends as module costs. Installation and O & M costs are not likely to change significantly, they are assumed to be constant when calculating future system capital, installation and operational costs. The results of our projection, including uncertainty bands, are provided in Table A.6.

Table A.6: SPV System Capital Cost Projections ($/kW)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
50 W	6,430	7,480	8,540	5,120	6,500	7,610	4,160	5,780	6,950
300W	6,430	7,480	8,540	5,120	6,500	7,610	4,160	5,780	6,950
25 kW	6,710	7,510	8,320	5,630	6,590	7,380	4,800	5,860	6,640
5 MW	6,310	7,060	7,810	5,280	6,190	6,930	4,500	5,500	6,230

A.1.3 Uncertainty Analysis

An uncertainty analysis was carried out to estimate the range over which the generation cost could vary as a result of uncertainty in costs and capacity factor. Most variables were allowed to vary over a ±20% range. Projected SPV generation costs for the years 2010 and 2015 resulting from the uncertainty analysis are shown in Table A.7. The dependence of the generation cost on uncertainty of different parameters is shown with tornado charts given in Annex D.

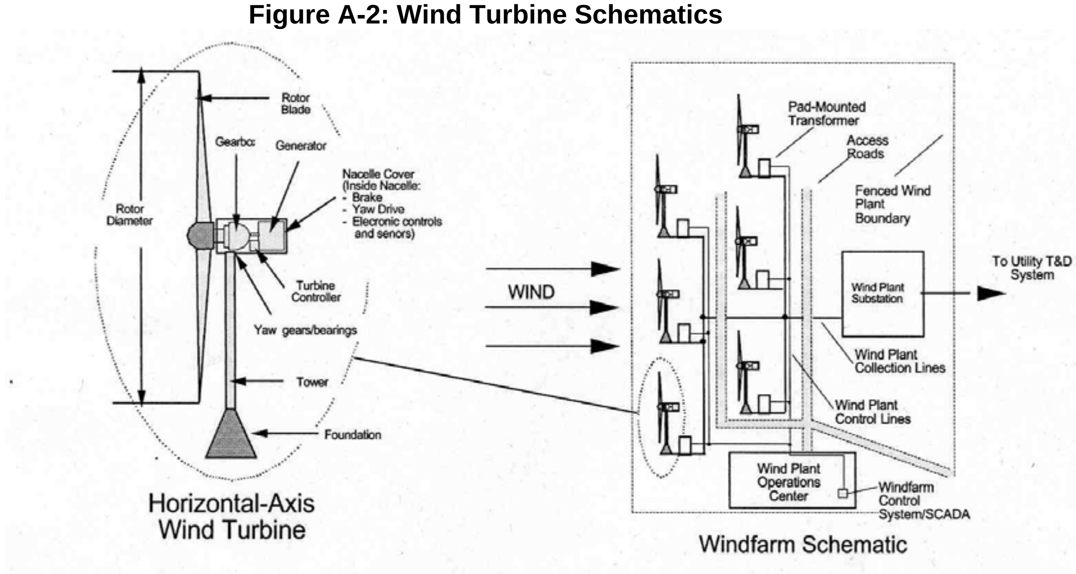
Table A.7: Uncertainty Analysis of SPV Generation Costing Costs (cents/kWh)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
50W	51.8	61.6	75.1	44.9	55.6	67.7	39.4	51.2	62.8
300W	46.4	56.1	69.5	39.6	50.1	62.1	34.2	45.7	57.0
25kW	43.1	51.4	63.0	37.7	46.2	56.6	33.6	42.0	51.3
5MW	33.7	41.6	52.6	28.9	36.6	46.3	25.0	32.7	41.4

A.2 *Wind Electric Power Systems*

A wind power generator converts the kinetic energy of the wind into electric power through rotor blades connected to a generator. Horizontal axis wind turbines are almost exclusively used for commercial power generation, although some vertical axis wind turbine designs have been developed. The mechanism to capture the energy and then transmit and convert into electrical power involves several stages, components and controls. Wind turbines can be broadly classified into two types according to capacity - small wind turbines (up to 100kW) and large wind turbines. Small wind turbines are used for grid, off grid and mini grid applications, while large wind turbines are used almost exclusively for interconnected grid power supply. Figure A-2 depicts both a horizontal wind turbine and a typical large-scale wind farm arrangement.

Figure A-2: Wind Turbine Schematics



Source: DOE/EPRI

A.4.3 Wind Turbine Technology Description

Major components of horizontal axis wind turbine include the rotor blades, generator aerodynamic power regulation, yaw mechanism, and the tower. The rotor blade is critical, as it captures the wind energy and converts it into the torque required to spin the generator. One measure of an aerodynamically efficient blade design is the weight/swept area ratio; this parameter can be used to compare efficiency across machines of similar design and capacity. Blade lengths increase with the size of the wind turbines, as longer lengths result in more energy capture. Longer blades require higher strength and lower mass, leading to common use of composite materials including carbon epoxy and fiber-reinforced plastic.

Kinetic energy captured by the rotor blades is transferred to the generator through the transmission shaft. The shaft is coupled directly or via a gearbox mechanism to the armature of either an asynchronous (induction) or synchronous generator. A wind turbine with an induction generator comes with gearboxes, which convert the cut-in to cut-out speed variations to one, two, or three speeds of the generator. In an induction generator the generator revolutions increase or decrease with the wind speed. For example, a two-speed generator has 4 poles at 1500 rpm and 6 poles at 1000 rpm. Wind turbines configured with synchronous generators have continuous speed variation according to the speed of the wind. Synchronous machines have no gear box and can be connected to the grid at almost any wind speed. Synchronous machines provide great operational flexibility and good power quality, but are expensive because of the need for power electronics. Both asynchronous and synchronous machines can operate over a significant range of wind speeds.

Wind turbine technology continues to evolve, with the doubly-fed induction generator (DFIG) Direct Drive (DD) synchronous machines under development. The DFIG incorporates most of the benefits of the variable speed drive system and has the advantage of minimal losses because of the fact that only a third of the power passes through the converter. Direct Drive synchronous machines have multi pole design for a wide speed range. Power electronics facilitates such wide speed ranges. All these generator developments rely on power electronics to control power quality. The cost of power electronics is falling, resulting in reduction of capital cost of the variable speed drives and thus lower generation costs for electricity produced by wind. The other major improvement is the increasing size and performance of wind turbines. From machines of just 25 kW twenty years ago, the commercial range sold today is from 600 up to 2,500 kW. In 2003 the average capacity of new turbines installed in Germany was 1,390 kW. With development of larger individual turbines the required capacity of a wind farm can be me with fewer individual turbines, which has beneficial effects on both investment and O&M costs.

Aerodynamic power regulation is a common feature of modern wind turbines allowing control of output power by mechanical adjustment of the rotational speed, especially at higher wind speeds. In a *pitch controlled* wind turbine, the turbine's electronic controller checks the power output of the turbine several times per second. When the power output becomes too high, it sends a signal to the blade pitch mechanism, which immediately pitches (turns) the rotor blades slightly out of the wind. Conversely, the blades are turned back into the wind whenever the wind drops again. *Stall*, or *passive control* through the blade design itself, requiring no moving parts. The profile of the rotor blade is aerodynamically designed to ensure that the moment the wind speed becomes too high; it creates turbulence on the side of the rotor blade, which is not facing the wind. Although power regulation through stall control avoids complex control systems, it represents a very complex aerodynamic design problem, including avoided the problem of stall-induced vibrations in the structure of the turbine. Finally, an *active stall* control mechanism is being used in larger (1 MW and above) wind turbines. At low wind speeds, the machines will usually be programmed to pitch their blades much like a pitch-controlled machine. However, when the machine reaches its rated power and the generator is about to be overloaded, the machine will pitch its blades in the opposite direction from what a pitch-controlled machine does. This is similar to normal stall power control, except that the whole blade can be rotated backwards (in the opposite direction as is the case with pitch control) by a few (3-5) degrees at the nominal speed range in order to give better rotor control. In other words, it will increase the angle of attack of the rotor blades in order to make the blades go into a deeper stall, thus wasting the excess energy in the wind. The result is known as the 'deep stall' effect, which leads to the power curve bending sharply to a horizontal output line at nominal power and keeping this constant value for all wind speeds between nominal and cut-out.

The wind tower is another critical wind turbine component, as it must provide the structural frame necessary to accommodate the external forces due both to the wind and the motions of the various components of a wind turbine. The tower must be designed to withstand vibrations as well as static and dynamic loads. The most important consideration in tower design is to avoid natural frequencies near rotor frequencies. The two most common tower designs are *lattice* and *tubular*. A *lattice tower* is cheaper compared to the tubular tower and, being usually a bolted structure, is easier to transport. However, tubular towers have several advantages over lattice towers. Not only is a tubular tower stiffer than a lattice tower, thus better able to withstand vibrations, it also avoids the many bolted connections of a lattice tower that require frequent checking and tightening. Moreover, tubular tower allows full internal access to the nacelle.

As wind turbines increase in size and height, tower design is becoming critical. Only recently the conventional wisdom was that traditional towers taller than 65m presented significant logistical problems and result in high costs. However, hub heights of 100m or more for commercial wind turbines are becoming more frequent (GE’s 2.3 MW turbine has a hub height of 100m), and efforts are underway to develop innovative construction materials and erection concepts to allow these tall turbine structures to be erected without adverse cost impact.

A final mechanical design feature is yaw control. The yaw control continuously orients the rotor in the wind direction. Large wind turbines mostly have active yaw control, in which the yaw bearing includes gear teeth around its circumference. A pinion gear on the yaw drive engages with those teeth, so that it can be driven in any direction. The yaw drive normally consists of electric motors, speed reduction gears, and a pinion gear. This is controlled by an automatic yaw control system with its wind direction sensor usually mounted on the nacelle of the wind turbine.

Wind turbine technology is being continuously improved worldwide, resulting in improved performance, more effective land utilization, and better grid integration. Technology development in the form of larger size wind turbines, larger blades, improved power electronics, and taller towers is noteworthy, resulting in dramatic improvement. Averaging 25 kW just twenty years ago, the commercial range sold today is typically from 600 up to 2,500 kW.

Small Wind Turbines

Small wind turbines are mostly used for charging batteries or supplying electrical loads in DC (12 or 24 volts), bus-based off-grid power systems. However, when used in conjunction with a suitable DC-AC inverter and a battery bank, the turbine can also deliver power to a mini-grid. A particularly attractive configuration is small wind turbines in the 5 KW generating AC power for village-scale mini-grids.

As with larger wind turbines, almost all small wind turbines are horizontal axis machines with the same basic components as their larger brethren. The major components of a typical horizontal axis small wind turbine include:

- A simple alternator which converts the rotational energy of the rotor into three-phase alternating current (AC) electricity. The alternator utilizes permanent magnets and has an inverted configuration in that the outside housing (magnet) rotates, while the internal windings and central shaft are stationary.
- Turbine blades and a rotor system, usually comprising three fibre glass blades;
- A simple lattice tower and tail assembly, the latter composed of a tail boom and the tail fin which keeps the rotor aligned into the wind at wind speeds below the limiting, or cut-out, wind speed. At wind speed exceeding cut-out the tail turns the rotor away from the wind to limit its speed.
- A power controller unit which serves as the central connection point for the electrical portion of the system and regulates the charging and discharging of the battery bank and incorporates protection features including load dumping and turbine protection.

Wind Turbine Economic and Environmental Assessment

The key design and performance assumptions regarding of wind turbines with output capacities from 0.3 kW to 100,000 kW are shown in Table A.8. We selected an average Capacity Factor of 30% across the board, even though Capacity factors are highly dependent on wind speeds at a given location and can vary from 20% to 40%. The uncertainty analysis performed will accommodate a broader rage of capacity factor.

Table A.8: Wind Turbine Design Assumptions

Capacity (MW)	300W	100kW	10MW	100MW
Capacity Factor (%)	25	25	30	30
Life span (year)	20	20	20	20
Annual Gross Generated Electricity (MWh)	0.657	219	26,280	262,800

As with most other renewable energy systems, the direct environmental impact in terms of air or water emissions is nil. There are other environmental impacts including noise, bird mortality, and aesthetic/visual impact. All of these impacts are highly location-specific and considerable mitigation is possible with careful design of the wind turbines and their deployment. The magnitude of costs associated with these impacts or their mitigation will differ greatly from region to region, and therefore we have elected not to attempt to quantify them in the economic assessment.

Table A.9 below shows the capital costs for different size of wind power projects.

Table A.9: Wind Turbine Capital Cost in 2005 ($/kW)

Items	300W	100kW	10MW	100MW
Equipment	3,390	2,050	1,090	940
Civil	770	260	70	60
Engineering	50	50	40	40
Erection	660	160	100	80
Process Contingency	500	260	140	120
Total	5,370	2,780	1,440	1,240

Table A.10 shows the levelized generation costs given the performance parameters of Table A.8 and considering average O&M costs for wind power projects.

Table A.10: Wind Turbine Generating Cost in 2005 (cents/kWh)

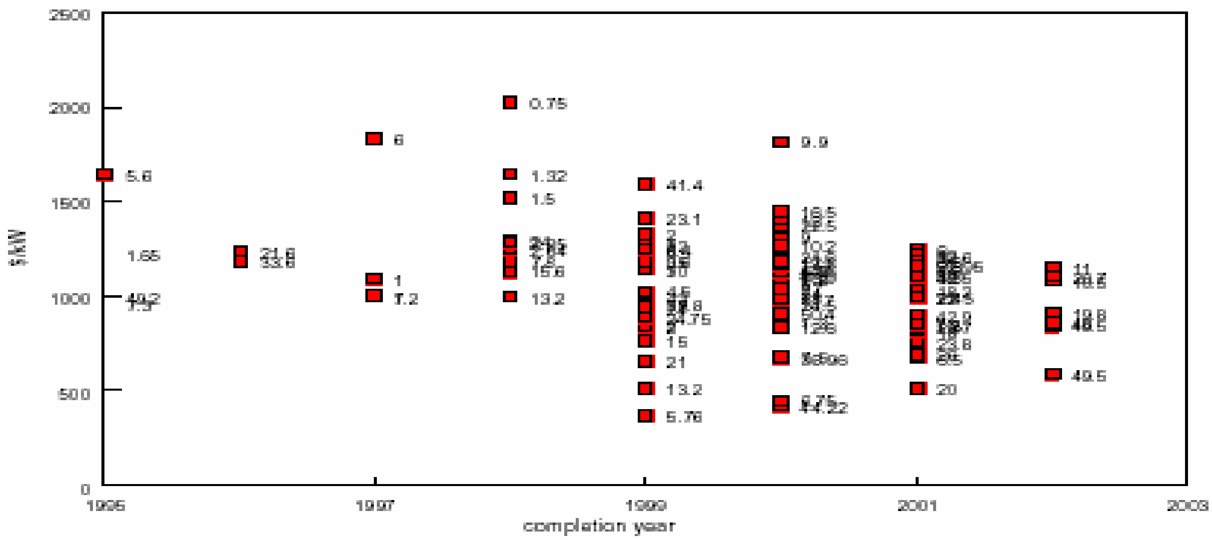
Items	300W	100kW	10MW	100MW
Levelized capital cost	26.18	13.55	5.85	5.04
Fixed O&M cost	3.49	2.08	0.66	0.53
Variable O&M cost	4.90	4.08	0.26	0.22
Fuel cost	0.00	0.00	0.00	0.00
Total	34.57	19.71	6.77	5.79

For small wind turbines the periodic cost of battery replacement was distributed (assuming 5 year average battery life) over system lifespan and included in the variable costs.

Future Wind Turbine Costs

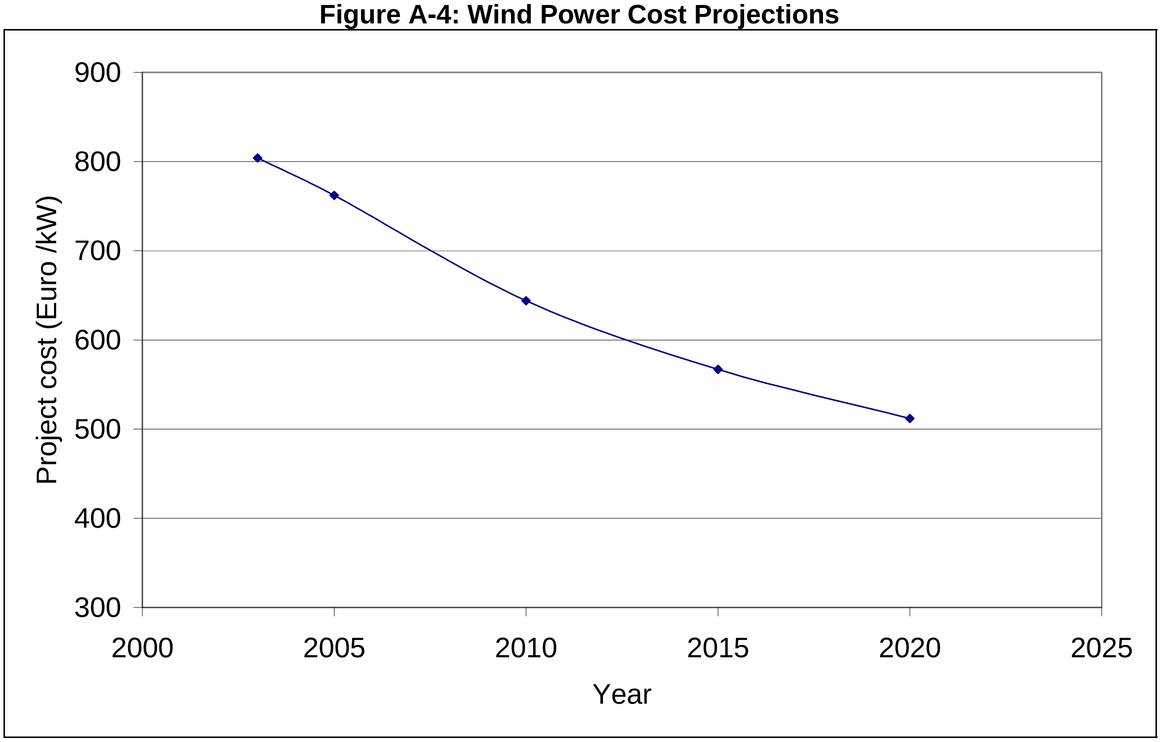
The costs of wind generators have been coming down over the years, as shown in Figure A-3. Most analysts expect this trend to continue in future, with reductions of as much as 36% in capital costs by 2020 forecast by the European Wind Energy Association (See Figure A-4).

Figure A-3: Wind Power Project Cost Trends



Source: Asia Alternative Energy Programme (ASTAE)

Figure A-4: Wind Power Cost Projections



Source: European Wind Energy Association

The Electric Power Research Institute (EPRI) also had made cost projections for the capital cost of wind power. As per the EPRI projections the costs for 10 MW plant would be about 1080$/kW in 2010 and 980$/kW in 2015 in terms of 1999$. In case of a 100MW plant the costs projections are about 850$/kW in 2010 and 750$.kW in 2015 in 1999$ terms.[3] We note, however, that the costs in many countries are lower than the EPRI costs. For example, in India the costs are about 1000 $/kW, while the costs in Germany, Denmark and Spain are in the 900 to 1200 €/kW in 2002.[4] Thus in our forecast of future wind turbine costs we have elected to use the EWEA cost projections as a lower bound and use the EPRI cost projections as an upper bound.[5]

Uncertainty Analysis

Table A.12 shows the results of our uncertainty analysis for wind power generation costs. Uncertainty analysis was performed to place bounds on both the inherent uncertainty stemming from a stochastic resource such as wind as well as the more-familiar uncertainties as regards forecast capital and other costs. The variation of the wind resource and thus wind turbine capacity factor from site to site can be generally captured by using the Weibull distribution. Since wind energy generation is a function of the wind speed variation as well as the power curve of the wind turbine, the capacity factor varies over time for a given location and for a specific time from location to location. In the present analysis the range of location-to-location variation of the capacity factor is used for the uncertainty analysis and is captured by letting the capacity factor range from 20% to 40%, with 30% as an average value. The uncertainty in projected capital costs, described above and shown in Table A.11, is included along with an assumed variability in O&M costs of ±20%.

Table A.11: Present and Projected Wind Turbine Capital Cost ($/kW)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300 W	4,820	5,370	5,930	4,160	4,850	5,430	3,700	4,450	5,050
100 kW	2,460	2,780	3,100	2,090	2,500	2,850	1,830	2,300	2,650
10 MW	1,270	1,440	1,610	1,040	1,260	1,440	870	1,120	1,300
100 MW	1,090	1,240	1,390	890	1,080	1,230	750	960	1,110

[3] Renewable Energy Technical Assessment Guide- TAG-RE: 2004, Electric Power Research Institute (EPRI), 2004
[4] Wind Energy – The Facts, Vol. 2: Costs and Prices, European Wind Energy Association, 2003
[5] We do this mathematically by using the GDP deflator to change the projection in 1999 dollar terms to 2004 dollar terms.

Table A.12: Present and Projected Wind Turbine Generation Cost, (cents/kWh)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300 W	30.1	34.6	40.4	27.3	32.0	37.3	25.2	30.1	35.1
100 kW	17.2	19.7	22.9	15.6	18.3	21.3	14.4	17.4	20.2
10 MW	5.8	6.8	8.0	5.0	6.0	7.1	4.3	5.5	6.5
100 MW	5.0	5.8	6.8	4.2	5.1	6.1	3.7	4.7	5.5

A.3 *SPV-Wind Hybrid Power Systems*

Another promising approach to meeting rural energy needs at the village level is PV-wind hybrid systems using small wind turbines.. Such a hybrid configuration is a viable alternative to expensive engine-generator sites for serving isolated mini-grids. The hybrid design approach also takes advantage of the differential availability of the solar resource and the wind resource, allowing each renewable resource to supplement the other, increasing the overall capacity factor.[6]

PV-Wind hybrid systems consist of the following components:

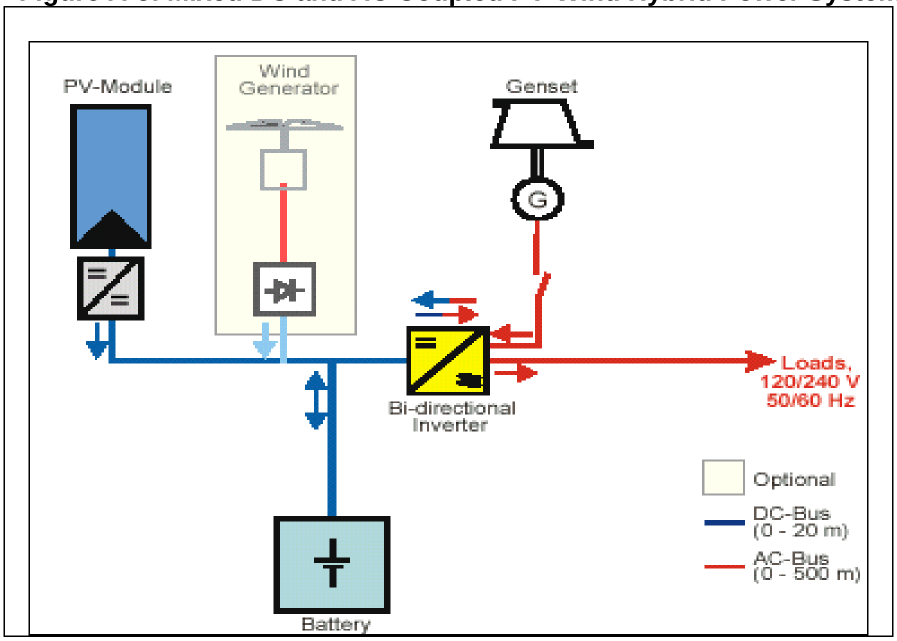
- One or more wind turbines (common capacity ranges from 5 to 100 kW)
- PV modules (capacity varies depending on load requirement and the nature of the control unit)
- Control unit (commonly known as inverter – cum – controller)
- Storage system (typically battery banks)
- Consumer load
- Additional controllable or dump load
- Additional provision for connecting diesel generating sets

The actual systems vary widely and depend on conditions specific to individual sites. The hybrid system architecture mainly depends on the nature of the inverter-cum-controller. The two most common system types are:

- A small AC mini-grid with DC-coupled components. Originally, this technology was created in order to provide AC power from DC sources and to use both DC and AC sources to charge batteries. Multiple AC generators are coupled on the AC side, and a suitable control strategy for generation and power delivery using a bi-directional inverter is implemented. The inverter can receive power from DC and AC generators and also works as a battery charger. The common power range is from 0.5 to 5 kW and DC voltage is 12, 24, 48 or 60 V. The system layout is shown in Figure A-5.
- Modular AC-coupled systems. Larger loads (3 to 100 kW) call for more traditional AC-coupled systems with all of the flexibility inherent to a more-conventional grid arrangement, but still incorporating battery storage and an optional DC bus. This arrangement requires coupling of all generators and consumers on the AC side. Since these kind of decentralized systems are grid compatible in their power characteristics, they can be deployed so that broader interconnection to other mini-grids or the national grid is possible in future. Such a structure allows maximum electrification flexibility in initially supplying rural villages with the power for basic needs and subsequently scaling-up the rural power available through progressive interconnection. The system layout is shown in the Figure A-6

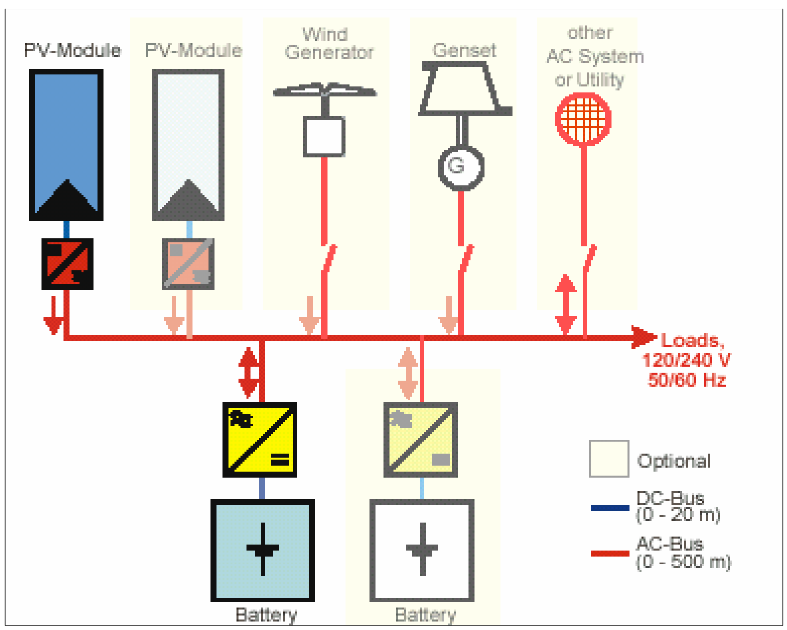
[6] Numerous studies including SWERA (Solar-Wind Energy Resource Assessment, UNDP) have observed this reverse coincidence of solar insolation and high wind speeds for many parts of the developing world.

Figure A-5: Mixed DC and AC Coupled PV-Wind Hybrid Power System



Source: DOE/EPRI

Figure A-6: Pure AC PV Wind Hybrid Power System



Source: DOE/EPRI

Solar-wind hybrid systems have been installed for a variety of applications around the world. Successful deployments include island mini-grids, remote facilities, and small buildings. Typical applications include water pumping, communications and hospitals.

A.4.1 Economic assessment

For the economic assessment we assume a system life of 20 years and a Capacity Factor of 30 percent. We note that the capital costs of hybrid systems are highly dependent on the system configuration and the individual capacities of the solar photovoltaic and wind energy systems. We have set typical costs for two size ranges - 300W and 100kW – as shown in Table A.13. These capital costs are calculated based on Indian small wind – PV hybrid systems' product data. [7]

Table A.13: PV-Wind Hybrid Power System 2005 Capital Cost ($/kW)

Items	300 W	100 kW
Equipment	4,930	3,680
Civil	460	640
Engineering	30	130
Erection	390	450
Process Contingency	630	520
Total	6,440	5,420

Table A.14 shows the results of PV-Wind hybrid system generating costs calculated in line with the methodology described in Annex B. Total O&M cost is assumed to be 2.5% of capital cost and is then divided into fixed and variable portions. Variable O&M cost also includes battery replacement aspect as per the SPV system.

Table A.14: PV-Wind Hybrid Power System 2005 Generating Cost (cents/kWh)

Items	300 W (CF 25%)	100 kW (CF 30%)
Levelized Capital cost	31.40	22.02
Fixed O&M cost	3.48	2.07
Variable O&M cost	6.90	6.40
Fuel cost	0.00	0.00
Total	41.78	30.49

The wind PV hybrid systems have a niche market in remote areas far from economical grid extension. The costs of these hybrid systems are projected to be reduced consistent with the cost projections for the individual solar PV and wind energy systems.

[7] See M/s. Auroville Wind Systems, particulary the 1.5 kW and 5 kW wind turbines with 130 Wp and 450Wp of SPV modules.

A.4.2 Uncertainty analysis

As with the individual SPV and wind technologies, the key uncertainties affecting delivered generation costs revolve around expected Capacity Factor and capital cost variability. Since the hybrid systems combine two resources, the range over which Capacity Factor can vary will be smaller than with the individual technologies. We assume a Capacity Factor in the range from 25% to 40%, with 30% as probable value. We carry forward the uncertainties in projected capital costs, shown in Table A.15, and assume a ± 20% variation in O&M costs in order to estimate the band of generation cost estimates in the years 2010 and 2015 shown in Table A.16.

Table A.15: PV Wind Hybrid Power System Projected Capital Cost ($/kW)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300W	5,670	6,440	7,210	4,650	5,630	6,440	3,880	5,000	5,800
100kW	4,830	5,420	6,020	4,030	4,750	5,340	3,420	4,220	4,800

Table A.16: PV Wind Hybrid Power System Projected Generating Cost (cents/kWh)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300W	36.1	41.8	48.9	31.6	37.8	44.5	28.1	34.8	40.9
100kW	26.8	30.5	34.8	23.8	27.8	31.7	21.4	25.6	29.1

A.4 *Solar Thermal Electric Power Systems*

Solar thermal power generation technologies comprise several technically viable options for concentrating and collecting solar energy in densities sufficient to power a heat engine. These include Parabolic Dish collectors, Parabolic Trough collectors, and Central Receivers. Only the Parabolic Trough configuration has found commercial application. Although several large solar thermal electric projects are in the planning stages, and other options are in the research and development stage, the amount of installed solar thermal electric capacity around the world is negligible compared with SPV or wind turbines. Only the parabolic trough based solar thermal electric system is considered for the present study.

A.4.1 Technology Description

The parabolic trough concentrator is essentially a trough lined with reflective material. The concentrators track the sun with a single-axis mechanical tracking system oriented east to west. The trough focuses the solar insolation on a receiver located along its focal line. A collector field consists of large number of concentrators sufficient to generate the required amount of thermal energy. A heat transfer fluid (or thermic fluid), typically high temperature oil, is circulated via pipes to the concentrators and the heated fluid is then pumped to a central power block, where it exchanges its heat to generate steam (See Figure A-7)**. The power block consists of steam turbine and generator, turbine and generator auxiliaries, feed-water and condensate system. A variant of this technology is the Direct Solar Steam (DSS) concentrator, which eliminates the heat transfer loop by generating steam directly at the concentrator. A solar thermal electric power plant can also have thermal storage, which improves the capacity factor but increases the cost. While both options are analysed here, the present trend is to use the solar thermal plant without thermal storage in large, grid-connected applications.**

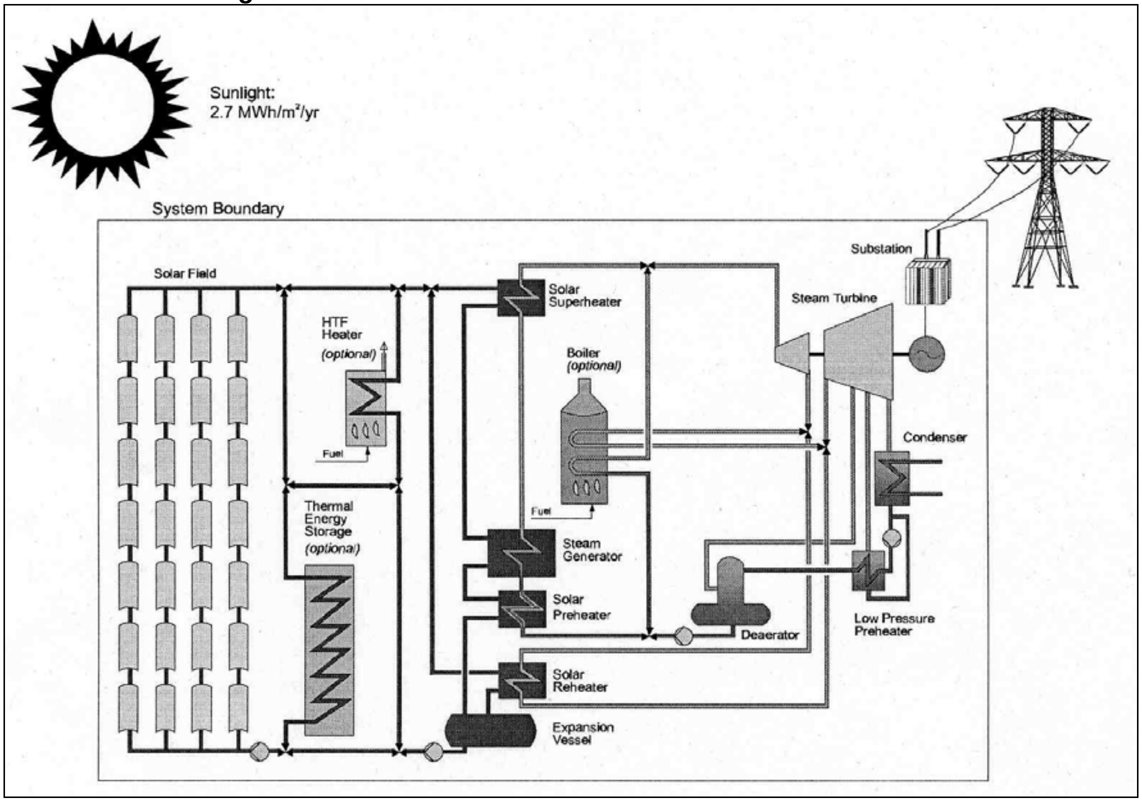
A.4.2 Economic assessment

The design and performance assumptions for solar thermal electric power projects are listed in Table A.17 below. We assessed two configurations (with and without storage) but only one size range – 30 MW – which is typical of several projects under development in Spain and the Middle East North Africa (MENA) region.[8] The capacity factor for solar thermal power projects is dependent on the availability of solar resource, especially in the case of plants without storage. A capacity factor of 20% was used for analysis of plants without thermal storage and 54% was used for analysis of plants with thermal storage.[9]

[8] See for example Project Information Document (PID) – Arab Republic of Egypt Solar Thermal Power Project. Report No. AB662 and *Solar Thermal Power 2020: Exploiting the Heat from the Sun to Combat Climate Change*, Greenpeace 2004.

[9] *Assessment of Parabolic Trough and Power Tower Solar technology Cost and performance Forecasts*, National Renewable Energy Laboratory (NREL), NREL/SR-550-34440, October 2003

Figure A-7: Solar Thermal Electric Power Plant Schematic



Source: DOE/EPRI

Table A.17: Solar Thermal Electric Power System Design Assumptions

Capacity (MW)	30MW (without thermal storage)	30MW (with thermal storage)
Capacity Factor (%)	20%	50%
Life span (year)	30	30
Gross Generated Electricity (GWh/year)	52	131

Table A.18 provides a capital cost breakdown based on NREL data for solar thermal power projects with and without thermal storage, exclusive of land costs.

Table A.18: Solar Thermal Electric Power System 2005 Capital Costs ($/kW)

Items	30 MW (without thermal storage)	30 MW (with thermal storage)
Equipment	890	1,920
Civil	200	400
Engineering	550	920
Erection	600	1,150
Process Contingency	240	460
Total	2,480	4,850

Harmful emissions and pollution impacts of solar thermal power generation are nil. Water requirements, mainly for the cooling towers, is an issue, as most potential sites for solar thermal power generation are in arid or desert areas.

The generating cost (See Table A.19) is estimated using the capital costs in Table A.18 and based on the performance parameters mentioned in Table A.17. O&M costs are taken from National Renewable Energy Laboratory (NREL) data.

Table A.19: Solar Thermal Electric Power 2005 Generating Costs (cents/kWh)

Items	30 MW (without thermal storage)	30 MW (with thermal storage)
Levelized Capital cost	13.65	10.68
Fixed O&M cost	3.01	1.82
Variable O&M cost	0.75	0.45
Fuel cost	0.0	0.0
Total	17.41	12.95

A.4.3 Future System Cost projections

The cost assessment report by NREL forecasts the possible cost reductions in the solar thermal power generation based on an analysis of technology improvement projections and scale up. The projected reduction (15% by 2010 for the non-storage configuration and 33% by 2015 for the storage case) is a result of lower solar collector system and mirror costs as well as cheaper storage costs due to technological improvements and economies of scale. These cost projections are shown in Table A.20 and are taken forward into the uncertainty analysis.

Table A.20: Solar Thermal Electric Power Capital Cost Projections ($/kW)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
30MW (without storage)	2,290	2,480	2,680	1,990	2,200	2,380	1,770	1,960	2,120
30 MW (with storage)	4,450	4,850	5,240	3,880	4,300	4,660	3,430	3,820	4,140

A.4.4 Uncertainty analysis

Solar thermal power plant capacity factor varies according to location; however, locating these large expensive plants in areas of high solar radiation will minimize any uncertainty associated with Capacity Factor. For our uncertainty analysis we will allow capacity factor to vary between 18–25%, with 20% as the probable value for plants without storage and no variation in case of the plants with storage.

Our uncertainty analysis for estimations of generation cost further assumes the capital cost variability shown in Table A.20 and an assumed ± 20 percent variation in operating costs. The results are shown in Table A.21.

Table A.21: Solar Thermal Electric Power Generating Cost Projections (cents/kWh)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
30MW (without storage)	14.9	17.4	21.0	13.5	15.9	19.0	12.4	14.5	17.3
30 MW (with storage)	11.7	12.9	14.3	10.5	11.7	12.9	9.6	10.7	11.7

A.5 *Geothermal Power Systems*

Geothermal energy arises from the heat deep within the earth. Worldwide, the most accessible geothermal resources are found along the boundaries of the continental plates, in the most geologically active portions of the earth.

Two primary types of geothermal resource are being commercially developed – naturally-occurring hydrothermal resources and engineered geothermal systems. Hydrothermal reservoirs consist of hot water and steam found in relatively shallow reservoirs, ranging from a few hundred to as much as 3,000 meters in depth. Hydrothermal resources are the current focus of geothermal development because they are relatively inexpensive to exploit. A hydrothermal resource is inherently permeable, which means that fluids can flow from one part of the reservoir to another, and can also flow into and from wells that penetrate the reservoir. In hydrothermal resources, water descends to considerable depth in the crust where it is heated. The heated water then rises until it becomes either trapped beneath impermeable strata, forming a bounded reservoir, or reaches the surface as a hot spring or steam vent. The rising water brings heat from the deeper parts of the earth to locations relatively near the surface.

The second type of geothermal resource is "engineered geothermal systems (EGS)", sometimes referred to as "hot dry rocks". These resources are found relatively deep in masses of rock that contain little or no steam, and are not very permeable. They exist in geothermal gradients, where the vertical temperature profile changes are greater than average (>50°C/km). A commercially attractive EGS would involve prospecting for hot rocks at depths of 4,000 meters or more. To exploit the EGS resource, a permeable reservoir must be created by hydraulic fracturing, and water must be pumped through the fractures to extract heat from the rock. Most of the EGS/HDR projects to date have been essentially experimental; but there is future commercial potential.

Commercial exploitation of geothermal systems in developing economies is constrained by two factors:

- Geothermal exploration, as with most resource extraction ventures, is inherently risky. Geothermal power systems are difficult to plan because what lies beneath the ground is only poorly understood at the onset of development. It may take significant work to prove that out a particular field, and many exploration efforts have failed altogether. The exception is areas with many hydrothermal manifestations (e.g., geysers, mud pots), such as The Geysers in the U.S. and a number of fields in Indonesia and Central America.
- Both exploration and development require substantial specialized technical capacity that is not usually available in developing countries unless there has been focused local capacity building or an influx of specialists and creation of local teams. Countries where such teams have been successful or are emerging include The Philippines, Mexico, Indonesia, Kenya, and El Salvador.

A.5.1 Technology Description

For developing country applications we assume that geothermal systems will be available in small size suitable for mini-grid applications and a larger size suitable for grid-electric applications:

- For mini-grid applications, 200 kW Binary hydrothermal
- For Grid applications, a 20 MW Binary hydrothermal and a 50 MW Flash hydrothermal

Figure A.8 provides a schematic for a binary hydrothermal electric power system of indeterminate size. Figure A.9 provides a schematic for a flash hydrothermal unit.

A.5.2 Environmental and Economic Assessment

Table A.22 provides the basic design and performance assumptions we associate with the binary hydrothermal and flash hydrothermal electric power project shown in Figure A-8

Figure A-8: Binary Hydrothermal Electric Power System Schematic

and Figure A-9.

Source: DOE/EPRI

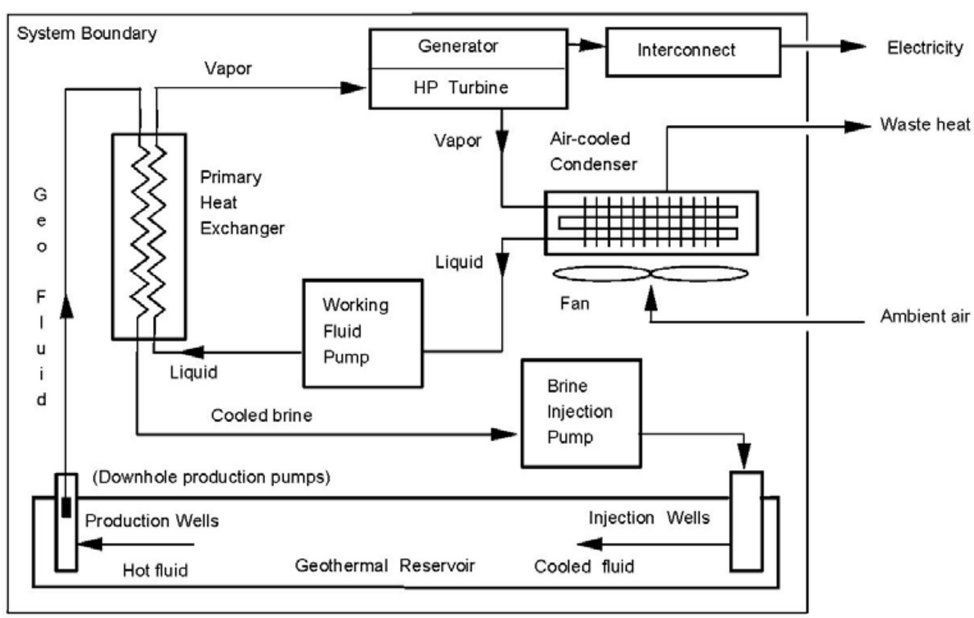
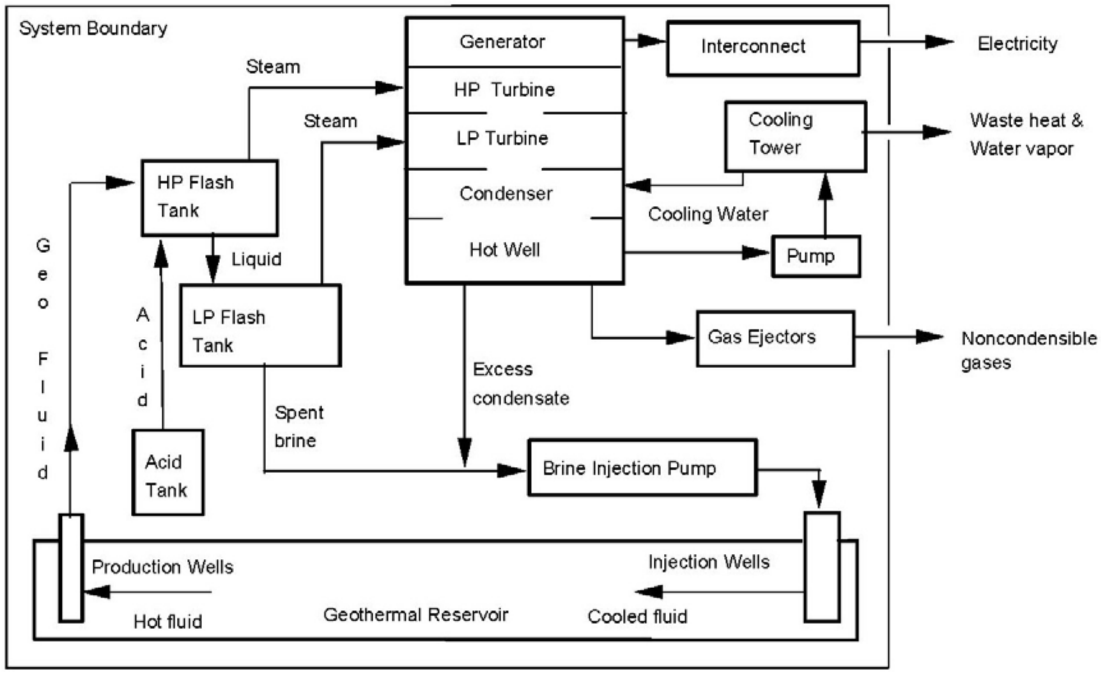


Figure A-9: Flash Hydrothermal Electric Power System



Source: DOE/EPRI

Table A.22: Basic Characteristics of Geothermal Electric Power Plants

	Binary Hydrothermal	Binary Hydrothermal	Flash Hydrothermal Plants
Capacity (MW)	200 kW	20 MW	50 MW
Capacity Factor (%)	70	90	90
Geothermal Reservoir Temperatures	125-170°C	125-170°C	>170°C
Life span (year) *	20	30	30
Net Generated Electricity (MWh/year)	1,230	158,000	394,200

* Although the plant life span is 20-30 years, wells will be depleted and new wells be drilled much before that time. An allowance for this additional drilling is included in the generating cost estimates.

Large geothermal plants can generally operate as base loaded facilities with capacity factors comparable to or higher than conventional generation (90% CF). Binary plants in mini-grid applications will have lower capacity factors (30-70%), due mainly to limitations in local demand. We consider only the high capacity factors for small binary systems, as they will be the most cost-effective. The viability of the geothermal resource is dictated by local geological conditions. For this report, we assume that hot water resources can be categorized as being either high temperature (>170°C) or moderate temperature (<170°C and >125°C).

Because they operate in a closed loop mode, binary plants have no appreciable emissions, except for very slight leakages of hydrocarbon working fluids. Some emissions of hydrogen sulfide are possible (no more than 0.015 kg/MWh), but H_2S removal equipment can easily eliminate any problem. CO_2 emissions are small enough to make geothermal power a low CO2 emitter relative to fossil fuel plants.

Table A.23 shows the conventional breakdown of geothermal capital costs into the standard cost components used in this study.

Table A.23: Geothermal Electric Power Plant 2005 Capital Costs ($/kW)

Items	200 kW Binary Plant	20 MW Binary Plant	50 MW Flash Plant
Equipment	4,350	1,560	955
Civil	750	200	125
Engineering	450	310	180
Erection	1,670	2,030	1,250
Total	7,220	4,100	2,510

Table A.24 shows a breakdown in the capital cost estimates organized by the sequence of development activities, e.g., Exploration Costs (to discover first productive well), Confirmation Costs (additional drilling to convince lenders that the site has commercial capability, Main Wells Costs (remaining wells drilled during construction phase) and remaining costs associated with construction of the power plant itself.

Table A.24: Geothermal Capital Costs by Development Phase ($/kW)

Items	200 kW Binary Plant	20 MW Binary Plant	50 MW Flash Plant
Exploration	300	320	240
Confirmation	400	470	370
Main Wells	800	710	540
Power Plant	4,250	2,120	1,080
Other	1,450	480	280
Total	7,220	4,100	2,510

For the 200 kW binary projects we set the contingency cost quite high, because very few projects of this size have been built. It is likely that the risk associated with such small projects would be unattractive for commercial firms, and thus a public sector entity would be the most likely implementing agency for such systems.

Table A.25 shows the results of converting capital cost into generating cost, in line with Annex B. O&M costs are stated as fixed costs here because the truly variable costs, e.g. lubricants, are very low. Most of the O&M is in labor for the power plant. O&M for binary systems includes replacement of down-hole production pumps at 3 to 4 year intervals.

Table A.25: Geothermal Power Plant 2005 Generation Cost (cents/kWh)

Items	200 kW Binary Plant	20 MW Binary Plant	50 MW Flash
Levelized Capital cost	12.57	5.02	3.07
Fixed O&M cost	2.00	1.30	0.90
Variable O&M cost	1.00	0.40	0.30
Total	15.70	6.72	4.27

A.5.3 Future Price of Geothermal Electric Power Plants

It is difficult to predict future prices for geothermal power systems. There have been long term trends (since 1980) of price declines, of about 20% per decade for power plants, and 10% per decade for geothermal production and injection wells (relative to petroleum wells). Recently, variations in oil prices have been so large that they obscure any useful projections in cost reductions of geothermal exploration or development. In fact, the recent increases in oil prices have driven up the apparent cost of geothermal wells in the U.S. in the past year. We assume a flat cost trajectory for this technology, as shown in Table A.26.

Table A.26: Geothermal Power Plant Capital Cost Projections ($/kW)

	2005	2010	2015
200 kW Binary Plant	7,220	6,580	6,410
20 MW Binary Plant	4,100	3,830	3,730
50 MW Flash Plant	2,510	2,350	2,290

Many industry analysts contend that geothermal R&D and improved economies of scale due to large-scale deployment can help the industry resume the downward trends seen since 1980. There may also be opportunities to locate binary systems in areas with shallow reservoirs, where the costs of drilling and well maintenance may be lower. The section on uncertainty analysis attempts to reflect this improvement potential through the quantification of a “minimum” capital cost. For purposes of the uncertainty analysis below we draw from the EPRI work on renewable energy to establish a range of expected capital cost reductions (generally, -20% and +10%) over the study period.

A.5.4 Uncertainty Analysis Future Price of Geothermal Electric Power Plants

The cost of geothermal power plants can be quite variable, depending on the specific resource that is being used. This fact is reflected in the range of capital costs presented in Table A.27.

Table A.27: Geothermal Power Plant Capital Cost Uncertainty Range ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
200 kW Binary	6,480	7,220	7,950	5,760	6,580	7,360	5,450	6,410	7,300
20 MW Binary	3,690	4,100	4,500	3,400	3,830	4,240	3,270	3,730	4,170
50 MW Flash	2,260	2,510	2,750	2,090	2,350	2,600	2,010	2,290	2,560

Table A.28 shows projected ranges in levelized generating cost given the capital cost ranges presented in Table A.27 and the O&M costs presented in Table A.25.

Table A.28: Geothermal Power Plant Projected Generating Cost (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
200 kW Binary	14.2	15.6	16.9	13.0	14.5	15.9	12.5	14.2	15.7
20 MW Binary	6.2	6.7	7.3	5.8	6.4	6.9	5.7	6.3	6.8
50 MW Flash	3.9	4.3	4.6	3.7	4.1	4.4	3.6	4.0	4.4

A.6 *Biomass Gasifier Power Systems*

Biomass gasification is the process through which solid biomass material is subjected to partial combustion in the presence of a limited supply of air. The ultimate product is a combustible gas mixture known as 'producer gas'. The combustion of biomass takes place in a closed vessel, normally cylindrical in shape, called a 'gasifier'. Producer gas typically contains nitrogen (50-54%), carbon dioxide (9-11%), methane (2-3%), carbon mono oxide (20-22%) and hydrogen (12-15%). Producer gas has relatively low thermal value, ranging from 1000-1100 k.cal/m^3 (5500 – MJ/m^3) depending upon the type of biomass used.

Gasification of biomass takes place in four distinct stages: drying, pyrolysis, oxidation/combustion and reduction. Biomass is fed at the top of the hopper. As the gasifier is ignited in the oxidation zone, the combustion takes place and the temperature rises (900-1200º C). As the dried biomass moves down, it is subjected to strong heating (200-600º C), in the pyrolysis zone. The biomass starts loosing the volatiles at above 200º C and, continues until it reaches the oxidation zone. Once the temperature reaches 400º C, the structure of wood or other organic solids breaks down due to exothermic reactions, and water vapor, methanol, acetic acid and tars are evolved. This process is called pyrolysis. These products of pyrolysis are drawn towards the oxidation zone, where a calculated quantity of air is supplied and the combustion (similar to normal stove/furnace) takes place. A portion of pyrolysis gases and char burns here which raises the temperature to 900º - 1200º C in the oxidation zone. Partial oxidation of biomass by gasifying agents (air or O_2) takes place in the oxidation zone producing high temperature gases (CO_2), also containing products of combustion, cracked and uncracked pyrolysis products, and water vapor (steam) which pass through the reduction zone consisting of a packed bed of charcoal. This charcoal is initially supplied from external sources, and later the char produced in the pyrolysis zone is simultaneously supplied. The reactions in the reduction zone are endothermic and temperature sensitive (900º C - 600º C). The principal chemical reactions taking place in a gasifier are shown in Table A.29.

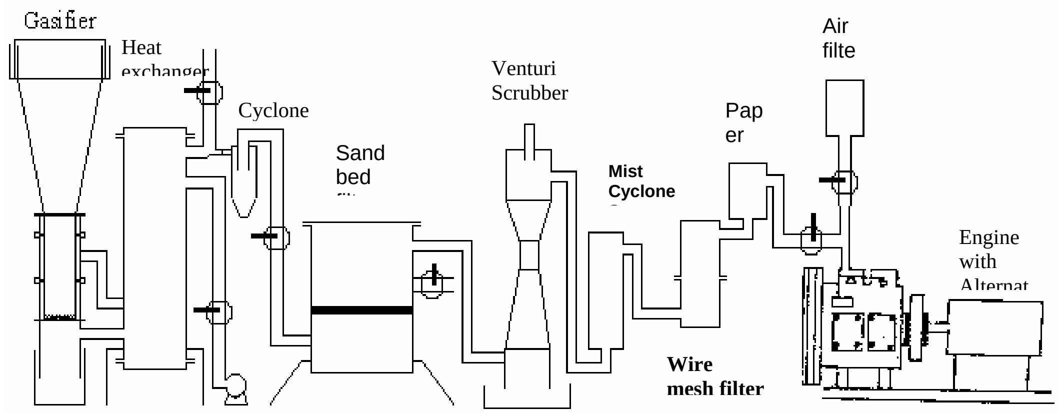
Table A.29: Principle Chemical Reactions in a Gasifier Plant

Reaction type	Reaction	Enthalpy (kJ/mol)
Devolatilization	C+heat = CH_4+condensable hydrocarbons + char	
Steam-carbon	C+H_2O+heat = CO+H_2	131.4
Reverse boudouard	C + CO_2 + heat = 2CO	172.6
Oxidation	C + O_2 = heat	-393.8
Hydro gasification	C+ 2H_2 = CH_4 + heat	-74.9
Water gas shift	H_2O + CO = H_2 + CO_2 + heat	-41.2
Methanation	3H_2 + CO = CH_4 + H_2O + heat 4H2 + CO_2 = CH_4 + 2H_2O + heat	-206.3 -165.1

In the above reactions, devolatilization takes place in the pyrolysis zone, oxidation in the oxidation zone, and all other reactions in the reduction zone. The low thermal value (about 10-15% of natural gas), of producer gas is mainly due to diluting effect of nitrogen present in the combustion air. Since nitrogen is inert, it passes through the gasifier without entering into any major chemical reactions. An efficient gasifier produces a clean gas over a range of flow rates of gas. If all the above mentioned processes take place efficiently, the energy content of the producer gas would contain about 70-78% of the energy content of the biomass entering the gasifier.

The gasification process is influenced by two parameters - properties of the biomass, and the gasifier design. Biomass properties such as energy content, density, moisture content, volatile matter, fixed carbon, ash content and also size and geometry of biomass affect the gasification process. The design of the oxidation zone is the most important, as the completion of each reaction depends on the residence time of biomass in the oxidation and reduction zones. Figure A-10 shows the schematic of a gasifier based power generation system.

Figure A-10: Biomass Gasifier Power System Schematic



Source: DOE/EPRI

A.6.1 Biomass Gasifier Technology Assessment

There are three main types of gasifiers – down draft, updraft and cross draft. In the case of down draft gasifiers, the flow of gases and solids occurs through a descending packed bed. The gases produced here contain the least amount of tar and particulate matter. Downdraft gasification is fairly simple, reliable and proven for certain fuels. In case of updraft gasifiers, the gases and solids have counter-current flow and the product gas contains a high level of tar and organic condensable. In the cross draft gasifier, solid fuel moves down and the airflow moves horizontally. This has an advantage in traction applications. But the product gas is however, high in tars and requires cleaning.

Other kinds of gasification technology include fluidized bed gasifiers and pyrolyzers. In a fluidized bed gasifier, the air is blown through a bed of solid particles at a sufficient velocity to keep them in a state of suspension. The bed is initially heated up and then the feedstock is introduced at the bottom of the reactor when the temperature of the reactor is quite high. The fuel material gets mixed up with the bed material and until its temperature is equal to the bed temperature. At this point the fuel undergoes fast pyrolysis reactions and evolves the desired gaseous products. Ash particles along with the gas stream are taken over the top of the gasifier and are removed from the gas stream, and the clean gas is then taken to engine for power generation.

A.6.2 Economic and Environmental Assessment

Table A.30 gives details of the design and performance parameters we will assume for the economic assessment of biomass gasifier technology.

Table A.30: Biomass Gasifier System Design Assumptions

Capacity (kW)	100 kW	20 MW
Fuel	Wood/wood waste/ agro waste	Wood/wood waste/ agro waste
Calorific value of fuel	4,000 kcal/kg	4,000 kcal/kg
Capacity factor	80%	80%
Producer Gas calorific value	1000-1200 kcal/Nm3	1000-1200 kcal/Nm3
Life Span of system	20 years	20 years
Specific fuel consumption	1.6 kg/kWh	1.5 kg/kWh

Biomass gasifier projects are considered to be Green House Gas (GHG) neutral, as there is sequestration of GHGs due to the growth of biomass feedstock - provided that the biomass used is harvested in a sustainable way. Environmental impacts associated with combustion of the biomass gas are assumed to be constrained by emissions control regulation, consistent with World Bank standards.

Table A.31 shows the capital costs associated with biomass gasifier based power plants of two representative sizes – 100 kW for mini grids and 20 MW for large-scale grid-connected applications.

Table A.31: Biomass Gasifier Power System 2005 Capital Cost ($/kW)

Capacity	100 kW	20 MW
Equipment cost	2,490	1,740
Civil cost	120	110
Engineering	70	40
Erection cost	70	60
Process Contingency	130	100
Total capital cost	2,880	2,030

Fuel cost is the most important parameter in estimating the generation costs of any biomass based power generation technology. The cost of biomass depends on many parameters, including project location, type of biomass feedstock, quantity required, and present and future alternative use. Biomass fuel costs can vary widely; in this study we use a range from 11.1 $/ton (0.64$/GJ) to 33.3$/ton (1.98 $/GJ), with 16.6$/ton (0.99$/GJ) as a probable value.

Based on the design and performance parameters given in Table A.30, the total generating cost can be estimated inclusive of O&M costs. Table A.32 shows the results.

Table A.32: Biomass Gasifier Power System 2005 Generating Cost (cents/kWh)

Capacity	100 kW	20 MW
Capital	4.39	3.09
Fixed O&M cost	0.34	0.25
Variable Cost	1.57	1.18
Fuel Cost	2.66	2.50
Total	8.96	7.02

A.6.3 Future Price and Uncertainty Analysis

The future cost of these systems will likely be less than at present, as biomass gasification has considerable potential for technology improvements and economies of mass production. We assume that improvements in the areas of low tar producing 2-state gasifiers and improved cleaning and cooling equipment will yield an eight percent reduction in capital costs by 2010 (See Table A.33).

The range over which projected biomass gasifier generation costs can vary are primarily a result of uncertainty in future cost projections plus variations in fuel costs. We carried out an uncertainty analysis to estimate the range over which the generation costs could vary due to these variable parameters and the projected generating cost bands are provided in Table A.34.

Table A.33: Biomass Gasifier Power System Capital Cost Projections ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Gasifier 100kW	2,490	2,880	3,260	2,090	2,560	2,980	1,870	2,430	2,900
Gasifier 20MW	1,760	2,030	2,300	1,480	1,810	2,100	1,320	1,710	2,040

Table A.34: Biomass Gasifier Power Generating Cost Projections (cents/kWh)

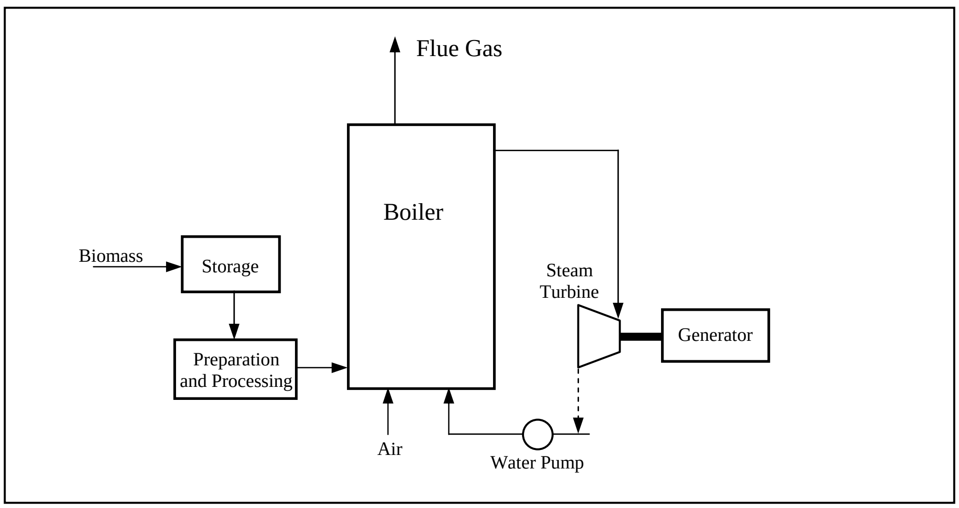
	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Gasifier 100kW	8.2	9.0	9.7	7.6	8.5	9.4	7.3	8.3	9.5
Gasifier 20MW	6.4	7.0	7.6	6.0	6.7	7.5	5.8	6.5	7.5

A.7 *Biomass Steam Power Systems*

Biomass combustion technologies convert biomass fuels into several forms of useful energy including hot air, steam or power generation. Biomass based power generation technologies can be classified as direct firing, gasification and pyrolysis. This section will cover the direct fired biomass combustion based electricity generation.

A biomass fired boiler generates high pressure steam by direct combustion of biomass in a boiler. The steam then passes through a steam turbine to produce electricity. A boiler's output contains 60 to 85 % of the potential energy in biomass fuel. There are three major types of biomass combustion boilers - pile burner, stationary/travelling grate combustors, and fluidized-bed combustors. A schematic diagram of direct-fired biomass electricity generating system is shown in Figure A-11.

Figure A-11: Biomass Steam Electric Power System Schematic



A.7.1 Technology Description

A Pile Burner combustion boiler consists of cells, each with an upper and lower combustion chamber. Biomass burns on a grate in lower chamber, releasing volatile gasses which then burn in the upper chamber. Current biomass combustor designs utilize high efficiency boilers and stationary or travelling grate combustors with automatic feeders that distribute the fuel onto a grate to burn. In stationary grate design, ashes fall into a pit for collection, whereas in travelling grate type the grate moves and drops the ash into a hopper.

Fluidized–bed combustors are the most advanced biomass combustors. In a fluidized–bed combustor the biomass fuel is in a small granular form (e.g., rice husk) and is mixed and burned in a hot bed of sand. Injection of air into the bed creates turbulence, which distributes and suspends the fuel while increasing the heat transfer and allowing for combustion below the temperature normally resulting in NO_x emissions. Combustors designed to handle high ash fuels and agricultural biomass residue have special features which handle slagging and fouling problems due to potassium, sodium and silica found in agricultural residues.

A.7.2 Economic and Environmental Assessment

The design and performance parameters assumed for biomass steam power projects are given in Table A.35. Note that only one size – large, grid-connected – is assessed. Such a large power system has a high Capacity Factor, assuming continuous availability of the biomass feedstock, comparable to that of a conventional central station power plant.

Table A.35: Biomass Steam Electric Power System Design Assumptions

	Biomass steam
Capacity (MW)	50MW
Capacity Factor (%)	80
Fuel	Wood/wood waste/ agro waste
Calorific value of fuel	4,000 kcal/kg
Specific fuel consumption	1.5 kg/kWh
Life span (year)	20
Gross Generated Electricity (GWh/year)	350

The biomass steam projects are considered to be Green House Gas (GHG) neutral, as there is sequestration of CO_2 due to the biomass cultivation, provided that the biomass used is harvested in sustainable way.

Table A.36 gives the capital cost breakdown for a biomass steam power plant.

Table A.36: Biomass Steam Electric Power Plant 2005 Capital Costs ($/kW)

Items	Cost
Equipment	1,290
Civil	170
Engineering	90
Erection	70
Process Contingency	80
Total	1,700

Based on the capacity factor and the life of the plant the capital cost is annualized and the generating cost is estimated in Table A.37.

Table A.37: Biomass Steam Electric Power Plant 2005 Generating Cost (cents/kWh)

Capital	2.59
Fix O&M	0.45
Variable O&M	0.41
Fuel	2.50
Total	5.95

A.7.3 Future Cost Projections and Uncertainty Analysis

The future costs for biomass steam generation projects are expected to drop as a result of increased market penetration and technology standardization. Cost reductions of about 10% by the year 2010 are expected and are reflected in Table A.38.

Table A.38: Biomass Steam Electric Power Plant Projected Capital Costs ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Biomass steam 50MW	1,500	1,700	1,910	1,310	1,550	1,770	1,240	1,520	1,780

The uncertainty analysis for generating cost was carried out using the range of present and future costs, as shown in Table A.38. However, the key uncertainty in estimating the generation costs of any biomass based power generation technology is fuel cost. The cost of biomass depends on large number of parameters including project location, type of biomass feedstock, quantity required, and present and future alternative use. Biomass fuel costs can vary widely; in this study we use a range from 11.1 $/ton (0.64$/GJ) to 33.3$/ton (1.98 $/GJ), with 16.6$/ton (0.99$/GJ) as probable value. An O&M cost variation of 20% was also assumed.

Based on the cost projections the generation cost for biomass steam power plant was estimated and shown in Table A.39 below. The effect of variation in different cost components in the generation cost is shown in the tornado charts in Annex D.

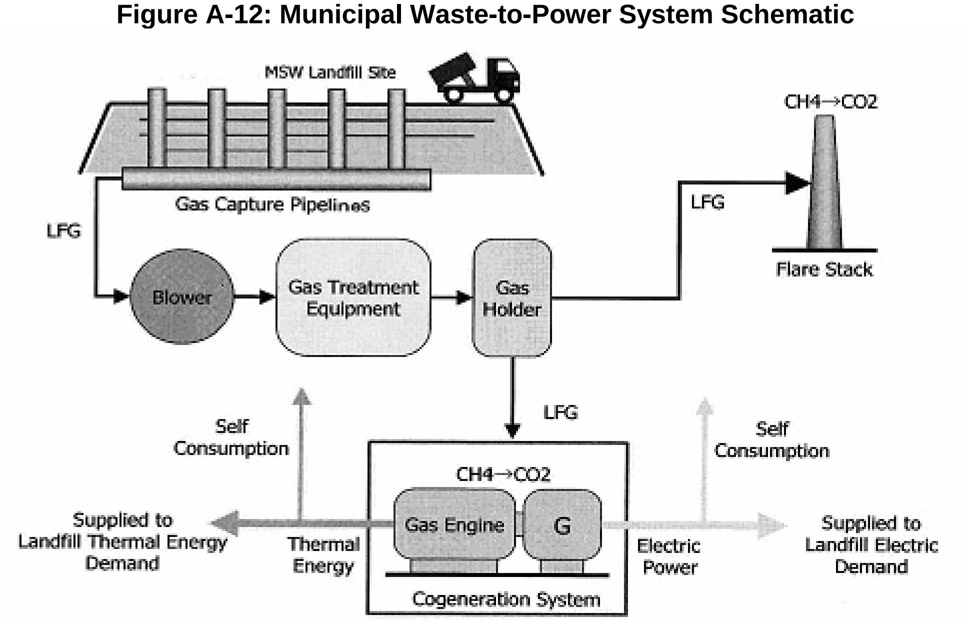
Table A.39: Biomass Steam Electric Power Projected Generating Costs (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Biomass steam 50MW	5.4	6.0	6.5	5.2	5.7	6.4	5.1	5.7	6.6

A.8 *Municipal Waste-to-Power System Using Anaerobic Digestion*

Municipal solid waste contains significant portions of organic materials that produce a variety of gaseous products when dumped, compacted, and covered in landfills. Anaerobic bacteria thrive in the oxygen-free environment, resulting in the decomposition of the organic materials and the production of primarily carbon dioxide and methane. Carbon dioxide is likely to leach out of the landfill because it is soluble in water. Methane, on the other hand, which is less soluble in water and lighter than air, is likely to migrate out of the landfill. Landfill gas energy facilities capture the methane (the principal component of natural gas) and combust it for energy. Figure A.12 shows a schematic diagram of a landfill-based municipal waste to energy operation.

Figure A-12: Municipal Waste-to-Power System Schematic



Source: Ministry of the Environment, Government of Japan

A.8.2 Technology Description

The biogas comprises methane, carbon dioxide, hydrogen and traces of hydrogen sulphide. The biogas yield and the methane concentration depend on the composition of the waste and the efficiency of the chemical and collection processes. The biogas produced is either used for thermal applications, such replacing fossil fuels in a boiler, or as a replacement for LPG for cooking. The biogas after treatment can also be used in gas engines to generate electric power.

A.8.3 Environmental and Economic Assessment

We assume the design and performance parameters listed in Table A.39 in the economic assessment.

Table A.40: Municipal Waste-to-Power System Design Assumptions

Capacity (MW)	5MW
Capacity Factor (%)	80
Fuel Type	Municipal Solid Waste
Life span (year)	20
Gross Generated Electricity (GWh/year)	35

Since the gas (mainly methane) derived from the waste is used for power generation, the emissions will be below the prescribed standards. Waste to energy projects result in net GHG emission reductions, since methane emissions that might otherwise emanate from land fill sites are avoided.

Table A.41 gives the capital cost breakdown for a typical MSW plant of indeterminate size.

Table A.41: Municipal Waste-to-Power System 2005 Capital Costs ($/kW)

Items	Cost
Equipment	1,500
Civil	900
Engineering	90
Erection	600
Contingency	160
Total	3,250

Using the assumed capacity factor and plant lifespan we annualize the capital cost is annualized and add O&M costs to produce the estimate of generating cost shown in Table A.42. Note that there is no fuel cost, as we assume the feedstock (municipal solid waste) will be provided free of charge. However, provision for royalties to an assumed municipal corporation from the sale of electricity and manure is included under variable costs.

Table A.42: Municipal Waste-to-Power System 2005 Generating Costs (cents/kWh)

Capital	4.95
Fix O&M	0.11
Variable O&M	0.43
Fuel	1.00
Total	6.49

A.8.4 Future Cost Projections and Uncertainty Analysis

There will be a decrease in future of the capital cost as well as generating costs of waste-to-power systems. We assume these trends will result in a decrease in equipment cost of 15% by 2015.

The uncertainty analysis for the generation cost was carried out using the range of expected capital and O&M, per Table A.43.

Table A.43: Municipal Waste-to-Power System Projected Capital Costs ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
MSW	2,960	3,250	3,540	2,660	2,980	3,270	2,480	2,830	3,130

Based on the capital cost projections the generating cost for MSW plant was estimated and shown in Table A.44 below. The effect of uncertainty in different cost components on the generation cost is shown in the tornado charts given in Annex D.

Table A.44: Municipal Waste-to-Power Projected Generating Cost (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
MSW	6.0	6.5	7.0	5.6	6.1	6.6	5.3	5.9	6.4

A.9 *Biogas Power Systems*

Biogas generation is a chemical process whereby organic matter is decomposed. Slurry of cow dung and other similar feedstock is retained in the biogas plant for a period of time called the hydraulic retention time (HRT) of the plant. When organic matter like animal dung, human excreta, leafy plant materials, etc. are digested anaerobically (in the absence of oxygen), a highly combustible mixture of gases comprising 60% methane (CH_4) and 37% carbon dioxide (CO_2) with traces of sulfur dioxide and 3% Hydrogen (H_2) is produced. A batch of 25 kg of cow dung digested anaerobically for 40 days produces 1 cubic meter of biogas with a calorific value of calorific value of 5125 kcal/m^3. The remaining slurry coming out of the plant is rich in manure value and useful for farming purposes.

A.9.1 Technology Description

Biogas plants are designed in two distinct configurations - the *floating drum* type and the *fixed dome* type. The floating drum plant (See Figure A.13) consists of a masonry digester and a metallic dome, which functions as a gas holder. The plant operates at a constant gas pressure throughout, i.e. the gas produced is delivered at the point of use at a predetermined pressure. The gas holder acts as the lid of the digester. When gas is produced in the digester, it exerts upward pressure on the metal dome which moves up along the central guide pipe fitted in a frame, which is fixed in the masonry. Once this gas is taken out through the pipeline, the gas holder moves down and rests on a ledge constructed in the digester. Thus a constant pressure is maintained in the system at all times. There is always sufficient slurry liquid in the annulus to act as a seal, preventing the biogas from escaping through the bottom of the gas holder.

In the fixed dome plant (See Figure A.14) the digester and the gas holder (or the gas storage chamber) form part of an integrated brick masonry structure. The digester is made of a shallow well having a dome shaped roof. The inlet and outlet tanks are connected with the digester through large chutes (inlet and outlet displacement chambers). The gas pipe is fitted on the crown of the dome and there is an opening on the outer wall of the outlet displacement chamber for the discharge of spent mass (digester slurry).

The output of the biogas plant can be used for cooking or any other thermal application. For this assessment we consider the biogas plant output to be power generation.

Figure A-13: Floating Dome Biogas Plant View

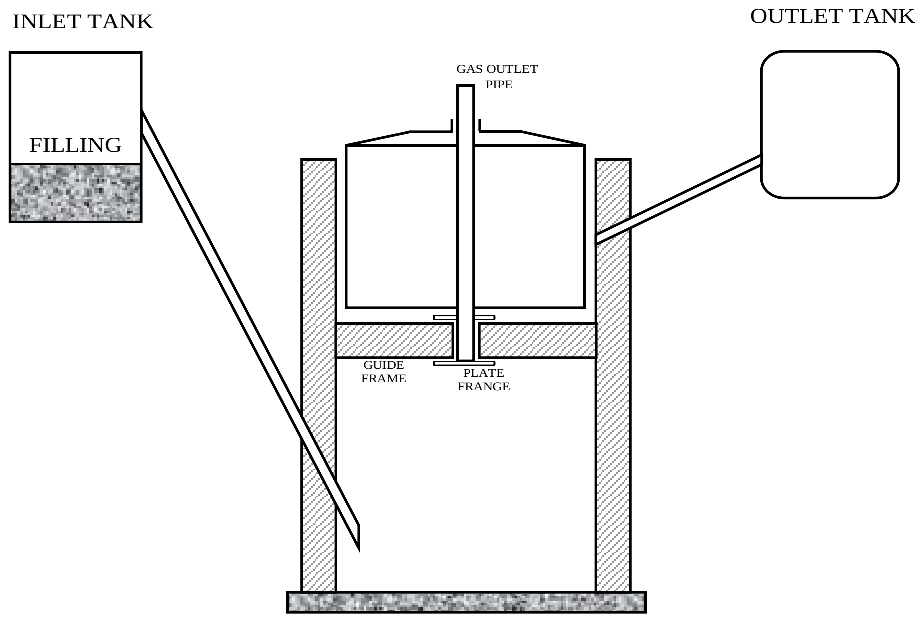
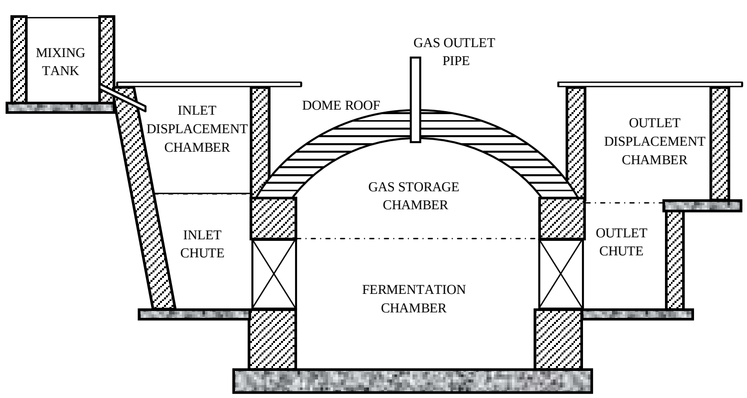


Figure A-14: Fixed Dome Biogas Plant View



A.9.2 Environmental and Economic Assessment

The design and performance assumptions for the biogas based power generation are given in Table A.45. We assume a biogas system sized to provide sufficient power for a 60 kW engine. We assume a capacity factor of 80%, which is achieved by properly sizing the plant and ensuring sufficient feedstock into the biogas system.

Table A.45: Biogas Power System Design Assumptions

Capacity (MW)	60 kW
Capacity Factor (%)	80
Life span (year)	20
Gross Generated Electricity	0.42 GWh

The biogas is mainly methane and thus when combusted will generate CO_2 emissions. However, the use of cow dung as an input means the methane which would have been produced from the cow dung is replaced with CO2, which has only a fraction of the green house gas impact as the captured and combusted methane.

Table A.46 below shows the capital costs assumed for the biogas power generation project.

Table A.46: Biogas Power System 2005 Capital Cost ($/kW)

Items	60kW
Equipment	1,180
Civil	690
Engineering	70
Erection	430
Contingency	120
Total	2,490

Table A.47 shows the generating cost based on the capital costs of Table A.46 and the design and performance parameters in Table A.45.

Table A.47: Biogas Power System 2005 Generating Cost (cents/kWh)

Items	60kW
Levelized Capital cost	3.79
Fixed O&M cost	0.34
Variable O&M cost	1.54
Fuel cost	1.10
Total	6.77

A.9.3 Future Cost Projections and Uncertainty Analysis

Biogas technology is very simple, uses local resources and has been in commercial operation for a long time.[10] Thus it is expected that the costs would not change over time (as the capital costs projects are in 2004 US$), as shown in Table A.48.

Table A.48: Biogas Power System Capital Cost Projections ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Biogas 60kW	2,260	2,490	2,790	2,080	2,330	2,570	2,000	2,280	2,540

An uncertainty analysis for future biogas power system generation cost was carried out using the range of likely variation in future costs, mainly the equipment costs and an assumed ± 20% variation in O&M cost. The uncertainly analysis results are shown in Table A.49.

Table A.49: Biogas Power System Generating Cost Projections (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Biogas 60kW	6.3	6.8	7.2	6.0	6.5	7.1	5.9	6.5	7.1

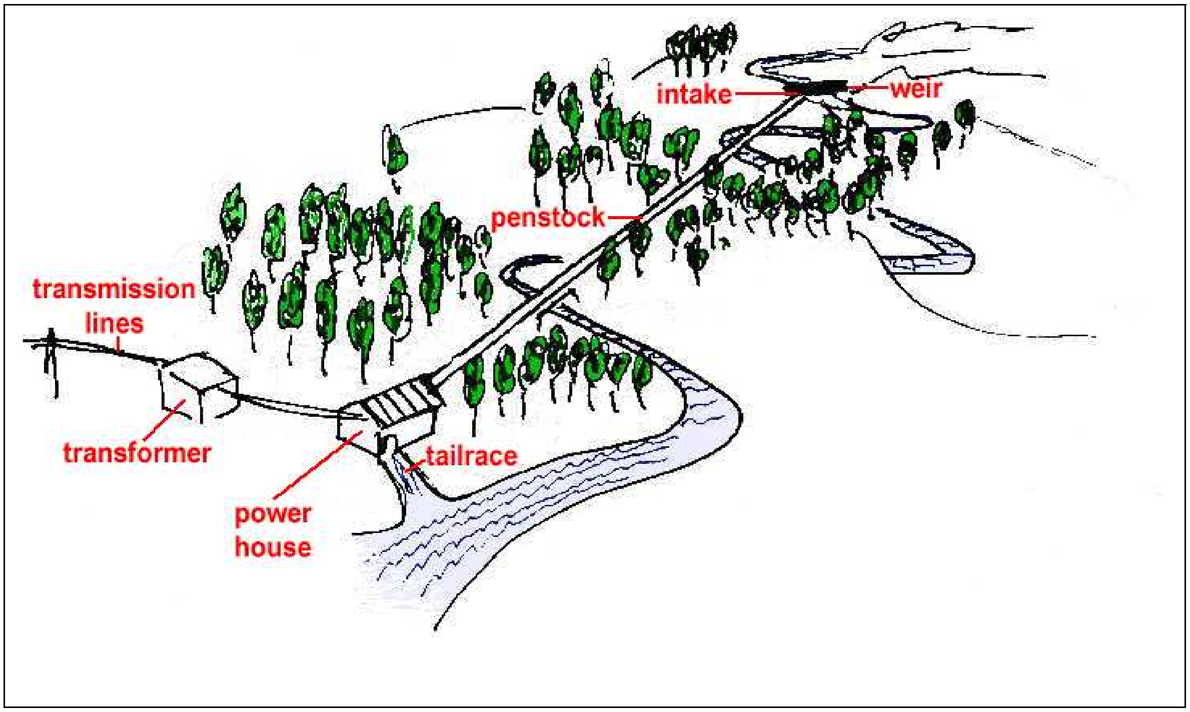
[10] e.g. the Indian Biogas program started in 1973

A.10 *Micro and Pico Hydroelectric Power Systems*

Micro-hydro and pico-hydro power projects are usually "Run of the River" schemes which operate by diverting part or all of the available water flow by constructing civil works, e.g., an intake weir, fore bay, and penstock (note: pico-hydro units do not have a penstock). Water flows through the civil works into a turbine, which drives a generator producing electricity. The water flows back into the river through additional civil works (the tail race). "Run of the River" schemes require no water catchments or storage, and thus have minimal environmental impacts.

The main drawback of "run of the river" hydro projects are seasonal variation in flow, which make it difficult to balance load and power output on an annual basis. Micro- and pico-hydro systems can be built locally at low cost, and their simplicity gives rise to better long-term reliability. They can provide a source of cheap, independent and continuous power, without degrading the environment. Figure A.15 shows a typical micro hydro configuration.

Figure A-15: Typical Micro-Hydroelectric Power Scheme



Source: microhydropower.net/ http://www.microhydropower.net/

A.10.1 Technology Description

A Micro-hydroelectric power project comprises two principle components: civil works and electro-mechanical equipment.

The civil works include:

- The weir, a simple construction that provides a regulated discharge to the feeder channel;
- The feeder channel, constructed of concrete with desilting tanks along its length;
- The fore bay, an open concrete or steel tank designed to maintain a balance in the power output by providing a steady design head for the project;
- The penstock, simply a steel, concrete or PVC pipe sized to provide a steady and laminar water flow into the turbine.

The electro-mechanical works include:

- A turbine sized according to the design head and water flow available, typically a Pelton or Turgo design for high-head applications and a Kaplan or Francis design for low head applications;
- A generator, usually a synchronous design for larger micro hydro sites and self excited induction design for low-power and pico-hydro applications.
- A governor, usually an electronic load governor or electronic load controller, depending on whether the turbine and generator operate on full or varying load conditions.

A pico-hydroelectric power plant is much smaller than a micro-hydro (e.g., 1 kW or 300W), and incorporates all of the electro-mechanical elements into one portable device. A pico-hydro device is easy to install: A 300W-class pico-hydroelectric can be installed by the purchaser because of the low (1-2 meters) reqired waterhead, whereas, a 1kW-pico-hydroelectric requires a small amount of construction work because of the higher (5-6 meters) required waterhead but provides a longer and more sturdy product life-span. They are typically installed on the river or stream embankment and can be removed during flood or low flow periods. The power output is sufficient for a single house or small business. Earlier pico-hydro devices were not equipped with any voltage or load control, which was a drawback as it produced lighting flicker and reduced appliance life. Newer pico-hydro machines come with embedded power electronics to regulate voltage and balance loads.

A.10.2 Economic Assessment

Table A.50 gives the details on the design and performance assumptions used to assess micro- and pico-hydro electric power projects. We selected three design points – a micro-hydro scheme of 100 kW and two pico-hydro schemes of 1 kW and 300 W respectively. There is a very large variation in the capacity factor depending upon the site conditions, which will be taken into account in the uncertainly analysis. In the case of off grid and mini-grid applications demand requirements are also a limiting factor. Most of these projects work on full-load, single point operation but for a limited period of time each day, so we assume an average capacity factor of 30%.

Table A.50: Mico/Pico-Hydroelectric Power Plant Design Assumptions

Capacity	300 W	1kW	100kW
Capacity Factor (%)	30	30	30
Source	River/Tributary	River/Tributary	River/Tributary
Life span (year)	5	15	30
Gross Generated Electricity (kWh/year)	788.4	2,628	26,2800

The cost estimations shown in Table A.51are drawn from numerous sources, principally Vietnam and the Philippines.

Table A.51: Micro/Pico-Hydroelectric Power Plant 2005 Capital Costs ($/kW)

Items/Models	300W	1kW	100kW
Equipment	1,560	1,960	1,400
Civil	—	570	810
Engineering	—	—	190
Erection	—	140	200
Total	1,560	2,600	2,500

Table A.52 shows the generation costs for micro/pico-hydro power calculated per the methodology described in Section 2.

Table A.52: Micro/Pico-Hydroelectric Power 2005 Generating Cost (cents/kWh)

Items/ Models	300W	1kW	100kW
Levelized Capital cost	14.24	12.19	9.54
Fixed O&M cost	0.00	0.00	1.05
Variable O&M cost	0.90	0.54	0.42
Fuel cost	0.00	0.00	0.00
Total	15.14	12.73	11.01

A.10.3 Future Cost and Uncertainty Analysis

There has been very little variation in the equipment cost of micro- and pico-hydro electric equipment. We therefore assume that the capital costs for pico/mini hydro technology will remain constant over the study period.

An uncertainty analysis was carried out to estimate the range over which the generation cost could vary as a result of uncertainty in costs as well as variability in the capacity factor. The capacity factor will vary widely depending upon the availability of hydro resource and the quality of the sizing and design process. We assume well-designed and well-sited schemes that would have lower capacity factor variability, 25% to 35%, with 30% as probable capacity factor. We allowed capital costs and O&M costs to vary across the range ± 20% (See Table A.53).

Table A.53: Micro/Pico-Hydroelectric Power Capital Cost Projections ($/kW)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300 W	1,320	1,560	1,800	1,190	1,485	1,770	1,110	1,470	1,810
1 kW	2,360	2,680	3,000	2,190	2,575	2,950	2,090	2,550	2,990
100kW	2,350	2,600	2,860	2,180	2,470	2,750	2,110	2,450	2,780

The generation costs estimated based on the cost projections in Table A.53 and the design parameters in Table A.50 are shown in Table A.54 below. The sensitivity of generation cost to parametric variation in the form of tornado charts is given in Annex D.

Table A.54: Micro/Pico-Hydroelectric Power Generating Cost Projections (cents/kWh)

Capacity	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300 W	12.4	15.1	18.4	11.4	14.5	18.0	10.8	14.3	18.2
1 kW	10.7	12.7	15.2	10.1	12.3	14.8	9.7	12.1	14.9
100kW	9.6	11.0	12.8	9.1	10.5	12.3	8.9	10.5	12.3

A.11 *Mini-Hydroelectric Power Systems*

As with Micro/Pico-Hydro, Mini Hydro-electric power schemes are usually "Run of the River" designs which operate by diverting the stream or river flow via civil works. A Mini Hydro scheme is based on the same basic design principles and comprises the same major civil and electro-mechanical components as a Micro/Pico-Hydro scheme. These projects do not require dams or catchments, which is preferable from an environmental point of view. Mini-hydro technology is well established around the world, and has found favor with private investors. The systems are simple enough to be built locally at low cost and have simple O&M requirements, which gives rise to better long-term reliability. These systems are highly bankable and provide a source of cheap, independent, and continuous power, without degrading the environment. Larger mini hydro projects are envisaged for grid-connected applications, while smaller mini hydro projects are suitable for mini-grids.

A.11.1 Technology Description

A mini-hydroelectric power project comprises two principle components:

- Civil works
- Electro Mechanical Equipment

The civil works include:

- The weir, a simple construction that provides a regulated discharge to the feeder channel;
- The feeder channel, constructed of concrete with desilting tanks along its length;
- The fore bay, an open concrete or steel tank designed to maintain a balance in the power output by providing a steady design head for the project;
- The penstock, simply a steel, concrete or PVC pipe sized to provide a steady and laminar water flow to the turbine.

The electro-mechanical works include:

- A turbine sized according to the design head and water flow available, typically a Pelton or Turgo design for high-head applications and a Kaplan or Francis design for low head applications;
- A generator, usually a synchronous design for larger micro hydro sites and self excited induction design for low-power and pico-hydro applications.
- A governor, usually an electronic load governor or electronic load controller, depending on whether the turbine and generator operate on full or varying load conditions.

A.11.2 Economic Assessment

We selected a representative mini hydroelectric power plant of 5 MW for the economic assessment. Table A.55gives the design and performance assumptions. A properly-sited, well-designed mini hydro project should have a capacity factor of 45% on average.[11]

Table A.55: Mini-Hydroelectric Power Plant Design Assumptions

Capacity (MW)	5MW
Capacity Factor (%)	45
Source	River/Tributary
Auxiliary power ratio (%)	1
Life span (year)	30
Gross Generated Electricity (gWh/year)	19.71

The capital cost of mini hydro projects is very site specific and can range between \$1400/kW and \$2200/kW. The probable capital cost is 1800\$/KW. Table A.56 shows a breakdown of the probable capital cost for a 5 MW mini hydro power project.

Table A.56: Mini-Hydroelectric Power Plant 2005 Capital Cost (\$/kW)

Capacity	5MW
Equipment	990
Civil	1,010
Engineering	200
Erection	170
Total	2,370

Following the methodology described in Section 2 we can estimate the generation costs on a levelized basis (See Table A.57).

Table A.57: Mini-Hydroelectric Power Plant 2005 Generating Cost (cents/kWh)

Items/ Models	5MW
Levelized Capital cost	5.86
Fixed O&M cost	0.74
Variable O&M cost	0.35
Fuel cost	0.00
Total	6.95

[11] Based on several sources: (i) inputs from Alternate Hydro Energy Centre(AHEC), Roorkee; (ii) *Small Hydro Power: China's Practice* – Prof Tong Jiandong, Director General, International Network for Small Hydro Power(IN-SHP); and (iii) *Blue AGE Report, 2004 - A strategic study for the development of Small Hydro Power in the European Union*, published by European Small Hydro Association (ESHA).

A.11.3 Future Cost and Uncertainty Analysis

The actual equipment cost of the technologies described above has not changed over the past five years; therefore, we assume mini hydro equipment costs will remain constant over the study period.

An uncertainty analysis was carried out to estimate the range over which the generation cost could vary as a result of uncertainty in costs as well as variations in capacity factor. The capacity factor would vary depending upon the availability of hydro resource and reliability of the electro-mechanical works. Depending upon the location the capacity factor for mini hydro plants vary in the range from 35% to 55%, with 45% as probable capacity factor. Assuming a ± 10-15 % variation in projected capital costs (See Table A.58) range together with O&M costs varied ±20% we can carry out our uncertainty analysis, the results of which are shown in Table A.59.

Table A.58: Mini-Hydroelectric Power Plant Capital Cost Projections ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
5 MW	2,140	2,370	2,600	2,030	2,280	2,520	1,970	2,250	2,520

Table A.59: Mini-Hydroelectric Power Generating Cost Projections (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
5 MW	5.9	6.9	8.3	5.7	6.7	8.1	5.6	6.6	8.0

A.12 *Large Hydroelectric Power and Pumped Storage Systems*

Unlike mini-, micro-, and pico-hydro schemes, large hydroelectric projects typically include dams and catchments for water storage in order to assure a very high capacity factor consistent with the very high construction costs of these facilities. The characteristics and costs of large hydroelectric power plants are greatly influenced by natural site conditions.

A.12.1 Technology Description

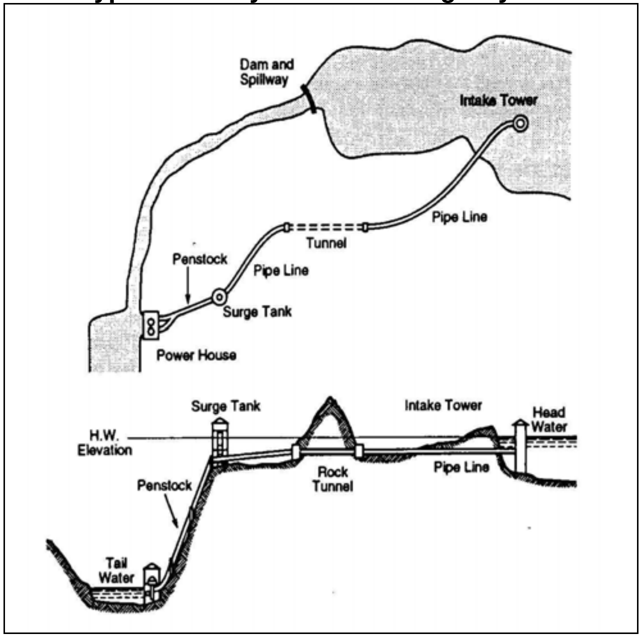
The distinguishing characteristic of large hydroelectric and large pumped storage projects is the dam design, which generally falls into three categories - Gravity Concrete Dams, Fill Dams and Arch Concrete dams:

- In a Gravity Concrete Dam the structure supports external force using the weight of concrete. Structurally this is a simple system with broad applicability to topographic conditions and excellent earthquake resistance.
- A Fill Dam consists of accumulated rock and soil as the main structural material. It can be built on sites where the foundation is poor, and can accommodate flexibility in design depending on the soil and stone materials available.
- An Arch type concrete dam utilizes the geometric form of the dam to economize on the amount on concrete required. It is generally restricted to narrow valleys.

The intake system determines the amount of pressure head and the way in which water flows to the hydroelectric turbines. There are two types of intake systems, Dam type and Dam-conduit type:

- A Dam-type intake system obtains its head by the rise in the reservoir water surface level. The hydroelectric power plants are installed directly under the dam, which allows effective use of water and no need for a feed channel.
- A Dam-conduit type stores the water in a high dam and water is introduced to the hydroelectric power plant via a feed channel (See Figure A-16).

Figure A-16: Conduit Type Intake System for a Large Hydroelectric Power Plant



There are three types of power generation systems - Reservoir, Pondage, and Pumped Storage:

- The Reservoir power generation system employs a reservoir such as artificial dam or natural lake. The water storage provided by the reservoir allows water level adjustment in accordance with seasonal flux in water inflow and power output.
- A Pondage type power generation system uses a regulating pond capable of adjusting for daily or weekly flux.
- A Pumped Storage power generation scheme is a specialized scheme in which several power plants are used to optimize the power output in accordance with diurnal variation in system load. In this scheme the hydroelectric power plant acts both as a generator and a pump, allowing water in a lower reservoir to be pumped up to upper reservoir during the low-load overnight period, and then generating electricity during peak load periods.

A.12.2 Economic Assessment

We will assess two cases – a 100 MW conventional hydroelectric facility and a 150 MW pumped storage hydroelectric facility. Design characteristics and performance parameters for the two cases are shown in Table A.60.

Table A.60: Large Hydroelectric Power Plant Design Assumptions

Items	Conventional Large Hydroelectric	Pumped Storage Hydroelectric
Capacity (MW)	100 MW	150 MW
Capacity Factor (%)	50 %	10%
Dam Type	Gravity concrete	Gravity concrete
Turbine Type	Francis	Francis reversible pump-turbine
Power Generation System	Pondage	Pumped Storage
Auxiliary power ratio (%)[12]	0.3%	1.3%
Life span (year)	40	40

The capital cost of hydroelectric power plants comprises civil costs (dam, reservoir, channel, power plant house, etc.), electric costs (water turbine, generator, substation, etc.), and other. The capital costs of large hydro power plants is dominated by the civil works. Table A.61 shows the estimated capital costs for the two large hydroelectric power cases assessed here.

Table A.61: Large Hydroelectric Power Plant 2005 Capital Cost ($/kW)

Items	Large Hydro	Pumped Storage Hydro
Equipment	560	810
Civil	1,180	1,760
Engineering	200	300
Erection	200	300
Total	2,140	3,170

The generating cost of hydro power plant (See Table A.62) is calculated by levelizing the capital costs and adding additional O&M components, per the method described in Section 2. The costs of large hydroelectric power plants are not expected to decrease in future, and are assumed constant over the study life as shown in Table A.63.

Table A.62: Large Hydroelectric Power Plant 2005 Generating Costs (cents/kWh)

Items	Large Hydro	Pumped Storage Hydro
Levelized Capital Cost	4.56	34.08
Fixed-OM(Operating and Maintenance) Cost	0.50	0.32
Variable-OM(Operating and Maintenance) Cost	0.32	0.33
Total	5.38	34.73

[12] Auxiliary power electricity in a hydro power plant is used for drainage system, cooling system, hydraulic system, switchboard system, motors, air-conditioning, lighting etc. Auxiliary power electricity ratio (= Auxiliary power electricity / Generating electricity) of the electric power used for these is an average of 0.5% or less in Large Hydro Type.

A.12.3 Uncertainty Analysis

An uncertainty analysis was carried out assuming that all cost data as well as capacity factor is variable within a ± 20 percent range.[13] The analysis results are shown in Table A.64 below.

Table A.63: Large Hydroelectric Power Plant Capital Cost Projections ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Large Hydro	1,930	2,140	2,350	1,860	2,080	2,290	1,830	2,060	2,280
Pumped Storage Hydro	2,860	3,170	3,480	2,760	3,080	3,400	2,710	3,050	3,380

Table A.64: Large Hydroelectric Power Generating Cost Projections (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Large Hydro	4.6	5.4	6.3	4.5	5.2	6.2	4.5	5.2	6.2
Pumped Storage Hydro	31.4	34.7	38.1	30.3	33.8	37.2	29.9	33.4	36.9

A.12.4 Environmental Impact

Environmental preservation is a key element in developing a hydro power plant and often dictates many details of construction and operation. It is necessary to investigate, predict and evaluate the potential environmental impact, both during construction and operation, and to take sufficient safeguards measures to prevent adverse environmental and social impacts. Potential environmental and social impacts including sediment transport and erosion, relocation of populations, impact on rare and endangered species, loss of livelihood, and passage of migratory fish species in hydro power plant.

[13] Except civil costs, which are allowed to vary ±30%, and the capacity factor of Large Hydro, which is constrained to only vary ±10%

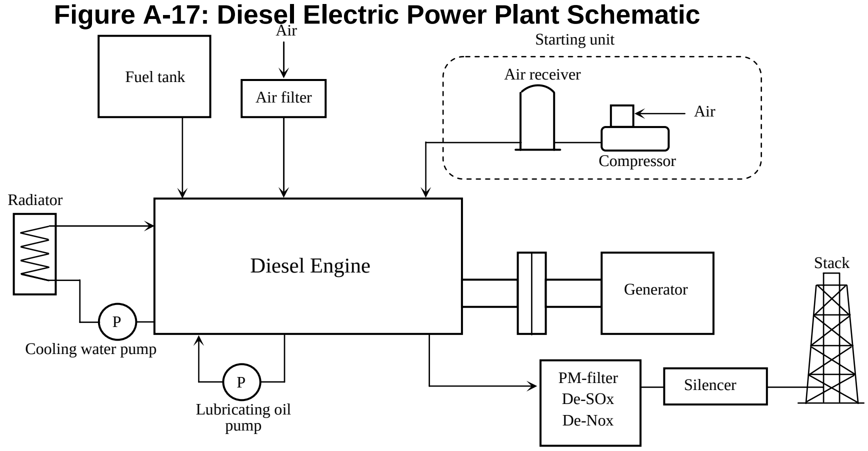
A.13 *Diesel/Gasoline Engine-Generator Power Systems*

Diesel and gasoline engines (both characterized as internal combustion (IC) engines) can accommodate power generation needs over a wide size range, from several hundred watts to 20 MW. Features including low initial cost, modularity, ease of installation, and reliability have led to their extensive use in both developed and developing countries. A typical configuration is an engine/generator set, where gasoline and diesel engines basically indistinguishable from their counterparts in transportation vehicles are deployed in a stationary application. However, in many developing countries slower speed diesel engines burning heavier and more polluting oils (e.g., residual oil or mazout) are used.

A.13.1 Technology Description

A gasoline engine generator is lightweight, portable and easy to install and operate – all important characteristics for off-grid electrification. However, as shown in Table A.64, it is not as efficient as a diesel generator, and the fuel costs are somewhat higher. A diesel generator includes the core of the diesel engine (prime mover), a generator and some auxiliary equipment, such as fuel feed equipment, air intake and exhaust equipment, cooling equipment, lubricating equipment and starting equipment (See Figure A-17).

Figure A-17: Diesel Electric Power Plant Schematic



A diesel generator has an efficiency of 35-45 %, and can use range of lower-cost fuels, including light oil, heavy oil, residual oil, and even palm or coconut oil, in addition to diesel. However, since the diesel equipment is heavier than a gasoline engine generator, it is mostly deployed in stationary applications. A diesel engine also has a wide capacity range, from 2 kW to 20 MW.

Table A.65: Characteristics of Gasoline and Diesel Generators

	Gasoline Generator	Diesel Generator
Thermal Efficiency (%LHV)	～27	30～45
Generating Capacity	～5kW	2kW～20, 000kW
Fuel Type	Gasoline	Light-Oil, Fuel-A, B, C Residual-Oil

In this section, we will consider four typical size diesel engines (300W, 1kW, 100 kW and 5 MW), which has seen a great number of installations for rural electrification in many countries including the Philippines and Indonesia.

A.13.2 Environmental and Economic Assessment

We have chosen four "typical diesel plants" to assess their economic effectiveness: a 300 W and a 1 kW gasoline engine-generator, and a 100 kW and a 5 MW diesel engine generator. The type of engine and fuel reflect available commercial products. The design and operating parameters for each case are shown in Table A.66 below.

Table A.66: Gasoline and Diesel Power System Design Assumptions

	300W (Off-grid)	1kW (Off-grid)	100kW (Mini-grid)	5MW (Grid)
Capacity Factor (%)	30	30	80	80/10
Engine Type	Gasoline	Gasoline	Diesel	Diesel
Fuel Type	Gasoline	Gasoline	Light oil	Residual oil
Thermal efficiency (LHV, %)	13	16	38	43
Life span (year)	10	10	20	20
Generated Electricity (GWh/year)	0.0008	0.003	0.7	35.0/4.4

As Table A.66 indicates, the smaller engines are assigned a capacity factor of 30%. The larger engines are assigned a capacity factor of 80%, based on fourteen hours/day of 100% rated output and ten hours/day of 50% rated output. The 5MW diesel plants are also considered as peaking (with 10% capacity factor) in grid-connected applications.

Small sized gasoline generators are assumed to have a 10-year life span reflecting frequent start-up/shut-downs, as well as the low maintenance common in most applications. The larger diesel units are assigned an operating life of 20 years.

Emissions from IC engines are shown in Table A.67 assuming fuel properties typically used in India. Emission control equipment costs are included in the capital cost for the two diesel generator cases.

Table A.67: Air Emissions Characteristics of Gasoline & Diesel Power Systems

	Emission Standard	Typical Emissions			
		Gasoline engine		Diesel engine	
		300W	1kW	100kW	5MW
PM	50mg/Nm^3	Zero	Zero	80 - 120	100 - 200
SOx	2000mg/Nm^3 (<500MW:0.2tpd/MW)	Very small	Very small	1,800 - 2,000	4,400 - 4,700
NOx	Oil: 460	1,000 – 1,400[14]		1,600 - 2,000	
CO_2	g-CO_2/net-kWh	1,500 – 1,900		650	

: Emissions control equipment is required

Table A.68 shows the capital cost[15] of gasoline and diesel engine-generators. Note that 300W and 1kW engines are portable, so only the equipment cost is included.

Table A.68: Gasoline and Diesel Power System 2005 Capital Costs ($/kW)

Items	300W	1kW	100kW	5MW
Equipment	890	680	600	510
Civil	—	—	10	30
Engineering	—	—	10	30
Erection	—	—	20	30
Total	890	680	640	600

Table A.69 shows the levelized generating costs, in line with the methodology described in Chapter 2. No fixed O&M cost is included for the small, portable gasoline engines.

Table A.69: Gasoline and Diesel Power System 2005 Generating Costs (cents/kWh)

Items	300W	1kW	100kW	5MW	
	CF=30%	CF=30%	CF=80%	CF=80%	CF=10%
Levelized Capital cost	5.01	3.83	0.98	0.91	7.31
Fixed O&M cost	—	—	2.00	1.00	3.00
Variable O&M cost	5.00	3.00	3.00	2.50	2.50
Fuel cost	54.62	44.38	14.04	4.84	4.84
Total	64.63	51.21	20.02	9.25	17.65

[14] The two smallest gasoline engine generators emit NOx beyond the WB's standard. However, since it is not realistic to add removal equipment to these small generators in order to follow a guideline strictly, cost for De-NOx equipment is not included.
[15] The Follow-up Study on the Effective Use of Captive Power in Java-Bali Region, Japan International Cooperation Agency (JICA), November 2004

A.13.3 Future Cost and Uncertainty Analysis

As is the case with all power generation options, the costs of power plants are site-specific; they also vary from country to country and from manufacturer to manufacturer. Table A.70 and Table A.71 provide the projected range of capital and generating costs at present and in future.

Table A.70: Gasoline and Diesel Power System Projected Capital Cost ($/kW)

Capacity	2005			2010			2015		
	Minimum	Probable	Maximum	Minimum	Probable	Maximum	Minimum	Probable	Maximum
300W	750	890	1,030	650	810	970	600	800	980
1kW	570	680	790	500	625	750	470	620	770
100kW	550	640	730	480	595	700	460	590	720
5MW	520	600	680	460	555	650	440	550	660

Table A.71: Gasoline/Diesel Power System Projected Generating Costs (cents/kWh)

Capacity	2005			2010			2015		
	Minimum	Probable	Maximum	Minimum	Probable	Maximum	Minimum	Probable	Maximum
300W	59.0	64.6	72.5	52.4	59.7	71.8	52.5	60.2	75.0
1kW	46.7	51.2	57.6	41.4	47.3	57.1	41.5	47.7	59.7
100kW	18.1	20.0	23.1	16.6	19.0	23.3	16.7	19.2	24.3
5MW (Base)	8.3	9.3	10.8	7.6	8.7	10.8	7.6	8.8	11.3
5MW (Peak)	16.2	17.7	19.6	15.0	16.7	19.1	14.9	16.7	19.6

A.14 *Combustion Turbine Power Systems*

Oil and Gas Combustion Turbines (CT) and Combined Cycle Gas Turbine (CCGT) Power Plants are considered together. The common element of these plants is the use of the gas turbine, most commonly burning natural gas but in some cases distillate or heavy oil. Open cycle plants utilize only a gas turbine and are used for peaking operation. CCGT power plants utilize both a gas turbine and a steam turbine and are used for intermediate and base load operation. Depending on the size and dispatching duty, industrial (large frame) or aero-derivative gas turbines may be used. Most of the large power generation applications are industrial large frame turbines; smaller plants (less than 100 MWs) use aero-derivatives. However, there is not a clear separating line between the two.

The advanced gas turbine designs available today are largely due to fifty years of development of aero-derivative jet engines for military applications and commercial aviation. Given the aircraft designer's need for engine minimum weight, maximum thrust, high reliability, long life and compactness, it follows that the cutting-edge gas turbine developments in materials, metallurgy and thermodynamic designs have occurred in the aircraft engine designs, with subsequent transfer to land and sea gas turbine applications. However, the stationary power gas turbine designers have a particular interest in larger unit sizes and higher efficiency.

The largest commonly used gas turbines are the so-called “F” class technology, with an output range of 200 – 300 MW, an open-cycle efficiency of 34 – 39 percent, and a weight of several hundred tons. Generally speaking, the industrial or frame type gas turbine tend to be a larger, more rugged, slightly less efficient power source, better suited to base-load operation, particularly if arranged in a combined-cycle block on large systems. Today the largest aero-derivative gas turbine has an output range of 40 MW, with a 40 percent simple-cycle efficiency and a weight of several tons.

A Combustion Turbine (CT) has many features desirable for power generation, including quick start up (within 10 minutes), capacity rating modularity (1MW-10MW), small physical footprint, and low capital cost. Gas turbines demand higher quality fuels (light oil or gas containing no impurities) than diesel generators, and have considerably higher O&M requirements.

A gas turbine (or turbines) combined with a steam turbine can form a combined cycle configuration in which the overall thermal efficiency is improved by utilizing the gas turbine exhaust heat energy. The combined cycle comes in a wide variety of forms, but the study focuses on the technical and cost characteristics of a typical, newly built 300 MW CCGT power plant. Larger plants (up to 500-700MW) are also available. The prominent feature of the system is its high efficiency, realized by combining a high temperature (1300 degree C) gas turbine with two or more middle- and bottom-cycles using the 300 degree C and 600 degree C waste heat out of the combustion turbine. This approach boosts the overall thermal efficiency from 36% to 51% (LHV). The combined cycle can be either single-shaft or multi-shaft design, depending on the number of combustion turbines aligned with the steam turbine. The type of design is determined according to whether the power plant is designed to operate on a partial load or a base load basis.

More advanced Class "G" and "H" gas turbines have been developed and are commercially available, with the combined cycle efficiency reaching to 60%. However, since the operational experience is limited, these types were not considered in this study.

A.14.1 Technical Description

A single-shaft CCGT consists of gas turbine, steam turbine and generator commonly coupled on the same shaft (See Figure A-18). In the case of multi-shafts (e.g. 2-7 shafts) configuration, each shaft can be shut down separately, and the plant has better part-load performance. This multi-shaft configuration is well suited for load following, and is adopted as the basis in this report for assessing the CCGT technology.

In a multi-shaft combined cycle configuration, waste heat from two or more gas turbines is collected via a dedicated waste heat recovery boiler to produce steam, which turns the steam turbine-generator. When the capacity of the steam turbine becomes larger, the thermal efficiency improves over its single-shaft counterpart, making it a competitive candidate for base load operation. However, a multiple–train single-shaft configuration has an advantage of operational flexibility. The combined cycle can be constructed in phases, with only the gas turbine installations at first for basic power supply, and expanded afterwards, by adding one or more bottoming cycles to complete an integral combined cycle power plant (See Figure A-19).

Figure A-18: Combined Cycle Gas Turbine (CCGT) Power Plants

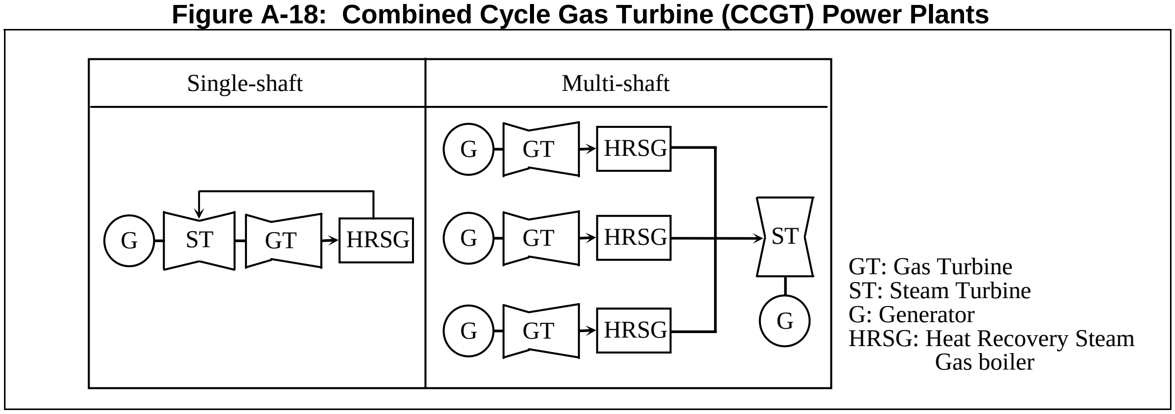
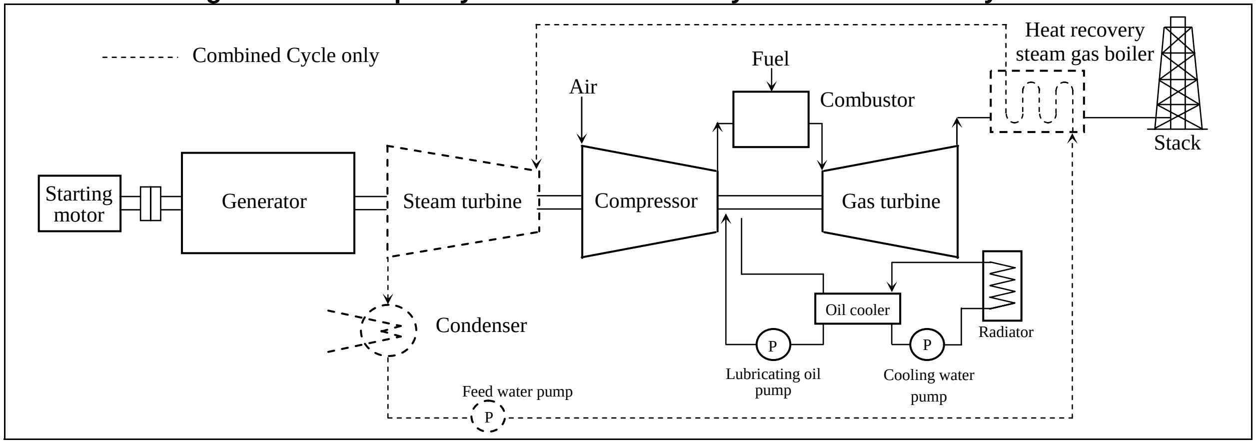


Figure A-19: Simple Cycle and Combined Cycle Gas Turbine Layouts



A.14.2 Environmental and Economic Assessment

Table A.72 presents the assumed design parameters and performance characteristics used in economic assessment of CT and CCGT power systems. For the CT we assume only a 10% capacity factor, reflecting a typical peak load application. For the CCGT we assume a combination of base load operations (100% capacity factor for 14 hours per day) and load following (50% capacity factor for 10 hours per day). Because the combustion turbine is used primarily during peak times, we assume the lower-cost 1100℃ turbine instead of the more efficient super-high temperature design assumed for the CCGT case. All other design parameters are derived based on typical Japanese CT and CCGT operations.

Table A.72 : CT and CCGT Power Plant Design Assumptions

	Combustion Turbine	Combined Cycle
Capacity (MW)	150MW	300MW
Capacity Factor (%)	10	80
Combustion Turbine Inlet temperature (℃)	1,100	1,300
Steam Turbine Inlet temperature (℃)	-	538/538/260
Fuel Type	Gas (Light-oil)	Gas (light-oil)
Thermal efficiency (LHV, %)	34	51
Auxiliary power ratio (%)	1	2
Life span (year)	25	25
Gross Generated Electricity (GWh/year)	131	2,102
Net Generated Electricity (GWh/year)	130	2,060

Assuming typical fuel properties found in India origin we can estimate the emissions of the CT and CCGT units (See Table A.73). We assume all environmental impacts are less than World Bank guidelines and therefore do not include the costs for emissions control equipment (such as SCR for NOx control) in the capital costs.

Table A.73: Air Emissions Characteristics of Gas Turbine Power Plants

	Emission Standard	Result			
		Combustion Turbine		Combined Cycle	
		Gas	Oil	Gas	Oil
PM	50mg/Nm^3	NA	Very small	NA	Very small
SOx	2000mg/Nm^3 (<500MW:0.2tpd/MW)	NA	Very small	NA	Very small
NOx	Gas Turbine for gas: 125mg/Nm^3; Oil: 460	100 - 120	160-200	100 - 120	150-180
CO_2	g-CO_2/net-kWh	600	780	400	520

Table A.74shows today's capital cost associated with Oil / Gas Combustion Turbine & Combined Cycle power plants.

Table A.74: Gas Turbine Power Plant 2005 Capital Costs ($/kW)

Items	Combustion Turbine	Combined Cycle
Equipment	370	480
Civil	45	50
Engineering	30	50
Erection	45	70
Contingency	20	30
Total	490	650

Table A.75 shows the result of levelized generation cost calculations, using the methodology described in Annex B.

Table A.75: Gas Turbine Power Plant 2005 Generating Cost (cents/kWh)

Items	Combustion Turbine (CF=10%)		Combined Cycle (CF=80%)	
	Natural Gas	Light-Oil	Natural Gas	Light Oil
Levelized Capital cost	5.66	←	0.95	←
Fixed O&M cost	0.30	←	0.10	←
Variable O&M cost	1.00	←	0.40	←
Fuel cost	6.12	15.81	4.12	10.65
Total	13.08	22.77	5.57	12.10

A.14.3 Future Cost and Uncertainty Analysis

The capital costs of Combustion Turbines and Combined Cycle power plants are decreasing as a result of both mass production and technological development. In this study, we assume that capital cost decrease 7% from 2004 to 2015.

The uncertainty analysis assumes that all cost data varies ±20%. The uncertainty analysis results are shown in Table A.76 and Table A.77.

Table A.76: Gas Turbine Power Plant Capital Cost Projections ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Combustion turbine	430	490	550	360	430	490	340	420	490
Combined cycle	570	650	720	490	580	660	450	560	650

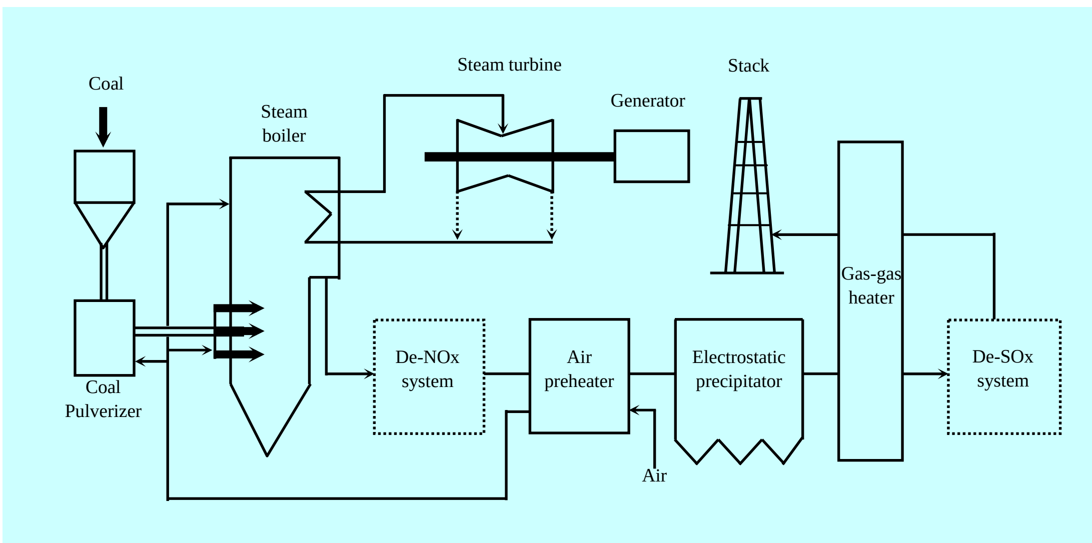
Table A.77: Gas Turbine Power Plant Generating Cost Projections (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Combustion turbine (Gas)	11.9	13.1	14.7	10.4	11.8	14.0	10.2	11.8	14.5
Combined cycle (Gas)	4.94	5.57	6.55	4.26	5.10	6.47	4.21	5.14	6.85

A.15 *Coal Steam Electric Power Systems*

"Pulverized Coal" (PC) plant is a term used for power plants which burns pulverized coal in a boiler to produce steam that is then used to generate electricity. PC plants are widely used throughout the world, in both developed and developing countries. Figure A-20 provides a typical schematic of such a plant equipped with post-combustion De-NOx (Selective Catalytic Reduction – SCR), particulate controls (Electrostatic Precipitator – ESP) and De-SOx (Flue Gas Desulfurization – FGD). SCR and FGD may not be needed depending on the coal characteristics and the environmental requirements applicable to the specific power plant site. However, more and more of the pulverized coal plants are being equipped with such environmental controls even for low-sulfur and low-NOx producing coals. Also, the Gas-to-Gas Heater may not be needed in all power plant sites.

Figure A-20: Pulverized Coal Steam Electric Power Plant Schematic



A.15.1 Technology Description

Pulverized coal plants involve:

- Grinding (pulverization) of coal;
- Combustion of coal in a boiler, producing steam at high temperature and pressure;
- Steam expansion into a turbine, which drives a generator producing electricity;
- Treatment of combustion products (flue gas) as required before they are released into the environment through the stack (chimney).

While there are many variations in the design of the specific components of the pulverized coal (PC) plant, the overall concept is the same. Variations may include:

- Boiler design, e.g., front wall-fired vs. opposed wall-fired vs. tangentially-fired vs roof-fired, all indicating how the burners are arranged in the boiler. Other alternative arrangements include cyclones and turbo, grate, cell or wet-bottom firing methods;
- NOx emissions control. Primary control is usually accomplished through low NOx burners and overfire air, but further NOx reduction may be needed using Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) or gas reburning;
- Control of particulates, accomplished through dry Electrostatic Precipitator (ESP), wet ESP or bag filters (baghouses).

The most important design feature of the PC plant relates to the steam conditions (pressure and temperature) entering the steam turbine. PC plants designed to have steam conditions below the critical point of water (about 22.1 MPa-abs) are referred to as “subcritical” PC plants, while plants designed above this critical point are referred to as “supercritical”. Typical design conditions for subcritical plants are: 16.7 MPa/538°C/538°C.

Supercritical PC plants can be designed over a spectrum of operating conditions above the critical point. However, for simplification and based on the industry experience, often the terms “supercritical” and “ultra-supercritical” are used.

- “Supercritical” plants are designed usually at an operating pressure above the critical point (>22.1 MPa), but steam temperatures at or below 565°C. Typical design conditions are: 24.2 MPa/565°C/565°C.
- “Ultra-supercritical” plants are design above these conditions.

Table A.78 shows typical design conditions of recent supercritical plants operating in Europe.

Increased steam conditions are important because they increase the plant efficiency. Figure A-21 shows how efficiency improves with higher temperatures and pressures. The relative difference in plant heat rate (inverse of efficiency) between a basic subcritical unit with steam conditions of 16.7 MPa/538°C/538°C and a supercritical unit operating at 24.2 MPa/538°C/565°C is about 4%. If steam conditions in the supercritical plant can be increased to 31 MPa/600°C/600°C/600°C (note: a second reheat step has been added), the heat rate advantage over a conventional subcritical unit reaches about 8%.

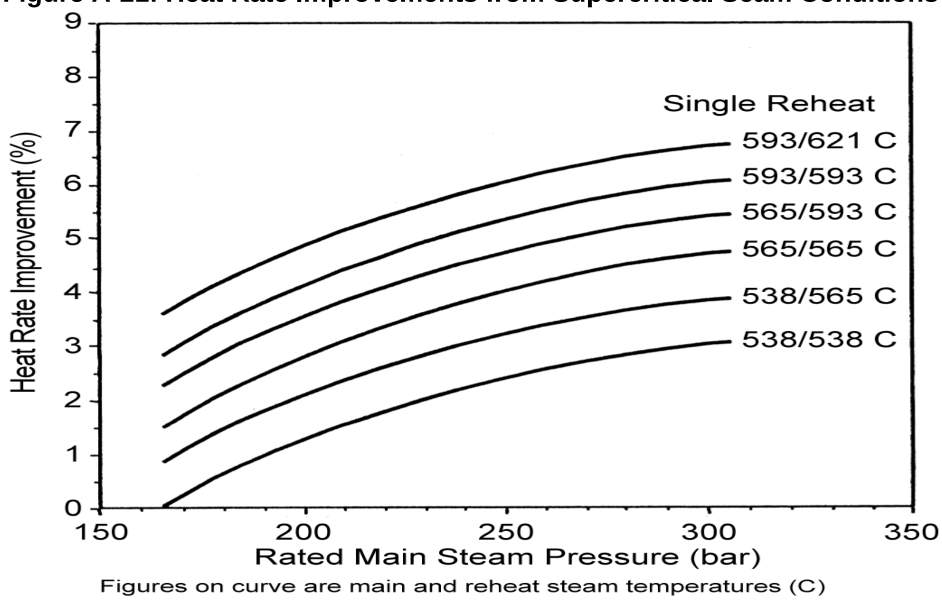
Further development of advanced materials is the key to even higher steam conditions and major development projects are in progress, particularly in Denmark, Germany, Japan and the US. Plants with pressure up to 35 MPa and steam temperatures up to 650 C (1200 F) are foreseen in a decade, giving an efficiency approaching 50%.

Table A.78: European Supercritical Pulverized Coal Power Plants

Power Plant	Fuel	Output MW	Steam Conditions MPa/°C/°C/°C	Startup Date
Denmark:				
Skaerbaek	Coal	400	29/582/580/580	1997
Nordiyland	Coal	400	29/582/580/580	1998
Avdoere	Oil, Biomass	530	30/580/600	2000
Germany:				
Schopau A,B	Lignite	450	28.5/545/560	1995–96
Schwarze Pumpe A,B	Lignite	800	26.8/545/560	1997–98
Boxberg Q,R	Lignite	818	26.8/545/583	1999–2000
Lippendorf R,S	Lignite	900	26.8/554/583	1999–2000
Bexbach II	Coal	750	25/575/595	1999
Niederausem K	Lignite	1000	26.5/576/599	2002

Source: World Bank, Technical Paper 011, May 2001

Figure A-21: Heat Rate Improvements from Supercritical Seam Conditions



Source: World Bank, Technical Paper 011, May 2001

This efficiency improvement represents proportional reduction of all pollutants (particulates, SO_2, NOx, mercury and CO_2, among others) per unit of generated electricity.

Both subcritical and supercritical plants are commercially available worldwide. Subcritical plants are used in all countries; supercritical are less widespread, but there are more than 600 plants in operation in countries such as China, East and West European countries, India, Japan South Korea and USA, some operating since the 1970s. Individual units of over 1,000 MWe are in operation, but most new plants are in the 500-700 MWe range.

A.15.2 Environmental and Economic Assessment

With regard to environmental performance, there are many technologies developed to reduce all "criteria pollutants" (particulates, SO2 and NOx) by more than 90% (nearly 100% with regard to particulates and SO2). Some of these technologies have resulted in emission levels comparable to natural gas power plants (except for CO2 emissions). Table A.79 presents typical emissions for a 300 MW sub-critical steam-electric power plant burning Australian coal. If lower emissions are required, there are many environmental control options to be employed to achieve them.

Table A.79: Air Emissions from a 300 MW Pulverized Coal Steam Eledtric Power Plant

	Emission Standard for Coal (World Bank 1998)	Result		Reduction equipment
		Boiler exhaust	Stack exhaust	
SOx	2000mg/Nm^3 (<500MW:0.2tpd/MW)	1700mg/Nm^3 (33 tpd)	←	Not required
NOx	750mg/Nm^3	500mg/Nm^3	←	Not required
PM	50mg/Nm^3	20,000mg/Nm^3	50mg/Nm^3	Required
CO_2	None	880g-CO_2/kWh	←	NA

Table A.80 shows design parameters and operating characteristics for typical steam-electric power plants of 300 and 500 MW size.

Table A.80: Pulverized Coal Steam Electric Power Plant Design Assumptions

Capacity (MW)	**300MW SubCr**	**500MW SubCr**	**500MW SuperCr**	**500MW USC**
Capacity Factor (%)	80	80	80	80
Steam Turbine Inlet pressure and temperature	16.7MPa /538/538	16.7MPa /538/538	24.2 MPa/565°C/565°C	31 MPa/600°C/600°C
Fuel type	Coal (Australia)	Coal (Australia)	Coal (Australia)	Coal (Australia)
Gross Plant efficiency (LHV, %)	40.9	41.5	43.6	46.8
Auxiliary power ratio (%)	6	5	5	5
Life span (year)	30	30	30	30
Capital Costs ($/kW)	1,020	980	1,010	1,090

The capital costs shown in the previous table have been developed assuming no FGD and SCR. In the absence of specific data for Tamil Nadu, India, international prices were used.[16] More specifically, the capital costs for USC are the average from the following sources after $170/kW were take out for FGD and SCR, which are not needed to meet the local regulations or the World Bank Guidelines:

The breakdown of the capital costs is shown in Table A.79. A clarification should be made on Process Contingency category. Project contingency (typically 15% of the capital costs) is already included in the above cost estimates. Process Contingency reflects additional uncertainty with technologies which have not been used widely or with coals representative in developing countries. 5% process contingency has been assigned to ultra-supercritical technology which has yet to be used in developing countries.

Table A.81: Pulverized Coal Steam Electric Power Plant Capital Cost Breakdown

Equipment	60-70%
Civil	9-12%
Engineering	9-11%
Erection	9-12%
Process Contingency	0-10%
Total	100%

Generating cost estimates are shown in Table A.82.

Table A.82: Pulverized Coal Steam Electric Power 2005 Generating Cost (cents/kWh)

	300MW SubCr	**500MW SubCr**	**500MW SuperCr**	**500MW USC**
Levelized Capital cost	1.76	1.67	1.73	1.84
Fixed O&M cost	0.38	0.38	0.38	0.38
Variable O&M cost	0.36	0.36	0.36	0.36
Fuel cost	1.97	1.92	1.83	1.70
Total	4.47	4.33	4.29	4.29

[16] See: Booras, G. (EPRI) "Pulverized Coal and IGCC Plant Cost and Performance Estimates", Gasification Technologies 2004, Washington, DC, October 3-6, 2004; Bechtel Power: "Incremental Cost of CO2 Reduction in Power Plants", presented at the ASME Turbo Expo, 2002; Florida Municipal Power Authority: "Development of High Efficiency, Environmentally Advanced Public Power Coal-fired Generation", Presented at the PowerGen International Conference, Las Vegas, NV, Dec 2003; and EPRI: "Gasification Process Selection-Trade offs and Ironies", presented at the Gasification Technologies Conference 2004

A.15.3 Future Price and Uncertainty Analysis

The total capital costs and generation costs for the options being considered are shown in Table A.83 and Table A.84.

Table A.83: Pulverized Coal Steam Electric Power Capital Cost Projections ($/kW)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300MW SubCr	1,080	1,190	1,310	960	1,080	1,220	910	1,060	1,200
500MW SubCr	1,030	1,140	1,250	910	1,030	1,150	870	1,010	1,140
500MW SuperCr	1,070	1,180	1,290	950	1,070	1,200	900	1,050	1,190
500MW USC	1,150	1,260	1,370	1,020	1,140	1,250	960	1,100	1,230

Table A.84: Pulverized Coal Steam Electric PowerGenerating Cost Projections (cents/kWh)

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
300MW SubCr	4.18	4.47	4.95	3.91	4.20	4.76	3.86	4.20	4.84
500MW SubCr	4.05	4.33	4.79	3.77	4.07	4.62	3.74	4.06	4.69
500MW SuperCr	4.02	4.29	4.74	3.74	4.04	4.56	3.72	4.03	4.63
500MW USC	4.02	4.29	4.71	3.74	4.02	4.51	3.69	3.99	4.55

A.16 *Coal IGCC Power Systems*

As Integrated Gasification Combined Cycle (IGCC) Power Plant in its simplest form is a process where coal is gasified with either oxygen or air, and the resulting synthesis gas, consisting of hydrogen and carbon monoxide, is cooled, cleaned and fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator (HRSG) where it produces steam that drives a turbine. Power is produced from both the gas and steam turbine-generators. By removing the emissions-forming constituents from the synthetic gas prior to combustion in the gas turbine, an IGCC power plant can meet very stringent emission standards.

There are many variations on this basic IGCC scheme, especially in the degree of integration. It is the general consensus among IGCC plant designers today that the preferred design is one in which the air separation unit (ASU) derives part of its air supply from the gas turbine compressor and part from a separate air compressor.

A.16.1 Technology Description

Three major types of gasification systems in use today: moving bed; fluidized bed; and entrained flow. All three systems use pressurized gasification (20 to 40 bars), which is preferable to avoid auxiliary power losses for synthetic gas compression. Most gasification processes currently in use or planned for IGCC applications are oxygen-blown, which provides potential advantages if sequestration of carbon dioxide emissions is a possibility.[17]

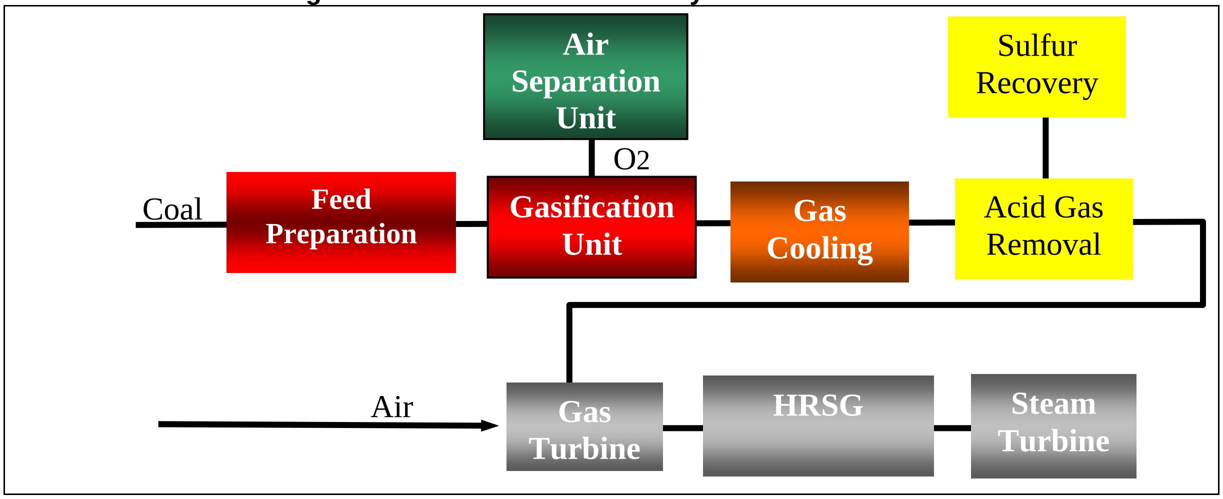
In the coal-fueled IGCC Power Plant design, the hot syngas leaving the gasifier goes to a residence vessel to allow further reaction. It is then cooled in the high temperature heat recovery (HTHR) section before almost all of the particulates are removed by a hot gas cyclone. The remaining particulates and water soluble impurities are removed simultaneously by wet scrubbing with water. The particulates are concentrated and recovered from the wash water by a filter system before being recycled to the gasifier for further reaction. Filtered water is recycled to the wet scrubber or is sent to the sour water stripper.

Figure A-22 provides a typical configuration for a coal fired IGCC power plant such as that considered in this study.

Most of the large components of an IGCC plant (such as the cryogenic cold box for the ASU, the gasifier, the syngas coolers, the gas turbine and the HRSG sections) can be shop-fabricated and transported to a site. The construction/installation time is estimated to be about the same (three years) as for a comparably sized conventional coal power plant.

[17] See various presentations from the Gasification Technologies Council

Figure A-22: Coal IGCC Power System Schematic



IGCC provides several environmental benefits over conventional units. Since gasification operates in a low-oxygen environment (unlike conventional coal plants, which is oxygen-rich for combustion), the sulfur in the fuel converts to hydrogen sulfide (H_2S), instead of SO_2. The H_2S can be more easily captured and removed than SO_2. Removal rates of 99% and higher are common using technologies proven in the petrochemical industry.

IGCC units can also be configured to operate at very low NO_x emissions without the need for selective catalytic reduction (SCR). Two main techniques are used to lower the flame temperature for NO_x control in IGCC systems. One saturates the syngas with hot water while the other uses nitrogen from the Air Separation Unit (ASU) as a diluting agent in the combustor. Application of both methods in an optimized combination has been found to provide a significant reduction in NO_x formation. NO_x emissions typically fall in the 15-20 parts-per-million (ppm) range, which is well below any existing emissions standard.

The basic IGCC concept was first successfully demonstrated at commercial scale at the pioneer Cool Water Project in Southern California from 1984 to 1989. There are currently two commercial sized, coal-based IGCC plants in the U.S. and two in Europe. The two projects in the U.S. were supported initially under the DOE's Clean Coal Technology demonstration program, but are now operating commercially without DOE support.

A.16.2 Environmental and Economic Assessment

Table A.85 provides the design parameters and operating characteristics assumed for the 300 MW coal-fired IGCC power plant assessed here.

Table A.85: Coal IGCC Power System Design Assumptions

Capacity (MW)	300MW	500MW
Capacity Factor (%)	80	
Life span (year)	30	
Fuel type	Coal (Australia)	
Gasifier Type	Coal Slurry Entrained Bed	
Oxygen Purity	95%	
Auxiliary power ratio (%)	11	10
Gross Thermal Efficiency (LHV, %)	47	48
Gross Generated Electricity (GWh/year)	2,102	3,504
Net Generated Electricity (GWh/year)	1,870	3,154

Assuming coal properties typical of Illinois # 6 coals the emissions characteristics of a 300 MW IGCC are shown in Table A.86. IGCC power plants are capable of removing 99% of sulfur in the fuel as elemental sulfur; hence sulfur emissions are extremely low. The high pressure and low temperature of combustion sharply reduces NO_x formation.

Table A.86: World Bank Air Emissions Standards and IGCC Emissions

	Emission Standard for Coal	IGCC Plant Emissions
SOx	2000mg/Nm^3 (<500MW:0.2tpd/MW)	> 0.30 gm/kWh
NOx	750mg/Nm^3	> 0.30 gm/kWh
PM	50mg/Nm^3	Negligible
CO_2	None	700~ 750 gm/kWh

Indicative capital costs for the IGCC plant considered are as shown in Table A.87, while conversion to levelized generation costs using the method described in Annex B yields the results shown in Table A.88.

Table A.87: Coal IGCC Power Plant 2005 Capital Costs ($/kW)

	300MW	500MW
Equipment & Material	1,010	940
Engineering	150	140
Civil	150	140
Construction	100	100
Process Contingency	200	180
Total Plant Cost	1,610	1,500

Table A.88: Coal IGCC Power Plant 2005 Generating costs (cents/kWh)

	300MW	500MW
Levelized Capital Cost	2.49	2.29
Fixed O & M	0.90	0.90
Variable O & M	0.21	0.21
Fuel	1.79	1.73
Total COE	5.39	5.14

A.16.3 Future Cost and Uncertainty Analysis

The cost of coal based IGCC power plants probably will not change over the next five years until the first generation commercial units are commissioned. Improvements in design with respect to advanced gas turbines and hot gas clean up systems may be expected over the next ten years. The results of operating experience accumulated in these plants and the confidence gained in the utility industry overall may bring down the cost of these plants by about 10% over the next ten years. In this assessment we assume that all cost data is variable ±30%, yielding the Monte Carlo simulation analysis results shown in Table A.89.

Table A.89: Coal IGCC Capital and Generating Cost Projections

		2005			2010			2015		
		Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Capital cost ($/kW)	300MW	1,450	1,610	1,770	1,200	1,390	1,550	1,070	1,280	1,440
	500MW	1,350	1,500	1,650	1,130	1,300	1,450	1,000	1,190	1,340
Generating cost (cent/kWh)	300MW	5.05	5.39	5.90	4.58	4.95	5.52	4.40	4.81	5.43
	500MW	4.81	5.14	5.62	4.38	4.74	5.28	4.21	4.60	5.19

A.17 *Coal-Fired AFBC Power Systems*

Atmospheric Fluidized Bed Combustion (AFBC) is a combustion process in which limestone is injected into the combustion zone to capture the sulfur in the coal. The calcium sulfate byproduct ($CaSO_4$ formed from the combination of SO_2 and the CaO in the limestone) is captured in the particulate control devices (electrostatic precipitator or bag filter) and disposed along with the fly ash.

A.17.1 Technology Description

There are two types of fluidized bed designs, the Bubbling AFBC and the Circulating AFBC. The difference is in the velocity of the gas inside the boiler and the amount of recycled material. Bubbling AFBC has lower velocity; hence less amount of material escapes the top of the boiler. Circulating AFBC has higher velocity and much higher amount of recycled material relative to the incoming coal flow.

Bubbling AFBC is used mostly in smaller plants (10-50 MW_e) that burn biomass and municipal wastes. Circulating AFBC, also known as Circulating Fluidized Bed (CFB), is used for utility applications, especially in plants larger than 100 MW_e. We focus on Circulating AFBC in this report.

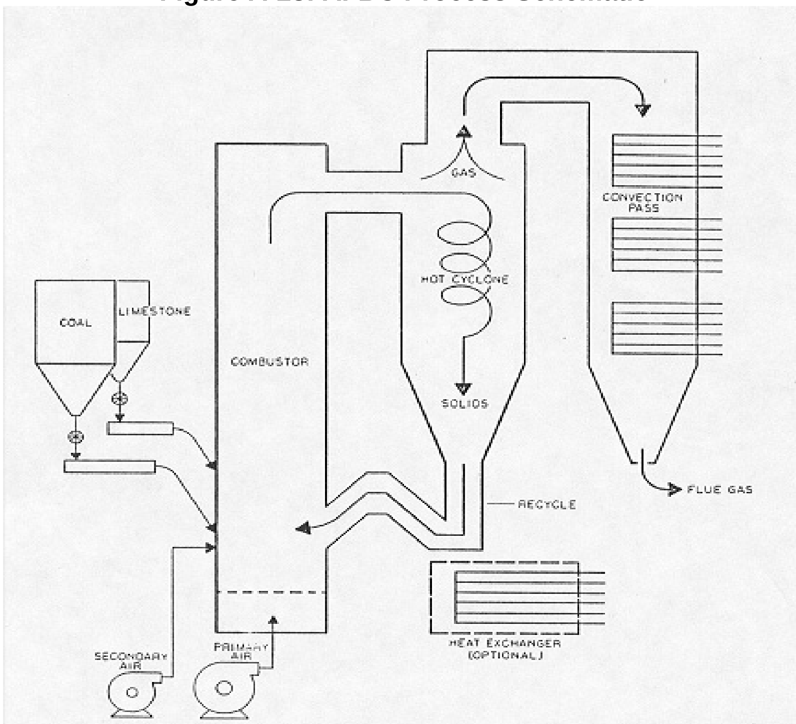
AFBC boilers (see Figure A-23) are very similar to conventional Pulverized Coal (PC) boilers. The majority of boiler components are similar, and hence manufacturing of the furnace and the back-pass can be done in existing manufacturing facilities. In addition, an AFBC boiler utilizes the Rankine steam cycle with steam temperatures and pressures similar to PC boilers. AFBC boilers can be designed for either sub-critical or supercritical conditions. Most AFBC boilers utilized so far are of the sub-critical type, mainly because the technology has been utilized in sizes up to 350 MW_e where sub-critical operation is more cost-effective. As the technology is scaled up (above 400-500 MW_e), the supercritical design may be used depending on site-specific requirements (e.g., cost of fuel and environmental requirements).

The difference of AFBC relative to PC boilers stems from lower operating temperatures and the injection of limestone in the furnace to capture SO_2 emissions. Typical maximum furnace temperature in a AFBC boiler are in the 1500-1600 °F (820–870 °C) range, while conventional PCs operate at 2200-2700 °F (1200–1500 °C). Low combustion temperature limits the formation of NO_X, and is also the optimum temperature range for in-situ capture of SO_2.

The injected limestone is converted to lime, a portion of which reacts with SO_2 to form calcium sulfate ($CaSO_4$), a dry solid which is removed in the particulate collection equipment. A cyclone is located between the furnace and the convection pass to capture un-reacted lime and limestone present in the flue gases exiting the furnace. The solids collected in the cyclone are re-circulated to the furnace to improve the overall limestone utilization. Limestone injection can remove up to 90 – 95+ percent of the sulfur in the coal[1], eliminating the need for flue gas desulfurization (FGD) downstream of the boiler. AFBCs have NO_X emissions 60-70 percent less than conventional PCs with low NO_X burners.

AFBC boilers can efficiently burn low reactivity and low-grade fuels, which may not be burned in conventional PCs. Such fuels include anthracite, coal cleaning wastes, and industrial and municipal wastes. High-ash fuels, such as lignite, are particularly suitable for AFBC technology.

Figure A-23: AFBC Process Schematic



Source: World Bank[18]

A.17.2 Environmental and Economic Assessment

Consistent with the methodology followed in this study and especially the assumptions made for the large power plants, AFBC power plant economics were developed for an indicative design located in India.

The design assumptions are as follows:

- Gross output: 300 MW
- Sub-critical steam cycle with steam conditions: 16.7MPa/538 °C/538 °C (2400psi/1000°F/1000°F)

[18] "The Current State of Atmospheric Fluidized-bed Combustion Technology", Washington, D.C.: The World Bank, Technical Paper # 107, Fall 1989

- Gross Thermal Efficiency: 41% (LHV)
- Auxiliary power ratio: 7%
- Plant life: 30 years
- CF 80%
- On-site coal storage: 30 days at 100% load and utilization factor
- Start-up fuel: oil
- Ash transferred through a pneumatic system to adjacent disposal pond

The emissions results for the indicative coal-fired AFBC design area compared with the World Bank's coal-fired power plant standards in Table A.90.

Table A.90: AFBC Emissions Results and World Bank Standards

	World Bank Emission Standard for Coal	Emissions Calculated for a Coal-Fired AFBC Design Located in India
SOx	2000 mg/Nm^3 (<500MW: 0.2 tpd/MW)	940 mg/Nm^3 [19]
NOx	750 mg/Nm^3	250 mg/Nm^3 [20]
PM	50 mg/Nm^3	Under 50 mg/Nm^3 [21]
CO_2	—	940 g-CO_2/year

The capital costs of an AFBC plant are affected by many site-specific factors, such as coal properties, environmental regulations, sourcing of the key components, and geophysical characteristics of the construction site. Table A.91 provides a sample of the relevant capital costs available for various locations.

Table A.91: Indicative AFBC Installations and Capital Cost Estimates

Location	Size (MW)	Capital Costs ($/kW)	Source
Elbistan, Turkey	250	1,100	World Bank, Turkey EER Report/Task 2
Generic, China	300	721	World Bank/ESMAP Paper 011[22]
Jacksonville, FL, USA	2X300	1,050	Coal Age Magazine, Nov 2002
Generic, Europe	150	1,273[23]	Eurostat (Les Echos Group), 2003[24]
Generic, USA	200	1,304	Alstom (2003)[25]

[19] Indian coal contain CaO in the ash and can capture SO2 without adding limestone. If the sulfur in the coal is relatively low and/or the environmental standards are not very strict, limestone may not be required.
[20] Lower than 100 mg/Nm3 (typically 30-50 mg/Nm3) is possible with the addition of SNCR (Selective Non-Catalytic Reduction) system in the AFBC boiler.
[21] Depends on ESP or fabric filter design; in some developing countries higher particulates (e.g., 100 or 150 mg/Nm3) may be allowed. In this case, the capital costs may be slightly lower (e.g., 10-15 $/kW)).
[22] ESMAP, "Technology Assessment of China Clean Coal Technologies: Electric Power Production", 2001
[23] Note: The publication provides the costs in Euros; considering that 1US$ was equal to 0.85 to 1.10 Euros during 2003, we assume that 1US$ equal 1.0 Euro
[24] Source: World Energy Council, "Performance of Generating Plant 2004", Section 3
[25] Marion, J., Bozzuto, C., Nsakala, N., Liljedahl, G., "Evaluation of Advanced Coal Combustion & Gasification Power Plants with Greenhouse Gas Emission Control", Topical Phase-I, DOE-NETL Report under Cooperative Agreement No. DE-FC26-01NT41146 Prepared by Alstom Power Inc., May 15, 2003

Generic, USA	664 (supercritical)	1,038	Alstom (2003)[26]
Average		1,081	

Based on these actual projects we provide the breakdown of coal-fired AFBC costs shown in Table A.92.

Table A.92: Coal Fired AFBC Power Plant 2005 Capital Costs ($/kW)

Items	300MW	500MW
Equipment	730	680
Civil	120	120
Engineering	110	110
Erection	120	110
Process Contingency	100	100
Total[27]:	1,180	1,120

Typical O&M values for a coal-fired AFBC plant are provided in Table A.91, while typical generating costs are shown in Table A.93.

Table A.93: Coal-Fired AFBC Power Plant 2005 O&M Costs (cents/kWh)

Items	300MW	500MW
Fixed-O&M Cost	0.50	0.50
Variable-O&M Cost	0.34	0.34
TOTAL O&M	0.84	0.84

Table A.94: Coal-Fired AFBC Power Plant 2005 Generating Cost (cents/kWh)

Items	300MW	500MW
Levelized Capital Cost	1.75	1.64
O&M Cost	0.84	0.84
Fuel Cost	1.52	1.49
Generating Cost	4.11	3.97

A.17.3 Technology Status and Development Trends

The technology is considered commercially available up to 350 MW, as demonstrated by hundreds of such boilers operating throughout the world (e.g., Australia, China, Czech Republic, Finland, France, Germany, India, Japan, Poland, South Korea, Sweden,

[26] Source: Palkes, M., Waryasz, R., "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants", Final DOE-NETL Report under Cooperative Agreement No. DE-FCP-01NT41222 Prepared by Alstom Power Inc., February, 2004
[27] Total Capital Requirement is "overnight costs" not including interest during construction

Thailand and USA). In 1996, EPRI estimated that there are approximately 300 AFBC units (larger than 22 tons/hr each) in operation worldwide. Since then (1996), the number of AFBC operating units has increased above six hundred units. Experience from these units has confirmed performance and emissions targets, high reliability and ability to burn a variety of low quality fuels.[28]

AFBC plants are being built worldwide, and are especially well-suited for solid fuels difficult to burn in a pulverized coal boiler (anthracite, lignite, brown coal, and coal wastes). AFBC plants can also utilize industrial and municipal solid wastes, petroleum coke, and other combustible industrial waste as supplemental fuels. AFBC technology is expected to be used widely in the future, mainly in new power plant applications. Costs are expected to decline, especially in developing countries such as China and India. Specific capital cost reductions are envisioned through:

- Scale up of the technology to 500-600 MW level; this has a potential reduction of 200-300 $/kW comparing the 500-600 MW plant to the 300 MW plant.
- Further improvement of plant design resulting in 5% reduction of capital costs every 5 years for the nominal 300 MW plant, resulting in capital costs of: 1,000 $/kW in 2010 and 950 $/kW in 2015[29].

A.17.4 Uncertainty Analysis

The analysis results using Monte Carlo simulation are shown in Table A.95.

Table A.95: Coal-Fired AFBC Power Plant Projected Capital and Generating Costs

		2005			2010			2015		
		Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Capital cost ($/kW)	300MW	1,060	1,180	1,300	940	1,070	1,210	880	1,040	1,180
	500MW	1,010	1,120	1,230	900	1,020	1,140	840	990	1,120
Generating cost (cent/kWh)	300MW	3.88	4.11	4.56	3.72	3.98	4.55	3.67	3.96	4.55
	500MW	3.75	3.97	4.40	3.61	3.81	4.42	3.58	3.83	4.71

[28]Palkes, M., Waryasz, R., "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants", Final DOE-NETL Report under Cooperative Agreement No. DE-FCP-01NT41222 Prepared by Alstom Power Inc., February, 2004

[29] All data in June 2004 US$

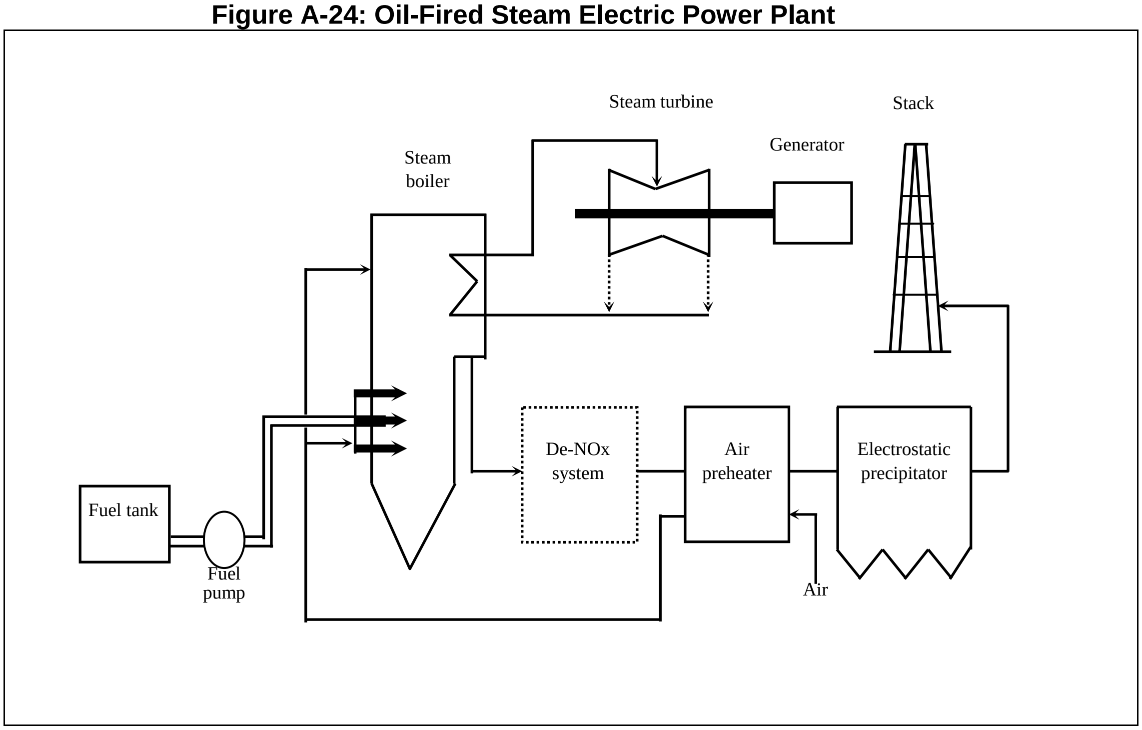
A.18 *Oil-Fired Steam Electric Power Systems*

Oil-fired steam power plants have been used around the world for many years and they are particularly common in countries with access to cheap oil (mainly oil-producing regions such as the Middle-East) and countries without access to other energy sources (e.g., Italy and Japan). However, after the two oil crises of the 1970s, oil is used less and less for power generation mainly due to the high prices, btu also the development of new, more efficient technologies. Nevertheless, oil continues to play some role in many countries.

A.18.1 Technology Description

The oil-fired power plant consists of a boiler, in which the oil is burned and water is heated to superheated (high temperature and pressure) steam; the steam in turn expands in a steam turbine which turns a generator to produce electricity. A schematic of an oil-fired steam-electric power plant is shown in Figure A.23. With the exception of the fuel being burned, the system configuration is very similar to pulverized coal power plants. As in these plants, oil-fired plants could be designed for supercritical or subcritical steam conditions. Subcritical is the most common, but supercritical plants have been used in countries such as Italy and Japan.

Figure A-24: Oil-Fired Steam Electric Power Plant



A.18.2 Environmental and Economic Assessment

Typical design and operating parameters for oil-fired plants are shown in Table A.96.

Table A.96: Oil-Fired Steam Electric Power Plant Design Assumptions

Capacity (MW)	300MW
Capacity Factor (%)	80
Steam Turbine Inlet pressure and temperature	16.7MPa /538/538
Fuel type	Residual oil
Gross Thermal efficiency (LHV, %)	41
Auxiliary power ratio (%)	5
Life span (year)	30
Gross Generated Electricity (GWh/year)	2,102
Net Generated Electricity (GWh/year)	1,997

A Capacity Factor of 80% is assumed, based on 14-hr operation at 100% (full load) output and 10-hr operation at 50% rated output per day.

Residual oil with properties typically found in India is used[30]. Emissions from a 300 MW oil-fired plant (SOx, NOx, PM and CO_2) are shown in Table A.95. For the oil quality assumed, the SO_x and NO_x emissions are below the World Bank's emission standards; therefore, only ESP (electrostatic precipitator) is included in the capital cost. However, for higher sulfur oil, SO2 emissions may require control either through treatment of the oil (before combustion) or through flue gas desulfurization, even though the latter is not common due to unfavorable economics. The most common is to use low-sulfur oil. NOx emissions could be a problem too, but in most cases properly designed burners (combustion system) could control NOx emissions to meet World Bank Environmental Guidelines and emission standards of most countries. For countries with very tight standards, SCR may be needed, in which case special consideration needs to be made to potential impacts from metals in the oil (especially Vanadium) on the effectiveness of the SCR catalyst.

[30] 1.2% sulfur content

Table A.97: Oil-Fired Steam Electric Power Plant Air Emissions

	Emission Standard for Oil	Emissions		Emission Control equipment
		Boiler exhaust	Stack exhaust	
SOx	2000mg/Nm^3 (<500MW:0.2tpd/MW)	1,500mg/Nm^3 (33 tpd)	Same	Not required
NOx	460mg/Nm^3	200mg/Nm^3	Same	Not required
PM	50mg/Nm^3	300mg/Nm^3	50mg/Nm^3	Required
CO_2	None	670g-CO_2/kWh	Same	NA

Table A.96 shows typical capital cost for oil-fired steam plants[31], while Table A.97 shows the generation costs using the methodology described in Section 2.

Table A.98: Oil-Fired Steam Electric Power Plant 2005 Capital Costs ($/kW)

Equipment	600
Civil	100
Engineering	80
Erection	100
Total	880

Table A.99: Oil-Fired Steam Electric Power 2005 Generating Costs (cents/kWh)

Levelized Capital cost	1.27
Fixed O&M cost	0.35
Variable O&M cost	0.30
Fuel cost (levelized fuel cost is as 5.8$/GJ)	5.32
Total	7.24

A.18.3 Future Cost and Uncertainty Analysis

Considering the uncertainty associated with the cost estimates (mainly due to site-specific considerations) capital and generation costs may vary (see Table A.98). The same table shows a decline in the capital costs over time, even though it is not substantial due to the fact that the technology is mature and is not expected to develop further.

[31] Preliminary Study on the Optimal Electric Power Development in Sumatra, Japan International Cooperation Agency (JICA), January 2003

Table A.100: Oil-Fired Steam Electric Power Plant Projected Capital and Generating Costs

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Capital cost ($/kW)	780	880	980	700	810	920	670	800	920
Generating cost (cent/kWh)	6.21	7.24	9.00	5.50	6.70	9.08	5.49	6.78	9.63

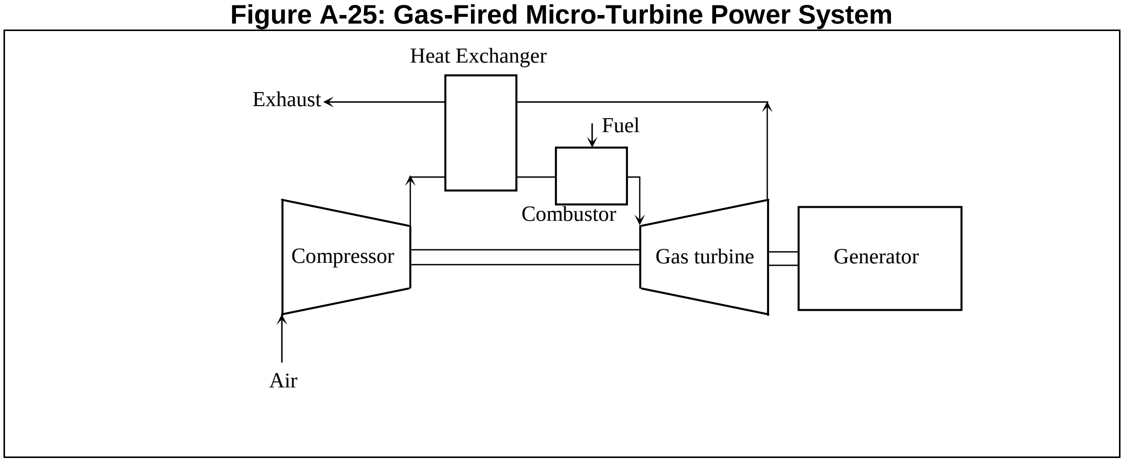
A.19 *Micro-Turbine Power Systems*

Micro-turbines are 25 kW to 250 kW turbine engines that run on natural gas, gasoline, diesel or alcohol. Derived from aircraft auxiliary power systems and automotive designs, micro-turbines have one or two shafts that operate at speeds of up to 120,000 revolutions per minute for single shaft engines and 40,000 rpm for duel shaft engines. Micro-turbines are a relatively new technology and are only now being sold commercially. They have capital cost of $500 to $1,000/kW and electrical efficiencies of 20 to 30 percent. Their main advantage is their small size and relatively low NO_x emissions. Main markets for this power generation technology include light industrial and commercial facilities that often pay higher price for electricity. The modest heat output can also be used for low-pressure steam or hot water requirements. According to trial calculation of EPRI, generating cost is reduced 40% by 100% cogeneration system.

A.19.1 Technology Description

Figure A-25 shows the schematic of Micro-turbine burning natural gas. Note that the basic layout is that of a Brayton cycle machine, identical to a larger scale simple cycle or closed cycle gas turbine plant.

Figure A-25: Gas-Fired Micro-Turbine Power System



A.19.2 Environmental and Economic Assessment

Table A.101 provides assumed design parameters and operating characteristics for a gas-fired micro-turbine.

Table A.101: Micro-Turbine Power Plant Design Assumptions

Capacity (MW)	150kW
Capacity Factor (%)	80
Gas Turbine Inlet temperature	950 degree
Operate speeds	90,000 rpm
Fuel type	Natural gas
Thermal efficiency (LHV, %)	30
Auxiliary power ratio (%)	0
Life span (year)	20
Generated Electricity (MWh/year)	1,051

Source: The Institute of Applied Energy (Japan)

The environmental impacts of micro-turbines are extremely low – just 30-60 mg/Nm^3 for NO_x and 670 g-CO_2/net-kWh.

Table A.102 provides estimated capital costs of a gas-fired Micro-turbine.

Table A.102: Micro-Turbine Power System 2005 Capital Cost ($/kW)

Equipment	830
Civil	10
Engineering	10
Erection	20
Process Contingency	90
Total	960

Table A.103 provides the results of the generation cost calculations, in line with the methodology described in Annex B.

Table A.103: Micro-Turbine Power Plant 2005 Generating Cost (cents/kWh)

Levelized Capital cost	1.46
Fixed O&M cost	1.00
Variable O&M cost	2.50
Fuel cost	26.86
Total	31.82

A.19.3 Future Cost and Uncertainty Analysis

The two main American micro-turbine manufacturers have announced target prices corresponding to their long-term plans for technology development and manufacturing scale-up. These forecasts are roughly half the current as-delivered cost (See Table A.102). We assume that the target price will be reached in 2025, a cost reduction trajectory equivalent to a decline of $20 per year over the study period.

Table A.104: Micro-Turbine Power System Target Price

Maker	$/kW
Elliott (USA)	400
Capstone (USA)	500

Source: The Institute of Applied Energy (Japan)

The cost of power plants changes with conditions such as maker, location, fuel price and so on. In this section, it is assumed that all costs have ±20% variability around the probable values. This uncertainty assumption together with the capital cost projections yields the projected capital and generating costs shown in Table A.103.

Table A.105: Micro-Turbine Power Plant Projected Capital and Generating Costs

	2005			2010			2015		
	Min	**Probable**	Max	Min	**Probable**	Max	Min	**Probable**	Max
Capital cost ($/kW)	830	960	1,090	620	780	910	500	680	810
Generating cost (cent/kWh)	30.4	31.8	33.9	28.8	30.7	33.5	28.5	30.7	34.2

A.20 *Fuel Cells*

Fuel cells produce direct current electricity through an electrochemical process. Reactants, most typically hydrogen and air, are continuously fed to the fuel cell reactor and power is generated as long these reactants are supplied (Figure A-26). A detailed description of the fuel cell technology status and applications is provided in the *Fuel Cell Handbook.*[32]

A.20.1 Technology Description

Operation of complete, self-contained, natural gas-fueled small (less than 12 MW) power plants has been demonstrated using four different fuel cell technologies. They are: polymer electrolyte fuel cell (PEFC), phosphoric acid fuel cell (PAFC), molten carbonate fuel cell (MCFC), and solid oxide fuel cell (SOFC). Over 200 PAFC have been sold worldwide since the early 1990s, when 200kW PAFC units were commercially offered by IFC. These systems were installed at natural gas-fueled facilities and are currently in operation. Lower capacity units operate at atmospheric pressures while an 11 MW system that went into operation at the Tokyo Power Company's Gio Thermal Station in 1991 operates at eight atmospheres. MCFC units rated at 300kW are also considered ready for commercialization.

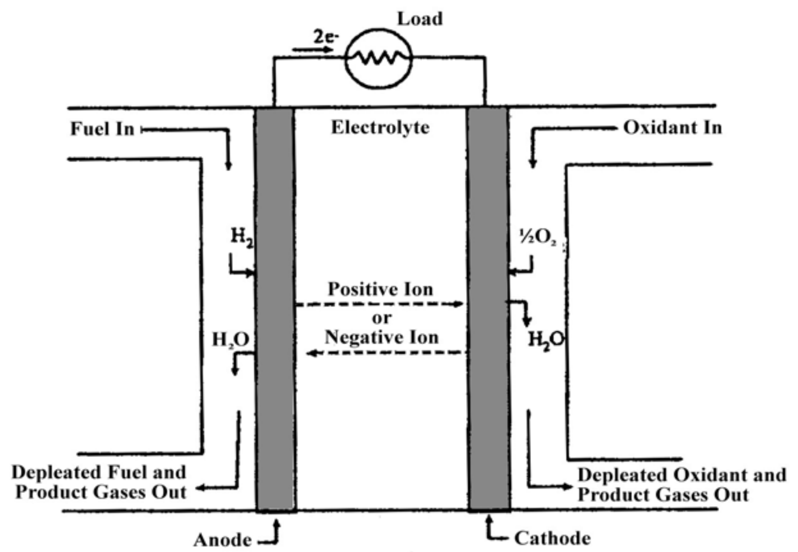
PEFC and PAFC operate at low temperatures, less than 500^{o}F, while MCFC and SOFC operate at high temperatures, 1,200^{o}F –1,850^{o}F. Operating pressures also vary from atmospheric pressures to about eight atmospheres depending on the fuel cell type and size. Pressurization generally improves fuel cell efficiency[33] but increases parasitic load and capital cost. It could also lead to operational difficulties such as corrosion, seal deterioration, and reformer catalyst deactivation. Most fuel cells require a device to convert natural gas or other fuels to a hydrogen-rich gas stream. This device is known as a fuel processor or reformer.

Fuel cell system performance is also sensitive to a number of contaminants. In particular, PEFC is sensitive to carbon monoxide, sulfur, and ammonia; PAFC to carbon monoxide and sulfur; MCFC to sulfur and hydrogen chloride; and SOFC to sulfur. Fuel cell system design must reduce these contaminants to levels that are acceptable to fuel cell manufacturers.

[32] *Fuel Cell Handbook, fifth edition*, U.S. DOE Office of Fossil Energy's National Energy Technology Laboratory, October 2000.

[33] Sy A. Ali and Robert R. Mortiz, *The Hybrid Cycle: Integration Of Turbomachinery With A Fuel Cell*, ASME, 1999.

Figure A-26: Operating Principles of a Fuel Cell



Source: Fuel Cell Handbook, October 2000

A.20.2 Environmental and Economic Assessment

We assume the design parameters and operating characteristics for fuel cells as shown in Table A.106.

Table A.106: Fuel Cell Power System Design Assumptions

	200 kW Fuel Cell	5 MW Fuel Cell
Capacity (MW)	200 kW	5 MW
Capacity Factor (%)	80	80
Fuel Type	Natural Gas	Natural Gas
Electrical efficiency (LHV, %)[34]	50	50
Auxiliary power ratio (%)	1	1
Life span (year)	20	20
Gross Generated Electricity (MWh/year)	1,402	35,040
Net Generated Electricity (MWh/year)	1,388	34,690

Fuel cells have essentially negligible air emissions characteristics, as shown in Table A.107.

[34]Operating fuel cells as a combined heat and power plant can increase fuel cell plant efficiency to 70%

Table A.107: Fuel Cell Power System Air Emissions

	Emission Standard	Fuel Cell Gas
PM	50mg/Nm^3	—
SOx	2000mg/Nm^3 (<500MW:0.2tpd/MW)	—
NOx	Gas: 320mg/Nm^3; Oil: 460	1.4 -3

Fuel cells do generate CO_2 emissions at a level comparable to direct combustion of gas (See Table A.108).

Table A.108: Fuel Cell Power System Carbon Dioxide Emissions

	200 kW Fuel Cell (CF=80 %)	5 MW Fuel Cell (CF=80 %)
	Gas	Gas
g-CO_2/kWh	370 - 465	370 - 465
10^3 ton/year	0.52 – 0.65	13 - 16

Table A.109 shows the estimated capital cost of a 200 kW and 5 MW fuel cells.

Table A.109: Fuel Cell Power System 2005 Capital Costs ($/kW)

Items	200 kW Fuel Cell	5 MW Fuel Cell
Equipment	3,100	3,095
Civil	0	5
Engineering	0	0
Erection	20	10
Process Contingency	520	520
Total	3,640	3,630

Table A.110 shows the results of converting the capital cost into per kWh cost, assuming a 20-year service life and using the methodology described in Annex B.

Table A.110: Fuel Cell Power System 2005 Generating Costs (cents/kWh)

Items	200 kW Fuel Cell	5 MW Fuel Cell
	Natural Gas	Natural Gas
Levelized Capital cost	5.60	5.59
Fixed O&M cost	0.10	0.10
Variable O&M cost	4.50	4.50
Fuel cost	16.28	4.18
Total	26.48	14.36

A.20.3 Future Cost and Uncertainty Analysis

The actual equipment cost for fuel cells is expected to decrease in the future due to technological improvements and reduced manufacturing costs. Cost projections reflecting these decreases are given in Table A.111.

Table A.111: Fuel Cell Power System Projected Capital and Generating Costs

	2005	2010	2015
200 kW Fuel Cell			
Total Installed Cost, ($/kW)	3,640	2,820	2,100
Total Generating Costs (c/kWh)	26.5	24.7	23.7
5 MW Fuel Cell			
Total Installed Cost, ($/kW)	3,630	2,820	2,100
Total Generating Costs (c/kWh)	14.4	12.7	11.7

The cost of power plants often changes with conditions such as maker, location, fuel price and so on. In this section we assume that all costs are variable within a ±20% range, with the results shown in Table A.112 and Table A.113.

Table A.112: Uncertainty in Fuel Cell Capital Cost Projections

	2005			2010			2015 [1]		
	Min	Probable	Maxi	Min	Probable	Max	Min	Probable	Max
200 kW Fuel Cell	3,150	3,640	4,120	2,190	2,820	3,260	1,470	2,100	2,450
5 MW Fuel Cell	3,150	3,630	4,110	2,180	2,820	3,260	1,470	2,100	2,450

Table A.113: Uncertainty in Fuel Cell Generating Cost Projections

	2005			2010			2015		
	Min	Probable	Maxi	Min	Probable	Max	Min	Probable	Max
200 kW Fuel Cell	25.2	26.5	28.2	22.8	24.7	26.6	21.5	23.7	25.8
5 MW Fuel Cell	13.2	14.4	15.8	11.0	12.7	14.4	9.6	11.7	13.4

B Description of Economic Assessment Methodology

Assessment results for generation technologies vary according to the operating environment. During an August 2004 inception meeting the study team suggested values for key operating assumptions, including average unit size, life span, output, and capacity factor. Consultation with the Bank Task Managers yielded the operating parameter assumptions and ranges specified in Table B.1, which were then used in the assessment process.

Table B.1: Power Generation Technology Configurations and Design Assumptions

Generating Types	Life Span (Year)	Off-grid		Mini-grid		Grid Connected			
						Base-Load		Peak	
		Capacity	CF (%)	Capacity	CF (%)	Capacity	CF (%)	Capacity	CF (%)
Solar PV	20 25	50W,300W	20	25kW	20	5MW	20		
Wind	20	300W	25	100kW	25	10MW, 100MW	30		
PV-Wind Hybrids	20	300W	25	100kW	30				
Solar thermal with storage Solar thermal without storage	30 30					30MW 30MW	50 20		
Geothermal Binary Geothermal Binary Geothermal Flash	20 30 30			200KW	70	20MW 50MW	90 90		
Biomass Gasifier	20			100kW	80	20MW	80		
Biomass Steam	20					50MW	80		
MSW/Landfill Gas	20					5MW	80		
Biogas	20			60kW	80				
Pico/Micro Hydro	5 15 30	300W 1kW	30 30	100kW	30				
Mini Hydro	30					5MW	45		
Large Hydro	40					100MW	50		
Pumped storage Hydro	40							150MW	10
Diesel/Gasoline Generator	10 20	300W, 1kW	30	100kW	80	5MW	80	5MW	10
Micro Turbines	20			150kW	80				
Fuel Cells	20			200kW	80	5MW	80		
Oil/Gas Comb. Turbines	25							150MW	10
Oil/Gas Combined Cycle	25					300MW	80		
Coal Steam Sub-critical Sub, SC, USC	30 30					300MW 500MW	80 80		
Coal IGCC	30 30					300MW 500MW	80 80		
Coal AFB	30 30					300MW 500MW	80 80		
Oil Steam	30					300MW	80		

Assessment results will also vary widely according to the values assumed for key economic parameters. Following World Bank guidance contained in the study's Terms of

Reference, we used a Discount Rate[35] set at 10%/year. We performed and expressed all economic analysis in constant June 2004 US dollars. Economic cost equivalent to international competitive price of machines, materials, and fuel are used. Transport costs are included and shown separately, and only labor expenses are assumed to differ between regions.

B.1 *Cost Formulations for Generation*

The Generating Cost of each resource is simply the sum of capital cost and operating cost, expressed on a levelized basis. This formulation (Equation 1) reflects an explicitly *economic* analysis, as opposed to a *financial* analysis.

Generating Cost = Capital Cost + Operating Cost *(Equation 1)*

Capital Cost is calculated on a unit basis using Equation 2. Costs which do not directly contribute to power generation, such as land, roads, offices, etc., are not included into the calculation.

Unit Capital Cost ($/kW) = (Equipment Cost including Engineering + Civil Cost + Construction Cost + Process Contingency) ÷generation capacity (kW)

(Equation 2)

Capital Cost can be expressed in levelized terms through Equation 3 below:

$$LevelizedCapitalCost(\$/kWh) = \frac{\sum \frac{Cn}{(1+r)^n}(\$)}{\sum \frac{En}{(1+r)^n}(kWh)} \qquad \textit{(Equation 3)}$$

Where *r* is the discount rate, *n* is the life span, *Cn* is the capital cost incurred in the *n*th year, and *En* is the net electricity supplied in the *n*th year

Operating Cost can be calculated using Equation 4 below,

Operating Cost ($/kWh) ={Fixed O&M Cost ($/yr) +Variable O&M Cost($/yr)+ Levelized Fuel Cost ($/yr)}÷ Net Electricity (kWh/yr)

(Equation 4)

Where:

[35] Used for calculating levelized cost

Fixed O&M Cost ($/yr) = *Operating labor, General and administrative, Insurance, Other*

Variable O&M Cost ($/yr) = *Maintenance labor and material, Supplies and consumables, Water and water treatment, Other*

Levelized Fuel Cost ($/yr) = *Levelized Heat unit price($/J) ×Gross Heat consumption(J/kWh)×Gross Electricity(kWh/yr)*

and:

Net Electricity (kWh/yr) = *Gross Electricity (kWh/yr)* − *Auxiliary Electricity (kWh/yr)*

B.2 *Cost Formulations for Distribution*

Distribution cost (in $/kWh) is calculated by Equation 5 below:

Distribution Cost = Levelized Capital Cost + O&M Cost + Cost of Losses

(Equation 5)

Where:

Levelized Capital Cost ($/year) = Capital Cost ($) x $\frac{1-R}{1-R^n}$

Levelized Capital Cost (¢/kWh) = Capital Cost ($) x $\frac{1-R}{1-R^n}$ /(Annual Generated Electricity (kWh) - Annual Distribution losses (kWh)) x 100

R = 1 / (1+r); r = discount rate (= 0.1); n = life time (assumed = 20 years)

Capital Cost = Materials Cost (MC) + Labor Cost

= Poles MC ＋Wires MC ＋Transformers MC ＋ Other MCs ＋Labor Cost

Distribution Losses (kWh) = Generated Electricity (kWh) x Distribution Loss Rate

O&M Cost ($/yr) = Capital Cost ($) x O&M Annual Cost Rate

O&M Annual Cost Rate(¢/kWh) = O&M Cost ($/year) / (Annual Generated Electricity- Annual Distribution Losses) x 100

Loss Cost (¢/kWh)

= (Generating Cost (¢/kWh) x Annual Distribution Losses (kWh))

/ (Annual Generated Electricity (kWh) - Annual Distribution losses (kWh))

The unit capital cost for distribution (in $/kW) is calculated per Equation 6 below:

Unit Distribution Capital Cost = Capital Cost/(Rated Output of Power Station (kW)- Distribution Losses (kW)) (Equation 6)

B.3 *Cost Formulations for Transmission*

Transmission cost (in \$/kWh) and unit transmission cost (\$/kW) is calculated in the same way as distribution costs, per Equations 7 and 8 below:

Transmission Costs = Levelized Capital Cost + OM Cost + Loss Cost (Equation 7)

Unit Capital Transmission Cost = Capital Cost/(Rated Output of Power Station (kW)- Transmission Losses (kW)) (Equation 8)

Transmission capital cost is calculated as a function of the distance from the generation area to the grid connecting point. Transmission losses are based on the I-squared losses of a representative transmission line, both as shown below

Transmission Capital Cost = Transmission Capital Cost /km x Distance (Line km) = Materials Cost (MC)/km + Labor Cost/km = Poles or Steel tower MC/km ＋Wires MC/km ＋ Other MCs/km ＋Labor Cost/km
Transmission Losses (kW/km) = $3I^2r$ / 1000 n = (rP^2/V^2) / (1000 n)
Transmission Losses (kWh/ km -year) = ($3I^2$ r / 1000 n) x 8760 C = Transmission Losses (kW/km) x 8760 C
Where: I = Current of line at Rated Capacity of Generation (A) r = Resistance (Ω/km) P = Rated Capacity of Generation (kW) V = Nominal Voltage (kV) C = Capacity Factor P = $\sqrt{3}$ x IV Power Factor = 1.0 n = "The number of circuits" x "the number of bundles"

B.4 *Cost Formulations for Distribution*

India is selected as the baseline country per the overall methodology. Average distribution capital costs over normal terrain in India are shown in Table B.2 and the component breakdown of capital cost for an 11kV line is shown in Table B.3.

Table B.2: Average Capital Cost of Distribution (per km)

Item	Average Capital Cost	Specifications
High voltage line	5,000($/km)	33kV-11kV
Low voltage line	3,500 ($/km)	230V
Transformer	3,500 ($/unit)	50kVA ,3φ11kV/400/230V

Source: Interviews with Indian Electric Power Companies conduced by TERI, Nov. 2004

Table B.3: Proportion of Capital Cost by Component of a 11 kV Line

Item		Specifications	Proportion of Capital Cost (%)
Materials	Poles	8 meter, concrete	13
	Wires	3.1km 30mm^2 ACSR	39
	Other materials	Insulator, arms etc	27
Labor			21

Source: Reducing the Cost of Grid Extension for Rural Electrification, NRECA, 2000.

Distribution capital costs are levelized per the methodology described above, and O&M cost calculated as 2% of the initial capital cost annually. Both can be expressed on a per-circuit-km basis (See Table B.4).

Table B.4: Levelized Capital Cost and O&M Cost per km

Item	Levelized Capital Cost	O&M Cost
High voltage line	535 ($/km-year)	100 ($/km-year)
Low voltage line	375 ($/km-year)	70 ($/km-year)
Transformer	375 ($/unit-year)	70 ($/unit-year)

The Capital and Levelized costs of distribution including costs of losses and O&M are shown in Table B.5 below. A value of 12 % is used for the distribution loss percentage.[36]

[36] Distribution Loss Percentage = Average T&D Loss Percentage x Distribution Loss Rate = 17.2 % x 0.7 = 12%

Table B.5: Capital and Variable Cost for Power Delivery, by Power Generation Technology

Generating Types	Mini-grid							
	Rated Output	CF (%)	¢/kWh			$/kW		
			2005	2010	2015	2005	2010	2015
Solar PV	25kW	20	7.42	6.71	6.14	56	56	56
Wind	100kW	25	3.80	3.61	3.49	193	193	193
PV-Wind Hybrids	100kW	30	5.09	4.72	4.42	193	193	193
Geothermal	200kW	70	2.53	2.38	2.34	193	193	193
Biomass Gasifier	100kW	80	1.58	1.51	1.48	193	193	193
Biogas	60kW	80	1.03	0.99	0.99	56	56	56
Micro Hydro	100kW	30	2.43	2.36	2.36	193	193	193
Diesel/Gasoline	100kW	80	3.08	2.94	2.97	193	193	193
Micro Turbines	150kW	80	4.69	4.54	4.54	193	193	193
Fuel Cells	200kW	80	3.99	3.72	3.58	193	193	193

B.5 *Transmission Cost Calculation*

We assume voltage level and line-types suited to power station size as shown in Table B.6.[37]

Table B.6: Voltage Level and Line-Type Relative to Rated Power Station Output

Rated output of power station (MW)	Representative voltage level (kV)	Line type	Capital cost per km (US$/km)
5	69	DRAKE 1cct	28,177
10	69	DRAKE 1cct	28,177
20	69	DRAKE 1cct	28,177
30	138	DRAKE 1cct	43,687
100	138	DRAKE 2cct	78,036
150	230	DRAKE 2cct	108,205
300	230	DRAKE (2) 2cct	151, 956

Source: Chubu Electric Power Company Transmission Planning Guidelines

As with the distribution calculation, capital and O&M costs can be expressed on a per-circuit-km annualized basis by levelizing the capital cost and assuming annual O&M costs are a fixed fraction of capital costs (See Table B.7); transmission losses per km are in Table B.8.

[37] These voltage levels and line types are decided upon by the "Alternative Thermal Method", which is used for transmission power plan in Chubu Electric Power Company.

Table B.7: Levelized Capital Cost and O&M Cost per Unit

Rated Output (MW)	Levelized Capital Cost ($/km-year)	O&M Cost ($/km-year)
5	3,015	845
10	3,015	845
20	3,015	845
30	4,675	1,311
50	4,675	1,311
100	8,350	2,341
150	11,578	3,246
300	16,259	4,559

Table B.8: Transmission Losses

Generating Types	Output (MW)	CF (%)	Transmission losses (kWh/km-year)	Transmission losses (kW/km)
Solar PV	5	20	823	0.47
Wind	10	30	4,941	1.88
Wind	100	30	61,627	23.45
Solar thermal	30	20	7,393	4.22
Geothermal	50	90	92,400	11.72
Biomass Gasifier	20	80	52,560	7.50
Biomass Steam	50	80	82,134	11.72
MSW/Landfill Gas	5	80	3,294	0.47
Mini Hydro	5	45	1,853	0.47
Large Hydro	100	50	102,711	23.45
Pumped storage Hydro (peak)	150	10	16,635	18.99
Diesel/Gasoline Generator	5	80	3,294	0.47
Diesel/Gasoline Generator (peak)	5	10	412	0.47
Fuel Cells	5	80	3,294	0.47
Oil/Gas Comb. Turbines (peak)	150	10	16,635	18.99
Oil/Gas Combined Cycle	300	80	266,164	37.98
Coal Steam	300	80	266,164	37.98
Coal IGCC	300	80	266,164	37.98
Coal AFB	300	80	266,164	37.98
Oil Steam	300	80	266,164	37.98

The capital and levelized costs of transmission are calculated per the method described above, and shown in Table B.9.

Table B.9: Capital and Delivery Cost of Transmission (2004 $)

Generating Types	Rated Output (MW)	CF (%)	(¢ x 10^{-2})/(kWh-km)			$/(kW-km)		
			2005	2010	2015	2005	2010	2015
Solar PV	5	20	4.80	4.75	4.71	5.64	5.64	5.64
Wind	10	30	1.60	1.58	1.57	2.82	2.82	2.82
Wind	100	30	0.54	0.53	0.52	0.78	0.78	0.78
Solar thermal without thermal storage	30	20	0.64	0.62	0.61	1.46	1.46	1.46
Geothermal	50	90	0.25	0.25	0.25	0.87	0.87	0.87
Biomass Gasifier	20	80	0.54	0.53	0.52	1.41	1.41	1.41
Biomass Steam	50	80	0.31	0.30	0.30	0.87	0.87	0.87
MSW/Landfill Gas	5	80	1.16	1.16	1.16	5.64	5.64	5.64
Mini Hydro	5	45	2.02	2.02	2.02	5.64	5.64	5.64
Large Hydro	100	50	0.37	0.37	0.37	0.78	0.78	0.78
Pumped storage Hydro (peak)	150	10	1.57	1.56	1.55	0.72	0.72	0.72
Diesel/Gasoline Generator	5	80	1.19	1.18	1.18	5.64	5.64	5.64
Diesel/Gasoline Generator (peak)	5	10	8.98	8.97	8.97	5.64	5.64	5.64
Fuel Cells	5	80	1.24	1.22	1.21	5.64	5.64	5.64
Oil/Gas Comb. Turbines (peak)	150	10	1.29	1.28	1.28	0.72	0.72	0.72
Oil/Gas Combined Cycle	300	80	0.17	0.16	0.16	0.51	0.51	0.51
Coal Steam	300	80	0.16	0.15	0.15	0.51	0.51	0.51
Coal AFB	300	80	0.15	0.15	0.15	0.51	0.51	0.51
Coal IGCC	300	80	0.17	0.16	0.16	0.51	0.51	0.51
Oil Steam	300	80	0.19	0.19	0.18	0.51	0.51	0.51

B.6 *Forecasting Capital Costs of Generation*

The forecast value of the future price in 2010 and 2015 is calculated by considering the decrease of the future price as a result of both technological innovation and mass production. A forecast decrease in capital cost is done for each generation technology group as shown in given Table B.10, reflecting the relative maturity of each generation technology.

Table B.10: Forecast Rate of Decrease in Power Generation Technologies

Decrease in Capital Cost (2004 to 2015)	Generating Technology Type
0% - 5%	Geothermal, Biomass steam, Biogas, Pico/Micro hydro, Mini hydro, Large hydro, Pumped storage, Diesel/Gasoline generator, Coal steam (Sub critical and Super critical), Oil steam
6% -10%	Biomass Gasifier, MSW/Landfill, Gas combustion, Gas combined cycle, Coal steam (USC), Coal AFBC
11% - 20%	Solar-PV, Wind, PV-Wind Hybrids, Solar thermal, Coal IGCC
21% -	Micro turbine, Fuel cells

B.7 *Uncertainty Analysis*

Key uncertainties considered include fuel costs, future technology cost and performance, and resource risks. Each was systematically addressed using a probabilistic approach based on the "Crystal Ball" software package. All uncertainty factors are estimated in a band, and generating costs are calculated by Monte Carlo Simulation. These probabilistic methods can also be applied to some other operational uncertainties, such as estimating the capacity factor of wind. The particular applications of uncertainty analysis techniques are described within each technology section. Generally speaking, the uncertainty analysis proceeds as follows:

- Uncertainty Factors are chosen
- High and Low of Uncertainty factors are set[38]
- Additional particular conditions are set. (e.g., resource variability, fuel cost, etc.)

B.8 *Accommodating the Intermittency of Renewable Energy Technologies*

In case of solar PV, wind PV and wind hybrids in a mini-grid area or off-grid configuration, battery costs or costs of a backup generator are included in the costs of the power system in order to smooth stochastic variations in the available resource and provide for a reliable power output. If the solar PV or wind PV system is grid-connected, intermittency is not a significant problem (unless renewable power penetration levels are very high) because the grid can absorb and accommodate such intermittency without requiring a backup power supply.

B.9 *Conformance with the Costing Methods Used in EPRI TAG-RE 2004*

The objective of this study is to provide a consistent set of technical and economic assessments of a broad range of power generation technologies so that the performance and costs of these technologies in various settings can be easily and impartially compared. In searching for an assessment methodology we chose the general approach and specific cost formulas contained in the Renewable Energy Technical Assessment Guide-TAG-RE: 2004[39] TAG-RE 2004, published by Electric Power Research Institute (EPRI). This sourcebook provides a comprehensive methodology for assessing various power generating technologies, including renewable energy technologies, and is the source of the detailed cost formulas used in the economic assessment. These formulations are described below.

[38] In order to make calculation results consistent, basic variables are set to ±20%

[39] EPRI (Electric Power Research Institute) publishes a series of Technology Assessment Guide, or TAGs, which contains very useful information about various generation, transmission, distribution, and environmental technologies. This study relied on the quantification methods contained in R*enewable Energy Technical Assessment Guide-TAG-RE: 2004*.

B.9.1 Capital Cost Formulas

TAG-RE 2004 defines capital cost formulas for regulated utilities. There are three related formulations of capital cost offered - (a) Total Plant Cost (TPC), (b) Total Plant Investment (TPI), and (c) Total Capital Requirement (TCR):

(a) Total Plant Cost (TPC) = (Process Facilities Capital Cost + General Facilities Capital Cost + Engineering Cost) + (Home Office Overhead Cost + Project & Process Contingency)

(Equation 9)

(b) Total Plant Investment (TPI) = TPC + adjustment for the escalation [40] *of capital costs during construction + AFUDC*

(Equation 10)

Where *AFUDC* is *Allowance for Funds Used during Construction*, representing the interest accrued on each expense from the date of the expense until the completion and commissioning of the facility. AFUDC is assumed to be 0 because the construction period is short in renewable generation systems. With an interest rate to 5-8% and a 2-5 year construction period, typical for large hydropower plants, the effect of AFUDC could add several percentage points to the TPI.

(c) *Total Capital Requirement (TCR) = TPI + owners' costs*

(Equation 11)

Where *owners' costs* include land & property tax, insurance, pre-production, startup, and inventory costs. However, in this study owners' costs are disregarded as negligible.

After considering these three available formulations we selected Total Plant Cost (TPC) as being the most useful for assessment purposes. The TPC formulation is capable of capturing the key differences in capital cost structure between the 22 generation technologies being assessed, without introducing additional complexities associated with financing, taxes and insurance, and other costs which are largely country-driven. Our use of TPC represents a strictly economic formulation of costs, allowing the results to be easily transferred from one country to another. A financial formulation of costs can then be easily overlaid onto TPC which will then be reflective country-specific conditions affecting power plant financing. We reiterate our capital cost formulation below:

Capital Cost = Total Plant Cost (TPC)

[40] The escalation rate adjustment for capital costs during construction is assumed to be 0.

= *(Process Facilities Capital Cost + General Facilities Capital Cost + Engineering Cost) + (Home Office Overhead Cost + Project & Process Contingency)*

(Equation 12)

= *Engineering Cost + Procurement Cost + Construction Cost + Contingency*

= *Equipment Cost + Civil Cost + Construction Cost + Contingency Cost*

(Equation 13)

We note that *Process Facilities Capital Cost*, *General Facilities Capital Cost* and *Engineering Cost* are equivalent to EPC (Engineering, Procurement, and Construction) cost. EPC cost also includes *Equipment Cost* (engineering etc), civil cost, and erection cost (labor, tool). We also roll together *Home Office Overhead Cost* and *Project & Process Contingency Cost* under the overall category of *Contingency Cost* to obtain the simple formulation of Equation (8), which will be used throughout the assessment.

B.9.2 Operating Cost and Generating Cost

TAG-RE 2004 defines operating cost by the following formula:

Operating Cost = *(Fixed O&M Cost + Variable O&M Cost + Fuel Cost + Other Fixed Cost + Other Net Cash Flow) ÷ Net Electricity,*

(Equation 14)

Where *Other Fixed Cost* includes income taxes and debt service and *Other Net Cash Flow* includes cash reserves.

We disregard *Other Fixed Cost* and *Other Net Cash Flow* because they constitute less than 10% of Fixed O&M Cost, Variable O&M Cost and Fuel Cost. This allows us to simplify the Operating Cost formulation to:

Operating Cost = *(Fixed O&M Cost + Variable O&M Cost + Fuel Cost) ÷ Net Electricity* *(Equation 15)*

We can then state the total power generation economic cost formulation as it in TAG-RE 2004 and in this study as follows:

Generating Cost = *Capital Cost + Operating Cost* *(Equation 16)*

B.10 *Capacity Factor and Availability Factor*

In order to express Capital Cost and Operating Cost on the same unit terms we must know the hours of operation of the power generation technology. This section briefly describes how Availability Factor and Capacity Factor were used in expressing costs of different power generation technologies. Capacity Factor is universally defined as "The ratio of the actual energy produced in a given period, to the hypothetical maximum possible". This definition applies regardless of power generation technology. We formulate the Capacity Factor calculation simply and universally as:

Capacity Factor = (Total MWh generated in period x 100)/Installed Capacity (MW) x period (hours) *(Equation 17)*

Several formulations of Availability Factor are found in the literature. The most common one is that in use by the North American Reliability Council (NERC):

Availability Factor = Available Hours/Period Hours *(Equation 18)*

Where *Available Hours* is the total *Period Hours* less forced outage, maintenance, and planned outage hours.

Availability Factor is a straightforward concept for conventional power generation technologies but becomes more difficult to apply with renewable energy technologies, where the availability factor is driven by the renewable resource availability. The literature is not helpful, as different formulations yield counter-intuitive results for expressing availability (See Table B.11). A wind generator "Availability factor" is defined as that fraction of a period of hours when the wind generator could be providing power if wind was available within the right speed range. This statement of availability does not factor in generator outages due to resource unavailability and therefore cannot be used to compare the power output of conventional vs. renewable energy power generators.

Table B.11: Availability Factor Values Found in the Power Literature

Type of Power Station		Value
Fossil		More than 75%
Renewable	Wind	95%
		97%
	Solar thermal	92.3%
	Ocean wave	95%
	Geothermal	More than 90%

In consideration of this definitional difficulty this report strictly relies on Capacity Factor as defined in Equation 12 for calculating Generating Costs on a per-kWh basis.

B.11 *Fuel Price Forecast*

Fuel prices used throughout this report are based on the IEA's (World Energy Outlook 2005) forecast. Since delivered fuel price is driven by the specific circumstances of exporting and importing countries, we developed the power generation cost estimation based on technology deployed and fuel consumed in India. This allows for the assessment results to be benchmarked and the numerical values extrapolated to other developing countries. We also levelize the forecast fuel price over the life span of each generating technology assessed. The procedure used for estimating fuel costs was as follows:

1. The fuel used for a cost model is chosen. (Example: Australian coal)
2. The actual user end price is examined.
3. The fixed component of fuel provision (transportation cost, local distribution cost, refining cost and so on) is examined, and the end-use price divided into a fixed and variable components
4. The future price of fuel is calculated by linking the variable component of fuel price to the IEA's forecast base price
5. A levelized fuel price is calculated specific to the life span of each generating technology
6. This levelized price is then used in the Generating Cost model.

Fuel price fluctuates according to market forces, affecting both conventional and hybrid generating costs. We incorporate price fluctuation in the case study by defining a range of price fluctuation capped at 200% of forecast base fuel price (See Table B.12).

Table B.12: Fossil Fuel Price Assumptions (2004$)

Crude Oil

Table B.4 (a) FOB Price of Crude Oil $/bbl ($/GJ)

		2005	2010	2015
Crude Oil (Dubai, Brent, WTI)	Base	53 (9.2)	38 (6.6)	37 (6.5)
	High	-	56 (9.8)	61 (10.6)
	Low	-	24 (4.2)	23 (4.0)

Coal

Table 2.4 (a) FOB Price of Coal $/ton ($/GJ)

		2005	2010	2015
Coal (Australia)	Base	57 (2.07)	38 (1.38)	39 (1.42)
	High	-	53 (1.92)	56 (2.04)
	Low	-	30 (1.10)	30 (1.10)

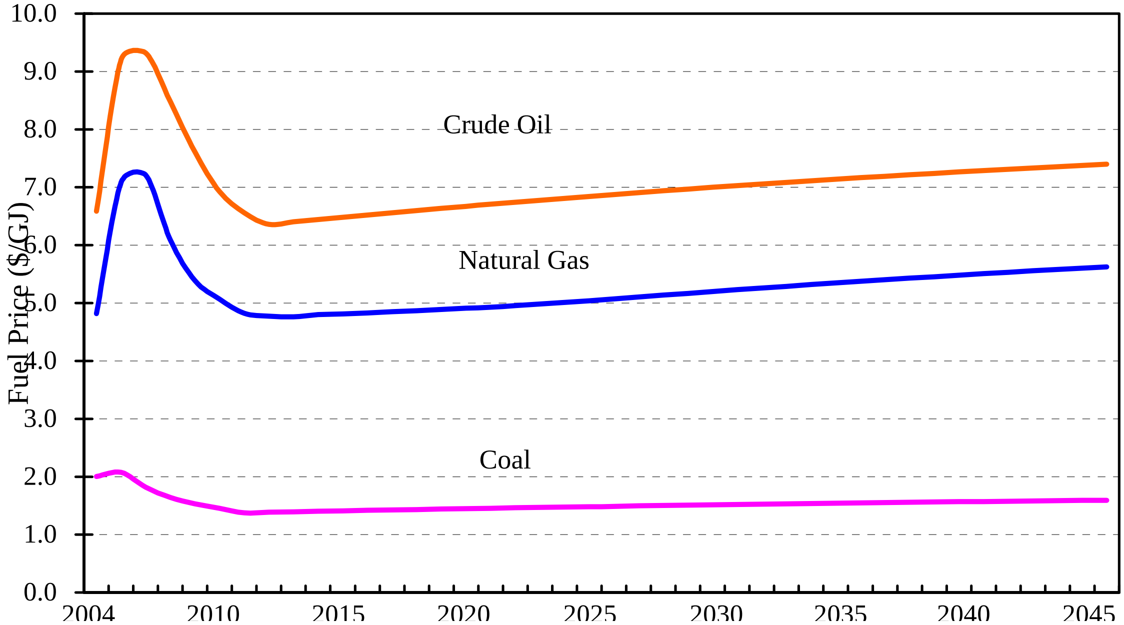
Natural gas

Table 2.4 (a) FOB Price of Natural Gas $/MMBTU ($/GJ)

		2005	2010	2015
Gas (US, European)	Base	7.5 (7.1)	5.1 (4.8)	5.1 (4.8)
	High	-	7.0 (6.6)	7.6 (7.2)
	Low	-	4.0 (3.8)	3.3 (3.1)

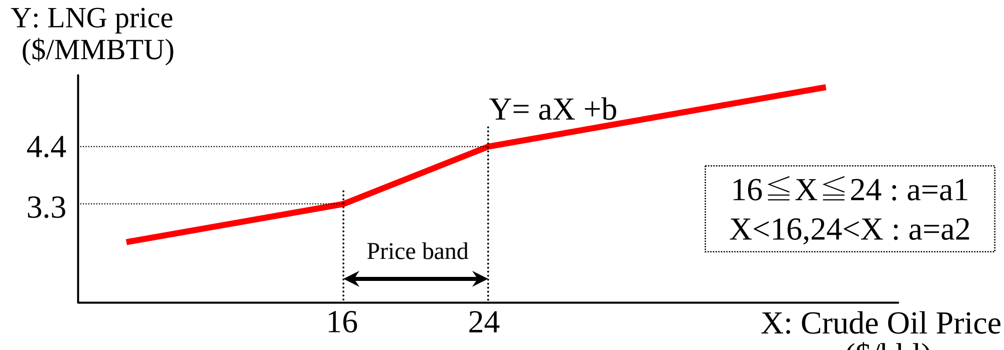
Figure B-1 compares the base price trajectory of each fossil fuel source.

Figure B-1: Fossil Fuel Price Assumptions (in 2004 $, FOB price base)



The estimation of LNG price is estimated separately, using a Japanese forecasting formula (Japan is one of the world's largest LNG importing countries). The formula estimates LNG price based on crude oil price. When the oil price exceeds a certain price band, the slope of the curve is moderated to reflect the likelihood of risk hedging by both sellers and buyers. The procedure and results is shown in Figure B-2.

Figure B-2: Procedure for Estimating LNG Prices



Graph 2.3.1 LNG - Oil Price Curve

Table 2.3.4 LNG Price (CIF) $ /MMBTU ($/GJ)

		2005	2010	2015
LNG	Base	6.5 (6.2)	5.5 (5.2)	5.5 (5.2)
	Hi	-	6.7 (6.4)	7.1 (6.7)
	Low	-	4.6 (4.4)	4.5 (4.3)

Table B.5 summarizes the results for all categories of end-use fuels needed to assess generating costs for each power generation technology. In all cases the values are user end price including fixed (e.g., transportation cost and local distribution cost) and variable components. Typically, the fixed cost component for oil is about 20-50% of the total delivered end-user price and a little higher for coal (30-50%) and lower for pipeline and LNG gas (20-30%). The bands of assumed price fluctuation for each forecast year are also shown.

Table B.13: Other Fuel Costs (2004 $/GJ)

		2005	2010	2015
Gasoline	Base	21.9	18.2	18.1
	High	—	22.7	23.9
	Low	—	14.9	14.6
Light-Oil	Base	17.1	13.8	13.7
	High	—	17.9	18.9
	Low	—	10.8	10.5
Residual-Oil	Base	7.0	5.2	5.2
	High	—	7.4	8.0
	Low	—	3.6	3.5
Coal (India)	Base	1.51	1.60	1.63
	High	—	2.20	2.31
	Low	—	1.36	1.38
Coal (Australia)	Base	2.60	1.60	1.95
	High	—	2.45	2.57
	Low	—	1.63	1.63
Natural Gas (Pipeline)	Base	7.2	5.1	5.1
	High	—	6.8	7.3
	Low	—	4.2	3.6

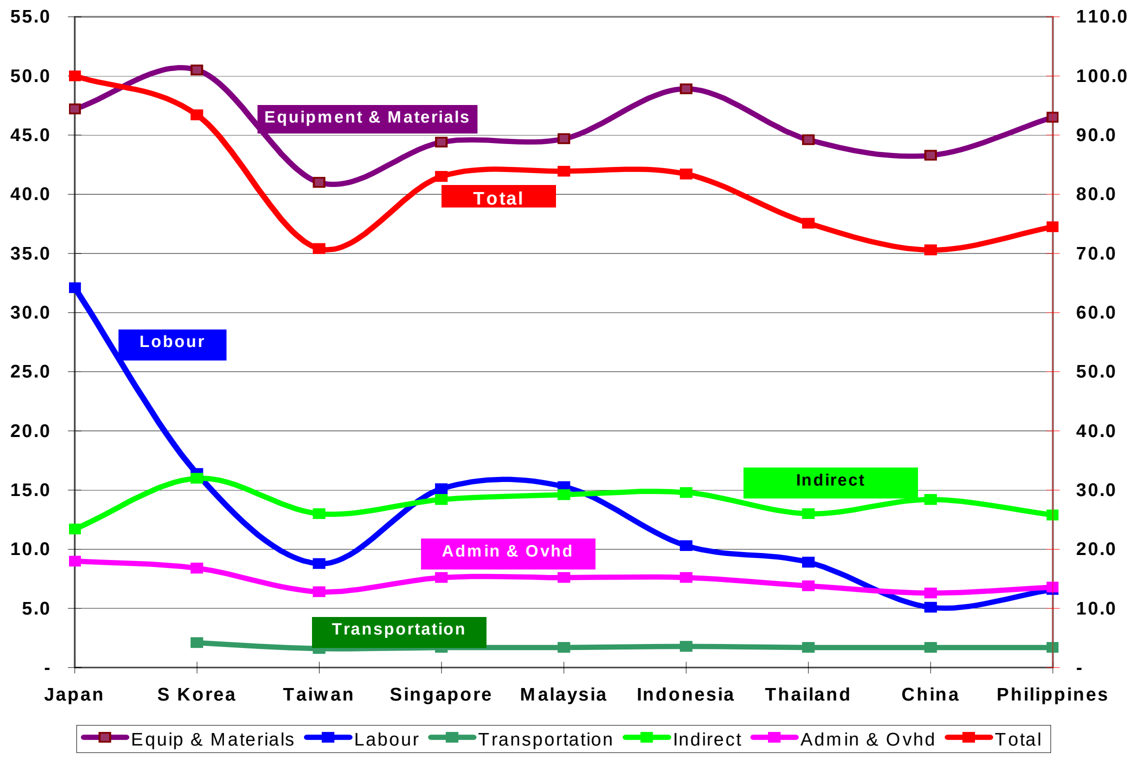
B.12 *Regional Adjustment*

One of the objectives of this study is to express all of the costing information (capital costs and operating costs) for the twenty-two power generation technologies on the same basis, including assumed location and fuel supply arrangements. However, all infrastructure capital and operating costs – engineering, equipment & material, construction, O&M, fuel, even contingency - vary depending on location. The largest variable requiring adjustment between different regions is labor cost, which is a major driver of both construction costs and O&M costs.

Location factors for the Asian region are provided in Figure B-3. In addition to the data presented for developing countries we also provide data for one developed economy (Japan). The data shown below suggests that the variation in costs of engineering, equipment and materials is quite small when procurement is done under ICB (International Competitive Bidding) or comparable guidelines. The labor costs vary from region to region, depending on GDP and per-capita incomes.[41]

[41] Useful references on this topic include: http://www.cia.gov/cia/publications/factbook, http://hdr.undp.org/reports/global/2003, http://www.worldfactsandfigures.com/gdp_country_desc.php, http://stats.bls.gov/fls/hcompsupptabtoc.htm, http://www.ggdc.net/dseries/totecon.html, and

Figure B-3: JSIM Location Factor for Southeast Asia (2002)



Source: Japan Society of Industrial Machinery Manufacturers 2004.

http://www-ilo-mirror.cornell.edu/public/english/employment/strat/publ/ep00-5.html

C Power Generation Technology Capital Cost Projections

C.1 *SPV*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
50W	Capital Cost	$/kW	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	Fixed O&M	cent/kWh	2.40	**3.00**	3.60	2.40	**3.00**	3.60	2.40	**3.00**	3.60
	Variable O&M	cent/kWh	10.40	**13.00**	15.60	9,75	**13.00**	15.60	9.10	**13.00**	15.60
	Capacity factor	%	15	**20**	25	15	**20**	25	15	**20**	25
300W	Capital Cost	$/kW	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	Fixed O&M	cent/kWh	2.00	**2.50**	3.00	2.00	**2.50**	3.00	2.00	**2.50**	3.00
	Variable O&M	cent/kWh	6.40	**8.00**	9.60	6.00	**8.00**	9.60	5.60	**8.00**	9.60
	Capacity factor	%	15	**20**	25	15	**20**	25	15	**20**	25
25kW	Capital Cost	$/kW	6,710	**7,510**	8,320	5,630	**6,590**	7,380	4,800	**5,860**	6,640
	Fixed O&M	cent/kWh	1.20	**1.50**	1.80	1.20	**1.50**	1.80	1.20	**1.50**	1.80
	Variable O&M	cent/kWh	5.60	**7.00**	8.40	5.25	**7.00**	8.40	4.90	**7.00**	8.40
	Capacity factor	%	15	**20**	25	15	**20**	25	15	**20**	25
5MW	Capital Cost	$/kW	6,310	**7,060**	7,810	5,280	**6,190**	6,930	4,500	**5,500**	6,235
	Fixed O&M	cent/kWh	0.78	**0.97**	1.16	0.78	**0.97**	1.16	0.78	**0.97**	1.16
	Variable O&M	cent/kWh	0.19	**0.24**	0.29	0.18	**0.24**	0.29	0.17	**0.24**	0.29
	Capacity factor	%	15	**20**	25	15	**20**	25	15	**20**	25

C.2 *Wind*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300W	Capital Cost	$/kW	4,820	**5,370**	5,930	4,160	**4,850**	5,430	3,700	**4,450**	5,050
	Fixed O&M	cent/kWh	2.79	**3.49**	4.19	2.79	**3.49**	4.19	2.79	**3.49**	4.19
	Variable O&M	cent/kWh	3.92	**4.90**	5.88		**4.90**	5.88		**4.90**	5.88
	Capacity factor	%	20	**25**	30	20	**25**	30	20	**25**	30
100kW	Capital Cost	$/kW	2,460	**2,780**	3,100	2,090	**2,500**	2,850	1,830	**2,300**	2,670
	Fixed O&M	cent/kWh	1.66	**2.08**	2.50	1.66	**2.08**	2.50	1.66	**2.08**	2.50
	Variable O&M	cent/kWh	3.26	**4.08**	4.90	3.11	**4.08**	4.90	2.96	**4.08**	4.90
	Capacity factor	%	20	**25**	30	20	**25**	30	20	**25**	30
10MW	Capital Cost	$/kW	1,270	**1,440**	1,610	1,040	**1,260**	1,440	870	**1,120**	1,300
	Fixed O&M	cent/kWh	0.53	**0.66**	0.79	0.53	**0.66**	0.79	0.53	**0.66**	0.79
	Variable O&M	cent/kWh	0.21	**0.26**	0.31	0.20	**0.26**	0.31	0.18	**0.26**	0.31
	Capacity factor	%	25	**30**	35	25	**30**	35	25	**30**	35
100MW	Capital Cost	$/kW	1,090	**1,240**	1,390	890	**1,080**	1,230	750	**960**	1,110
	Fixed O&M	cent/kWh	0.42	**0.53**	0.64	0.42	**0.53**	0.64	0.42	**0.53**	0.64
	Variable O&M	cent/kWh	0.18	**0.22**	0.26	0.17	**0.22**	0.26	0.15	**0.22**	0.26
	Capacity factor	%	25	**30**	35	25	**30**	35	25	**30**	35

C.3 *PV-Wind Hybrids*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300W	Capital Cost	$/kW	5,670	**6,440**	7,210	4,650	**5,630**	6,440	3,880	**5,000**	5,800
	Fixed O&M	cent/kWh	2.78	**3.48**	4.18	2.78	**3.48**	4.18	2.78	**3.48**	4.18
	Variable O&M	cent/kWh	5.52	**6.90**	8.28	5.18	**6.90**	8.28	4.83	**6.90**	8.28
	Capacity factor	%	20	**25**	30	20	**25**	30	20	**25**	30
100kW	Capital Cost	$/kW	4,830	**5,420**	6,020	4,030	**4,750**	5,340	3,420	**4,220**	4,800
	Fixed O&M	cent/kWh	1.66	**2.07**	2.48	1.66	**2.07**	2.48	1.66	**2.07**	2.48
	Variable O&M	cent/kWh	5.12	**6.40**	7.68	4.80	**6.40**	7.68	4.48	**6.40**	7.68
	Capacity factor	%	25	**30**	35	25	**30**	35	25	**30**	35

C.4 *Solar Thermal*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
30MW (without storage)	Capital Cost	$/kW	2,290	**2,480**	2,680	1,990	**2,200**	2,680	1,770	**1,960**	2,120
	Fixed O&M	cent/kWh	2.41	**3.01**	3.61	2.41	**3.01**	3.61	2.41	**3.01**	3.61
	Variable O&M	cent/kWh	0.60	**0.75**	0.90	0.56	**0.75**	0.90	0.53	**0.75**	0.90
	Capacity factor	%	15	**20**	25	15	**20**	25	15	**20**	25
30MW (with storage)	Capital Cost	$/kW	4,450	**4,850**	5,240	3,880	**4,300**	4,660	3,430	**3,820**	4,140
	Fixed O&M	cent/kWh	1.46	**1.82**	2.18	1.46	**1.82**	2.18	1.46	**1.82**	2.18
	Variable O&M	cent/kWh	0.36	**0.45**	0.54	0.34	**0.45**	0.54	0.31	**0.45**	0.54
	Capacity factor	%	45	**50**	55	45	**50**	55	45	**50**	55

C.5 *Geothermal*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
200kW Binary	Capital Cost	$/kW	6,480	**7,220**	7,950	5,760	**6,580**	7,360	5,450	**6,410**	7,300
	Fixed O&M	cent/kWh	1.60	**2.00**	2.40	1.60	**2.00**	2.40	1.60	**2.00**	2.40
	Variable O&M	cent/kWh	0.80	**1.00**	1.20	0.79	**1.00**	1.20	0.77	**1.00**	1.20
20MW Binary	Capital Cost	$/kW	3,690	**4,100**	4,500	3,400	**3,830**	4,240	3,270	**3,730**	4,170
	Fixed O&M	cent/kWh	1.04	**1.30**	1.56	1.04	**1.30**	1.56	1.04	**1.30**	1.56
	Variable O&M	cent/kWh	0.32	**0.40**	0.48	0.31	**0.40**	0.48	0.31	**0.40**	0.48
50MW Flash	Capital Cost	$/kW	2,260	**2,510**	2,750	2,090	**2,350**	2,600	2,010	**2,290**	2,560
	Fixed O&M	cent/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.72	**0.90**	1.08
	Variable O&M	cent/kWh	0.24	**0.30**	0.36	0.24	**0.30**	0.36	0.23	**0.30**	0.36

C.6 *Biomass Gasifier*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
100kW	Capital Cost	$/kW	2,490	**2,880**	3,260	2,090	**2,560**	2,980	1,870	**2,430**	2,900
	Fixed O&M	cent/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.27	**0.34**	0.41
	Variable O&M	cent/kWh	1.26	**1.57**	1.88	1.22	**1.57**	1.88	1.18	**1.57**	1.88
	Fuel	cent/kWh	2.13	**2.66**	3.19	2.13	**2.66**	3.46	2.13	**2.66**	3.72
20MW	Capital Cost	$/kW	1,760	**2,030**	2,300	1,480	**1,810**	2,100	1,320	**1,710**	2,040
	Fixed O&M	cent/kWh	0.20	**0.25**	0.30	0.20	**0.25**	0.30	0.20	**0.25**	0.30
	Variable O&M	cent/kWh	0.94	**1.18**	1.42	0.92	**1.18**	1.42	0.89	**1.18**	1.42
	Fuel	cent/kWh	2.00	**2.50**	3.00	2.00	**2.50**	3.25	2.00	**2.50**	3.50

C.7 *Biomass Steam*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
50MW	Capital Cost	$/kW	1,500	**1,700**	1,910	1,310	**1,550**	1,770	1,240	**1,520**	1,780
	Fixed O&M	cent/kWh	0.36	**0.45**	0.54	0.36	**0.45**	0.54	0.36	**0.45**	0.54
	Variable O&M	cent/kWh	0.33	**0.41**	0.49	0.32	**0.41**	0.49	0.32	**0.41**	0.49
	Fuel	cent/kWh	2.00	**2.50**	3.00	2.00	**2.50**	3.25	2.00	**2.50**	3.50

C.8 *MSW/Landfill Gas*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
5MW	Capital Cost	$/kW	2,960	**3,250**	3,540	2,660	**2,980**	3,270	2,480	**2,830**	3,130
	Fixed O&M	cent/kWh	0.09	**0.11**	0.13	0.09	**0.11**	0.13	0.09	**0.11**	0.13
	Variable O&M	cent/kWh	0.34	**0.43**	0.52	0.33	**0.43**	0.52	0.32	**0.43**	0.52
	Fuel	cent/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.30	0.80	**1.00**	1.40

C.9 *Biogas*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
60kW	Capital Cost	$/kW	2,260	**2,490**	2,720	2,080	**2,330**	2,570	2,000	**2,280**	2,580
	Fixed O&M	cent/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.27	**0.34**	0.41
	Variable O&M	cent/kWh	1.23	**1.54**	1.85	1.21	**1.54**	1.85	1.19	**1.54**	1.85
	Fuel	cent/kWh	0.88	**1.10**	1.32	0.88	**1.10**	1.43	0.88	**1.10**	1.54

C.10 *Pico/Micro Hydro*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300W	Capital Cost	$/kW	1,320	**1,560**	1,800	1,190	**1,485**	1,770	1,110	**1,470**	1,810
	Fixed O&M	cent/kWh	-	**-**	-	-	**-**	-	-	**-**	-
	Variable O&M	cent/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.71	**0.90**	1.08
	Capacity factor	%	25	**30**	35	25	**30**	35	25	**30**	35
1kW	Capital Cost	$/kW	2,360	**2,680**	3,000	2,190	**2,575**	2,950	2,090	**2,550**	2,990
	Fixed O&M	cent/kWh	-	**-**	-	-	**-**	-	-	**-**	-
	Variable O&M	cent/kWh	0.43	**0.54**	0.65	0.43	**0.54**	0.65	0.43	**0.54**	0.65
	Capacity factor	%	25	**30**	35	25	**30**	35	25	**30**	35
100kW	Capital Cost	$/kW	2,350	**2,600**	2,860	2,180	**2,470**	2,750	2,110	**2,450**	2,780
	Fixed O&M	cent/kWh	0.84	**1.05**	1.26	0.84	**1.05**	1.26	0.84	**1.05**	1.26
	Variable O&M	cent/kWh	0.34	**0.42**	0.50	0.33	**0.42**	0.50	0.33	**0.42**	0.50
	Capacity factor	%	25	**30**	35	25	**30**	35	25	**30**	35

C.11 *Mini Hydro*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
5MW	Capital Cost	$/kW	2,140	**2,370**	2,600	2,030	**2,280**	2,520	1,970	**2,250**	2,520
	Fixed O&M	cent/kWh	0.59	**0.74**	0.89	0.59	**0.74**	0.89	0.59	**0.74**	0.89
	Variable O&M	cent/kWh	0.28	**0.35**	0.42	0.28	**0.35**	0.42	0.28	**0.35**	0.42
	Capacity factor	%	35	**45**	55	35	**45**	55	35	**45**	55

C.12 *Large Hydro*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
100MW	Capital Cost	$/kW	1,930	**2,140**	2,350	1,860	**2,080**	2,290	1,890	**2,060**	2,280
	Fixed O&M	cent/kWh	0.40	**0.50**	0.60	0.40	**0.50**	0.60	0.40	**0.50**	0.60
	Variable O&M	cent/kWh	0.26	**0.32**	0.38	0.25	**0.32**	0.38	0.25	**0.32**	0.38
	Capacity Factor	%	40	**50**	60	40	**50**	60	40	**50**	60

C.13 *Pumped Storage Hydro*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
150MW	Capital Cost	$/kW	2.860	**3,170**	3,480	2,760	**3,080**	3,400	2,710	**3,050**	3,380
	Fixed O&M	cent/kWh	0.26	**0.32**	0.38	0.26	**0.32**	0.38	0.26	**0.32**	0.38
	Variable O&M	cent/kWh	0.26	**0.33**	0.40	0.26	**0.33**	0.40	0.26	**0.33**	0.40

C.14 *Diesel/Gasoline Generator*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300W	Capital Cost	$/kW	750	**890**	1,030	650	**810**	970	600	**800**	980
	Fixed O&M	cent/kWh	-	**-**	-	-	**-**	-	-	**-**	-
	Variable O&M	cent/kWh	4.00	**5.00**	6.00	3.97	**5.00**	6.00	3.94	**5.00**	6.00
	Fuel	cent/kWh	47.39	**54.62**	64.40	40.55	**50.13**	65.25	40.47	**50.71**	69.19
1kW	Capital Cost	$/kW	570	**680**	790	500	**625**	750	470	**620**	770
	Fixed O&M	cent/kWh	-	**-**	-	-	**-**	-	-	**-**	-
	Variable O&M	cent/kWh	2.40	**3.00**	3.60	2.39	**3.00**	3.60	2.38	**3.00**	3.60
	Fuel	cent/kWh	38.50	**44.38**	52.32	32.95	**40.73**	53.02	32.88	**41.20**	56.21
100kW	Capital Cost	$/kW	550	**640**	730	480	**595**	700	460	**590**	720
	Fixed O&M	cent/kWh	1.60	**2.00**	2.40	1.60	**2.00**	2.40	1.60	**2.00**	2.40
	Variable O&M	cent/kWh	2.40	**3.00**	3.60	2.39	**3.00**	3.60	2.38	**3.00**	3.60
	Fuel	cent/kWh	11.53	**14.04**	17.82	10.01	**13.09**	18.37	9.98	**13.27**	19.60
5MW	Capital Cost	$/kW	520	**600**	680	460	**555**	650	440	**550**	660
	Fixed O&M	cent/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	cent/kWh	2.00	**2.50**	3.00	1.99	**2.50**	3.00	1.98	**2.50**	3.00
	Fuel	cent/kWh	3.64	**4.84**	6.64	2.92	**4.39**	6.90	2.91	**44.8**	7.49

C.15 *Micro Turbine*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
150W	Capital Cost	$/kW	830	**960**	1,090	620	**780**	910	500	**680**	810
	Fixed O&M	cent/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	cent/kWh	2.00	**2.50**	3.00	1.83	**2.50**	3.00	1.69	**2.50**	3.00
	Fuel	cent/kWh	25.11	**26.86**	29.40	23.60	**26.00**	29.63	23.46	**26.15**	30.62

C.16 *Fuel Cells*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
200kW	Capital Cost	$/kW	3,150	**3,640**	4,120	2,190	**2,820**	3,260	1,470	**2,100**	2,450
	Fixed O&M	cent/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	cent/kWh	3.60	**4.50**	5.40	3.15	**4.50**	5.40	2.69	**4.50**	5.40
	fuel	Cent/kWh	15.22	**16.28**	17.82	14.30	**15.76**	17.96	14.22	**15.85**	18.56
5 MW	Capital Cost	$/kW	3,150	**3,630**	4,110	2,180	**2,820**	3,260	1,470	**2,100**	2,450
	Fixed O&M	cent/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	cent/kWh	3.60	**4.50**	5.40	3.15	**4.50**	5.40	2.69	**4.50**	5.40
	fuel	Cent/kWh	3.37	**4.18**	5.34	2.67	**3.78**	5.45	2.61	**3.85**	5.90

C.17 *Combustion Turbine*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
150MW	Capital Cost	$/kW	430	**490**	550	360	**430**	490	340	**420**	490
	Fixed O&M	cent/kWh	0.24	**0.30**	0.36	0.24	**0.30**	0.36	0.24	**0.30**	0.36
	Variable O&M	cent/kWh	0.80	**1.00**	1.20	0.78	**1.00**	1.20	0.77	**1.00**	1.20
	Fuel	cent/kWh	4.89	**6.12**	7.95	3.93	**5.57**	8.14	3.84	**5.68**	8.80

C.18 *Combined Cycle*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300W	Capital Cost	$/kW	570	**650**	720	490	**580**	660	450	**560**	650
	Fixed O&M	cent/kWh	0.08	**0.10**	0.12	0.08	**0.10**	0.12	0.08	**0.10**	0.12
	Variable O&M	cent/kWh	0.32	**0.40**	0.48	0.31	**0.40**	0.48	0.31	**0.40**	0.48
	Fuel	cent/kWh	3.29	**4.12**	5.35	2.64	**3.75**	5.48	2.59	**3.83**	5.93

C.19 *Coal Steam*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300MW	Capital Cost	$/kW	1,080	**1,190**	1,310	960	**1,080**	1,220	910	**1,060**	1,200
	Fixed O&M	cent/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
	Variable O&M	cent/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.28	**0.36**	0.43
	Fuel	cent/kWh	1.67	**1.97**	2.50	1.54	**1.87**	2.51	1.54	**1.90**	2.63
500MW Sub Cr	Capital Cost	$/kW	1,030	**1,140**	1,250	910	**1,030**	1,150	870	**1,010**	1,140
	Fixed O&M	cent/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
	Variable O&M	cent/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.28	**0.36**	0.43
	Fuel	cent/kWh	1.62	**1.92**	2.44	1.50	**1.82**	2.45	1.50	**1.85**	2.57
500MW SC	Capital Cost	$/kW	1,070	**1,180**	1,290	950	**1,070**	1,200	900	**1,050**	1,190
	Fixed O&M	cent/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
	Variable O&M	cent/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.28	**0.36**	0.43
	Fuel	cent/kWh	1.55	**1.83**	2.32	1.43	**1.73**	2.33	1.43	**1.76**	2.44
500MW USC	Capital Cost	$/kW	1,150	**1,260**	1,370	1,020	**1,140**	1,250	960	**1,100**	1,230
	Fixed O&M	cent/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
	Variable O&M	cent/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.27	**0.36**	0.43
	Fuel	cent/kWh	1.44	**1.70**	2.16	1.33	**1.61**	2.17	1.33	**1.64**	2.27

C.20 *Coal IGCC*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300MW	Capital Cost	$/kW	1,450	**1,610**	1,770	1,200	**1,390**	1,550	1,070	**1,280**	1,440
	Fixed O&M	cent/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.72	**0.90**	1.08
	Variable O&M	cent/kWh	0.17	**0.21**	0.25	0.16	**0.21**	0.25	0.15	**0.21**	0.25
	Fuel	Cents/kWh	1.51	**1.79**	2.27	1.40	**1.70**	2.28	1.40	**1,72**	2.39
500MW	Capital Cost	$/kW	1,350	**1,500**	1,650	1,130	**1,300**	1,450	1,000	**1,190**	1,340
	Fixed O&M	cent/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.72	**0.90**	1.08
	Variable O&M	cent/kWh	0.17	**0.21**	0.25	0.16	**0.21**	0.25	0.15	**0.21**	0.25
	Fuel	Cents/kWh	1.47	**1.73**	2.20	1.36	**1.64**	2.21	1.36	**1.67**	2.32

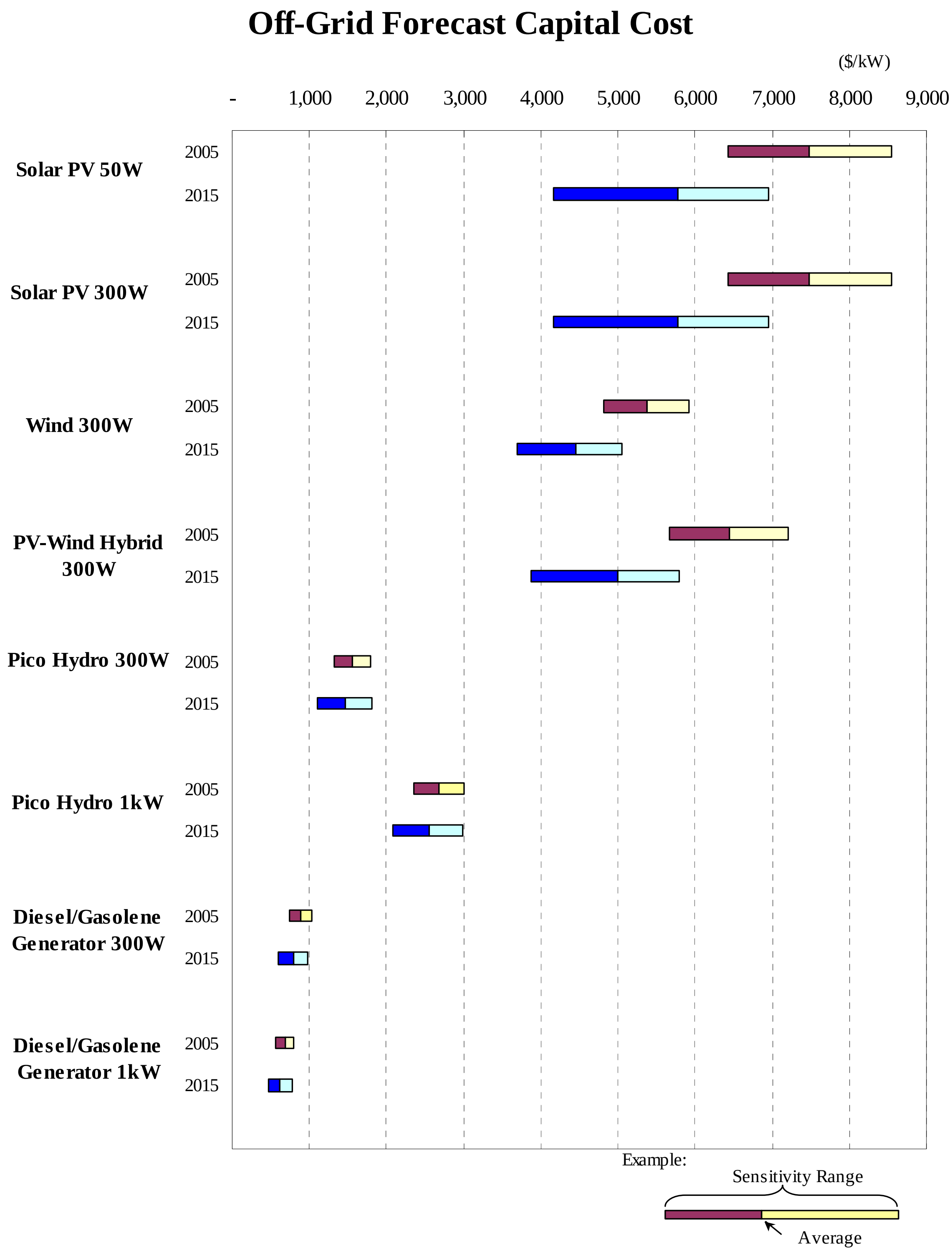
C.21 *Coal AFBC*

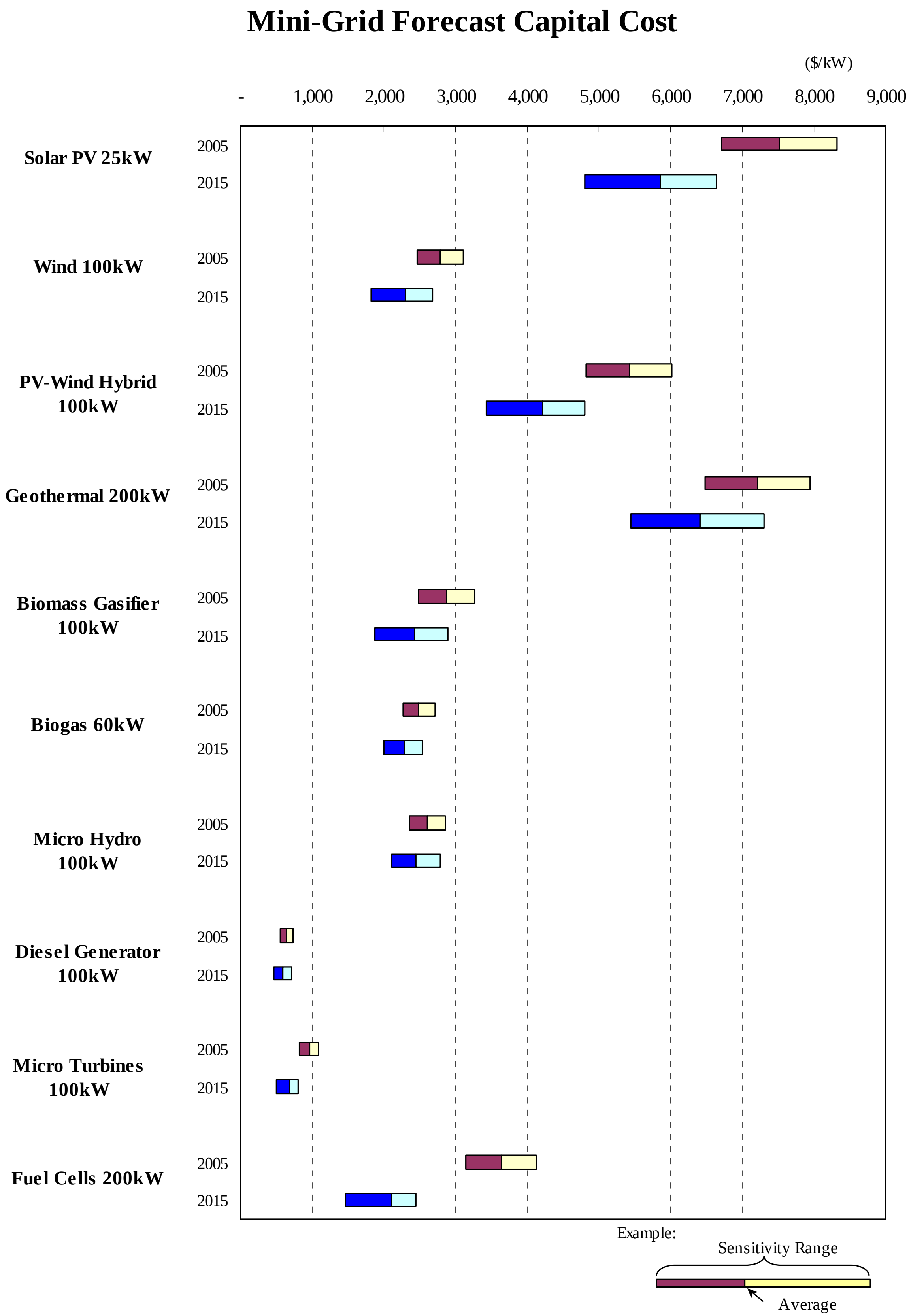
Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300MW	Capital Cost	$/kW	1,060	**1,180**	1,300	940	**1,070**	1,210	880	**1,040**	1,180
	Fixed O&M	cent/kWh	0.40	**0.50**	0.60	0.40	**0.50**	0.60	0.40	**0.50**	0.60
	Variable O&M	cent/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.26	**0.34**	0.41
	Fuel	Cents/kWh	1.32	**1.52**	2.00	1.31	**1.56**	2.20	1.33	**1.58**	2.24
500MW	Capital Cost	$/kW	1,010	**1,120**	1,230	900	**1,020**	1,140	840	**990**	1,120
	Fixed O&M	cent/kWh	0.40	**0.50**	0.60	0.40	**0.50**	0.60	0.40	**0.50**	0.60
	Variable O&M	cent/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.26	**0.34**	0.41
	Fuel	Cents/kWh	1.29	**1.49**	1.96	1.26	**1.52**	2.15	1.30	**1.54**	2.19

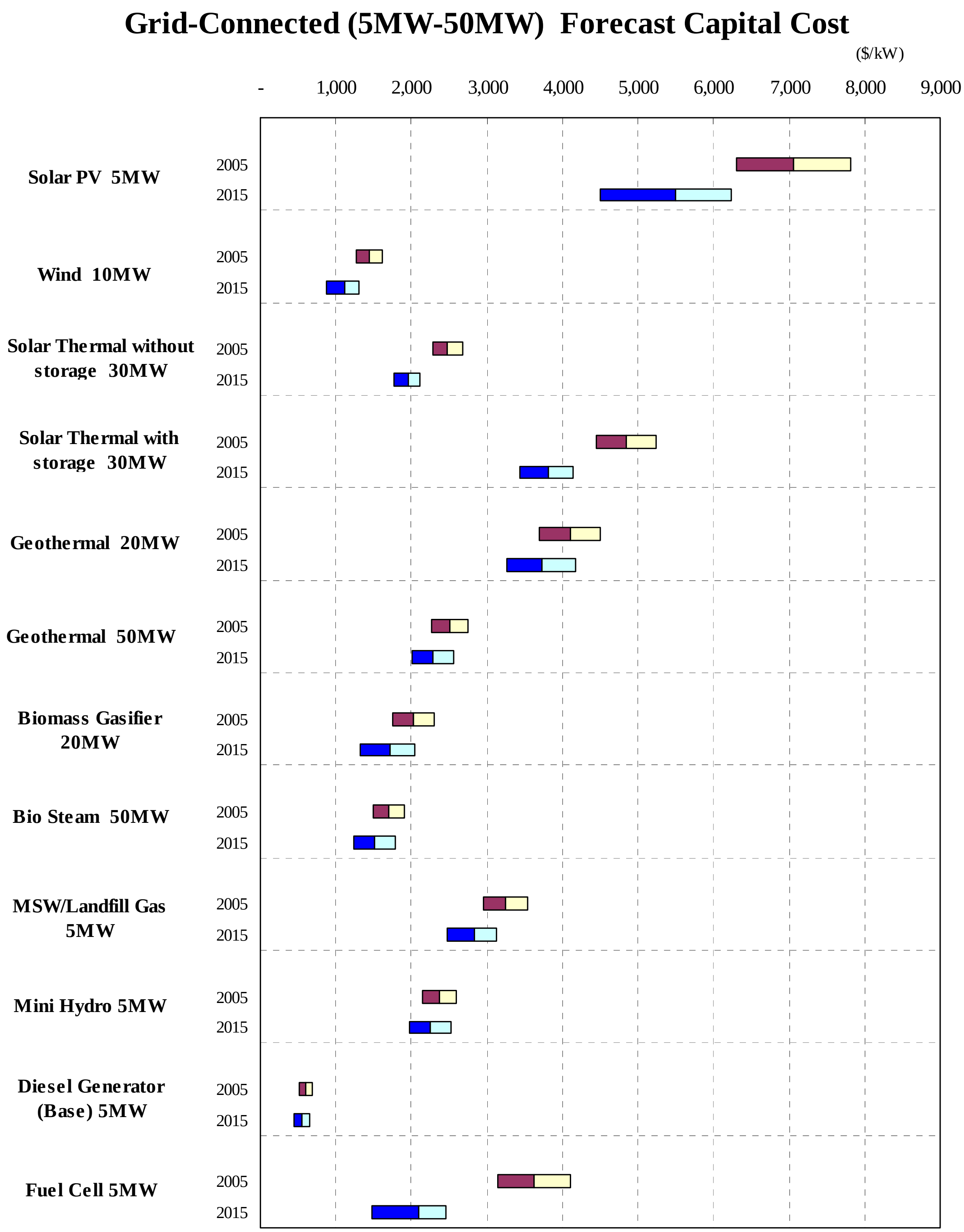
C.22 *Oil Steam*

Capacity	Contents	Units	2005			2010			2015		
			Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum	Minimum	**Probable**	Maximum
300MW	Capital Cost	$/kW	780	**880**	980	700	**810**	920	670	**800**	920
	Fixed O&M	cent/kWh	0.28	**0.35**	0.42	0.28	**0.35**	0.42	0.28	**0.35**	0.42
	Variable O&M	cent/kWh	0.24	**0.30**	0.36	0.24	**0.30**	0.36	0.24	**0.30**	0.36
	Fuel	cent/kWh	3.95	**5.32**	7.52	3.23	**4.88**	7.84	3.22	**4.97**	8.49

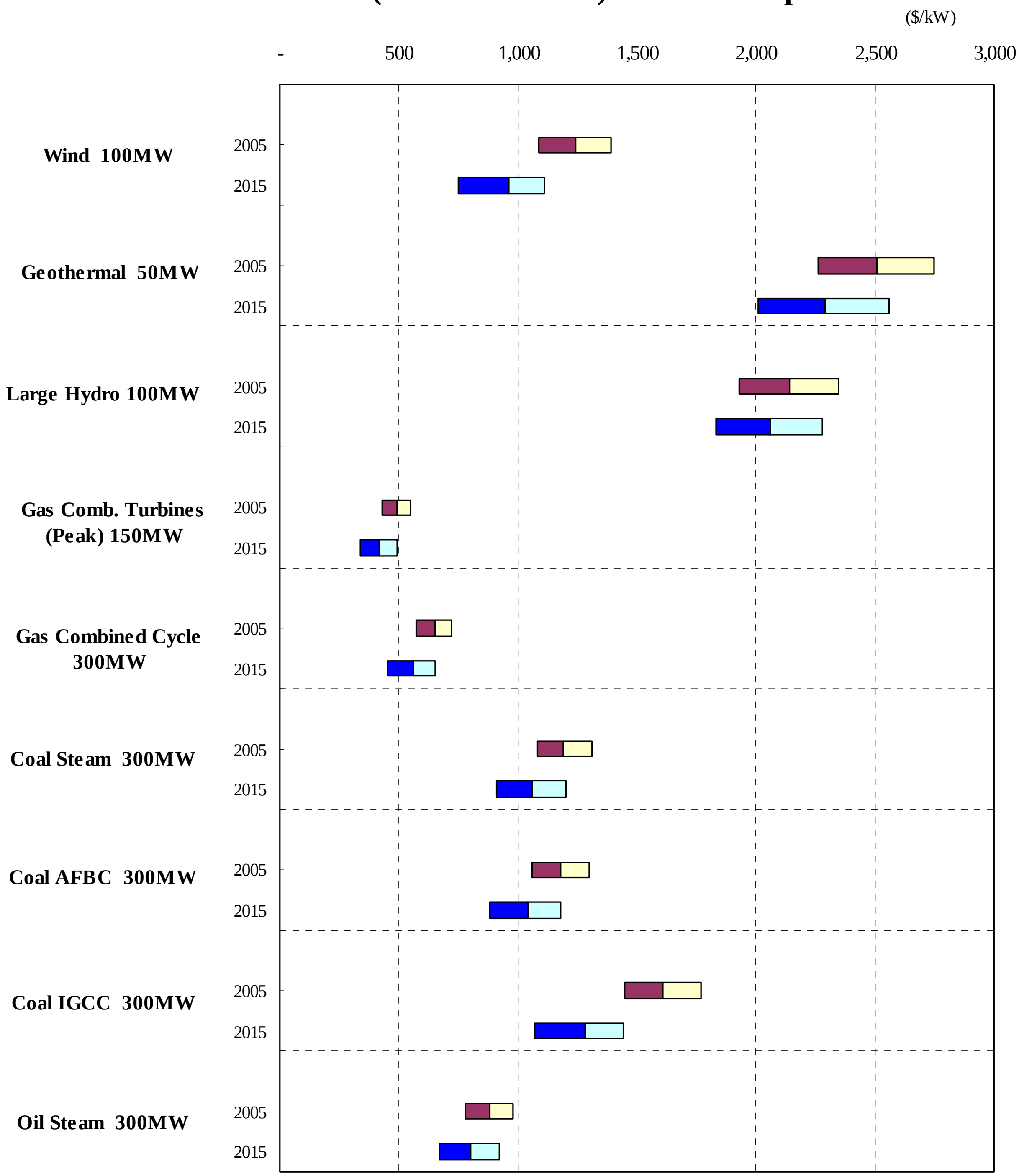
D High/Low Charts for Power Generation Capital and Generating Costs

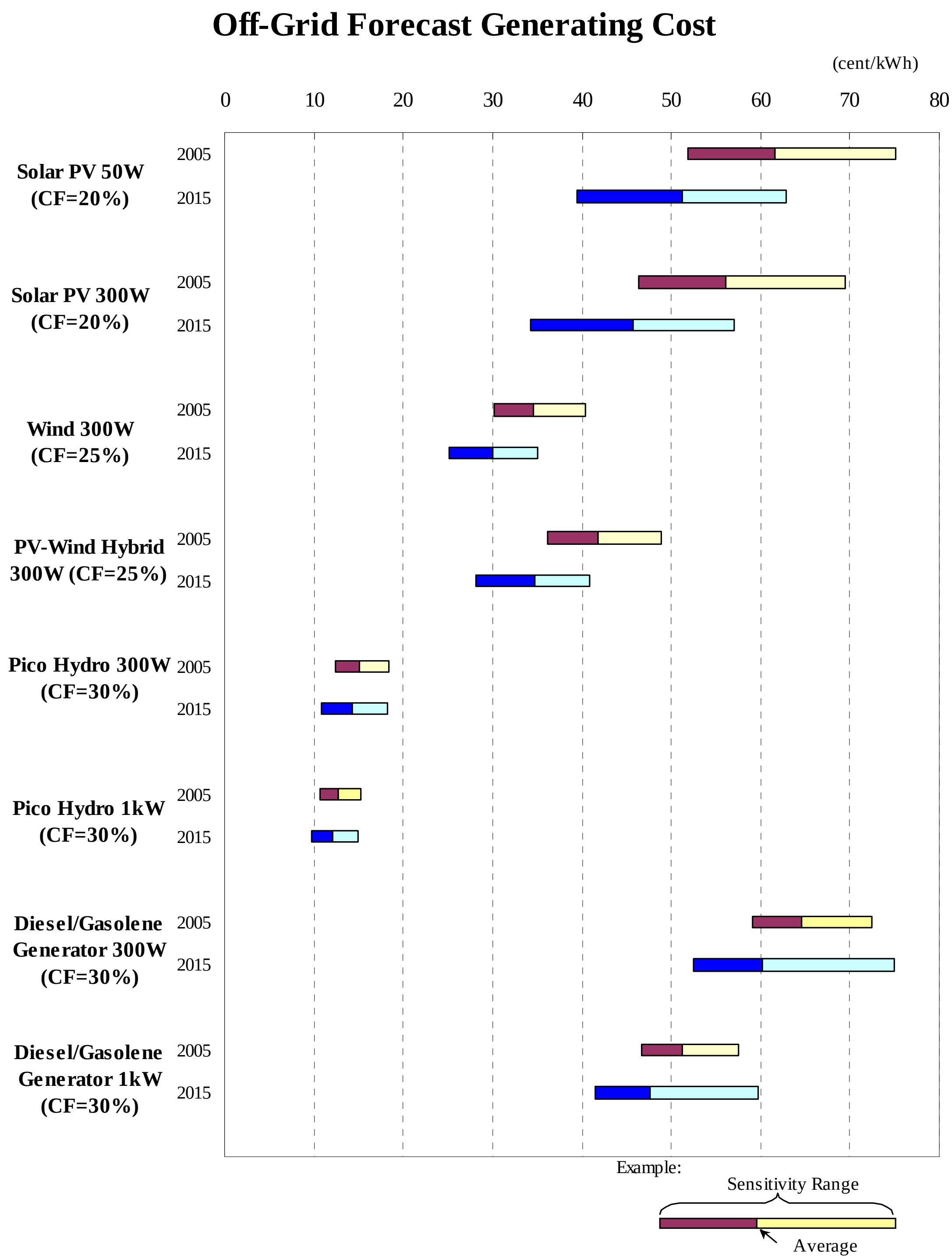

Off-Grid Forecast Capital Cost
($/kW)
- 1,000 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000
Solar PV 50W
Solar PV 300W
Wind 300W
PV-Wind Hybrid 300W
Pico Hydro 300W
Pico Hydro 1kW
Diesel/Gasolene Generator 300W
Diesel/Gasolene Generator 1kW
2005
2015
Example:
Sensitivity Range
Average


Mini-Grid Forecast Capital Cost
($/kW)
- 1,000 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000
Solar PV 25kW
Wind 100kW
PV-Wind Hybrid 100kW
Geothermal 200kW
Biomass Gasifier 100kW
Biogas 60kW
Micro Hydro 100kW
Diesel Generator 100kW
Micro Turbines 100kW
Fuel Cells 200kW
2005
2015
Example:
Sensitivity Range
Average

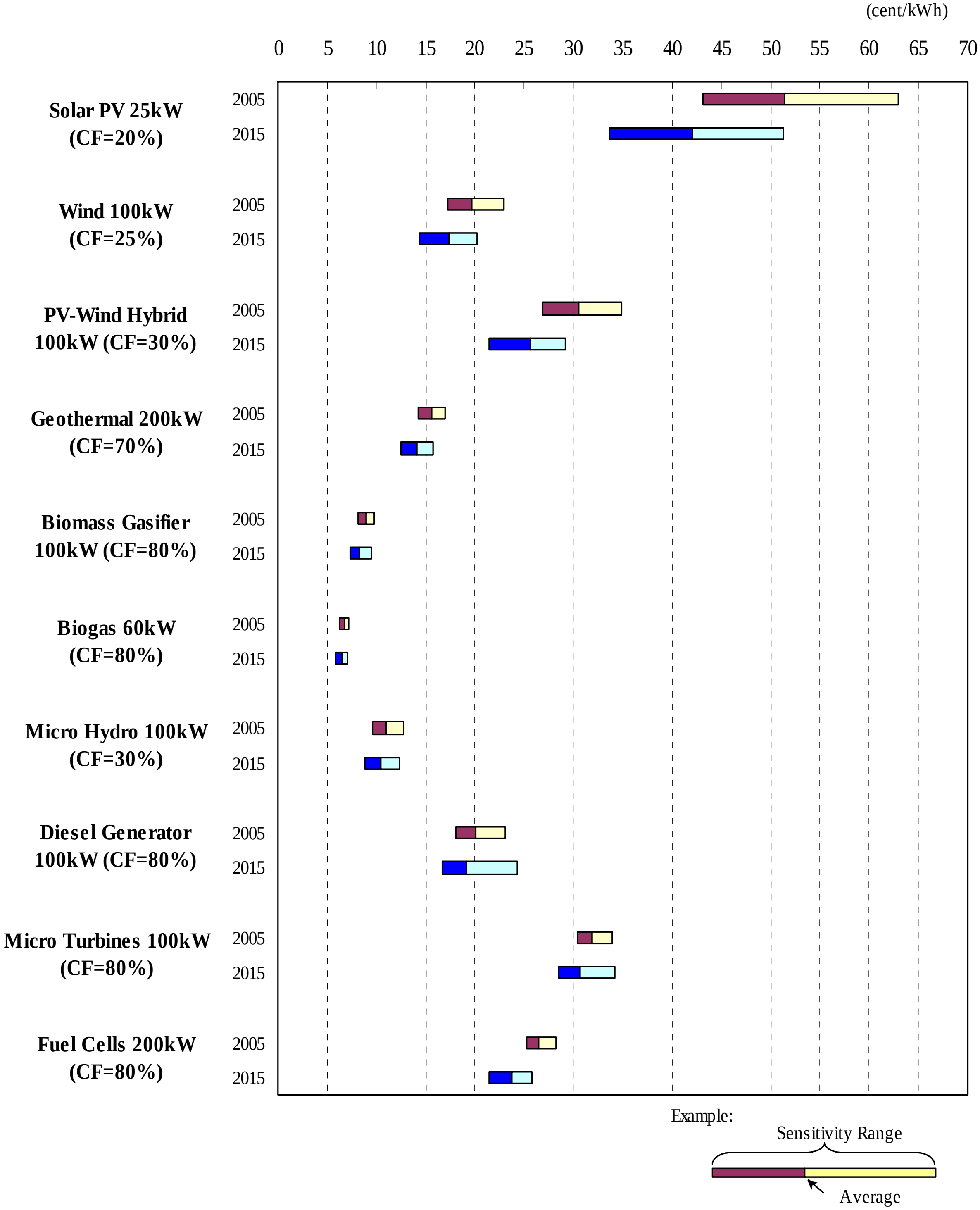

Grid-Connected (5MW-50MW) Forecast Capital Cost
($/kW)
- 1,000 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000
Solar PV 5MW
Wind 10MW
Solar Thermal without storage 30MW
Solar Thermal with storage 30MW
Geothermal 20MW
Geothermal 50MW
Biomass Gasifier 20MW
Bio Steam 50MW
MSW/Landfill Gas 5MW
Mini Hydro 5MW
Diesel Generator (Base) 5MW
Fuel Cell 5MW
2005
2015

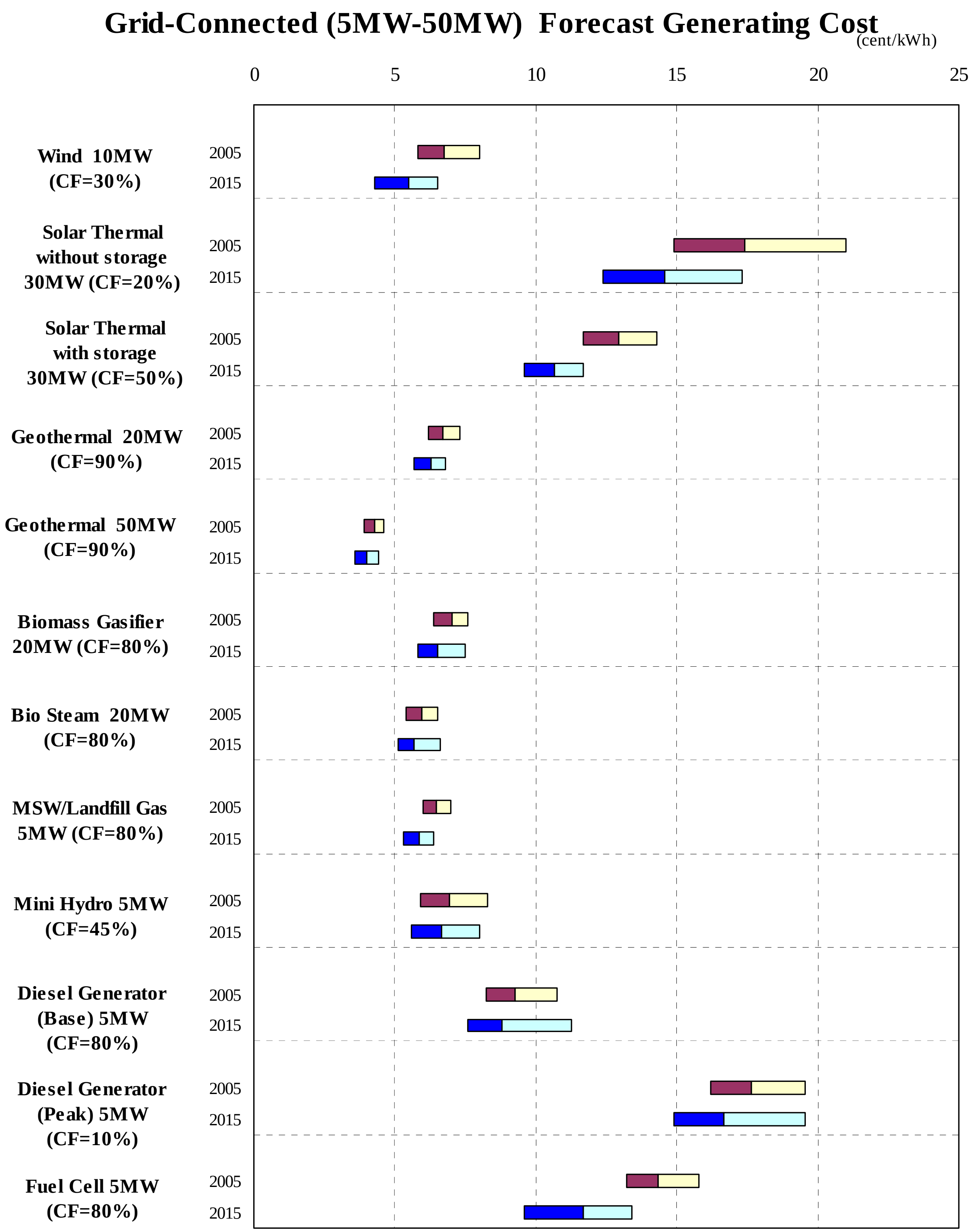
Grid-Connected (50MW-300MW) Forecast Capital Cost

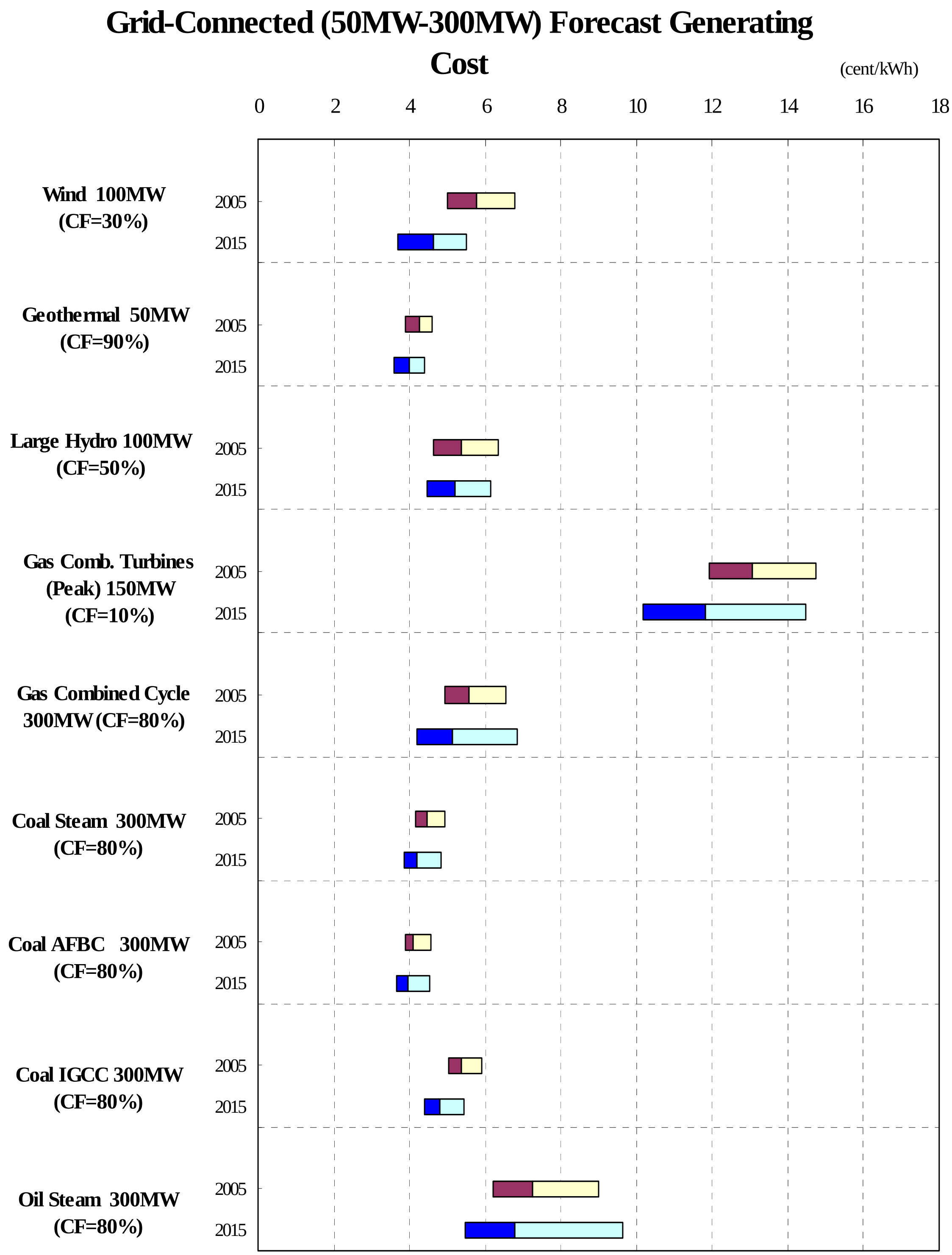


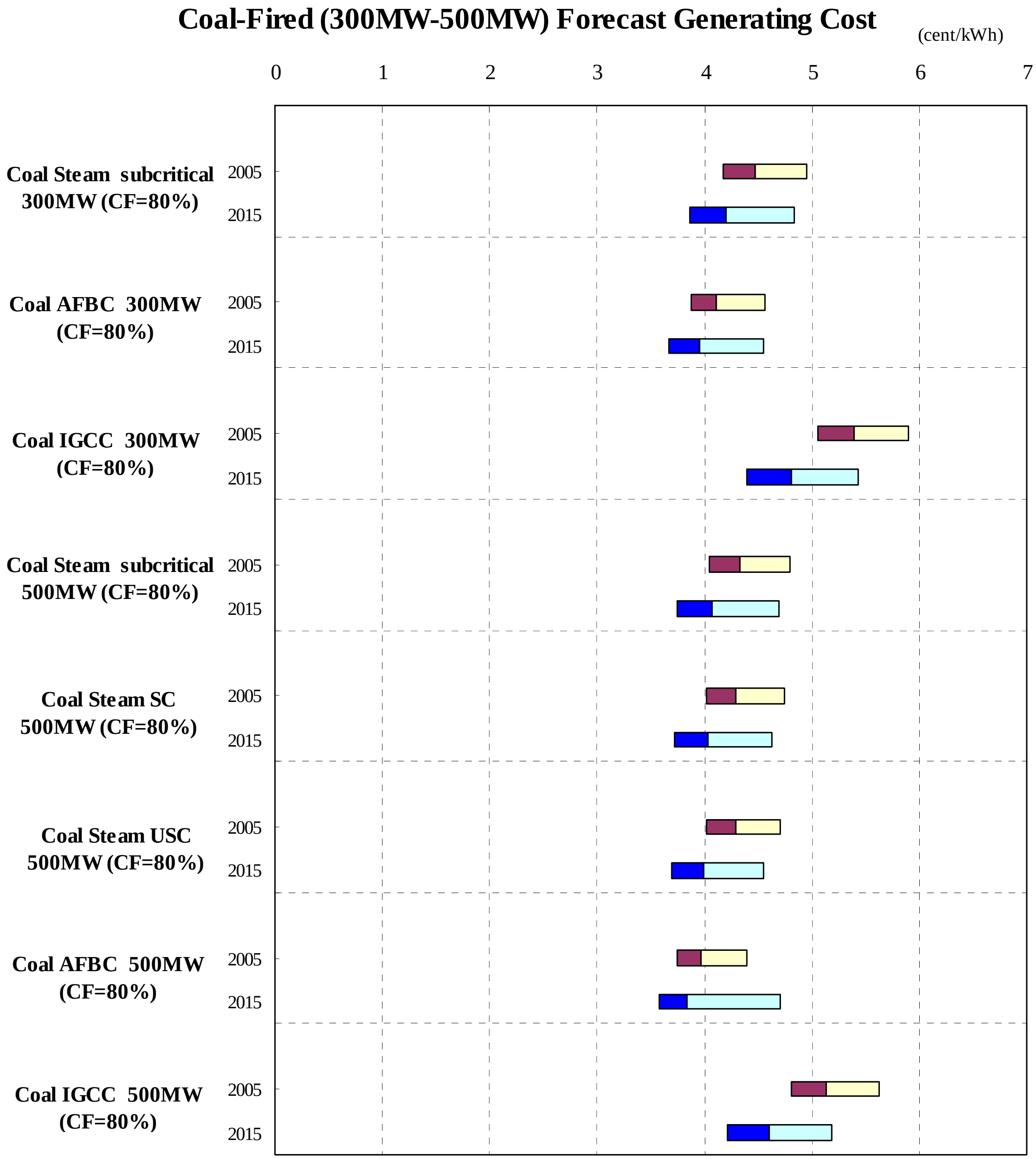

Off-Grid Forecast Generating Cost
(cent/kWh)
0
10
20
30
40
50
60
70
80
Solar PV 50W (CF=20%)
Solar PV 300W (CF=20%)
Wind 300W (CF=25%)
PV-Wind Hybrid 300W (CF=25%)
Pico Hydro 300W (CF=30%)
Pico Hydro 1kW (CF=30%)
Diesel/Gasolene Generator 300W (CF=30%)
Diesel/Gasolene Generator 1kW (CF=30%)
2005
2015
Example:
Sensitivity Range
Average

Mini-Grid Forecast Generating Cost




Grid-Connected (5MW-50MW) Forecast Generating Cost
(cent/kWh)
0
5
10
15
20
25
Wind 10MW (CF=30%)
Solar Thermal without storage 30MW (CF=20%)
Solar Thermal with storage 30MW (CF=50%)
Geothermal 20MW (CF=90%)
Geothermal 50MW (CF=90%)
Biomass Gasifier 20MW (CF=80%)
Bio Steam 20MW (CF=80%)
MSW/Landfill Gas 5MW (CF=80%)
Mini Hydro 5MW (CF=45%)
Diesel Generator (Base) 5MW (CF=80%)
Diesel Generator (Peak) 5MW (CF=10%)
Fuel Cell 5MW (CF=80%)
2005
2015


Grid-Connected (50MW-300MW) Forecast Generating Cost
(cent/kWh)
0
2
4
6
8
10
12
14
16
18
Wind 100MW (CF=30%)
Geothermal 50MW (CF=90%)
Large Hydro 100MW (CF=50%)
Gas Comb. Turbines (Peak) 150MW (CF=10%)
Gas Combined Cycle 300MW (CF=80%)
Coal Steam 300MW (CF=80%)
Coal AFBC 300MW (CF=80%)
Coal IGCC 300MW (CF=80%)
Oil Steam 300MW (CF=80%)
2005
2015


Coal-Fired (300MW-500MW) Forecast Generating Cost
(cent/kWh)
0
1
2
3
4
5
6
7
Coal Steam subcritical 300MW (CF=80%)
Coal AFBC 300MW (CF=80%)
Coal IGCC 300MW (CF=80%)
Coal Steam subcritical 500MW (CF=80%)
Coal Steam SC 500MW (CF=80%)
Coal Steam USC 500MW (CF=80%)
Coal AFBC 500MW (CF=80%)
Coal IGCC 500MW (CF=80%)
2005
2015

E Data Tables for Generation Capital Cost and Generating Cost

Generating Types	Capacity	2005			2010			2015		
		Mini	**Probable**	Max	Mini	**Probable**	Max	Mini	**Probable**	Max
Solar PV	50W	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	300W	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	25kW	6,710	**7,510**	8,320	5,630	**6,590**	7,380	4,800	**5,860**	6,640
	5MW	6,310	**7,060**	7,810	5,280	**6,190**	6,930	4,500	**5,500**	6,235
Wind	300W	4,820	**5,370**	5,930	4,160	**4,850**	5,430	3,700	**4,450**	5,050
	100kW	2,460	**2,780**	3,100	2,090	**2,500**	2,850	1,830	**2,300**	2,670
	10MW	1,270	**1,440**	1,610	1,040	**1,260**	1,440	870	**1,120**	1,300
	100MW	1,090	**1,240**	1,390	890	**1,080**	1,230	750	**960**	1,110
PV-Wind Hybrids	300W	5,670	**6,440**	7,210	4,650	**5,630**	6,440	3,880	**5,000**	5,800
	100kW	4,830	**5,420**	6,020	4,030	**4,750**	5,340	3,420	**4,220**	4,800
Solar thermal (without thermal storage)	30MW	2,290	**2,480**	2,680	1,990	**2,200**	2,380	1,770	**1,960**	2,120
Solar thermal (with thermal storage)	30MW	4,450	**4,850**	5,240	3,880	**4,300**	4,660	3,430	**3,820**	4,140
Geothermal	200kW (Binary)	6,480	**7,220**	7,950	5,760	**6,580**	7,360	5,450	**6,410**	7,300
	20 MW (Binary)	3,690	**4,100**	4,500	3,400	**3,830**	4,240	3,270	**3,730**	4,170
	50MW (Flash)	2,260	**2,510**	2,750	2,090	**2,350**	2,600	2,010	**2,290**	2,560
Biomass Gasifier	100kW	2,490	**2,880**	3,260	2,090	**2,560**	2,980	1,870	**2,430**	2,900
	20MW	1,760	**2,030**	2,300	1,480	**1,810**	2,100	1,320	**1,710**	2,040
Biomass Steam	50MW	1,500	**1,700**	1,910	1,310	**1,550**	1,770	1,240	**1,520**	1,780
MSW/Landfill Gas	5MW	2,960	**3,250**	3,540	2,660	**2,980**	3,270	2,480	**2,830**	3,130
Biogas	60kW	2,260	**2,490**	2,720	2,080	**2,330**	2,570	2,000	**2,280**	2,540
Pico/Micro Hydro	300W	1,320	**1,560**	1,800	1,190	**1,485**	1,770	1,110	**1,470**	1,810
	1kW	2,360	**2,680**	3,000	2,190	**2,575**	2,950	2,090	**2,550**	2,990
	100kW	2,350	**2,600**	2,860	2,180	**2,470**	2,750	2,110	**2,450**	2,780
Mini Hydro	5MW	2,140	**2,370**	2,600	2,030	**2,280**	2,520	1,970	**2,250**	2,520
Large Hydro	100MW	1,930	**2,140**	2,350	1,860	**2,080**	2,290	1,830	**2,060**	2,280
Pumped storage Hydro	150MW	2,860	**3,170**	3,480	2,760	**3,080**	3,400	2,710	**3,050**	3,380
Diesel/Gasoline Generator	300W	750	**890**	1,030	650	**810**	970	600	**800**	980
	1kW	570	**680**	790	500	**625**	750	470	**620**	770
	100kW	550	**640**	730	480	**595**	700	460	**590**	720
	5MW(Base-Load)	520	**600**	680	460	**555**	650	440	**550**	660
	5MW(Peak-Load)	520	**600**	680	460	**555**	650	440	**550**	660
Micro Turbines	150kW	830	**960**	1,090	620	**780**	910	500	**680**	810
Fuel Cells	200kW	3,150	**3,640**	4,120	2,190	**2,820**	3,260	1,470	**2,100**	2,450
	5MW	3,150	**3,630**	4,110	2,180	**2,820**	3,260	1,470	**2,100**	2,450
Oil/Gas Comb. Turbines	150MW(1,100C class)	430	**490**	550	360	**430**	490	340	**420**	490
Oil/Gas Combined Cycle	300MW(1,300C class)	570	**650**	720	490	**580**	660	450	**560**	650
Coal Steam with FGD & SCR (Subcritical)	300MW	1,080	**1,190**	1,310	960	**1,080**	1,220	910	**1,060**	1,200
Coal Steam with FGD & SCR (Subcritical)	500MW	1,030	**1,140**	1,250	910	**1,030**	1,150	870	**1,010**	1,140
Coal Steam with FGD & SCR (SC)	500MW	1,070	**1,180**	1,290	950	**1,070**	1,200	900	**1,050**	1,190
Coal Steam with FGD & SCR (USC)	500MW	1,150	**1,260**	1,370	1,020	**1,140**	1,250	960	**1,100**	1,230
Coal AFB without FGD & SCR	300MW	1,060	**1,180**	1,300	940	**1,070**	1,210	880	**1,040**	1,180
	500MW	1,010	**1,120**	1,230	900	**1,020**	1,140	840	**990**	1,120
Coal IGCC without FGD & SCR	300MW	1,450	**1,610**	1,770	1,200	**1,390**	1,550	1,070	**1,280**	1,440
	500MW	1,350	**1,500**	1,650	1,130	**1,300**	1,450	1,000	**1,190**	1,340
Oil Steam	300MW	780	**880**	980	700	**810**	920	670	**800**	920

Generating Types	Capacity	2005			2010			2015		
		Mini	**Probable**	Max	Mini	**Probable**	Max	Mini	**Probable**	Max
Solar PV	50W	51.8	**61.6**	75.1	44.9	**55.6**	67.7	39.4	**51.2**	62.8
	300W	46.4	**56.1**	69.5	39.6	**50.1**	62.1	34.2	**45.7**	57.0
	25kW	43.1	**51.4**	63.0	37.7	**46.2**	56.6	33.6	**42.0**	51.3
	5MW	33.7	**41.6**	52.6	28.9	**36.6**	46.3	25.0	**32.7**	41.4
Wind	300W	30.1	**34.6**	40.4	27.3	**32.0**	37.3	25.2	**30.1**	35.1
	100kW	17.2	**19.7**	22.9	15.6	**18.3**	21.3	14.4	**17.4**	20.2
	10MW	5.8	**6.8**	8.0	5.0	**6.0**	7.1	4.3	**5.5**	6.5
	100MW	5.0	**5.8**	6.8	4.2	**5.1**	6.1	3.7	**4.7**	5.5
PV-Wind Hybrids	300W	36.1	**41.8**	48.9	31.6	**37.8**	44.5	28.1	**34.8**	40.9
	100kW	26.8	**30.5**	34.8	23.8	**27.8**	31.7	21.4	**25.6**	29.1
Solar thermal (without thermal storage)	30MW	14.9	**17.4**	21.0	13.5	**15.9**	19.0	12.4	**14.5**	17.3
Solar thermal (with thermal storage)	30MW	11.7	**12.9**	14.3	10.5	**11.7**	12.9	9.6	**10.7**	11.7
Geothermal	200kW (Binary)	14.2	**15.6**	16.9	13.0	**14.5**	15.9	12.5	**14.2**	15.7
	20 MW (Binary)	6.2	**6.7**	7.3	5.8	**6.4**	6.9	5.7	**6.3**	6.8
	50MW (Flash)	3.9	**4.3**	4.6	3.7	**4.1**	4.4	3.6	**4.0**	4.4
Biomass Gasifier	100kW	8.2	**9.0**	9.7	7.6	**8.5**	9.4	7.3	**8.3**	9.5
	20MW	6.4	**7.0**	7.6	6.0	**6.7**	7.5	5.8	**6.5**	7.5
Biomass Steam	50MW	5.4	**6.0**	6.5	5.2	**5.7**	6.4	5.1	**5.7**	6.6
MSW/Landfill Gas	5MW	6.0	**6.5**	7.0	5.6	**6.1**	6.6	5.3	**5.9**	6.4
Biogas	60kW	6.3	**6.8**	7.2	6.0	**6.5**	7.1	5.9	**6.5**	7.1
Pico/Micro Hydro	300W	12.4	**15.1**	18.4	11.4	**14.5**	18.0	10.8	**14.3**	18.2
	1kW	10.7	**12.7**	15.2	10.1	**12.3**	14.8	9.7	**12.1**	14.9
	100kW	9.6	**11.0**	12.8	9.1	**10.5**	12.3	8.9	**10.5**	12.3
Mini Hydro	5MW	5.9	**6.9**	8.3	5.7	**6.7**	8.1	5.6	**6.6**	8.0
Large Hydro	100MW	4.6	**5.4**	6.3	4.5	**5.2**	6.2	4.5	**5.2**	6.2
Pumped storage Hydro	150MW	31.4	**34.7**	38.1	30.3	**33.8**	37.2	29.9	**33.4**	36.9
Diesel/Gasoline Generator	300W	59.0	**64.6**	72.5	52.4	**59.7**	71.8	52.5	**60.2**	75.0
	1kW	46.7	**51.2**	57.6	41.4	**47.3**	57.1	41.5	**47.7**	59.7
	100kW	18.1	**20.0**	23.1	16.6	**19.0**	23.3	16.7	**19.2**	24.3
	5MW(Base-Load)	8.3	**9.3**	10.8	7.6	**8.7**	10.8	7.6	**8.8**	11.3
	5MW(Peak-Load)	16.2	**17.7**	19.6	15.0	**16.7**	19.1	14.9	**16.7**	19.6
Micro Turbines	150kW	30.4	**31.8**	33.9	28.8	**30.7**	33.5	28.5	**30.7**	34.2
Fuel Cells	200kW	25.2	**26.5**	28.2	22.8	**24.7**	26.6	21.5	**23.7**	25.8
	5MW	13.2	**14.4**	15.8	11.0	**12.7**	14.4	9.6	**11.7**	13.4
Oil/Gas Comb. Turbines	150MW(1,100C class)	11.9	**13.1**	14.7	10.4	**11.8**	14.0	10.2	**11.8**	14.5
Oil/Gas Combined Cycle	300MW(1,300C class)	4.94	**5.57**	6.55	4.26	**5.10**	6.47	4.21	**5.14**	6.85
Coal Steam with FGD & SCR (Subcritical)	300MW	4.18	**4.47**	4.95	3.91	**4.20**	4.76	3.86	**4.20**	4.84
Coal Steam with FGD & SCR (Subcritical)	500MW	4.05	**4.33**	4.79	3.77	**4.07**	4.62	3.74	**4.06**	4.69
Coal Steam with FGD & SCR (SC)	500MW	4.02	**4.29**	4.74	3.74	**4.04**	4.56	3.72	**4.03**	4.63
Coal Steam with FGD & SCR (USC)	500MW	4.02	**4.29**	4.71	3.74	**4.02**	4.51	3.69	**3.99**	4.55
Coal AFB without FGD & SCR	300MW	3.88	**4.11**	4.56	3.72	**3.98**	4.55	3.67	**3.96**	4.55
	500MW	3.75	**3.97**	4.40	3.61	**3.86**	4.42	3.58	**3.83**	4.71
Coal IGCC without FGD & SCR	300MW	5.05	**5.39**	5.90	4.58	**4.95**	5.52	4.40	**4.81**	5.43
	500MW	4.81	**5.14**	5.62	4.38	**4.74**	5.28	4.21	**4.60**	5.19
Oil Steam	300MW	6.21	**7.24**	9.00	5.50	**6.70**	9.08	5.49	**6.78**	9.63

F Environmental Externalities

This section reviews methods for estimating environmental externality (damage) costs and provides examples of how such costs could be incorporated in technology selection. Literature references are provided throughout the document, so the reader can obtain more information and guidance on how to carry out an environmental externality assessment as it relates to a specific project.

F.1 *Methodology*

The concept of "environmental externalities" is based on the following principles:

- *Power Production costs* usually include all the costs incurred by the project entity (owner), assuming that market prices are not distorted. Key parameters which bound the calculation of production costs are: the *project boundary*, which is usually the physical boundary of the project and includes all the associated costs (expenses) to build and operate the facility; and the *project time horizon*, which is usually the operating life of the facility, as defined by the "design life" as well as any operating permits.
- *Social costs* are the costs incurred due to the project by society. Social costs are usually higher than production costs because:
  - The project boundary is wider; leading to costs incurred outside the project boundaries (water pollution, air pollution, effects on other economic activities) but not factored into power production costs.
  - The project may continue to have impacts on the environment or other economic activities long after the established project time horizon.
- The difference between social and production costs are the externality costs. The microeconomics literature and most project evaluation guidelines state that any comprehensive economic analysis should include externalities.

The methodology for estimating a project's externality costs involves five steps:

- Determine the pollutant loads (e.g., air and water emissions);
- Estimate impact on environmental quality;
- Assess the level of exposure;
- Estimate the impacts on the environment and health; and
- Estimate the monetary value of impacts.

F.1.1 Determine pollutant loads

In this step the amount of pollution caused by the project is estimated, usually in tons per year. However, certain pollutants may have different impacts at different times. For example, NO_x emissions may need to be estimated on an hourly rate (tons/day or tons/hr) during peak ozone times. All pollutants should be estimated, including air emissions

(SO_2, NO_x, CO and CO_2), water effluents, solid wastes, etc. The main factors affecting the amount of pollutants released include:

- Size of facility;
- Fuel composition;
- Efficiency of the power plant, [42] which in turn is affected by fuel characteristics and plant design;
- Environmental control equipment employed; and
- Utilization (Capacity) factor
- Environmental regulations, which may limit the rate of the pollutant (Kg/MWh or Kg/fuel input) and/or the total amount (tons/yr).

F.1.2 Estimate impact on environmental quality[43]

In this step the impact of the pollutants on environmental quality is estimated. Over time pollutants will gradually increase the atmospheric and water-borne loading of chemical compounds. Determination of this environmental quality impact for a given project is very site-specific and involves tools such as pollution transport, transformation, and dispersion and deposition models. Key factors to take into account include:

- Topography of the plant;
- Prevailing winds and climatic factors, especially the direction and strength of wind and water flow.
- Stack (chimney) height.
- Characteristics of the pollutants. For example, PM (particulate matter) can affect the concentration of the air in the proximity to the project, while gaseous pollutants (e.g., SO_2, $NO_{x,}$) are dispersed over a wide radius.

The measure of environmental quality is usually driven by environmental regulations. For example, regulations limit the average annual concentration of SO_2; therefore, dispersion modeling will to assess whether the annual emissions from the project will increase the ambient SO_2 concentration above allowable levels.

Environmental quality also involves impacts on habitats, recreation areas and aesthetics. While these are difficult to quantify, it is important to note the potential impacts and take them into account in a semi-quantitative or qualitative manner.

F.1.3 Assess the level of exposure

Environmental quality degradation affects people, materials, wildlife and vegetation. This step assesses the level of this exposure. Key factors to be considered include:

- Density of receptors as a function of distance from the plant
- Age of population

[42] We will refer to “power plant” or “plant” because the focus of this report is power plants; however, the same environmental externality methodology could be applied for other industrial facilities

[43] The World Bank’s Pollution Prevention and Abatement Handbook 1998 provides a comprehensive guide of the dispersion (pg. 82) and water quality models (pg. 101), which are available and commonly used to perform this step.

- Vulnerability to the pollutant
- Local economic activity (possibly represented by GDP), agricultural production, etc.

F.1.4 Estimate of the environmental and health effects (Dose-Response Relationship)

This step estimates the impacts on people, plants, animals and materials of exposure to increased pollutant concentrations. Impacts include: human mortality and morbidity, loss of habitat, agricultural impacts, materials and structures corrosion, and aesthetic impacts. These responses are usually estimated through a Dose-Response Relationship (DRR) that relates the severity or the probability of a response to the amount of pollutant the" receptor" is exposed to. DDRs are statistical relationships using historical data from the same or similar locations. Epidemiologic studies or laboratory studies may be needed to determine these relationships.[44]

F.1.5 Valuation (Estimating the monetary equivalent) of environmental and health impacts)

Valuation of health and environmental impacts is the most challenging step, because it involves subjective judgment of the value of human life, cost of illness (medical costs), value of degraded scenery, etc. Many different approaches are used to determine the value of these impacts including:

- The *Human capital approach*, which places a value on premature death based on a person's future earning capacity.
- The *Cost of illness approach,* similar to the human capital approach, which considers the lost economic output due to inability to work plus out-of-pocket costs (e.g., medical expenses).
- The *Preventive expenditures approach*, which infers the amount people are willing to pay to reduce health risks.
- The *Willingness-to-pay approach*, which is based on what people are willing to pay to reduce health risks they may face.
- The *Wage differential approach,* which uses differences in wage rates to measure the compensation people require for (perceived) differences in the probability of dying or falling ill from increased exposure to a pollutant.
- The *Contingent valuation approach*, which uses survey information to determine people's willingness to pay to reduce exposure to pollution.

F.2 *Suitability of the Methodology to Developing Countries*

The methodology described above is universal and as such suitable for developing countries. The issues associated with the methodology relate to the uncertainty and

[44] The World Bank's Pollution Prevention and Abatement Handbook 1998 (see pgs 58 and 63) provides a comprehensive of DRR determination.

subjectivity of some analyses (especially Steps 2, 4 and 5), but these issues are faced in all countries. Developing countries are likely to find it more difficult to obtain certain information required for the analysis, such as data on air quality, health statistics of the population and even economic activity. Nevertheless, the methodology applies and many such studies have been carried out.[45] Also, while there are many issues associated with the methodology, applying it raises the awareness level of the impacts from environmental pollution (cause-and-effect relationships) and has an overall positive effect on all stakeholders.

There have been numerous analytic studies of environmental externalities in the US and elsewhere. These various studies have explicitly or implicitly placed a valuation on environmental emissions (See Table F.1). These values should be taken as indicative, as each location and setting may result in significantly different numerical results. Furthermore, externality values vary significantly even for similar locations, indicating the subjectivity and influence of key assumptions. For example, SO2 externalities in the various states of the US vary from 150 to 4,486 $/ton, even though the setting from state to state is very similar (e.g., Massachusetts and New York). Similarly, NOx varies from 850 to 9,120 $/ton, particulates from 333 to 4,608 $/ton and CO2 from 1 to 25 $/ton. Nevertheless, these estimates define a range which is presumably acceptable. This range can be become narrower by considering that some of these pollutants have become commodities and are traded. Considering that the externalities and the emission control costs are expected to be above the traded values, the lower limit of the externality range can be adjusted accordingly. For example in the US, NOx values in the last two years (2002-04) have ranged from 2,500 to 5,000 $/ton. So, the externality range define in the above table (850 - 9,120 $/ton) can be adjusted to 2,500 - 9,120 $/ton.

Note that externalities in developing countries are an order of magnitude lower than in OECD countries. This may change as income per capita (and GDP) of developing countries increases, but for the time being, this significant difference will likely continue.

With regard to CO2, many studies have estimated the global damage in the 3 to 20 $/ton CO2 range; IPCCC puts the damage costs in the 1.4 to 28.6 $/ton CO2 (5 to 105 $/ton of carbon). Of course, recent trading of greenhouse gas emission reductions (ranging from 3 to 15 $/ton of CO2) can be taken as another indicator.

[45] See for example: Asian Development Bank (1996): “Economic Evaluation of Environmental Impacts”, Asian Development Bank; Bates, R., et al (1994): Alternative policies for the control of air pollution in Poland”, World Bank Environment Paper No. 7; Bennagen, E.C. (1995): “Philippine environmental and natural resources accounting project/ANRAP sectoral studies on pollution”, USAID; Cropper, M. L., Simon, N.B., Alberini, A., and Sharma, O.K. (1997): “The Health Effects of Air Pollution in Delhi, India”, Policy Research Working Paper 1860, World Bank

Table F.1: Indicative Results of Environmental Externality Studies

	Location	SO2	NOx	Particulates	CO2
Pace University[1]	USA (general)	4,474	1,807	2,623	15
DOE[2]	USA/California	4,486	9,120	4,608	9
DOE[2]	USA/Massachusetts	1,700	7,200	4,400	24
DOE[2]	USA/Minnesota	150	850	1,274	9.8
DOE[2]	USA/Nevada	1,716	7,480	4,598	24
DOE[2]	USA/New York	1,437	1,897	333	1
DOE[2]	USA/Oregon	0	3,500	3,000	25
World Bank[3]	Philippines	95	71	67	NA
World Bank[4]	China/Shanghai	390	454	1,903	NA
World Bank[4]	China/Henan	217	252	940	NA
World Bank[4]	China/Hunan (2000)	364	201	801	NA

Sources Of Data

1	Pace University, "Environmental Costs of Electricity", Ocean Publications (1990)
2	DOE/EIA-0598, "Electricity Generation and Environmental Externalities: Case Studies" (1995)
3	World Bank/Assessment of the value of Malampaya natural gas for the power sector of the Philippines (1996)
4	World Bank/Technology Assessment of Clean Coal Technologies for China/Volume III (2001)

F.3 *Examples of Environmental Externality Studies*

During the period 1999-2001, the World Bank carried out a number of studies in China focusing on clean coal technologies, environmental controls and integration of environmental aspects in power system planning.[46] Three case studies were carried out, in the City of Shanghai and the Provinces of Henan and Hunan. The cases of Shanghai and Henan Province employ a top-down approach; mainly due to lack of data and resources to carry out a very comprehensive assessment, it was decided to utilize values from other countries (e.g., State of New York, USA) and adjust them for the key characteristics of each site (Shanghai and Henan Province). In the case of Hunan Province a comprehensive assessment was carried out including dispersion of pollutants and health impacts. Externality values developed for the State of New York[47] were used as a basis for the study. First the New York values were adjusted for income per capita

[46] The results of these studies are documented in three volumes entitled "Technology Assessment of Clean Coal Technologies for China". Volume III describes the methodology developed to integrate environmental considerations in power system planning including externalities
[47] Ref: Rowe et al, "New York Externality Model", 1994

differences.[48] The values obtained were multiplied by the number of affected individuals as a function of the distance from a presumed power plant (see Table F.2). For all pollutants (TSP, SO_2 or NO_x), the environmental damage is approximately twice in Shanghai than in Henan, mainly because of higher population density.

Table F.2: Externality Values for Two Chinese Cities ($ 1996/ton)[49]

	Shanghai	*Henan*
TSP/PM10	1903	940
SO_2	390	217
NO_x	454	252

A second case study applied a Dispersion Modeling and Damage Cost Estimation Approach to Hunan Province. The externality cost of each pollutant (SO_2, NO_x and TSP) was estimated independently using dispersion modeling and damage cost valuation approach. For SO_2, the entire province was taken into account, and three major types of damage were considered: crops, forests, and human health. Since particulates (TSP) affect more the urban areas, Changsha City, the capital of Hunan province, was selected and the damage on human health caused by TSP was estimated. NOx was assessed over the whole Province, but the dispersion analysis was not as detail as the SO2. Table E-3 provides a summary of the key parameters considered in these assessments.

Table F.3: Key Parameters for Hunan Externality Cost Assessment

	SO_2	**TSP**	**NOx**
Geographical region	Hunan Province	Changsha City	Hunan
Base Year	1995	1998	1998
Period of analysis	2000 – 2020	2000 – 2020	2000 – 2020
Increments	5 years	5 years	5 years
Damage Considered	Crops, Forest Human Health	Human Health (from TSP only)	Health, Material Visibility

Source: World Bank/ESMAP

[48] Income per capita data (purchasing power parity basis) were obtained from the World Bank "World Development Report 1996/From Plan to Market".
[49] World Bank/ESMAP, "ENVIRONMENTAL COMPLIANCE IN THE ENERGY SECTOR: Methodological Approach and Least-cost Strategies; Shanghai Municipality & Henan and Hunan Provinces, China", August 2000

A dose-response technique was used to estimate decreased yield of crop and forest damage. Human health cost was estimated using previous studies employing the human capital approach and the willingness to pay approach, generating a linear relationship between damages and SO2 concentration. The results are presented in Table F.4.

Table F.4: Hunan Province: SO2 Emission Damage Cost (1995-2000)

Year		1995	2000	2005	2010	2015	2020
Emission (10^6 ton)							
Non-power		0.80	0.88	1.06	1.24	1.43	1.63
Power		0.09	0.10	0.11	0.14	0.22	0.32
Total		**0.89**	**0.99**	**1.17**	**1.38**	**1.65**	**1.95**
Damage Cost (billion RMB)	Crops	0.54	0.60	0.74	0.93	1.16	1.42
	Health	0.38	0.84	1.46	2.32	3.43	4.98
	Forest	1.20	1.55	2.38	3.47	4.92	6.50
	Total	**2.12**	**2.99**	**4.58**	**6.72**	**9.51**	**12.90**
Damage Cost							
(RMB/ton)		2,384	3,022	3,912	4,884	5,736	6,595
(US$/ton)[50]			**364**	**471**	**588**	**691**	**795**

Source: World Bank/ESMAP

To estimate TSP-related damage, dose-response functions were used based upon research of the effects of TSP on human health in Chongqing, and which included three kinds of effects: mortality, hospitalization and visits to a medical doctor. Then, a variant of the New York State model was used. Based upon the annual emission level for TSP and the estimated population by local, regional and distant, deposition of TSP was estimated. By using the Per capita GDP purchasing power parity, the damage cost from US was converted to Hunan Province. The results of the TSP analysis are presented in Table F.5.

Table F.5: TSP Emission Damage Cost in Changha City and Hunan Province

	1998	2000	2010	2020
Emissions, ton/year (000)				
Changsha City	20	20.7	24.5	30.9
Hunan Province	1,342	1,417	1,677	2,113
Total Damage Cost (M RMB)				
Changsha City	196	271	631	1,177
Hunan Province	6,810	9,420	21,930	40,900
Incremental Cost (RMB/ton)				
Changsha City	9,991	13,098	25,756	38,125
Hunan Province	5,073	6,651	13,078	19,358

[50] Note: Assume exchange rate of 8.3 RMB/US$

Incremental Cost (US$/ton)				
Changsha City	1,204	1,578	3,103	4,593
Hunan Province	**611**	**801**	**1,576**	**2,332**

Source: World Bank/ESMAP

For NOx, there are two major sources: coal combustion and automobiles. For valuation of the damage cost, an emissions-based valuation method and the New York methodology was used. The results are shown in Table E-6 below.

Table F.6: NOX Emission Damage Cost in Changsha City and Hunan Province

	1998	2000	2010	2020
Emissions, ton/year (000)				
Changsha City				
Hunan Province	433	362	256	247
Total Damage Cost (M RMB)				
Changsha City				
Hunan Province	552	605	842	1,195
Incremental Cost (RMB/ton)				
Changsha City				
Hunan Province	1,275	1,671	3,286	4,865
Incremental Cost (US$/ton)				
Changsha City				
Hunan Province	**154**	**201**	**396**	**586**

Source: World Bank/ESMAP

F.4 *Using Environmental Externalities for Selecting Power Generation Technologies*

Usually the technology and the fuel characteristics determine the level of each pollutant being emitted (e.g., in tons/MWh). If the externality cost ($/ton) is known, the plant causes a damage equivalent to: tons/MWh X $/ton = $/MWh. From the analytical point of view, externality costs is a component which could be added to the variable O&M costs ($/MWh) of each plant or technology. If such externality costs are included in technology evaluations, the comparison internalizes externalities.

Many of the models used in power system planning and technology evaluation include inputs for externality costs ($/ton) for the key pollutants. If they do not, the analyst would need to calculate the externality costs in $/MWh (tons/MWh X $/ton) for each technology and add it to the variable O&M costs. This could be done in a sophisticated power system planning model, as well as a simple spreadsheets developed by the analyst to do technology screening or more detail technology evaluation.

The key question is always *what is the right externality value to use?* As mentioned earlier, externality values are site-specific and only after a thorough evaluation of site-specific considerations could be developed. However, very often even a preliminary assessment could be insightful. For example, the following steps could be taken:

- *Step 1:* Review relevant literature and identify a range for externality values of each pollutant
- *Step 2:* Adjust these values to reflect population density and income in the site being considered (vs. literature data)
- *Step 3:* Carry out a sensitivity analysis using the high and low externality values from the range being established in the previous step. If neither the low nor the high externality values change the technology choice (not uncommon), there is no need for more detail externality evaluation, at least with regard to technology choice. If the externality values change the technology choice, more detailed, site-specific assessment of the environmental externalities may be needed.

F.5 *References*

1. DOE/EIA-0598 (1995): "Electricity Generation and Environmental Externalities: Case Studies”

2. Douckery, D.W., Pope, C.A., Xiping, X., Spengler, J., Ware, J., Fay, B., and Speizer, J. (1993): “An association between air pollution and mortality in six U.S. cities”, New England Journal of Medicine 329 (24): 1753-59

3. ESMAP (1999): “India/Environmental Issues in the Power Sector”, World Bank, ESMAP Report 213/99

4. Friedrich, R., and Voss, A. (1993): “External cost of electricity generation”, Energy Policy Vol. 21, No. 2

5. Hohmeyer, O. (1998): “Social costs of energy consumption”, Springer Verlag, Berlin Lvovsky, K., et al (2000): “Environmental Costs of Fossil Fuels”, World Bank Paper No 78

6. Maddison, D., et al. (1997): Air pollution and the social costs of fuels”, World Bank, Environment Dept.

7. Margulis, S. (1991): “Back of the envelop estimates of environmental damage costs in Mexico”, World Bank

8. Meier, P., and Munasinghe, M. (1994): “Incorporating environmental concerns into power sector decisionmaking”, World Bank Environment Paper No. 6

9. Oak Ridge National Laboratory (1994): “Estiamting fuel cycle externalities: analytical methods and issues”, Report No. 2, McGraw-Hill/Utility Data Institute, Washington, DC

10. Ostro, B. (1994): “A methodology for estimating air pollution health effects”, WHO/EHG/96, World Health Organization

11. Ostro, B. (1994): “Estimating the Health Effects of Air Pollution: A Methodology with an Application to Jakarta, Indonesia”, Policy Research Working Paper 1301, World Bank

12. Ostro, B., Sanchez, J., Aranda, C., and Eskeland, G. S., (1995): “Air Pollution and Mortality: Results from Santiago, Chile”, Policy Research Working Paper 1453, World Bank

13. Pace University (1990): “Environmental Costs of Electricity”, Ocean Publications

14. Pearce, D.W., Bann, C., and Georgiou, S. (1992): “The social costs of fuel cycles”, HMSO, London

15. Scholz, U. et al (1993): “Energy use and air pollution in Indonesia”, Avebury Studies in Green Research

16. Van Horen, C (1996): “Counting the social costs: electricity and externalities in South Africa”, Elan Press, Cape Town

17. World Bank/ESMAP, "ENVIRONMENTAL COMPLIANCE IN THE ENERGY SECTOR: Methodological Approach and Least-cost Strategies; Shanghai Municipality &Henan and Hunan Provinces, China", August 2000