energy

Department:
Energy
REPUBLIC OF SOUTH AFRICA

POWER GENERATION TECHNOLOGY DATA FOR INTEGRATED RESOURCE PLAN OF SOUTH AFRICA

Technical Update, April 2017

Prepared by: Electric Power Research Institute (EPRI)

Power Generation Technology Data for Integrated Resource Plan of South Africa

Technical Update, April 2017

Project Manager
C. Gross

System Operations and Planning

EPRI Project Manager
C. Lyons

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THE FOLLOWING ORGANIZATION PREPARED THIS REPORT:

Electric Power Research Institute (EPRI)

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The following organization prepared this report:

Electric Power Research Institute (EPRI)
3420 Hillview Ave
Palo Alto, CA 94304

Principal Investigators
G. Booras
C. Lyons
B. Nguyen (Nexant)

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Power Generation Technology Data for Integrated Resource Plan of South Africa. EPRI, Palo Alto, CA: 2015.

PRODUCT DESCRIPTION

This report is an update of the study results published by EPRI in August 2015.

Results and Findings

This technical update provides cost and performance data on renewable resource-based technologies such as wind, solar thermal, solar photovoltaic (PV), and biomass; fossil fuel-based technologies such as pulverized coal (PC), fluidized bed combustion (FBC), integrated coal gasification combined cycle, open cycle gas turbine (GT), combined cycle gas turbine (CCGT), and nuclear technologies. In addition, an overview of the biogas and underground coal gasification (UCG) process to produce methane and synthesis gas has been provided. Lead-Acid and Sodium Sulfur battery storage technologies have been added to this update to supplement the renewable energy technologies. This update includes technology enhancements, market factors influence, enhancements to design, and revisions to cost and performance data. The Department of Energy (DOE), South Africa is in the process of evaluating these technologies for future capacity additions, and the data in this report will facilitate the integrated resource plan (IRP) process of South Africa.

Challenges and Objectives

Power generation technologies are on the threshold of efficiency improvements; at the same time, the question of capital and operating costs of new units is somewhat uncertain due to the impact of a global market demand competing for the same resources. This makes a comparative assessment of these technologies with a consistent approach to the cost and performance analysis essential to a power generation company's strategy for fleet transition from older to newer units. The objective of this report is to address these challenges and provide data on technologies in a consistent manner.

Applications, Values, and Use

This study is part of EPRI's ongoing work to address technology improvements and monitor cost and performance of developing and mature technologies. While EPRI promotes collaborative research amongst members, specific reports tailored to individual countries help EPRI staff to collaborate closely with the member staff and gain perspective on unique situations where the technologies may be deployed. This perspective can then be translated into a much broader collaborative effort to benefit all members.

Approach

This report is an update of an August 2015 report. It utilizes past EPRI research in power generation technologies' cost and performance along with EPRI staff expertise to update estimates for South African conditions.

Keywords
Power generation
Nuclear technologies
Coal technologies
Natural gas technologies
Renewable technologies
Storage battery technologies

EXECUTIVE SUMMARY

Introduction

The DOE South Africa is in the process of preparing an IRP. The DOE South Africa has stipulated that the data included in the IRP must be obtained from an independent source. To obtain this independently sourced data, ESKOM had engaged the Electric Power Research Institute (EPRI) in 2010 and 2012 to provide technology data for new power plants that would be included in the IRPs. The 2010 and 2012 reports have been extensively reviewed with public comments and acceptance. The 2015 report was a technical update of the technologies' cost and performance with technology enhancements, market factor influences, and additional technology cases for inclusion in the 2015 IRP. The DOE South Africa has requested that the 2015 report be updated to show the costs at the January 2017 ZAR – US dollar exchange rate. For this update, the 2015 baseline cost for each technology was adjusted to January 2017 US dollar using an annual escalation rate of 2.5%. The baseline costs were then converted to ZAR based on the currency exchange rate on January 1, 2017.

This technical update incorporates cost and performance data for a number of power generation technologies applicable to South African conditions and environments. Estimates pertinent to South African conditions were developed based on a compilation of existing U.S. and international databases and adjustments based on third-party vendor indices and EPRI in-house expertise specifically tailored to technology design conditions in South Africa.

The scope of EPRI's effort includes presenting the capital cost, operations and maintenance (O&M) cost, and performance data, as well as a comprehensive discussion and description of each technology. A market analysis on the state of the South African power market was also used to support the cost analysis contained within this report. A summary of that research is below.

Global Data energy analysts estimate that South Africa consumed 209 TWh of electricity 2014; a slight decrease of 1.3% from 2012 levels. The decrease in consumption is consistent with trends beginning in 2012. In that year, South Africa faced a power supply crunch, during which consumers were urged to reduce consumption in order to avoid power shortages. Although power demand has grown steadily, generation has fallen due to the need for frequent unplanned power plant maintenance. In addition, Mozambique was affected by floods in 2013, which reduced its electricity exports to South Africa by almost 50%, in turn reducing the amount of power available for supply in South Africa in the same year. Capacity margins were as low as 3.3% in March 2013, compared with around 17% in December 2012 (Viser, 2013).

In 2014, South Africa generated 233 TWh and was an overall net exporter of electricity. During the 2015 – 2020 forecast period, electricity consumption is expected to increase from 216 TWh to 230 TWh. To support this growth and replace the aging fleet of generating units, energy analysts project an addition of approximately 20 GW of installed power generation by 2020. This growth includes the commercialization of two thermal-fired power plants, Kusile Power Station and Medupi Power Station. Both were expected to begin their operations in 2013 but are still under construction due to labor strikes in the region. Unfortunately, the labor strikes are currently common. This influenced EPRI's decision to reflect a downward trend in productivity compared to the last IRP report published in 2012.

The costs of bulk materials in South Africa have escalated significantly. Although raw material pricing tends to be less expensive in South Africa compared to the United States, the potential savings are offset by higher productions costs resulting from less sophisticated production techniques and lower worker productivity.

The rationale for the costs presented in this report is as follows:

- Estimates (constant January 2017) represent composite material and labor cost estimates from first quarter 2015.
- The material, productivity, and labor rate factors reflect the exchange rate of 13.57 ZAR to 1 US Dollar. All costs are reported in January 2017 South African Rand. It is common for estimates to be developed by applying conversion factors to a reference estimate. However, estimate factors do carry some limitations.
- Factors developed for this report considered "point factors", meaning they represent a specific point in time. The factors underlying the data in this report can change quickly and markedly both on worldwide and local market conditions.

The cost and performance estimates included in this report are based on a conceptual level of effort idealized for representative generating units at appropriate South African locations and have been normalized where possible to produce a consistent database. However, site-specific and company-specific conditions dictate design and cost variations that require a much higher level of effort and is not reflected here.

In developing these estimates, an effort was made to forecast probable capital expenditures associated with commercial-scale technology projects. Cost estimating is, however, part science and part art; it relies heavily on current and past data and on project execution plans, which are based on a set of assumptions. The successful outcome of any project—project completion within the cost estimate—depends on adherence to an execution plan and the assumptions without deviation. These estimates represent the ongoing technology monitoring effort at EPRI to update the current Technical Assessment Guide (TAG®) database and information. EPRI's TAG® Program has been providing cost and performance status and market trends of power generation technologies for over three decades and is considered a reliable source of data for future capacity planning by U.S. industry personnel as well as by regulators involved in the resource planning and approval process.

Estimate Result Uncertainties

Uncertainties exist both in the baseline U.S. estimates as well as in the adjustment factors used to develop South African cost and performance estimates. The uncertainties in the U.S. estimates include impact of market trends in labor cost, equipment, and material costs. The uncertainties in the South African cost estimates include:

- Skilled labor availability
- Fabrication and manufacturing capability for plant components
- Labor productivity
- Equipment and material transportation cost
- Expatriate skilled labor, supervision and management requirement
- Design and engineering labor requirement

Results

The following tables provide a summary of the technologies evaluated in this study. Overview on UCG is included, but cost and performance data is not provided due to insufficient design and cost data.

Table 1
Coal Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
PC (1)		
Without FGD	1, 2, 4, 6 x 750 MW	Mine-mouth at 1800 m elevation
With FGD	1, 2, 4, 6 x 750 MW	Mine-mouth at 1800 m elevation
With Carbon Capture	1, 2, 4, 6 x 750 MW	Mine-mouth at 1800 m elevation
Integrated Gasification Combined Cycle (IGCC), without Carbon Capture	1, 2, 4, 6 x 644 MW	Mine-mouth at 1800 m elevation
With Carbon Capture	1, 2, 4, 6 x 644 MW	Mine-mouth at 1800 m elevation
FBC		Mine-mouth at 1800 m elevation
Without limestone	1, 2, 4, 6 x 250 MW	Mine-mouth at 1800 m elevation
With limestone for in-bed sulfur removal	1, 2, 4, 6 x 250 MW	Mine-mouth at 1800 m elevation
With Carbon Capture	1, 2, 4, 6 x 250 MW	Mine-mouth at 1800 m elevation

(1) Multiple units are sequentially built

Table 2
Nuclear Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Nuclear (with seawater cooling) (2)		
AP1000	1, 2, 4, 6 x 1,115 MW	Coastal, near Port Elizabeth or north of Cape Town
Areva EPR	1, 2, 4, 6 x 1,600 MW	Coastal, near Port Elizabeth or north of Cape Town

(2) Multiple units are sequentially built

Table 3
Gas Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
CCGT	500-800 MW	Coastal, LNG based
Open Cycle Gas Turbine (OCGT)	100-190 MW	Coastal, LNG based
Internal Combustion Engine (ICE)	2 MW, 9.4 MW	Coastal, LNG based

Table 4
Renewable Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Wind	20, 50, 100, 200 MW	Coastal
Parabolic Trough		
Without storage	125 MW	Upington
With indirect storage (3, 6, 9, & 12 hours)	125 MW	Upington
Central Receiver		
With direct storage (3,6, 9, & 12 hours)	125 MW	Upington
PVs		
Thin Film – rooftop	0.25, 1 MW	Johannesburg and Cape Town
Thin Film – ground mounted	1, 10 MW	Johannesburg and Cape Town
Concentrating	10 MW	Upington
Biomass		
Forestry Residue	25 MW	Eastern coast
Municipal Solid Waste (MSW)	25 MW	Major cities
Landfill Gas Engines	5 MW	Major cities
Biogas Engines	5 MW	Major cities

The following tables provide a summary of the levelized costs of electricity from this study.

Table 5
PC without FGD Levelized Cost of Electricity

Technology	1x750 MW, No FGD	2x750 MW, No FGD	4x750 MW, No FGD	6x750 MW, No FGD
Rated Capacity, MW Net	750	1,500	3,000	4,500
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	301.8	301.8	301.8	301.8
O&M (ZAR/MWh)	171.9	166.1	159.2	155.9
Capital (ZAR/MWh)	727.6	689.7	651.9	632.9
LCOE (ZAR/MWh)	**1,201.2**	**1,157.6**	**1,112.8**	**1,090.6**

Table 6
PC with FGD Levelized Cost of Electricity

Technology	1x750 MW, with FGD	2x750 MW, with FGD	4x750 MW, with FGD	6x750 MW, with FGD
Rated Capacity, MW net	750	1,500	3,000	4,500
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	305.2	305.2	305.2	305.2
O&M (ZAR/MWh)	255.4	246.4	235.5	230.5
Capital (ZAR/MWh)	906.2	858.8	811.5	787.8
LCOE (ZAR/MWh)	**1,466.8**	**1,410.5**	**1,352.1**	**1,323.5**

Table 7
PC with Carbon Capture Levelized Cost of Electricity

Technology	1x750 MW, with CCS	2x750 MW, with CCS	4x750 MW, with CCS	6x750 MW, with CCS
Rated Capacity, MW net	750	1,500	3,000	4,500
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	438.5	438.5	438.5	438.5
O&M (ZAR/MWh)	441.3	428.6	413.0	405.7
Capital (ZAR/MWh)	1,684.1	1,618.7	1,553.4	1,520.7
LCOE (ZAR/MWh)	**2,563.9**	**2,485.8**	**2,404.9**	**2,365.0**

Table 8
IGCC without Carbon Capture Levelized Cost of Electricity

Technology	One 2x2x1 Shell IGCC	Two 2x2x1 Shell IGCC	Four 2x2x1 Shell IGCC	Six 2x2x1 Shell IGCC
Rated Capacity, MW net	644	1,288	2,576	3,864
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	303.3	303.3	303.3	303.3
O&M (ZAR/MWh)	300.9	262.1	238.5	229.0
Capital (ZAR/MWh)	1,224.9	1,151.9	1,079.0	1,042.5
LCOE (ZAR/MWh)	**1,829.2**	**1,717.4**	**1,620.8**	**1,574.9**

Table 9
IGCC with Carbon Capture Levelized Cost of Electricity

Technology	One 2x2x1 Shell IGCC with CCS	Two 2x2x1 Shell IGCC with CCS	Four 2x2x1 Shell IGCC with CCS	Six 2x2x1 Shell IGCC with CCS
Rated Capacity, MW net	644	1,288	2,576	3,864
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	389.9	389.9	389.9	389.9
O&M (ZAR/MWh)	411.9	368.1	340.6	329.4
Capital (ZAR/MWh)	1,632.5	1,535.3	1,438.0	1,389.4
LCOE (ZAR/MWh)	**2,434.3**	**2,293.2**	**2,168.5**	**2,108.7**

Table 10
Fluidized Bed without FGD Levelized Cost of Electricity

Technology	1x250 MW, No FGD	2x250 MW, No FGD	4x250 MW, No FGD	6x250 MW, No FGD
Rated Capacity, MW net	250	500	1,000	1,500
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	334.1	334.1	334.1	334.1
O&M (ZAR/MWh)	243.0	237.0	229.3	225.8
Capital (ZAR/MWh)	933.0	877.5	821.9	794.1
LCOE (ZAR/MWh)	**1,510.2**	**1,448.7**	**1,385.4**	**1,354.0**

Table 11
Fluidized Bed with FGD Levelized Cost of Electricity

Technology	1x250 MW, with FGD	2x250 MW, with FGD	4x250 MW, with FGD	6x250 MW, with FGD
Rated Capacity, MW net	250	500	1,000	1,500
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	335.4	335.4	335.4	335.4
O&M (ZAR/MWh)	289.7	283.4	269.0	272.3
Capital (ZAR/MWh)	950.8	894.2	837.6	809.3
LCOE (ZAR/MWh)	**1,575.9**	**1,513.0**	**1,442.0**	**1,417.0**

Table 12
Fluidized Bed with FGD and Carbon Capture Levelized Cost of Electricity

Technology	1x250 MW, with CCS	2x250 MW, with CCS	4x250 MW, with CCS	6x250 MW, with CCS
Rated Capacity, MW net	250	500	1,000	1,500
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	482.5	482.5	482.5	482.5
O&M (ZAR/MWh)	398.9	390.9	380.8	376.1
Capital (ZAR/MWh)	1,663.6	1,589.3	1,514.9	1,477.6
LCOE (ZAR/MWh)	**2,545.0**	**2,462.7**	**2,378.1**	**2,336.2**

Table 13
Nuclear Areva EPR Levelized Cost of Electricity

Technology	1 Unit	2 Units	4 Units	6 Units
Rated Capacity, MW net	1,600	3,200	6,400	9,600
Capacity Factor, %	90	90	90	90
Fuel Cost (ZAR/MWh)	269.7	269.7	269.7	269.7
O&M (ZAR/MWh)	170.6	150.5	140.5	134.8
Capital (ZAR/MWh)	1,979.4	1,955.1	1,905.5	1,859.1
LCOE (ZAR/MWh)	**2,419.6**	**2,375.3**	**2,315.6**	**2,263.6**

*Multiple units are sequentially built, with construction and startup of each subsequent unit occurring every 2 years

Table 14
Nuclear AP1000 Levelized Cost of Electricity

Technology	1 Unit	2 Units	4 Units	6 Units
Rated Capacity, MW net	1,117	2,234	4,468	6,702
Fuel Cost (ZAR/MWh)	286.2	286.2	286.2	286.2
O&M (ZAR/MWh)	190.2	161.6	147.2	139.0
Capital (ZAR/MWh)	1,520.0	1,501.2	1,464.1	1,426.6
LCOE (ZAR/MWh)	**1,996.5**	**1,949.0**	**1,897.5**	**1,851.9**

*Multiple units are sequentially built, with construction and startup of each subsequent unit occurring every 2 years

Table 15
Levelized Cost of Electricity for Multiple Nuclear Units with the Same Commercial Service Date

Technology	6x1600 MW, Areva	8x1115 MW, AP1000
Rated Capacity, MW net	9,600	8,936
Fuel Cost (ZAR/MWh)	269.7	286.2
O&M (ZAR/MWh)	134.8	118.1
Capital (ZAR/MWh)	2,119.0	1,586.3
LCOE (ZAR/MWh)	**2,523.4**	**1,990.6**

Table 16
GT and ICE Levelized Cost of Electricity

Technology	OCGT	CCGT without CCS	CCGT with CCS	ICE	ICE
Rated Capacity, MW net	132	732	635	1.90	9.40
Capacity Factor, %	10	50	50	50	50
Fuel Cost (ZAR/MWh)	736.5	472.8	569.0	605.8	561.3
O&M (ZAR/MWh)	210.2	67.5	139.8	187.8	258.4
Capital (ZAR/MWh)	1,513.9	339.1	743.0	423.9	454.2
LCOE (ZAR/MWh)	**2,460.5**	**879.4**	**1,451.8**	**1,217.5**	**1,274.0**

Table 17
Wind Levelized Cost of Electricity – 10 x 2 MW Farm

Technology	Wind			
Rated Capacity, MW net	20			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Capacity Factor, %	21.6	27.4	37.2	46.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	361.9	282.9	208.5	168.2
Capital (ZAR/MWh)	2539.3	1986.0	1463.3	1180.7
LCOE (ZAR/MWh)	**2,901.2**	**2,269.0**	**1,671.8**	**1,348.9**

Table 18
Wind Levelized Cost of Electricity – 25 x 2 MW Farm

Technology	Wind			
Rated Capacity, MW net	50			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Capacity Factor, %	21.6	27.4	37.2	46.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	365.5	287.0	210.8	170.8
Capital (ZAR/MWh)	2442.2	1917.4	1408.4	1140.8
LCOE (ZAR/MWh)	**2,807.7**	**2,204.4**	**1,619.2**	**1,311.5**

Table 19
Wind Levelized Cost of Electricity – 50 x 2 MW Farm

Technology	Wind			
Rated Capacity, MW net	100			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Capacity Factor, %	21.6	27.4	37.2	46.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	368.0	291.8	214.8	173.6
Capital (ZAR/MWh)	2372.1	1880.9	1384.5	1119.1
LCOE (ZAR/MWh)	**2,740.0**	**2,172.7**	**1,599.3**	**1,292.7**

Table 20
Wind Levelized Cost of Electricity – 100 x 2 MW Farm

Technology	Wind			
Rated Capacity, MW net	200			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Capacity Factor, %	21.6	27.4	37.2	46.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	371.2	294.9	217.3	175.7
Capital (ZAR/MWh)	2346.7	1864.6	1374.1	1110.8
LCOE (ZAR/MWh)	**2,717.8**	**2,159.6**	**1,591.4**	**1,286.5**

Table 21
Solar Thermal Parabolic Trough Levelized Cost of Electricity

Solar Thermal Technology	Parabolic Trough				
Rated Capacity, MW net	125				
Hours of Storage	0	3	6	9	12
Capacity Factor, %	25.6	32.5	38.0	45.6	53.9
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	501.3	405.6	356.0	304.3	267.1
Capital (ZAR/MWh)	4,702.9	4,984.8	5,259.1	5,371.9	5,447.2
LCOE (ZAR/MWh)	**5,204.1**	**5,390.4**	**5,615.1**	**5,676.1**	**5,714.3**

Table 22
Solar Thermal Central Receiver Levelized Cost of Electricity

Solar Thermal Technology	Central Receiver				
Rated Capacity, MW net	125				
Hours of Storage	0	3	6	9	12
Capacity Factor, %	29.3	39.5	51.0	60.3	69.7
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	402.3	307.2	248.1	215.8	191.6
Capital (ZAR/MWh)	4,040.6	3,659.9	3,485.9	3,340.6	3,230.7
LCOE (ZAR/MWh)	**4,442.9**	**3,967.1**	**3,734.0**	**3,556.4**	**3,422.3**

Table 23
Thin Film CdTe Levelized Cost of Electricity – Fixed Tilt

Solar PV Technology	**Cape Town**				**Johannesburg**			
Rated Capacity, MW	0.25	1.0	1.0	10.0	0.25	1.0	1.0	10.0
Mounting Location	Rooftop (0^o tilt)	Rooftop (0^o tilt)	Ground (latitudinal tilt)	Ground (latitudinal tilt)	Rooftop (0^o tilt)	Rooftop (0^o tilt)	Ground (latitudinal tilt)	Ground (latitudinal tilt)
Capacity Factor, %	16.6	16.6	18.5	18.5	17.2	17.2	19.1	19.1
Fuel Cost, (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	176.1	176.7	178.3	178.3	170.2	170.7	172.5	172.5
Capital (ZAR/MWh)	6,547.7	5,012.5	3,416.5	3,372.6	6,327.5	4,844.1	3,304.8	3,262.5
LCOE (ZAR/MWh)	**6,723.9**	**5,189.2**	**3,594.8**	**3,550.9**	**6,497.8**	**5,014.7**	**3,477.3**	**3,435.0**

Table 24
Thin Film CdTe Levelized Cost of Electricity – Tracking

Solar PV Technology	**Cape Town**				**Johannesburg**			
Rated Capacity, MW	1.0	10.0	1.0	10.0	1.0	10.0	1.0	10.0
Mounting Location	Single Axis	Single Axis	Double Axis	Double Axis	Single Axis	Single Axis	Double Axis	Double Axis
Capacity Factor, %	22.4	22.4	24.1	24.1	23.1	23.1	24.9	24.9
Fuel Cost, (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	157.3	157.3	161.0	161.0	152.1	152.1	155.8	155.8
Capital (ZAR/MWh)	3,376.0	3,339.5	3,487.2	3,453.3	3,265.7	3,230.4	3,375.3	3,342.5
LCOE (ZAR/MWh)	**3,533.2**	**3,496.7**	**3,648.2**	**3,614.2**	**3,417.9**	**3,382.5**	**3,531.0**	**3,498.2**

Table 25
c-Si Levelized Cost of Electricity – Fixed Tilt

Solar PV Technology	**Cape Town**				**Johannesburg**			
Rated Capacity, MW	0.25	1.0	1.0	10.0	0.25	1.0	1.0	10.0
Mounting Location	Rooftop (0^{o} tilt)	Rooftop (0^{o} tilt)	Ground (latitudinal tilt)	Ground (latitudinal tilt)	Rooftop (0^{o} tilt)	Rooftop (0^{o} tilt)	Ground (latitudinal tilt)	Ground (latitudinal tilt)
Capacity Factor, %	17.2	17.2	19.3	19.3	17.8	17.8	19.9	19.9
Fuel Cost, (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	169.6	169.2	151.7	158.1	163.9	163.5	146.8	163.5
Capital (ZAR/MWh)	6,200.0	4,699.6	2,835.0	2,706.1	5,991.7	4,541.6	2,742.3	2,797.5
LCOE (ZAR/MWh)	**6,369.6**	**4,868.8**	**2,986.7**	**2,864.3**	**6,155.6**	**4,705.1**	**2,889.1**	**2,961.0**

Table 26
c-Si Levelized Cost of Electricity – Tracking

Solar PV Technology	**Cape Town**				**Johannesburg**			
Rated Capacity, MW	1.0	10.0	1.0	10.0	1.0	10.0	1.0	10.0
Mounting Location	Single Axis	Single Axis	Double Axis	Double Axis	Single Axis	Single Axis	Double Axis	Double Axis
Capacity Factor, %	23.4	23.4	25.1	25.1	24.1	24.1	26.0	26.0
Fuel Cost, (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	143.9	143.9	148.0	148.0	139.3	139.3	143.2	143.2
Capital (ZAR/MWh)	2,719.8	2,688.4	2,764.7	2,735.6	2,631.0	2,600.6	2,676.0	2,647.8
LCOE (ZAR/MWh)	**2,863.7**	**2,832.4**	**2,912.7**	**2,883.7**	**2,770.2**	**2,739.8**	**2,819.3**	**2,791.0**

Table 27
CPV Levelized Cost of Electricity

Technology	CPV
Rated Capacity, MW	10.0
Capacity Factor, %	22.8
Fuel Cost (ZAR/MWh)	0.0
O&M (ZAR/MWh)	163.5
Capital (ZAR/MWh)	3,660.2
LCOE (ZAR/MWh)	**3,823.7**

Table 28
Biomass Levelized Cost of Electricity

Biomass Technology	Forestry Residue	MSW	Landfill Gas	Biogas
Rated Capacity, MW Net	25	25	5	5
Capacity Factor, %	85	85	85	85
Fuel Cost (ZAR/MWh)	516.0	2.6	41.2	40.2
O&M (ZAR/MWh)	325.7	1,109.8	429.3	351.1
Capital (ZAR/MWh)	1,649.1	3,155.8	637.6	1,580.6
LCOE (ZAR/MWh)	**2,490.8**	**4,268.2**	**1,108.1**	**1,971.9**

Table 29
Energy Storage Levelized Cost of Electricity

Technology	Li-ion	Li-ion	CAES
System Size, MW	3	3	180
Storage Capacity, hrs	1	3	8
Fuel Cost (ZAR/MWh)	0.0	0.0	285.5
Charging Cost (ZAR/MWh)	1,382.8	1,382.8	919.3
O&M (ZAR/MWh)	2,327.2	778.1	88.1
Capital (ZAR/MWh)	4,944.7	3,980.4	1,445.5
LCOE (ZAR/MWh)	**8,654.7**	**6,141.3**	**2,738.5**

The following figures provide a comparison of the levelized costs of electricity from this study and a comparison of the 2012 and 2015 total plant costs (TPC). The capital estimates were developed for each technology based on U.S. conditions. These baseline cost estimates were then adjusted to the cost of construction in South Africa using the adjustment factors developed for South African market conditions. These costs were converted to ZAR using the exchange rate of 13.57 ZAR to 1 US Dollar. This represents a significant strengthening of the US dollar relative to the South African Rand since the 2012 Study. The effect of the exchange rate and the escalation in costs resulted in a pronounced increase in the capital cost estimates for 2017 vs. 2012.

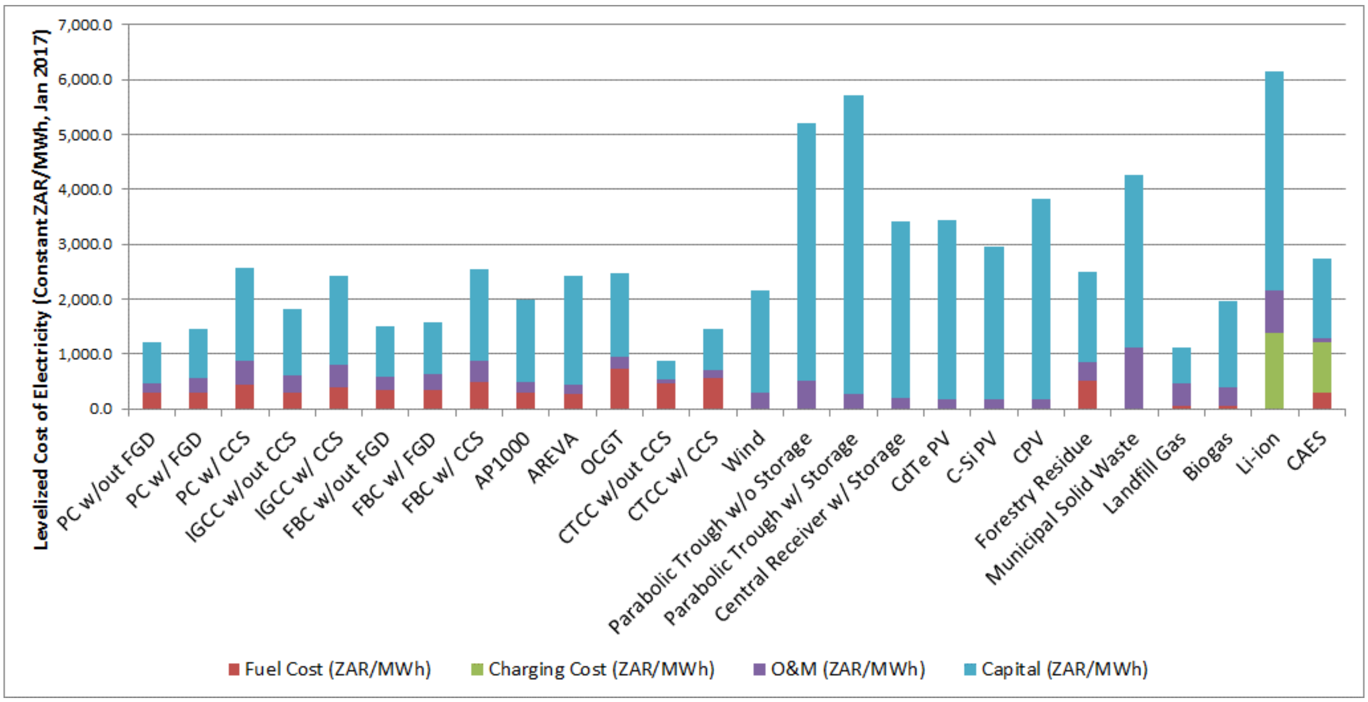


Figure 1
Comparison of Representative Levelized Cost of Electricity Results

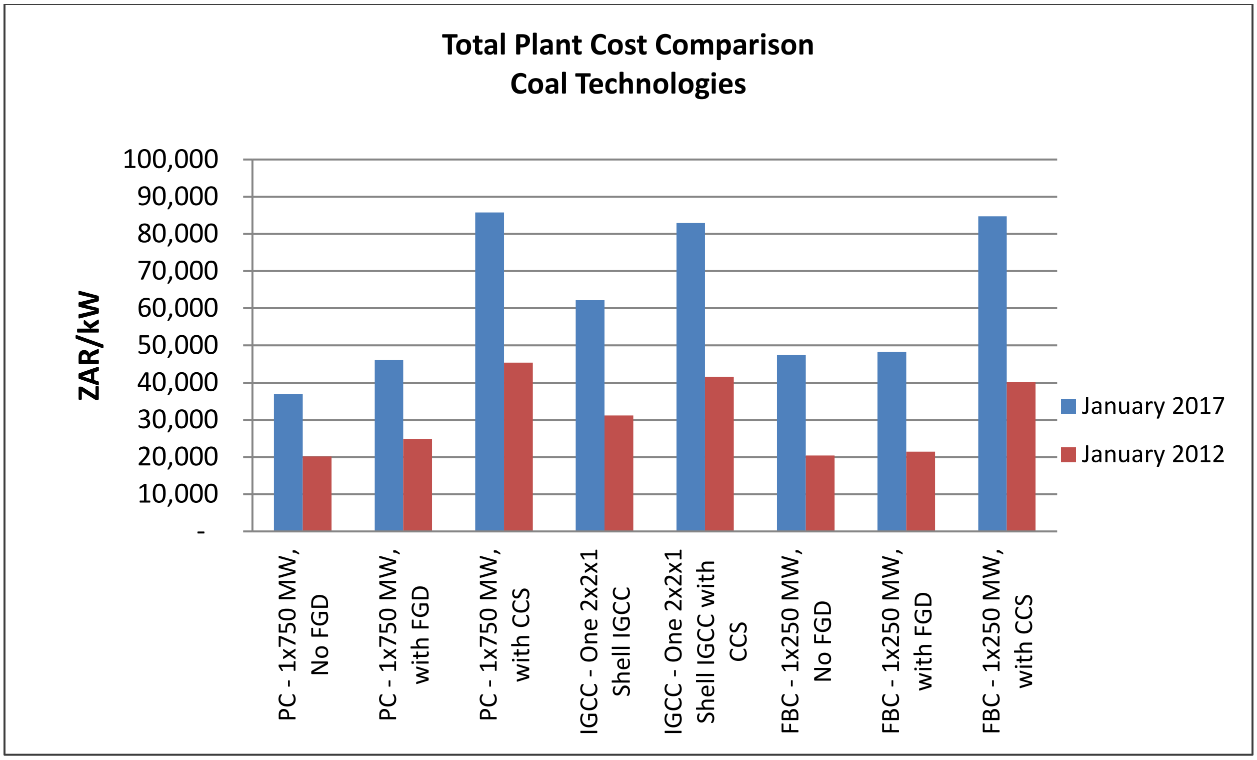


Figure 2
TPC Comparison for Coal Technologies

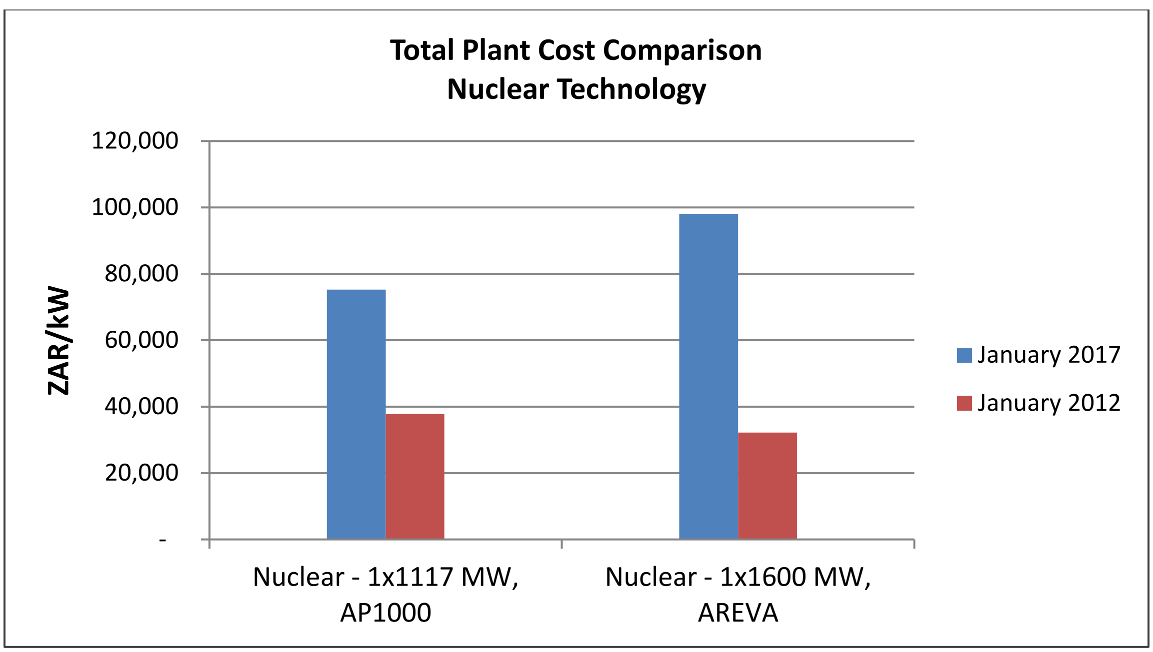


Figure 3
TPC Comparison for Nuclear Technology

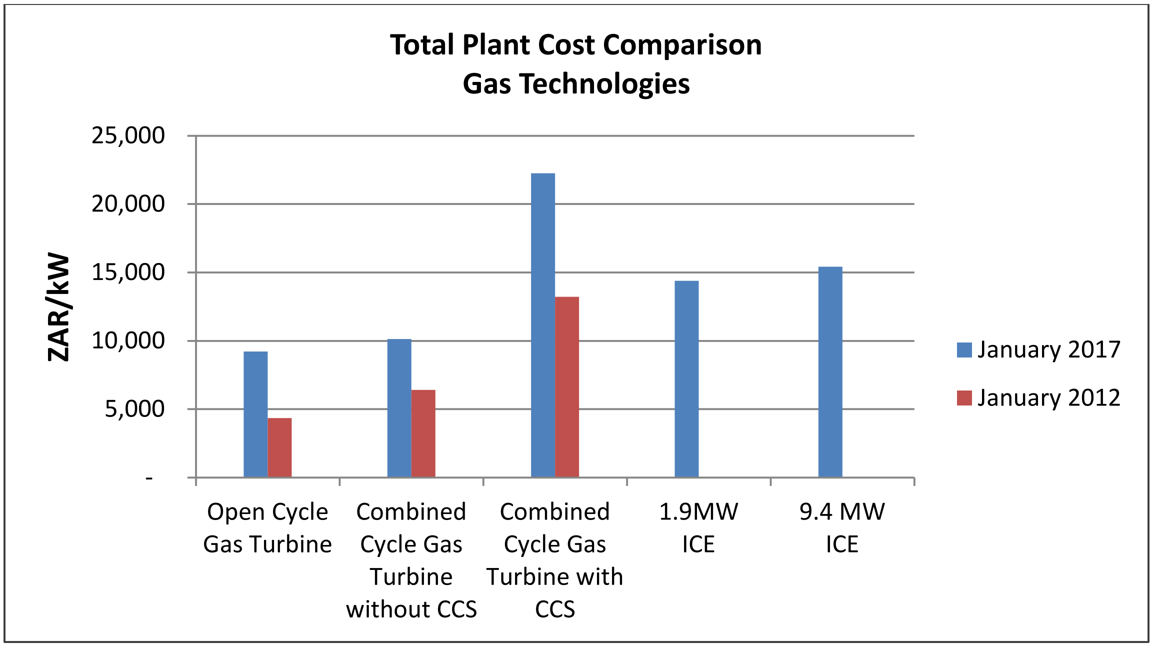


Figure 4
TPC Comparison for Combustion Turbine Technology

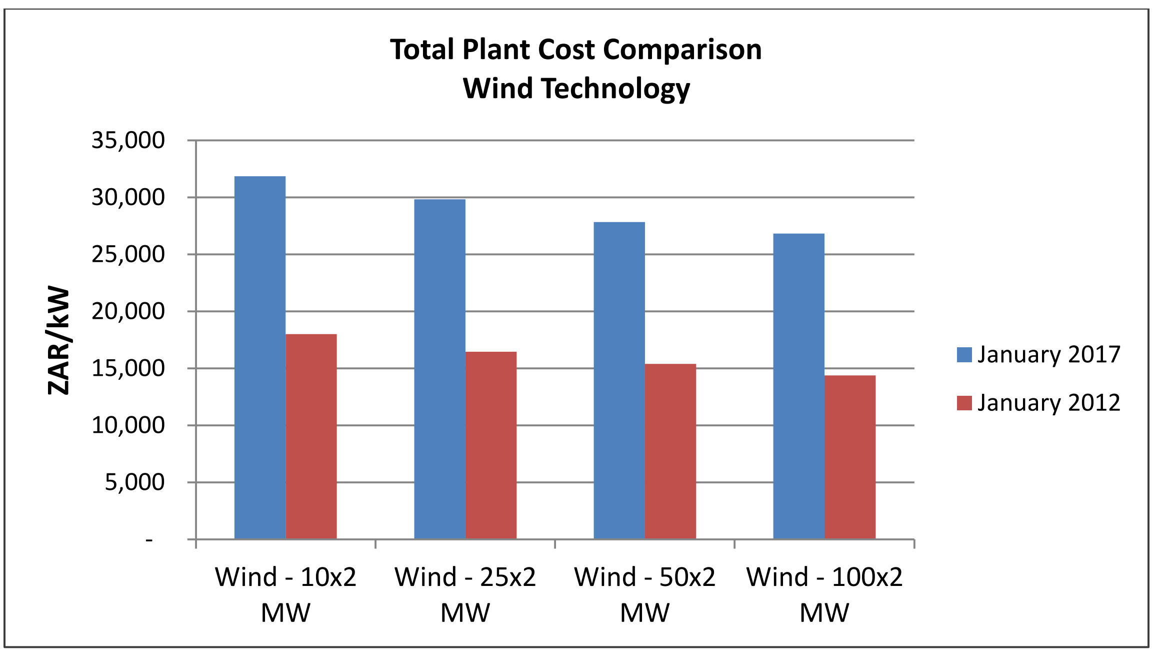


Figure 5
TPC Comparison for Wind Technology

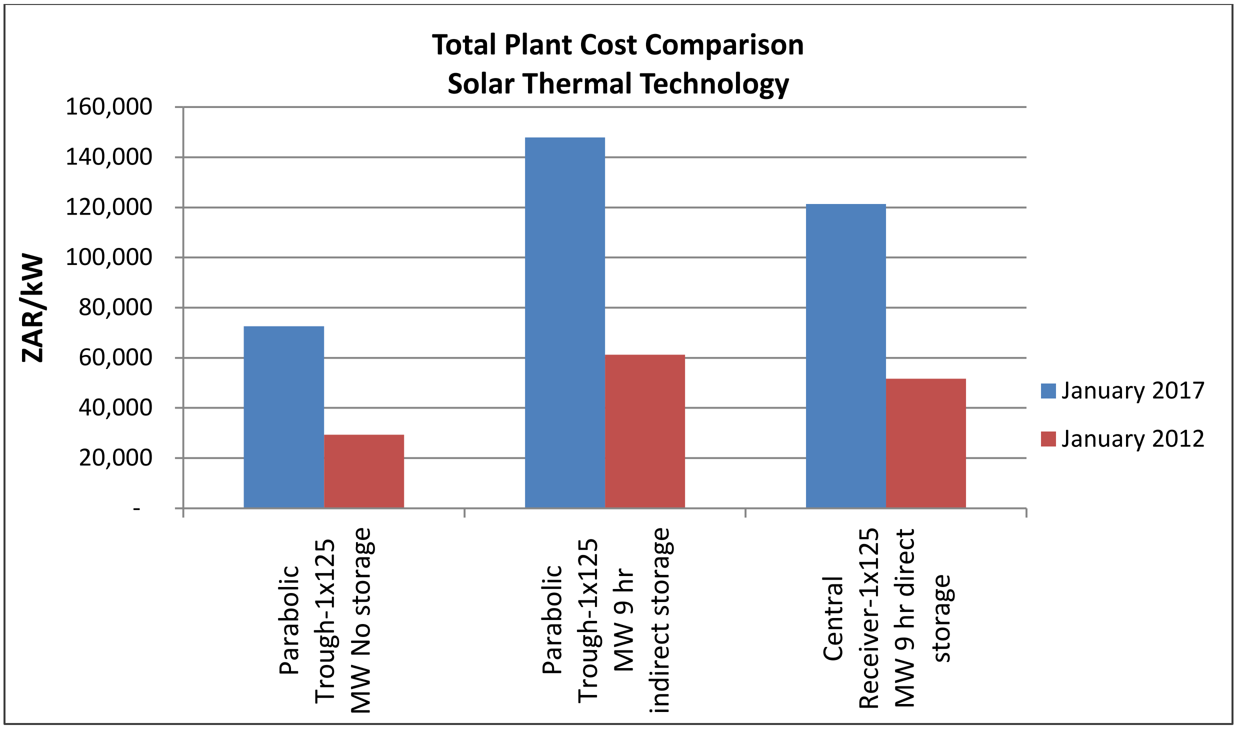


Figure 6
TPC Comparison for Solar Thermal Technology (125 MW)

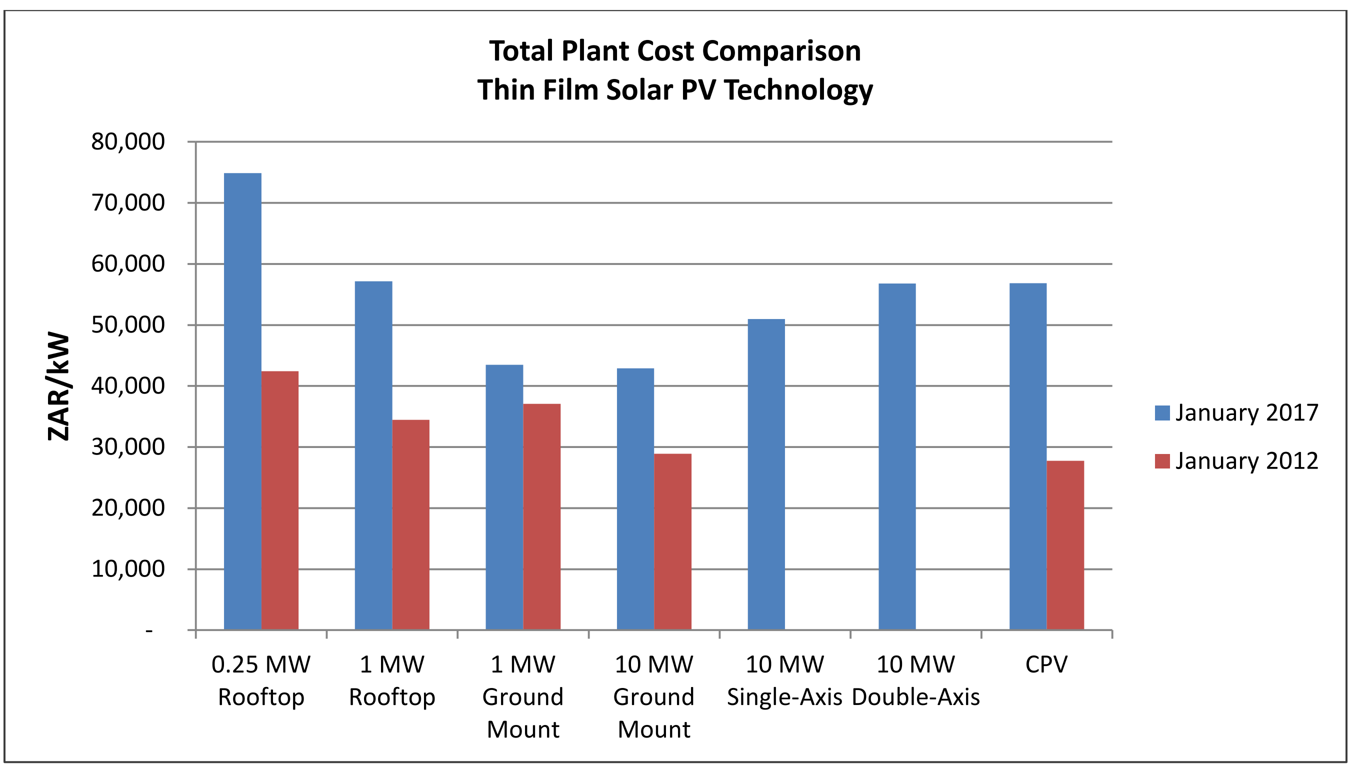


Figure 7
TPC Comparison for Solar PV Technology

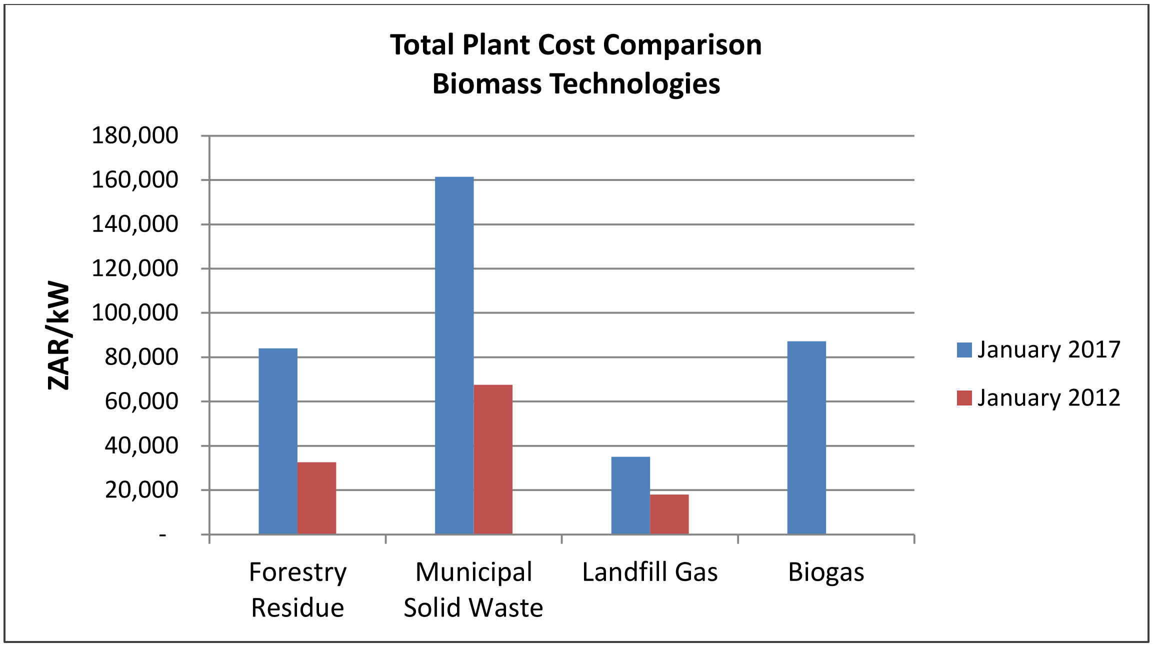


Figure 8
TPC Comparison for Biomass Technologies

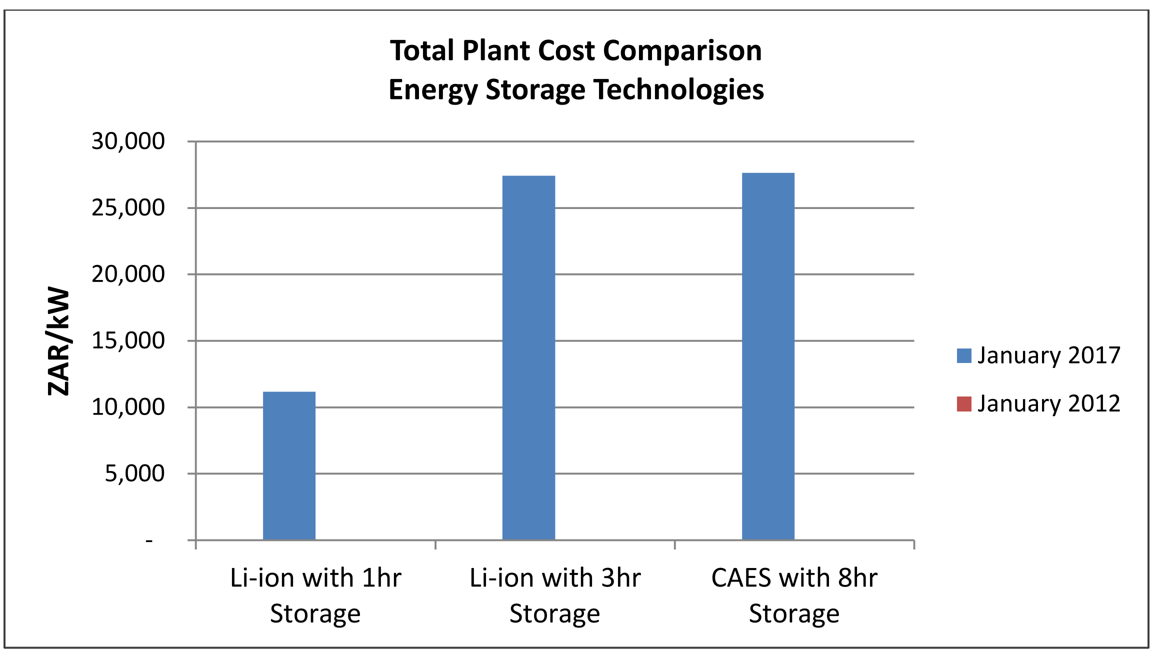


Figure 9
TPC for Energy Storage Technologies

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

Introduction

EPRI developed power generation technology data for new power plants that was included in South Africa's 2010 and 2012 IRPs. This report updates the technology data of the 2012 study to 2015 costs. This technical update incorporates technology enhancements, market factor impacts, and improvements to design and cost estimate basis. The scope of this report includes capital cost, operations and maintenance (O&M) cost, and performance data. A comprehensive discussion and description of each technology also is presented. Costs are reported in January 2017 South African Rand.

In this report, technology data are customized to South African conditions and environment. The estimates are developed based on a compilation of existing U.S. and international databases and adjustments based on third-party vendor indices and EPRI in-house expertise. Adjustments are made based on estimates of South African conditions in the following areas:

- Skilled labor availability
- Fabrication and manufacturing capability for plant components
- Labor productivity
- Equipment and material transportation cost
- Expatriate skilled labor, supervision and management requirement

While the above areas are taken into consideration, they are not broken down and shown as individual components in the estimates. Tariffs imposed by the South African government on imported labor, equipment, and materials are not included in the estimates.

Conventional power plants have continued to see a modest escalation in costs since the end of the Great Recession. Meanwhile, the costs of some renewable technologies, most notably PVs, have continued to decline as developers expand production and utilities increase installed capacity.

The cost and performance estimates included in this report are based on conceptual level of effort idealized for representative generating units at appropriate South Africa locations and have been normalized where possible to produce a consistent database. However, site-specific and company-specific conditions dictate design and cost variations that require a much higher level of effort and is not reflected here.

In developing these estimates, an effort was made to forecast probable capital expenditures associated with commercial-scale technology projects. Cost estimating is, however, part science and part art; it relies heavily on current and past data and on project execution plans, which are based on a set of assumptions. The successful outcome of any project—project completion within the cost estimate—depends on adherence to an execution plan and the assumptions without deviation. These estimates represent the ongoing technology monitoring effort at EPRI to update the current Technical Assessment Guide (TAG®) database and information. EPRI's TAG® Program has been providing cost and performance status and market trends of power generation technologies for over three decades and is considered a reliable source of data for future capacity planning by U.S. industry personnel as well as by regulators involved in the resource planning and approval process.

Objectives

EPRI has developed cost and performance estimates for the following power plant technologies based on South African conditions and environments:

- PC
- Integrated coal gasification combined cycle
- FBC
- Nuclear
- CCGT
- OCGT
- Internal combustion engine (ICE)
- Wind
- Parabolic trough with and without storage
- Central receiver with direct storage
- Thin film solar PV
- Crystalline silicon (c-Si) PV
- Concentrating PV
- Biomass/MSW/Landfill Gas/Biogas
- Methane production from biogas (overview only due to lack of design and cost data)
- Synthesis gas production from UCG (overview only due to lack of design and cost data)
- Batteries
- Compressed air energy storage (CAES)

The design conditions pertaining to a location for a power plant generally dictate the performance and cost of the power plant based on a specific technology. EPRI has historically developed an annual database of technology cost and performance estimates for a number of U.S. locations. Using adjustment factors comparing U.S. and South African conditions for labor, material, and equipment costs, as well as ambient conditions and resource availability, EPRI developed estimates for these technologies for South Africa.

For each technology listed above, EPRI developed cost estimates of plant construction, operation and maintenance (O&M), and fuel. The plant's performance, water and sorbent usage, and emissions were also estimated. From these results, EPRI developed levelized cost of electricity estimates. This report also includes a section discussing the issues surrounding the integration of renewable technologies and their inherent intermittency with the existing electrical grid.

Task Descriptions

EPRI performed the following tasks to develop the cost and performance estimates presented in this report.

Establish the Design Basis

The first step in this evaluation was to establish the technical parameters of the various power generation technologies including the location of the power plant, the ambient conditions at that site, the fuel characteristics or resource potential, and the generating unit size.

Develop Cost Adjustment Factors

EPRI's subcontractor, WorleyParsons, developed cost adjustment factors to adjust existing EPRI data from US Gulf Coast to South African costs. Factors considered included the following:

- Skilled labor availability
- Fabrication and manufacturing capability for plant components
- Labor productivity
- Equipment and material transportation cost
- Expatriate skilled labor, supervision and management requirement
- Design and engineering labor requirement
- Develop baseline capital cost estimates

Develop Baseline Capital Cost Estimates

Baseline cost estimates were developed for each technology and modified where appropriate using in-house models and data. A mutual definition of project cost boundaries was established in the Design Basis to allow capital costs to be estimated consistently. Equipment, material, and installation costs were based on EPRI's information and databases, not solicited through data requests from third-party vendors. These baseline estimates were prepared for U.S. conditions.

Develop Baseline O&M Cost Estimates

Baseline O&M estimates were developed for each technology and modified where appropriate based on in-house models and data were divided into fixed and variable components.

Revise Baseline Capital and O&M Estimates

Using the adjustment factors developed for South African market conditions, the capital and O&M cost estimates were adjusted to South African costs and summarized.

Develop Performance Parameters

Performance parameters were developed for the technologies included in this evaluation based on in-house data and adjusted to the South African conditions established in the Design Basis. Performance parameters included net plant output and heat rate, auxiliary power consumption, plant availability, water usage, sorbent usage, and plant emissions.

Develop Levelized Cost of Electricity Estimates

The constant dollar levelized cost of electricity for each technology was estimated using EPRI's TAGWeb® software. Financial parameters for the cost of electricity evaluation were chosen for illustrative purposes. The cost of electricity evaluations are broken down into capital, O&M, and fuel cost components.

Estimate Result Uncertainties

Uncertainties exist both in the baseline U.S. estimates as well as in the adjustment factors used to develop South African cost and performance estimates. An analysis of the uncertainty surrounding these factors using Monte Carlo simulation is included in this report.

Perspective: Technology Life-Cycle Analysis and Learning Curve

Power generation technology components are complex and capital intensive, thus it is important to understand the "life cycle" of the technologies and the learning curve aspect. Power generation technologies have varying degrees of integration of a few technology components. Through the operating years, these technologies mature and, to maintain competitiveness and market requirements, components of the aging plant have to be replaced or a new plant has to be built. Regulatory requirements also may require the addition of new components, such as environmental controls.

The following technology life-cycle/learning curve charts give an overview of the business aspects of technology in the industry. This is nothing new in a free-market-based industry where a company's performance is based on making the right technology choice at the right time. However, many companies in the electric power industry, in transition from a regulated to a partially deregulated arena, are faced with the dilemma of implementing new technologies that require high capital investment.

Technology performance becomes a key issue in new technology implementation along with fuel price, market demand for electricity, and electricity price. For example, when natural gas was in the \$2- to \$3-per-million Btu range and the market price for electricity was strong, the low capital cost of combustion turbines seemed like a sure bet with a quick return on investment and profits. This view held even with high heat rates and low capacity factor. However, with an increase in natural gas prices combined with a decline in demand for electricity and price, several combustion turbines were shut down, unable to meet the lower market price for electricity. The lower market price for electricity was supported by the older, inefficient coal-fired power plants and, as illustrated in the charts, they were "cash cows." The environmental controls requirement on these older plants may or may not change the situation very much.

Informed planning should consider the factors affecting a generation technology over each stage of its life cycle. Life-cycle analysis provides a long-term perspective on a technology's technical and economic viability with respect to factors such as technology performance, fuel availability and costs, regulatory climate, emission controls, and land and water issues. As shown in the following figures, this perspective can help planners assess the risk/return and capital requirements associated with different generation technologies over their life cycles in the context of their existing operating fleet as well as in the planning of new plants.

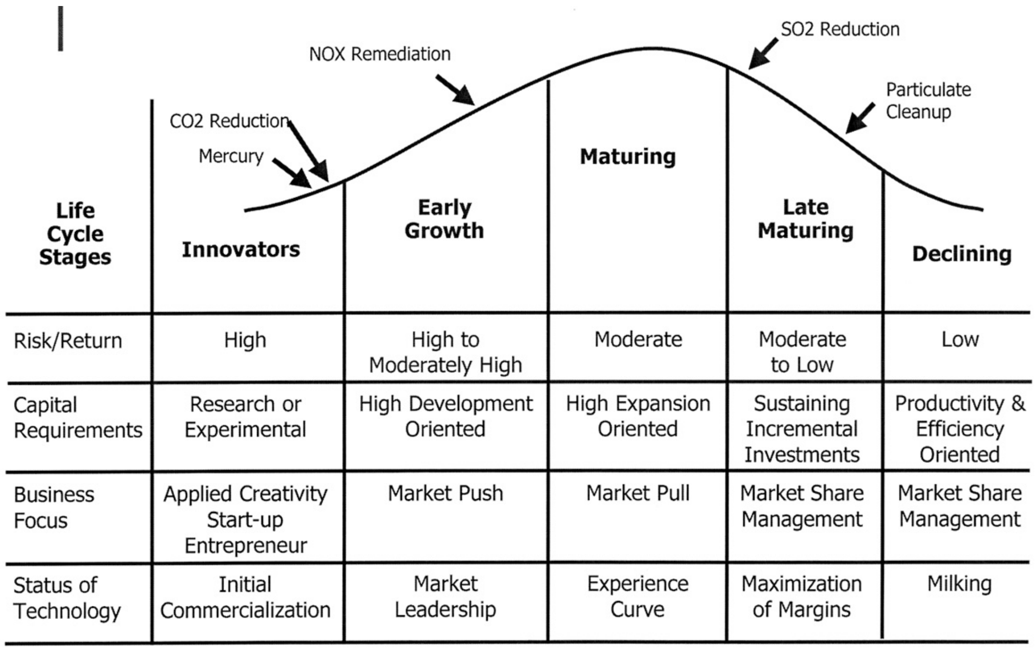


Figure 1-1
Life-Cycle Analysis: Environmental Actions

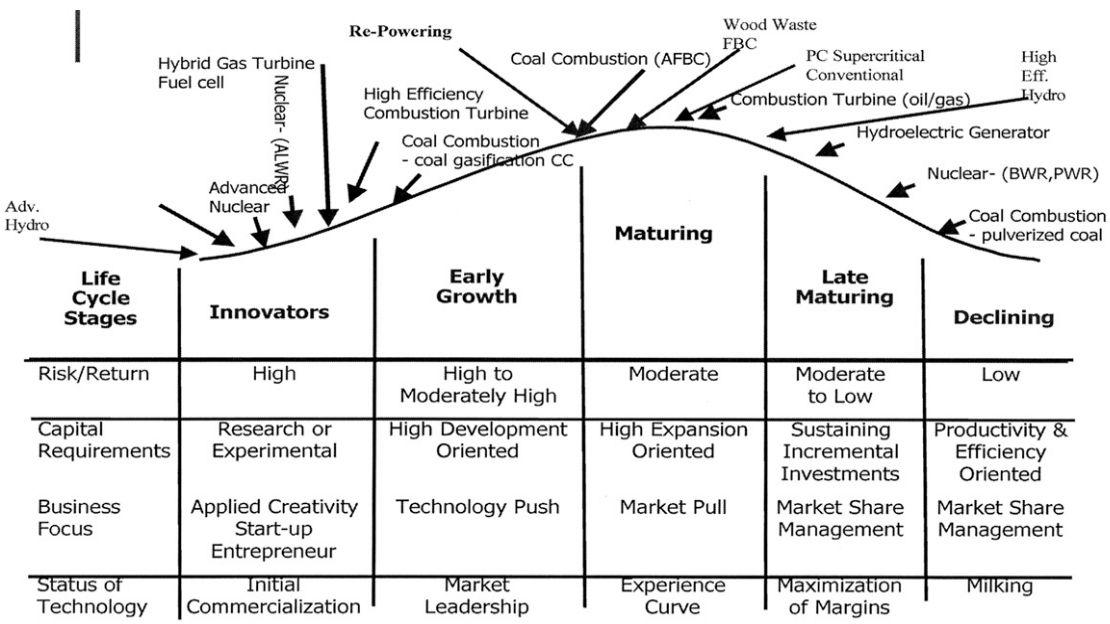


Figure 1-2
Life-Cycle Analysis: Generation Technology Options

2
BACKGROUND AND GENERAL APPROACH

Introduction

A comprehensive list of coal, nuclear, gas, and renewable technologies was selected for the overall evaluation. These are shown in Tables 2-1 to 2-4.

For all of the technologies selected, the cycle configurations, equipment included, and materials used are currently available and used commercially in power plant systems. These technologies do not represent projected potential advancements over currently available systems. Due to shortages of water availability throughout South Africa, each of these technologies, with the exception of nuclear, was configured with air cooling of the condensers and auxiliary equipment to minimize water consumption. The nuclear plant is assumed to use once-through cooling by sea water. Coal plants were evaluated both with and without consideration of CO_2 capture. Pulverized coal plants were evaluated both with and without flue gas desulfurization (FGD) units for control of sulfur emissions.

Estimates were developed based on existing U.S. cost and performance estimate data. These estimates were then adjusted to South African conditions via the use of adjustment factors developed by EPRI and its subcontractor, WorleyParsons, who has offices in both the US and South Africa.

Table 2-1
Coal Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
PC		
Without FGD	1, 2, 4, 6 x 750 MW	Mine-mouth at 1800 m elevation
With FGD	1, 2, 4, 6 x 750 MW	Mine-mouth at 1800 m elevation
IGCC	1, 2 x 500-800 MW	Mine-mouth at 1800 m elevation
FBC		Mine-mouth at 1800 m elevation
Without limestone	1, 2, 4, 6 x 250 MW	Mine-mouth at 1800 m elevation
With limestone for in-bed sulfur removal	1, 2, 4, 6 x 250 MW	Mine-mouth at 1800 m elevation

Table 2-2
Nuclear Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Nuclear (with seawater cooling)		
AP1000	1, 2, 4, 6 x 1,115 MW	Coastal, near Port Elizabeth or north of Cape Town
Areva EPR	1, 2, 4, 6 x 1,600 MW	Coastal, near Port Elizabeth or north of Cape Town

Table 2-3
Gas Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
CCGT	500-800 MW	Coastal, LNG based
OCGT	100-190 MW	Coastal, LNG based
ICE	2 MW	Coastal, LNG based

Table 2-4
Renewable Technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Wind	20, 50, 100, 200 MW	Coastal
Parabolic Trough		
Without storage	125 MW	Upington
With indirect storage	125 MW	Upington
Central Receiver		
With direct storage	125 MW	Upington
PVs		
Thin Film – rooftop	0.25, 1 MW	Johannesburg and Cape Town
Thin Film – ground mounted	1, 10 MW	Johannesburg and Cape Town
C-Si – rooftop	0.25, 1 MW	Johannesburg and Cape Town
C-Si – ground mounted	1, 10 MW	Johannesburg and Cape Town
Concentrating	10 MW	Upington
Biomass		
Forestry Residue	25 MW	Eastern coast
MSW	25 MW	Major cities
Landfill Gas Engines	5 MW	Major cities

Table 2-5
Storage Technologies

Technology Type	Rated Capacity, MWe	Assumed Location
Batteries	3 MW	Major cities
Compressed Air Storage	180 MW	To be determined based on site testing

3
DESIGN BASIS

Introduction

This section provides a guideline of the assumptions made when assessing the various power generation technologies examined in this study. It outlines the technical parameters of the plants, characterizes the site conditions, and establishes fuel properties and emissions criteria, where applicable. Establishing a clear design basis makes it possible to compare costs and performance for a range of technologies in a consistent manner.

For all technologies included in this study, minimal site clearance and preparation is assumed and no provision is made for new infrastructure or improvements to existing infrastructure, such as roads, transmission lines, etc., as these are quite specific and design requirements can vary from one location to another.

Coal Technologies

Location

The site location chosen for the coal plants in this study is a generic Greenfield site in northern South Africa near Matimba, 50 km southeast of the Botswana border. The site is assumed to be mine mouth, removing the need for a nearby railroad for fuel delivery purposes. For all technologies, the primary assumption is that dry cooling systems are necessary and, therefore, no assumption was made about the site's proximity to a raw water supply.

Ambient Conditions

The annual average ambient air conditions for northern South Africa used for the coal technologies in this study are listed below.

Dry bulb temperature	32.2°C
Atmospheric pressure	0.81 bar
Equivalent altitude	1800 m

Duty Cycle

The coal plants in this study are all base load units. Base load units are characterized by high availability and high efficiency, but generally have less flexibility in their output and are less efficient under part-load conditions, thus minimizing their use as load-following units. A capacity factor of 85% is assumed for all of the base load coal units. The plant technical parameters for the coal plants are shown in Table 3-1.

Table 3-1
Coal Plant Technical Parameters

	Turndown	Cycling Capability Start-up to Full Load	Ramp rates
Ultra Supercritical PC	Minimum boiler load: 25-30%	Very hot start-up: < 1h Hot start-up: 1.5 to 2.5 h Warm start-up: 3 to 5 h Cold start-up: 6 to 7 h	30-50% load: 2-3% / min 50-90% load: 4-8% / min 90-100% load: 3-5% / min
IGCC	40-50% of MCR	Ambient start-up: 36 h Hot start-up: 4 h	50-100% load: 3% / min
FBC	40% of MCR	See below	

With regards to the FBC plants, the water/steam cycles of the FBC units are typically similar to those of the PC units, which would suggest that the FBC units would have the same load following capability as the PC units. However, typical FBC's fuel feed and combustion systems are different from a PC units design and therefore would require supplementary fuel to maintain minimum load below 40% MCR.

In terms of cycling, FBC units are somewhat susceptible to refractory damage, and thus it is advantageous to keep the bed temperature as close to the operating range as possible as well as avoid long cooling off periods between runs.

Additional design features can be incorporated accommodate more flexible operation regimes. For example, Foster Wheeler offers an optimized reheat steam bypass system for temperature control during start-up and shut-down. That design also includes in duct and over grid start up burners.

For IGCC, Figure 3-1 shows a typical ambient start schedule with the following assumptions:

- All utilities such as electricity, instrument air, cooling water and steam are available.
- It is assumed that the ASU for a plant designed for ramping duty would have liquid manufacturing capability, so that stored liquid would be available to achieve an accelerated cool down (1-2 days). Note that Figure 3-30 shows 36 hours
- It is assumed that the plant incorporates a rapid response turbine that can be started on natural gas and switched to syngas once that becomes available
- The timing for the gasifier pre-heat as shown is for a membrane wall gasifier. The 4 hours indicated is actually generous for this activity. Note that for a refractory lined gasifier, a 24-36 hour pre-heat duration, similar to the ASU, can be assumed. However, repeated temperature cycling from operation to ambient and back would cause such damage and reduced life to the refractory that it would not be chosen, if cycling operation were considered.
- The timing for cooling down the AGR depends on the type of AGR selected. An ambient system such as MDEA would not need any cooling down at all. Rectisol requiring cool down to -30°C would require longest.
- The SRU is maintained at temperature using the fuel gas burner. Generally, it would be normal practice to maintain the SRU furnace warm to avoid shutdown corrosion.

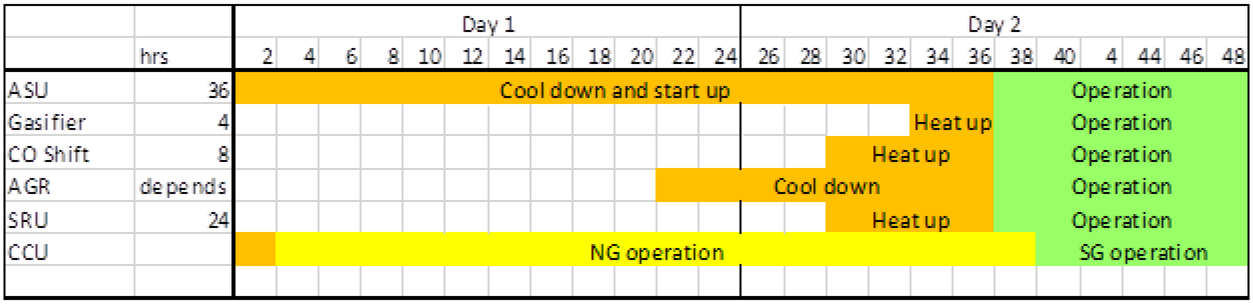


Figure 3-1
Typical Ambient Start Schedule for IGCC

Figure 3-2 shows a hot start schedule. There can be several definitions of a "hot start". For the purposes of this discussion, it is assumed that the plant has been shut down and depressurized, but maintained "ready-to-start" over a short period of time such as over-night. For such interruptions, the plant can be maintained at or near operating temperatures. For longer periods the utility cost of maintaining ready-to-start status is expected to be economically unattractive and is not considered under this heading. The hot start schedule is based on the following assumptions:

- All utilities such as electricity, instrument air, cooling water and steam are available.
- The ASU is boxed-in cold, but the air compressor is not running. Time to reach oxygen purity is about two hours.
- On the assumption of a membrane wall gasifier, the gasifier itself can have been allowed to cool down. (Note that while a refractory lined gasifier is capable of being maintained hot and "ready-to-start", it will in some cases be necessary on shut-down to replace the operating burner/feed injector with a pre-heat burner to maintain the ready-to-start status. On decision to start, the pre-heat burner would need to be replaced by the operation burner. This is expected to take about two hours. Such a procedure is typical of spare gasifiers in chemical operation. However, repeated temperature cycling from operation to ambient and back would cause such damage and reduced life to the refractory that it would not be chosen, if cycling operation were considered.)
- The gas treating sections are at close to (though not necessarily at) operating temperatures.
- The SRU is maintained at temperature using the fuel gas burner. Generally, it would be normal practice to maintain the SRU furnace warm to avoid shutdown corrosion.
- The combustion turbine is a rapid response machine which can start up on natural gas at short notice. The switch to syngas operation can be made in less than four hours.

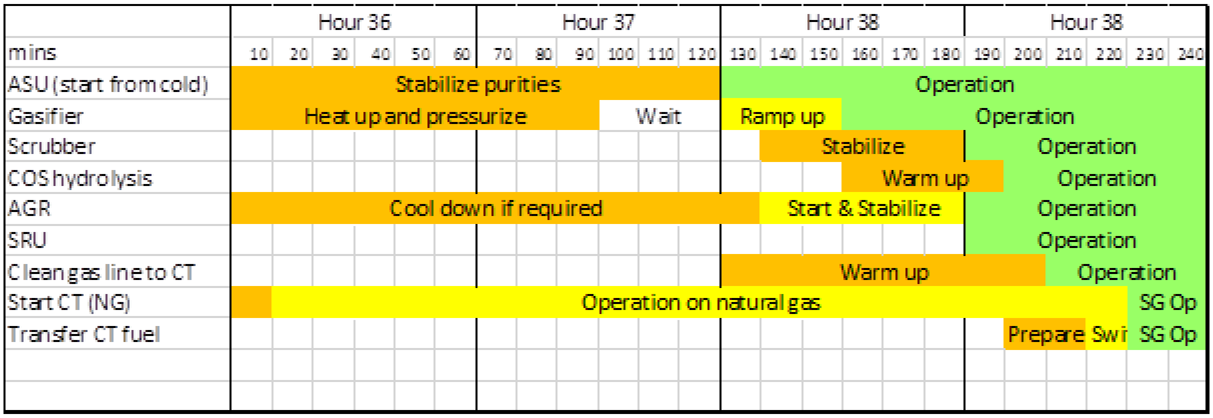


Figure 3-2
Typical Hot Start Schedule for IGCC

Generating Unit Size

The coal plants in this study are 250 MW and larger. The rated capacities of the PC units are 750 MW and were evaluated for stations consisting of one, two, four, and six units. The net capacity of IGCC plants and UCG combined cycle (UCGCC) plants is dictated by the size and type of GT used as a primary power generator for this technology. For the IGCC plants, each unit consists of two gasifiers, two GTs, and one steam turbine. IGCC plants were evaluated with one or two units. The FBC unit has a rated capacity of 250 MW and the plants are built up of one, two, four, and six 250-MW units. All plants considered generate electricity that is delivered to the local grid at a frequency of 50 Hz.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For example, the cost boundary for a steam plant includes all major parts of the unit, such as boiler and turbine generator, and all support facilities needed to operate the plant. These support facilities include fuel receiving/handling and storage equipment; emissions control equipment when included in the plant design; wastewater-treatment facilities; and shops, offices, and cafeteria. CO_2 compression equipment and energy penalties are included for plants with CO_2 capture, but the capital costs for the CO_2 pipeline and storage area for sequestration are not included.

The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines. The switchyard and transmission lines are generally influenced by transmission system-specific conditions and are therefore not included in the cost estimate. Though typically included within the cost boundary for EPRI estimates, the estimates included in this study do not include a railroad spur that these plants are mine mouth, thus negating the need for rail connections.

The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

Fuel Systems

The coal type considered for the coal plants in this study is high-ash bituminous coal. The characteristics and analysis of this coal is presented in Table 3-2. The plant sites are assumed to be mine mouth with conveyors delivering coal from the mine to the site. Coal storage is sized for 40-day storage.

Table 3-2
South African Coal Characteristics

Coal Composition	**Coal (As Received, wt %)**
Moisture	10.00
Carbon	46.92
Hydrogen	2.25
Nitrogen	1.05
Chlorine	0.00
Sulfur	0.83
Oxygen	7.79
Ash	31.16
Ash Mineral Analysis	
SiO_2	58.00
Al_2O_3	22.00
Fe_2O_3	3.80
TiO_2	1.80
P_2O_5	0.40
CaO	5.00
MgO	1.40
Na_2O	0.45
K_2O	0.79
SO_3	5.20
Unknown (by diff.)	1.16
Heating Value (As Received) - Calculated	
Higher MJ/kg (Btu/lb)	17.85 (7,673)
Lower MJ/kg (Btu/lb)	17.12 (7,363)

Resource Potential

South Africa’s coal reserves and resources were most recently detailed by the Council of Scientific and Industrial Research (CSIR)[1] at 194.4 billion tons, of which reserves are placed between 35 and 50 billion tons. The uncertainty on the reserve estimation stems from disparate views on which resources are economic to mine. In 2014, about 84% of South Africa’s primary energy needs are provided by coal[2].

In 2013, South African coal production amounted to 259.7 million tons[3]. Coal from South African mines is both consumed locally and exported. Coal exports (27% or 74.4 million tons in 2014) were largely to India (30.5 million tons) and the Netherlands (9.7 million tons). Export coal is generally cleaned to separate unwanted constituents, such as rocks and minerals, from the carbonaceous material, a process known as beneficiation. This process currently yields more than 70 MMtons/year of coal discards and has resulted in an accumulation of close to 1.5 billion tons based on a 2011 study[4].

If the business-as-usual approach to coal mining/utilization is maintained into the future, the highest quality coal will either be exported for sale on the world market or sold at a steep premium in South Africa to cover the opportunity cost of not selling to the overseas market. The demand for export coal is expected to grow, while the supply of the highest quality coal will not increase due to the degradation of coal quality at existing mines. The opening of new mines may mitigate the loss in coal quality, depending on the makeup of the seam and the split between export and in-country use. In addition to the pressure from the export coal market, previous experience in South Africa has shown that either the yield or the quality of the coal from the mine declines over the life of the project. Consequently, it can be expected that the quality of average coal consumed will decrease over a period of time.

A potential source of solid fuel is the large stores of “discard coal” that have been produced by coal beneficiation processes over a number of years. These processes upgrade South African coal for the export market, but also leave behind a high ash waste pile. This accumulated discard coal could potentially fuel power plants that are specifically designed for this quality of coal. However, a power plant designed to operate on this low grade fuel would be more expensive to build than one operating on minemouth coal, and thus far, the price differential between conventional coal resources and the discard coal has not been sufficient to justify building the more expensive design. Nevertheless, as conventional coal quality continues to decline, and if coal prices continue to increase, the discard coal may become a cost-effective fuel source.

Use of discard coal would probably require FBC technology given the relatively poor quality of the fuel. FBC plants may capture up to 80% of the coal-bound sulfur in the fluidized bed with injection of a sorbent. This technique will allow for sulfur capture without increasing plant water consumption, unless greater than 80% capture will be needed. At that point, a wet scrubber may be needed to get the remaining sulfur out of the flue gas and plant water consumption will increase slightly.

[1] CSIR Bulletin no. 113

[2] Bloomberg New Energy Finance, 2015. Electricity Mix by Capacity, Country Profile of South Africa

[3] Chamber of Mines, 2015

[4] “Potential and Technical Basis for Utilizing Coal Beneficiation Discards in Power Generation b Applying Circulating Fluidized Bed Boilers Lloyd”. Belaid, Mohamed; Falcon, Rosemary; Vainikka, Pasi; and Kamohelo V. Patsa, June 2013.

Other Factors

Emissions Criteria

The PC units in this study were evaluated both with and without a flue gas desulphurization (FGD) unit for sulfur dioxide removal and FBC units were evaluated with and without limestone for in-bed sulfur capture. IGCC technologies must include acid gas removal for sulfur capture to protect the GTs and, therefore, were only evaluated with sulfur removal. In all cases, a limestone forced oxidation system wet scrubber achieving 95% removal of inlet SO_2 was the FGD technology of choice. South African limestone deposits located in the Northern Cape Province are assumed to be able to adequately supply the needs of the wet FGD systems via traditional transportation methods of truck or by rail car. As ESKOM moves forward with specific plant locations and plant designs, the availability of high quality limestone and appropriate transportation needs will need to be confirmed.

A recent study[5] completed by Andover Technology Partners and JLM Environmental Consulting indicates that based on a thorough review of operating data from US power plants, the addition of a scrubber minimally increases the heat rate. When taking the full population of scrubbed and unscrubbed units, the study did not indicate a significant difference

CO_2 Capture and Storage

Coal technologies are evaluated both with and without CO_2 capture in this study. All technologies that include CO_2 capture have a capture rate of 85-90%. For PC and FBC plants with carbon capture, the plant design basis also includes a FGD for sulfur control. In keeping with previous editions of this report and the strong, site specific nature of the storage costs associated with CO_2 capture and storage, the CO_2 pipeline and storage area for sequestration are not included in these capital cost estimates.

Dry Cooling

Due to limited water supply in South Africa, dry cooling systems are necessary for all coal plant units.

Ash Handling

Due to water supply conditions in South Africa, ash removal is handled dry.

Nuclear Technologies

Location

Nuclear plants will be located on the coast of South Africa so that they can utilize once-through cooling with sea water. New nuclear units would be located either at the existing nuclear station at Koeberg or on the southern coast about 50 to 100 km west of Port Elizabeth.

[5] "Evaluation of Heat Rates of Coal Fired Electric Power Boilers." Staudt, James E. and Jennifer Macedonia. Power Plant Pollutant Control "MEGA" Symposium Paper Presentation. August 2014.

Duty Cycle

The nuclear plants in this study are base load units. Base load units are characterized by high availability and high efficiency, but generally have less flexibility in their output and are less efficient under part-load conditions, thus minimizing their use as load-following units. A capacity factor of 90% is assumed for all of the base load nuclear units. This sentiment is very consistent with the US market.

However, in some foreign markets with large shares of nuclear capacity (namely France and Germany), operational flexibility is a key ingredient to successful grid operations that now includes larger amounts of intermittent generation. In 1991, European utilities developed the European Utilities' Requirements, which explicitly defines load cycling in the operating handbook of nuclear power plants along with the appropriate safety margins. This paved the way for more modern nuclear reactor designs. The French pressurized water reactor (PWR) makes use of "grey" control rods that allows for load cycling of 30 – 100% of the plant capacity.

The impacts of load following with nuclear plants are varied. Assuming a nuclear plant is designed to load follow, experience in European countries indicate that cycling nuclear facilities can be accomplished safely. Load following does have negative impacts on plant equipment as witnessed in the acceleration of equipment and ageing. For plants that are designed with cycling in mind, precautions can be included in planning to minimize O&M costs, but translates into higher capital costs. For existing, older plants, additional expenditures will be needed to allow for load following capabilities. In France, the impact of load following practices on the average unit capacity factor is estimated at less than 3%.[6]

Generating Unit Size

The primary Generation III/III+ nuclear reactor designs being pursued for installation in South Africa include the Westinghouse AP1000 and AREVA EPR. These units range in size from 1,200 MW to 1,600 MW. Estimates within this report will cover the range of these plants with stations consisting of one-unit, two-unit, four-unit, and six-unit sequential construction.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For a nuclear plant, this includes the nuclear reactor and the power block, and all support facilities needed to operate the plant, such as wastewater-treatment facilities, shops, offices, and cafeteria. The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines. The nuclear units evaluated in this study employ once-through seawater cooling.

The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on

[6] "Load-following with nuclear power plants." NEA News 2011- No 29.2, and 'Technical and economic aspects of load following with nuclear power plants,' June 2011.

assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

Resource Potential

Nuclear fuel typically consists of uranium dioxide enriched to 3-5% (by weight) using the uranium-235 isotope. Natural uranium, mixed oxide (MOX) consisting of both plutonium and enriched uranium oxides, thorium, and actinides are also used as nuclear fuel.

It is assumed that enriched uranium is initially imported from Europe and the fuel cost includes the cost of transportation. The government of RSA have completed studies indicating the country's ability to support the nuclear fuel requirements of a 10GW nuclear fleet. This shift in fuel sourcing from external to internal is seen as a necessary move for national security. Although no definitive timeline was provided, the earlier reports indicate the reliance on South African uranium mines is feasible by 2030.[7]

Nuclear Fuel and Waste Transport/Storage/Disposal

The nuclear fuel cycle, as illustrated in the figure below, includes uranium recovery, conversion, enrichment and fabrication to produce fuel for nuclear power stations. Nuclear fuel costs consist of both front-end and back-end costs. Front-end costs are outlined in Table 3-3 and are a result of 2008 study by the World Nuclear Association.[8] The uranium price in the table has been modified to reflect current global uranium prices, while the other costs were escalated by annual inflation.[9] Back-end costs can be incurred in one of two ways – direct disposal (once-through fuel cycle option) or reprocessing of nuclear fuel to be reused. Back-end costs are particularly challenging due to uncertainty around the long project life of nuclear plants. This includes the state of technological advances and regulatory policies. In addition, the costs are country specific. The back-end cost developed in this report assumes direct disposal. The costs outlined in Table 3-4 include on-site, temporary storage costs while a permanent storage solution is being developed and a tax to support development of a permanent storage plan.

[7] "South Africa Could Resume Uranium Enrichment". www.nti.org/gsn/artilce. April 2012.
[8] "The Economics of Nuclear Power." World Nuclear Association. November 2008.
[9] http://www.indexmundi.com/commodities/

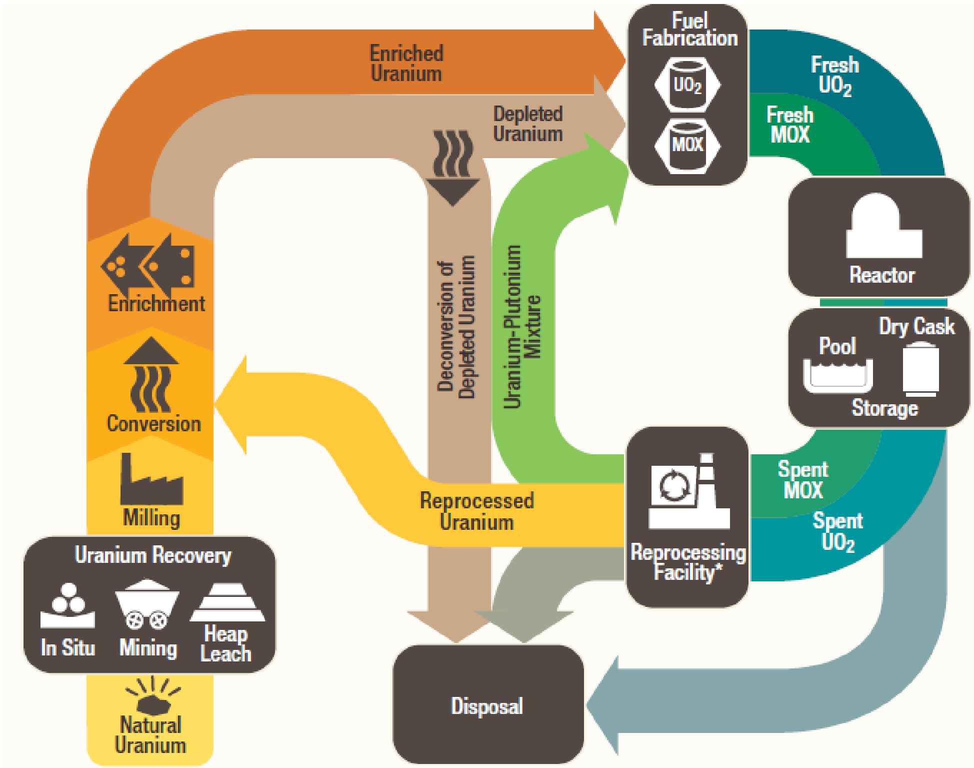


Figure 3-3
Nuclear Fuel Cycle[10]

Table 3-3
Front-End Nuclear Fuel Costs, 2015$

Process Step	Cost ($/kg U)
Uranium: 8.9 kg U_3O_8 × $79	703
Conversion: 7.5 kg U × $14	105
Enrichment: 7.3 SWU × $156	1,139
Fabrication: per kg	281
Total ($/kg U)	2,228

[10] "The U.S. Nuclear Regulatory Commission (NRC) 2015-2016 Information Digest." Office of Public Affairs U.S. Nuclear Regulatory Commission. August 2015.

Table 3-4
Disposal Costs[11]

Process Step	Cost (2015$/MWh)
Temporary On-site Storage ($/MWh)	$0.11
Permanent Disposal ($/MWh)	$1.30
Total ($/MWh)	$1.41

Other Factors

Once-Through Cooling

Unlike the other technologies evaluated in this study, the nuclear units are coastally located and employ once-through seawater cooling.

Gas Technologies

Location

The site location chosen for this study is a generic coastal Greenfield site in South Africa. It was assumed that these coastal locations are near liquefied natural gas (LNG) terminals for easy access to a fuel supply. For all technologies, the primary assumption is that dry cooling systems are necessary and, therefore, no assumptions were made about the site's proximity to a raw water supply.

Ambient Conditions

The annual average ambient air conditions for coastal South Africa used for the gas plants in this study are listed below.

Design dry bulb temperature	25°C
Average dry bulb temperature	16.5°C
Relative humidity	75%
Atmospheric pressure	101 kPa
Equivalent altitude	sea level

Duty Cycle

The CCGT evaluated in this study is an intermediate unit while the OCGT is a peaking unit. Intermediate units have costs and operating flexibility that is a cross between a base load unit and a peaking unit. They generally have increased output flexibility compared to base load units, but have longer construction time and higher capital costs than peaking units. Peaking units, like the open cycle GT, typically have lower capital costs, shorter construction time, quicker start-up and higher flexibility in their plant output compared to base load units. However, they generally have

[11] "The Economic Future of Nuclear Power." The University of Chicago, 2004.

higher fuel costs and can be less efficient and, therefore, run less frequently than base load units. A capacity factor of 50% is assumed for the CCGT unit and a capacity factor of 10% is assumed for the OCGT. Table 3-5 shows the plant technical parameters for the OCGT and CCGT gas plants.

Table 3-5
Gas Plant Technical Parameters

CT	Start Time	Shutdown Time	Ramp Rate	Ramping Range	Minimum Load
9E.04 OCGT	12 minutes	12 minutes	11 MW/minute	0% - 100% in 12 minutes	30%
9F.03 CCGT	Cold start: 240 minutes Warm start: 125 minutes Hot start: 90 minutes	30 minutes	20 MW/minute (CTG only)	Cold Start: 0%-20%: 165-169 mins 20%-100%: 219-230 mins Warm Start: 0%-20%: 76-79 mins 20%-100%: 106-116 mins Hot Start: 0%-20%: 59-63 mins 20%-100%: 74-84 mins	30%

In addition to the CCGT and OGCT generation systems, this study also evaluates a distributed generation technology – the internal combustion engine (ICE), also known as the reciprocating engine. The ICE unit is a standalone configuration at an unoccupied (new) site and is assumed to be within or near town or metropolitan areas. The ICE evaluated in this study is an intermediate unit to support load following needs on the grid.   The engine-generator for the case is designed to reach 25% load in 2 minutes and full load in 10 minutes (from warm stand-by condition). It is worth mentioning that in contrast to other types of fossil-fired generating technologies, reciprocating engines exhibit diseconomy of scale. On $/kW basis, freight on-board (FOB) prices generally increase as engine size increases and rpm decreases. The $/kW cost is a function of the reduction in crankshaft speed (decrease in power output per unit of cylinder displacement) and increased engine weight. Units greater than about 10 MW are derived from marine diesel engines. These larger engines are generally built when ordered and in much smaller numbers than 1-5 MW engines. Therefore, the larger engines do not have the economy associated with mass production. Smaller engines are derived from automotive, large truck, and locomotive designs that have the benefit of larger production quantities. The automotive/truck diesel engines represent the highest degree of mass production and generally have very low relative capital costs (on the basis of $ per unit of power output). A capacity factor of 65% is assumed for the ICE unit.

Generating Unit Size

The CCGT plant is a 2x1 unit at just over 750 MW gross, with each combustion turbine contributing 245 MW and the steam turbine contributing 262 MW. The OCGT is about 133 MW gross. The ICE units are 2MW and 9.4MW. Although it is not covered in this report, some interest has been growing in combining the operational flexibility of internal combustion engines with the efficiency improvement of combined cycles. Wärtsilä is currently offering a "Flexicycle power plant" that is based on the Wärtsilä engine. A 12-engine power plant coupled to 12 heat recovery steam generators (HRSG) feeding a single ST would provide 200MW.

The generating stations covered in this report are assumed to deliver electricity to the local grid at a frequency of 50 Hz.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For example, the cost boundary for a combined cycle plant includes all major parts of the unit, such as the gas and steam turbine, heat recovery steam generator (HRSG), and the turbine generators, and all support facilities needed to operate the plant. These support facilities include emissions control equipment; wastewater-treatment facilities; and shops, offices, and cafeteria. CO_2 compression equipment and energy penalties are included for plants with CO_2 capture, but the capital costs for the CO_2 pipeline and storage area for sequestration are not included.

The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines. The switchyard and transmission lines are generally influenced by transmission system-specific conditions and are therefore not included in the cost estimate.

The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

Fuel Systems

Table 3-6 shows the LNG composition and heating value used in this analysis.

Table 3-6
Natural Gas Characteristics

Composition (wt%, dry basis)	LNG
Methane	90.06
Ethane	8.56
Propane	1.05
n-Butane	0.21
n-Pentane	0.04
Hexanes	0.05
Nitrogen	0.03
Carbon Dioxide	--
Heating Value (dry basis)	

Higher MJ/SCM (Btu/SCF)	39.3 (1,054)
Lower MJ/SCM (Btu/SCF)	35.5 (950)

Resource Potential

South Africa currently utilizes natural gas from existing off-shore fields. However, it is believed that these fields are nearing depletion. As a result, the Petroleum, Oil and Gas Corporation of South Africa (Pty) Limited (PetroSA), is pursuing LNG imports for a coastal LNG terminal to supplement and eventually replace the depleting off-shore supplies. South Africa's closest source of LNG is the central African Atlantic coast, e.g. Equatorial Guinea. South Africa is far closer to the global supplier Qatar than all the countries in the North Atlantic, and it is relatively close to the up-and-coming suppliers off the Northwest Shelf of Australia (e.g. Pluto) and northern tier off-shore region of Australia (e.g. Browse).

In addition to power production, a primary consumer of natural gas in South Africa is PetroSA's gas to liquid (GTL) complex at Mossel Bay, where natural gas is converted to a synthetic liquid fuel to supply the transportation fuel market, as well as other liquid fuel markets in South Africa.

Other Factors

CO_2 Capture and Storage

The CCGT plant is evaluated both with and without CO_2 capture in this study, with a capture rate of 85-90%. The CO_2 pipeline and storage area for sequestration are not included in these capital cost estimates. CO_2 capture and storage is not considered for OCGT plant.

Dry Cooling

Due to limited water supply in South Africa, a dry cooling system is necessary for the CCGT unit.

Renewable Technologies

Wind Turbines

Location

Voluminous wind data for 10 different locations, both interior as well as coastal locations, were collected at 60 meters hub height, and supplied for this technical update. However, because of the extensive effort involved to perform a detailed analysis a quick scan of the data showed that the locations were amenable to a sustained minimum of 4m/sec to 8m/sec at 20% to 40% capacity factor and these wind speeds were assumed for the design basis.

Generating Unit Size

The wind farms investigated in this study all consist of 2-MW turbines. The four farm sizes investigated are 20 MW, 50 MW, 100 MW, and 200 MW.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For wind farms, this area includes interconnections among the turbines and a substation, in addition to the wind turbines, foundations, and control systems. The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

Resource Potential

The performance of the wind turbines at wind speeds of 4m/sec to 8m/sec (annual average) are evaluated. Table 3-7 shows the wind class range for each wind speed. The wind speeds were monitored and collected at 60 meters/sec.

Table 3-7
Wind Speed Classes

Wind speed, meters/sec	Wind Class
5.0	1
6.0	2
7.0	3
8.0	5

Figure 3-4 shows the estimated annual wind speed in meters per second at a height of 100 m above ground level. It was developed by the South African National Energy Development Institute (SANEDI). The best wind resource areas in South Africa are generally in the northwest coastal area near Namibia and the southeast coastal area. The US average wind tower hub height in 2014 was 80m.[12] The German average wind tower hub height in 2014 was a little less than 95m. For this report, it is assumed the hub height was 80m. Based on EPRI research conducted in 2014, on average, 100m towers have a 5 – 10% installed capital cost premium and a 10 – 15% premium for O&M costs. The benefit of a higher hub height is apparent in the increase in the capacity factor due to access to higher wind speeds. In terms of performance enhancement, EPRI research found that a 100m hub height provided a 15 – 20% increase in capacity factor over an 80m hub height. The increased capacity factor yielded a 5 – 10% reduction in the levelized cost of energy (LCOE).

[12] 2014 Wind Technologies Market Report. US Department of Energy, August 2015.

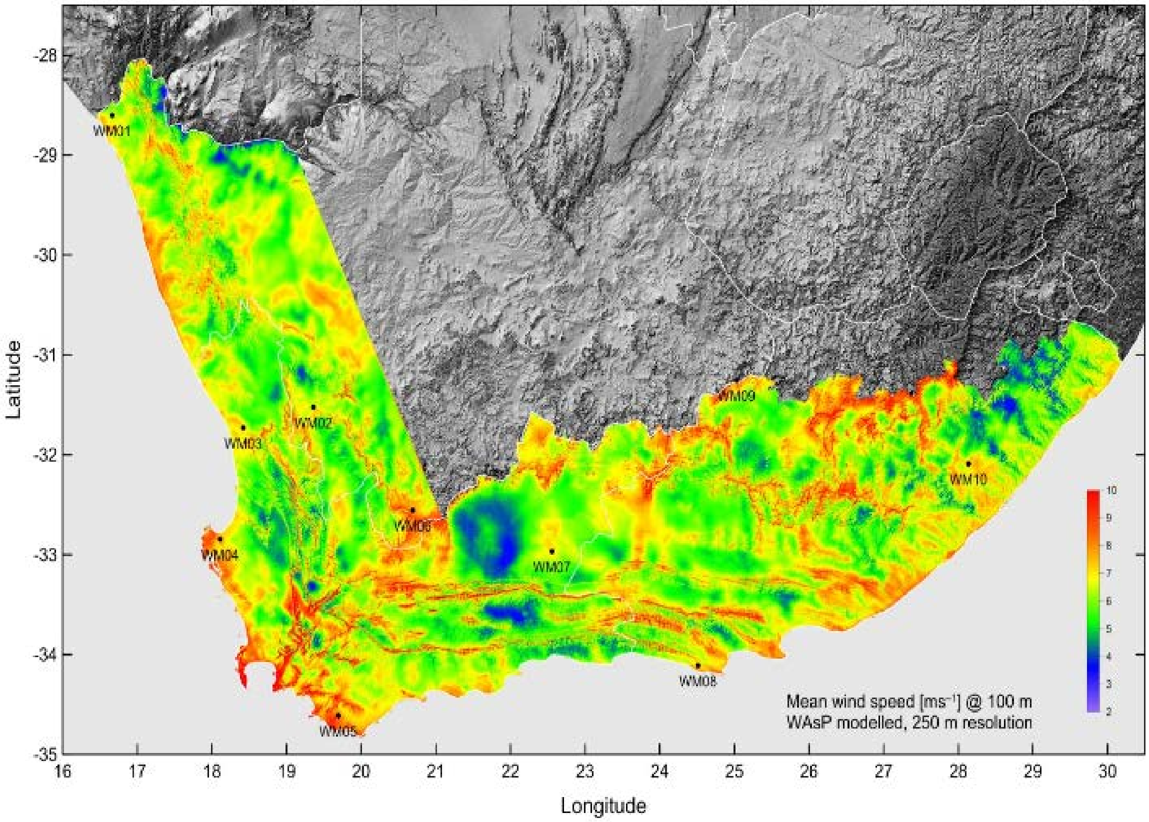


Figure 3-4
South African Wind Resource (measured at 100 m)

Table 3-8 shows a sample of the wind atlas mast information collected by Eskom. Although the data presented by Eskom is quite exhaustive, it requires a lot more evaluation and analysis to determine turbine size. The approach taken here is to present a range of wind speeds that could be used as annual average and present the cost estimates and cost of electricity for the 2MW turbine size. It is assumed that experts in the field of turbine selection would use the information presented to arrive at appropriate turbine selections for the different locations. The following information supports this approach.

Table 3-8
Wind Atlas Mast Information

Site	Closest town	Dominant wind directions derived from SAWS	General boom directions	General anemometer direction	Latitude (Degrees, Minutes, Seconds)	Longitude (Degrees, Minutes, Seconds)	Latitude (Decimal degrees)	Longitude (Decimal degrees)	A.m.s.l.	Magnetic Declination (degrees)	Data Start date (15m mast)
WM01	Alexander Bay	South (Alexander Bay)	E-W	W	- 28°36’06”S	16°39’51”E	-28.601882	16.664410	152	-19.5	2010/06/23
WM02	Calvinia	E/W (Calvinia);	NW-SE	SE	- 31°31’29”S	19°21’38”E	-31.524939	19.360747	824	-24.5	2010/06/30
WM03	Vredendal	NW and SSE (Namaqua Sands)	WNW-ESE	ESE	- 31°43’49”S	18°25’11”E	-31.730507	18.419916	241	-24.2	2010/06/24
WM04	Vredenburg	S and SSW (Langebaanweg)	E-W	W	- 32°50’46”S	18°06’33”E	-32.846328	18.109217	22	-23.4	2010/05/18
WM05	Napier	W and E (Struisbaai and Hermanus)	N-S	S	- 34°36'42"S	19°41'32"E	-34.611915	19.692446	288	-26.0	(2010/02/11) 2010/05/20
WM06	Sutherland	W to E, no dominant in reanalysis p gradient	N-S	N	- 32°33'24"S	20°41'28"E	-32.556798	20.691243	1581	-24.9	2010/09/17
WM07	Beaufort West	E, ENE (Beaufort west), SW, SSW	NW-SE	SE	- 32°58'00"S	22°33'24"E	-32.966723	22.556670	1047	-26.1	2010/05/28
WM08	Humansdorp	WSW (Tsitsikamma)	NW-SE	SE	- 34°06’35”S	24°30’51”E	-34.109965	24.514360	110	-29.6	2010/08/04
WM09	Noupoort	SSE, NNW (Noupoort)	WSW-ENE	WSW	- 31°15’09”S	25°01’42”E	-31.252540	25.028380	1806	-24.9	2010/09/01
WM10	Butterworth	SSW-W (Umtata)	NNE-SSW	SSW	- 32°05’26”S	28°08’09”E	-32.090650	28.135950	925	-28.9	2010/08/05

Wind energy is divided into seven classes based on the wind speed measured at a height of 50 m (164 ft) above grade. The wind power is classified from Class 1 to Class 7 with a classification of one being a low wind speed at less than 5.6 m/s (18.4 ft/s) and seven being wind with a speed greater than 8.8 m/s (28.9 ft/s) as shown in Table 3-9 (source: NREL). As would be expected, strong, frequent winds are the best for generating electricity. Currently, areas with wind speeds of Class 5 and higher are being used with large wind turbines with the future goal of utilizing Class 4 sites.

Table 3-9
Wind Power Density Classification at 10 m and 50 m (a)

Wind Power Class*	10 m (33 ft)		50 m (164 ft)	
	Wind Power Density (W/m^2)	Speed(b) m/s (mph)	Wind Power Density (W/m^2)	Speed(b) m/s (mph)
1	0	0	0	0
2	100	4.4 (9.8)	200	5.6 (12.5)
3	150	5.1 (11.5)	300	6.4 (14.3)
4	200	5.6 (12.5)	400	7.0 (15.7)
5	250	6.0 (13.4)	500	7.5 (16.8)
6	300	6.4 (14.3)	600	8.0 (17.9)
7	400	7.0 (15.7)	800	8.8 (19.7)
	1000	9.4 (21.1)	2000	11.9 (26.6)

Table Notes:

a) Vertical extrapolation of wind speed based on the 1/7 power law.

b) Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea-level conditions. To maintain the same power density, speed increases 3%/1000 m (5%/5000 ft) elevation.

* Each wind power class should span two power densities. For example, Wind Power Class = 3 represents the Wind Power Density range between 150 W/m^2 and 200 W/m^2. The offset cells in the first column attempt to illustrate this concept.

Wind turbines are designed to function within a wind speed window, which is defined by the “cut-in” and “cut-out” wind speeds. Below the cut-in wind speed, the energy in the wind is too low to be of use; once the wind reaches the cut-in speed, the turbine comes online and power output increases with wind speed up to the speed for which it is rated. The turbine produces its rated output at speeds between the rated wind speed and the cut-out speed – the speed at which the turbine shuts down to prevent mechanical damage.

The nameplate capacity of a wind turbine is determined by the manufacturer, but it can be approximated by the size of the generators being used. Individual designs range from less than 1 kW for remote sites with low power needs to typical utility scale wind turbines in the range of 1.5 to 3 MW in size, with larger ones in limited production and under development.

The International Electrotechnical Commission (IEC) code 61400 governs wind turbines. Table 9-2 from IEC describes the four IEC wind turbine classifications. The selection of a wind turbine model for a particular site should be performed by someone qualified in this area and that the information in Table 3-9 and Table 3-10 is not sufficient to perform an optimal selection.

Table 3-10
IEC Wind Turbine Classification

Wind Turbine Generator Class	I	II	III	IV
V_{ave} average wind speed at hub-height (m/s)	10.0	8.5	7.5	6.0
V_{50} extreme 50-year gust (m/s)	70	59.5	52.5	42.0
I_{15} characteristic turbulence Class A	18%			
I_{15} characteristic turbulence Class B	16%			
α wind shear exponent	0.20			

Solar Thermal

Two concentrating solar power (CSP) technologies were evaluated: parabolic trough with three, six, nine, and twelve hours of indirect molten salt storage, and central receiver with three, six, nine, and twelve hours of direct molten salt storage.

Location

Solar thermal technologies were evaluated north of Upington, in the desert-like northwest part of South Africa near the Namibian border.

Ambient Conditions

The annual average ambient air conditions for the region near Upington, South Africa are listed below.

Design dry bulb temperature	35°C
Average dry bulb temperature	20.6°C
Relative humidity	40%
Atmospheric pressure	96 kPa
Equivalent altitude	814 m
Average direct normal solar radiation	309 Wh/m^2

Generating Unit Size

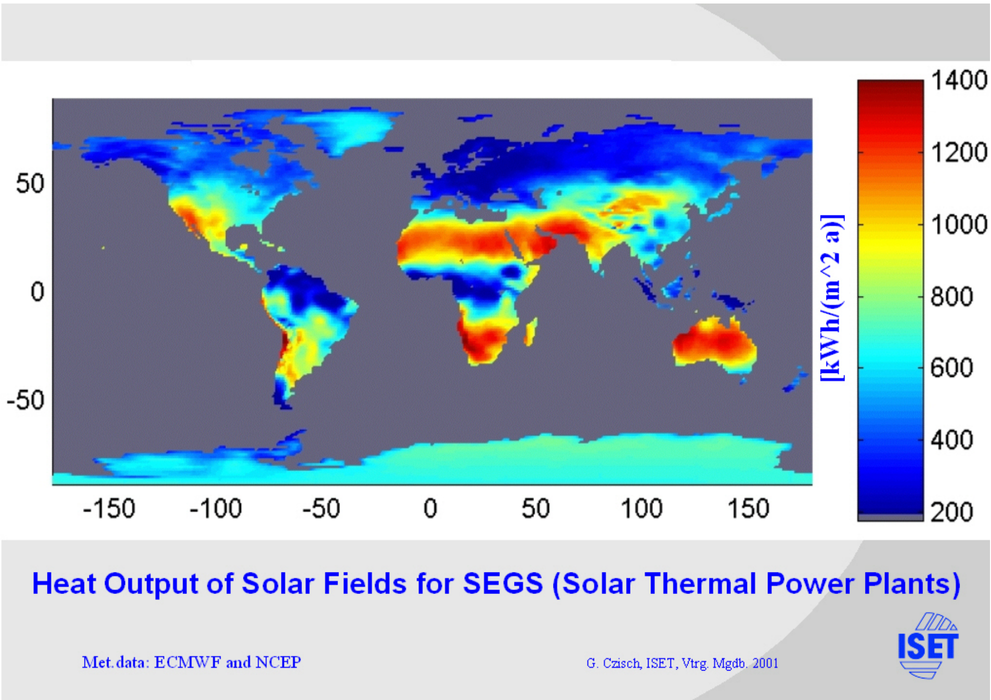
Both the parabolic trough plant and the central receiver plant for this study were evaluated at 125 MW. The parabolic trough plant was evaluated with three, six, nine, and twelve hours of indirect molten salt storage. The central receiver plant was evaluated with three, six, nine, and twelve hours of direct molten salt storage.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For solar thermal plants, this area includes the collectors, any thermal storage units, the steam generating unit, and the power island, as well as any support facilities needed to operate the plant and an interconnection substation. The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

Resource Potential

CSP technologies, such as parabolic trough and central receiver, require direct normal irradiance (DNI). This requirement means that incident sunlight must strike the solar collectors at an angle of 90 degrees in order for the sunlight to be focused onto the receivers. Figure 3-5 shows worldwide solar DNI data. The DLR-ISIS images were obtained from the Institute of Atmospheric Physics, German Aerospace Center (DLR)[13]. The long-term variability of direct irradiance was derived from ISCCP data and compared with re-analysis data[14]. South Africa clearly has one of the best solar resources in the world.



[13] Institute of Atmospheric Physics, German Aerospace Center (DLR). Lohmann, S., C. Schillings, B. Mayer and R. Meyer (2006a).
[14] "Long-term variability of solar direct and global radiation derived from ISCCP data and comparison with reanalysis data**."** S. Lohmann, C. Schillings, B. Mayer and R. Meyer. *Solar Energy*, Volume 80, Issue 11, November 2006, pp. 1390-1401

Figure 3-5
Worldwide DNI Data

Figure 3-6 below shows the annual direct normal solar energy in Africa in kWh/m^2/day.

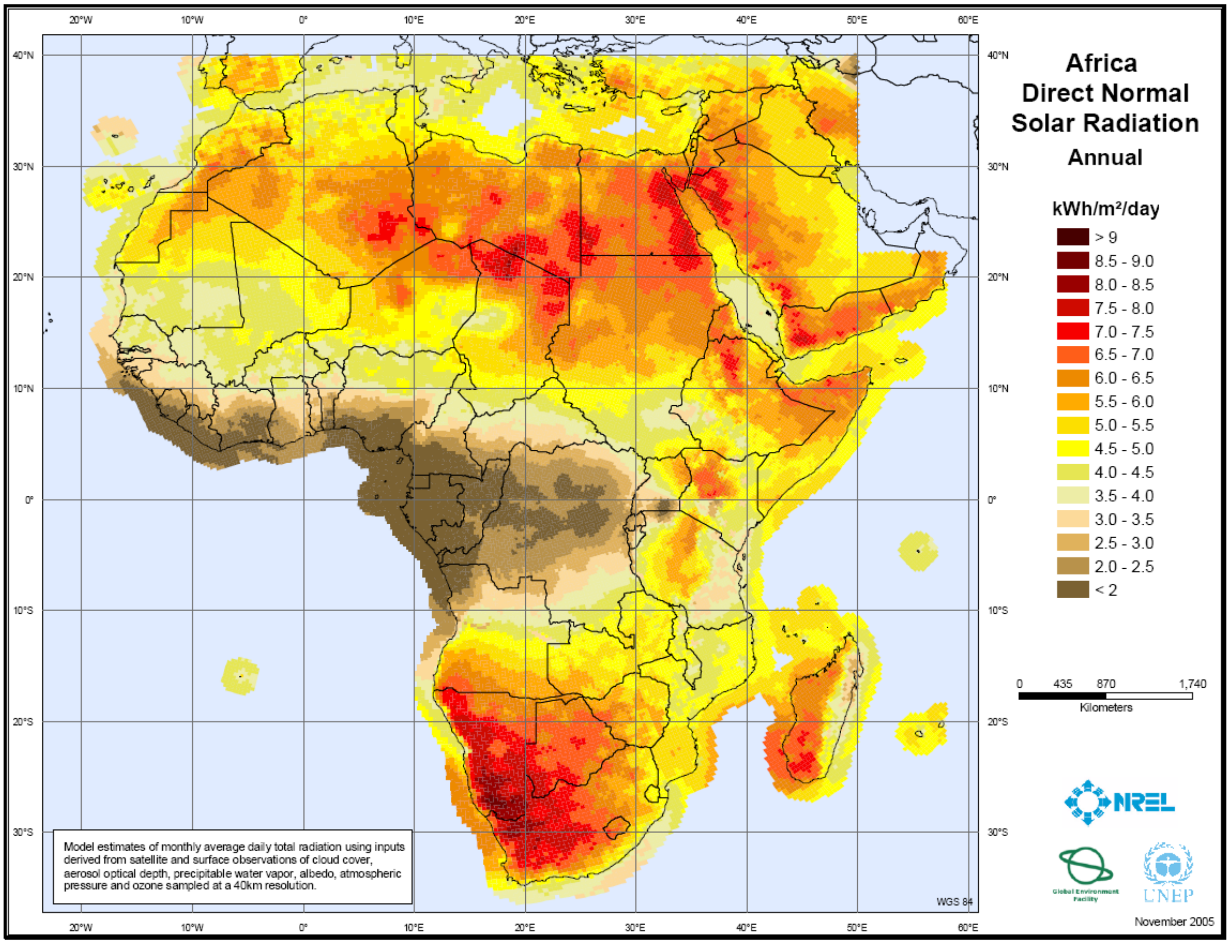


Figure 3-6
African Annual Direct Normal Radiation

Solar PVs

Three solar PV technologies were evaluated: fixed-tilt cadmium telluride (CdTe) thin film PV, fixed-tilt c-Si PV, and two-axis tracking gallium arsenide (GaAs) concentrating PV.

Location

Fixed-tilt thin film and c-Si PV technologies were modeled for two locations: Cape Town and Johannesburg. Concentrating PV technologies were modeled for Upington with the same direct normal radiation data as the solar thermal technologies.

Ambient Conditions

The annual average ambient air conditions for Cape Town and Johannesburg, South Africa used in this study are listed below. Those used for Upington are included in the solar thermal design basis.

Cape Town:

Average dry bulb temperature	16.5°C
Relative humidity	75%
Atmospheric pressure	101 kPa
Equivalent altitude	42 m
Average horizontal diffuse solar radiation	72 Wh/m^2

Johannesburg:

Average dry bulb temperature	15.8°C
Relative humidity	60%
Atmospheric pressure	82 kPa
Equivalent altitude	1700 m
Average horizontal diffuse solar radiation	94 Wh/m^2

Generating Unit Size

The thin film and c-Si PV systems evaluated in this study were evaluated both as commercial/industrial rooftop units (250 kWe and 1 MWe) and ground-mounted utility-scale systems (1 MWe and 10 MWe). The National Energy Regulator of South Africa (NERSA) provides feed-in tariffs for units greater than 1 MWe, making this size of unit attractive to developers. However, the potential for net-metering laws could make rooftop units appealing as well. The concentrating PV systems were evaluated at 10 MWe.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For solar PV plants, this area includes the solar PV arrays, support structures, inverters, a solar tracker if required, wiring, and an interconnection substation. The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

Resource Potential

Flat-plate PV systems can utilize diffuse radiation as well as normal radiation. Ground mounted PV panels are usually installed at a latitudinal tilt, which optimizes annual energy production, while rooftop panels may be installed more horizontally due to structural and wind-loading considerations. Figure 3-7 shows the annual solar resource in Africa at a latitudinal tilt while Figure 3-8 shows the annual horizontal solar resource in Africa.

Like the concentrating solar thermal technologies, concentrating PV requires direct normal radiation. The solar resource component utilized by this technology corresponds with Figure 3-4 shown in the solar thermal section.

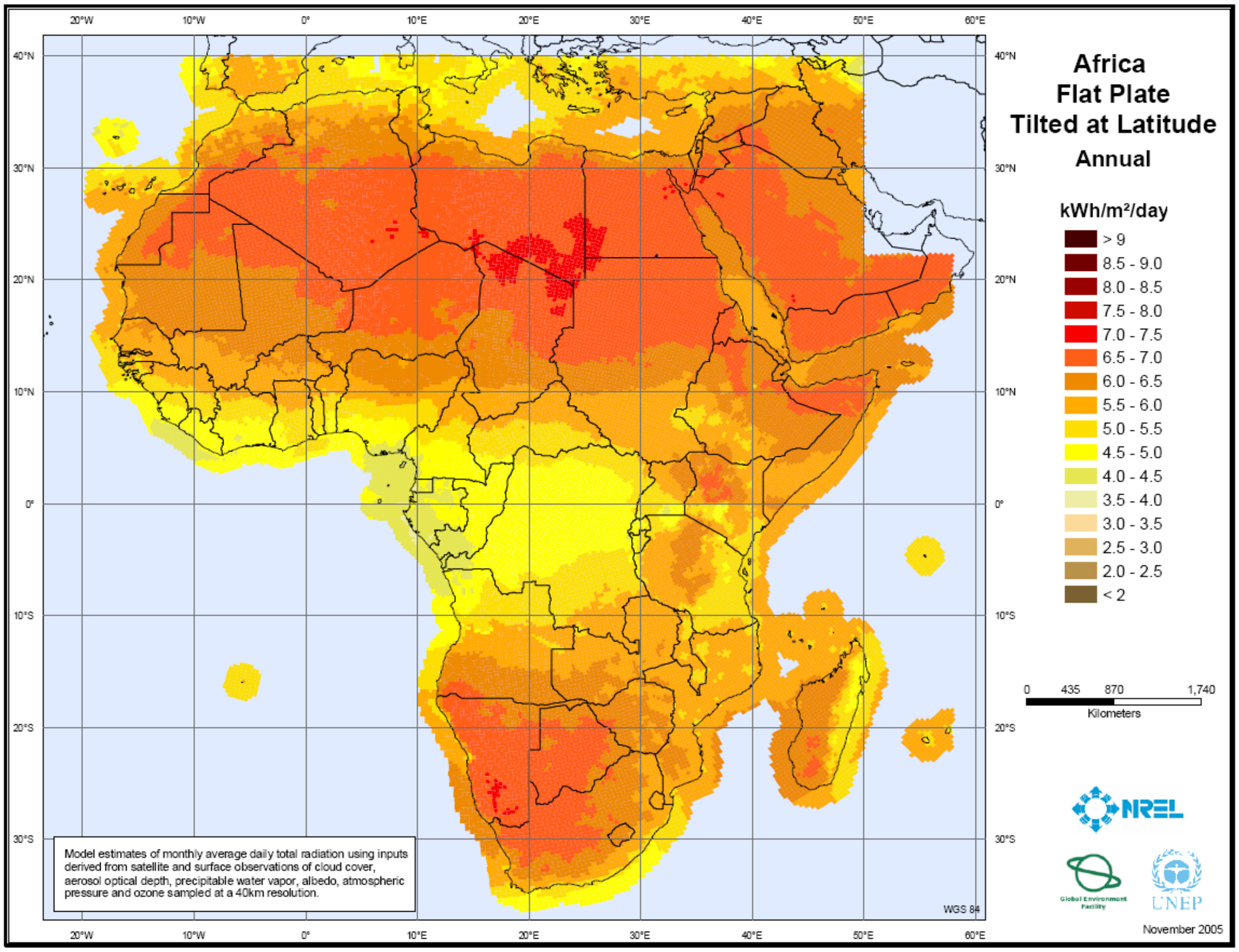


Figure 3-7
African Annual Latitudinal Solar Radiation

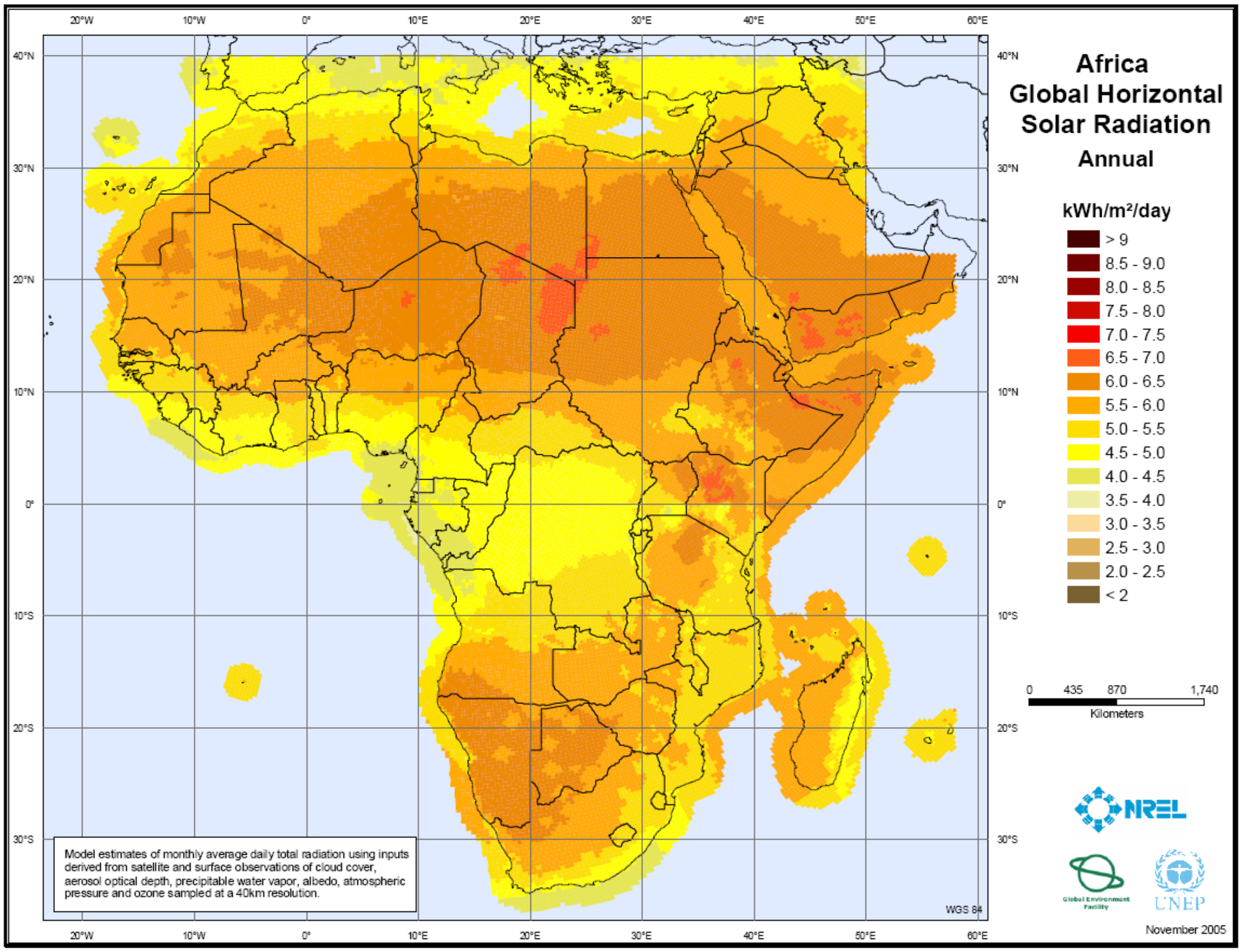


Figure 3-8
African Annual Horizontal Solar Radiation

Biomass

Two types of biomass boiler systems were evaluated in this study: plants firing forestry residue and plants firing MSW. In addition, reciprocating engines firing landfill gas were evaluated.

Location

The biomass plants evaluated in this study are generic Greenfield plants. It is assumed that the forestry residue-fired biomass plants are located on the eastern coast of South Africa. While the western part of South Africa is more desert-like, the eastern coast is rainier and has a more plentiful supply of wood for use as biomass fuel. The MSW-fired plants and the landfill gas reciprocating engines are assumed to be located near population centers where waste will be more readily accessible.

Generating Unit Size

This study evaluated forestry residue and MSW boiler units at 25 MW rated capacity. The size of biomass generating units is generally limited by the availability of biomass fuel and the cost of transporting the fuel to the site. The landfill gas reciprocating engine plant was assumed to be four 1.25 MW units for a total rated capacity of 5 MW.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For a biomass-fired steam plant, the cost boundary includes all major parts of the unit, such as boiler and turbine generator, and all support facilities needed to operate the plant. These support facilities include fuel receiving/handling and storage equipment; emissions control equipment when included in the plant design; wastewater-treatment facilities; and shops, offices, and cafeteria. For the landfill gas engines, the cost boundary includes the spark ignition reciprocating engines and exhaust stacks, as well as all engine auxiliaries, buildings, and the landfill gas piping within the project fence line.

The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines. The switchyard and transmission lines are generally influenced by transmission system-specific conditions and are therefore not included in the cost estimate.

The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

Fuel Systems

The biomass fuels considered for this study are woodchips, representing forestry residue, unprocessed MSW, and landfill gas. Table 3-11 summarizes the characteristics of the solid fuels and Table 3-12 summarizes the characteristics of the landfill gas. Solid biomass storage is sized for five-day storage.

Table 3-11
Biomass Characteristics

Composition (% wt)	Woodchips	MSW
Moisture	40.37	24.80
Carbon	29.54	27.45
Hydrogen	3.52	3.69
Nitrogen	0.15	0.54
Chlorine	0.00	0.66
Sulfur	0.03	0.17
Oxygen	24.23	19.28
Ash	2.17	23.39
Heating Value		

Dry MJ/kg (Btu/lb)	19.7 (8,480)	
Wet MJ/kg (Btu/lb)	11.8 (5,057)	11.4 (4,896)

Table 3-12
Landfill Gas Characteristics

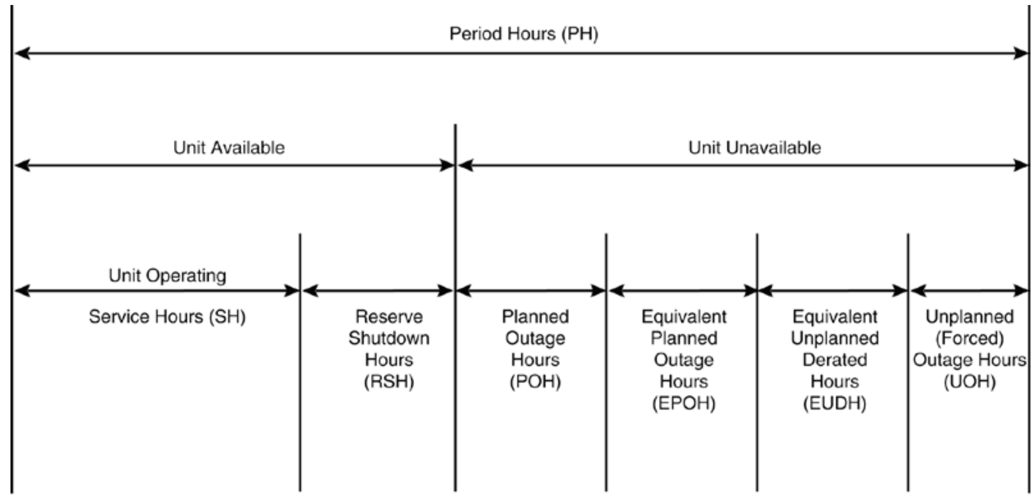
Composition (wt%, dry basis)	Landfill Gas
Methane	45
Carbon Dioxide	40
Moisture	10
Nitrogen	4
Oxygen	<1
Ammonia	<1
Sulfides	<1
Other trace elements	<1
Heating Value (dry basis)	
Higher MJ/SCM (Btu/SCF)	18.6 (500)

Resource Potential

It is anticipated that nearly 1500 MW of biomass-generated power could be installed within South Africa. Of this, nearly half is expected to come from MSW. Landfill gas is currently used in South Africa more typically for rural heating application than for electricity generation; however, there is potential for this resource to expand.

Availability Estimates

The figure below shows the terms, definitions, and supporting variables for availability calculations, as defined by the National Electric Reliability Council (NERC). For this study, availability is presented as equivalent availability and, when available, broken down into equivalent planned outage rate (maintenance) and equivalent unplanned outage rate (unplanned outages) based on previous studies. A specific analysis of availability for South Africa was not conducted.



OA—Operating Availability (%) $= \dfrac{PH - UOH - POH}{PH} \times 100$

EA—Equivalent Availability (%) $= \dfrac{PH - EUDH - UOH - POH - EPOH}{PH} \times 100$

$= (1 - EPOR)(1 - EUOR)$ where: $RSH = 0$

FOR—Forced Outage Rate (%) $= \dfrac{UOH}{SH + UOH} \times 100$

EPOR—Equivalent Planned Outage Rate (%) $= \dfrac{POH + EPOH}{PH} \times 100$

EUOR—Equivalent Unplanned Outage Rate (%) $= \dfrac{UOH + EUDH}{SH + UOH} \times 100$

UOR—Unplanned Outage Rate (%) $= \dfrac{UOH}{PH - POH} \times 100$

OR—Operating Reliability (%) $= (1 - EUOR) \times 100$

Period of Demand $= PH - RSH - POH - EPOH$

Figure 3-9
Availability Definitions and Calculations

4
CAPITAL COST ESTIMATING BASIS

Cost estimates were developed for each technology evaluated in this report. TPC and O&M costs are presented as “overnight costs”, which assume that the plant is built overnight and, thus does not include interest and financing costs. All costs are expressed in January 2017 South African Rand (ZAR). These TPC estimates include:

- Equipment,
- Materials,
- Labor (direct and indirect),
- Engineering and construction management, and
- Contingencies (process and project)

Owner’s costs are excluded from TPC estimates, but are included in total capital requirement (TCR) estimates used for cost of electricity calculations.

The TPCs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies evaluated. The amount of contingency varies among the technologies and systems based on assessment of cost risk of the various technologies. The selected values are considered appropriate for the state of experience for each technology.

For all technologies included in this study, minimal site clearance and preparation is assumed and no provision is made for new infrastructure or improvements to existing infrastructure, such as roads, transmission lines, etc., as these are quite specific and design requirements can vary from one location to another.

After TPC estimates were developed for each technology, the TCR and levelized cost of electricity estimates were calculated using the TAGWeb® software.

This section describes the methodology used for developing overnight TPC and O&M estimates and then the TAGWeb® assumptions used for calculating TCR. It also discusses the approach to assessing fleet strategy and the uncertainties and sensitivities associated with the cost and performance estimates.

Baseline Cost Estimating Methodology

The baseline cost for each technology was estimated by EPRI using a combination of in-house data and adjustment factors developed by EPRI’s subcontractor. Recent EPRI studies were used as a baseline for the cost estimates. These estimates were adjusted as necessary to match the design basis for the current study by adjusting the size of the plant, including dry cooling, utilizing the proper fuel type when applicable, and modifying estimates for the specified ambient conditions. Based on current market trends, these baseline estimates were then adjusted to January 2015 U.S. dollars (USD) as necessary for the 2015 IRP. For this update, an annual escalation rate of 2.5% was applied to the 2015 baseline estimates to adjust the costs to January 2017.

Once capital and O&M costs were established for a U.S. based plant with the same design as the design basis in January 2015, cost estimates were adjusted to determine how much it would cost to build the same plant in South Africa, based on the adjustment factors developed by EPRI's subcontractor and in-house EPRI assumptions.For this update, these costs were adjusted to January 2017 USD using an annual escalation rate of 2.5%, then the costs were converted to ZAR based on the exchange rate between U.S. dollars and the South African Rand at the beginning of January 2017.

All costs are expressed on South African Rand per kilowatt or per kilowatt-year basis are in terms of net plant output.

Adjustments to Costs

Adjustments to South African Construction Costs

EPRI's subcontractor developed a set of factors for conversion of construction costs developed in the US gulf coast to the cost of construction in South Africa. These factors are shown in Table 4-1. From this table, it can be seen that most of the materials used for construction in South Africa are expected to cost about the same as in the U.S. Generally, raw material pricing tends to be less expensive in South African than the United States as it is mined and refined locally. However, these are offset by higher production costs resulting from less advanced production techniques and lower worker productivity.

With lower labor productivity, the number of hours required for construction is expected to be higher in South Africa than in the U.S., ranging from 90% to 145% more labor hours (labor productivity factors of 1.90 to 2.45), depending on the craft. At the same time, the labor rate in South Africa is between 35% to 57% lower (labor rate factors of 0.65 to 0.43) than in the U.S., depending on the craft. An across the board labor productivity factor of 2.3 times the U.S. was used. For the labor rate, a factor of 0.56 times the U.S. was used.

Table 4-1
U.S. to South Africa Construction Factors

Discipline Name	Materials	Labor Productivity	Labor Rate
CIVIL	1.00	1.90	0.72
CONCRETE	1.00		0.72
STRUCTURAL STEEL	1.00	2.30	0.57
MECHANICAL	1.00	2.30	0.67
PIPING	1.10	2.45	0.68
VALVES	1.10	2.45	0.68
INSULATION	1.00	2.20	0.62
ELECTRICAL BULKS	1.00	2.15	0.52
INSTRUMENTATION	1.15	2.15	0.52

PAINTING	1.00	2.00	0.76
ELECTRICAL EQUIPMENT	1.00	2.05	0.62
VALUE USED	**1.00**	**2.30**	**0.56**

EPRI assumed that a portion of the equipment used for these plants would be imported from outside of South Africa, while the remainder of the plants' materials and construction labor would be supplied from within South Africa. Based on both in-house data and cost information from the Medupi Power Project PC plant, EPRI estimated the breakdown between imported and local equipment, materials, and labor for each technology. EPRI then estimated the percentage of the local costs that were material costs and the percentage that were labor costs, based on typical in-house labor/material ratio data and the assumption that 95% of the imported costs were material or equipment costs. Table 4-2 shows the assumptions about the percentage of plant costs that are imported vs. local equipment, materials, and labor, as well as the assumed material vs. labor breakdown for the local portion of the cost.

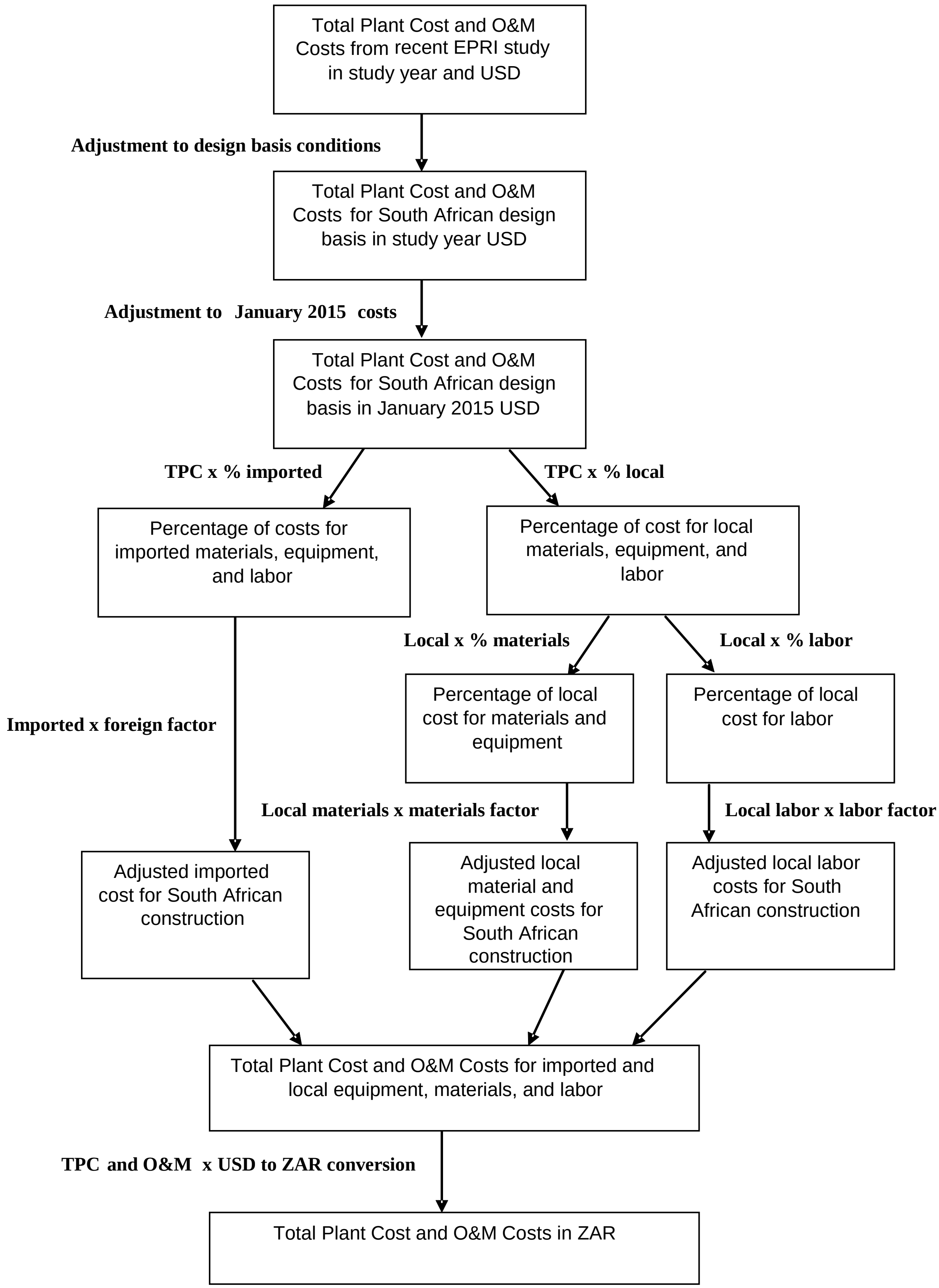
Table 4-2
Assumptions of Imported vs Local, Material vs Labor Percentages

Technology	Imported	Local	Materials (Local)	Labor (Local)
PC	35%	65%	50%	50%
Integrated Gasification Combined Cycle	35%	65%	60%	40%
FBC	35%	65%	50%	50%
Nuclear	35%	65%	60%	40%
CCGT	35%	65%	60%	40%
OCGT	35%	65%	85%	15%
Wind	70%	30%	75%	25%
Solar Thermal	50%	50%	45%	55%
Solar PV	70%	30%	60%	40%
Biomass	35%	65%	50%	50%

Based on these breakdowns, the U.S. based costs were adjusted to South African costs in the following manner:

- The TPC was broken down into the imported portion and the local portion of the costs.
- It was assumed that the imported portion of the costs would remain the same as the U.S. (in USD) based on the assumption that the same transportation costs applied for shipping to the U.S. and South Africa.
- The local portion of the costs was broken down into materials and labor and adjusted according to the factors provided in Table 4-1.
- The imported and local costs were then combined, in U.S. dollars, and converted to ZAR based on the currency exchange rate on January 1, 2017 of 13.57 ZAR/USD.

The flow diagram below shows this cost estimating approach graphically.



Adjustments to O&M Costs

O&M costs were also adjusted to South African conditions and currency. Baseline O&M estimates were developed along with TPC according to the design basis for the study. Because fixed O&M costs are often scaled with the capital costs of a plant, the same adjustment factors used for the TPC were also applied to the fixed O&M estimates. Variable O&M costs were adjusted using the currency exchange rate, but did not take into account the material and labor factors. In most cases, the O&M is split into fixed and variable. In cases where this split is not available or one of the components is quite small, only one category is shown.

TCR Calculations

After the TPC was developed for each technology, the TCR was calculated using the TAGWeb® software for cost of electricity calculation purposes. The TCR includes all capital necessary to complete the entire project. It consists of the following costs:

- Total plant investment at the in-service date, including an allowance for funds used during construction (AFUDC), sometimes called “interest during construction.”
- Owner costs, such as:
    - Prepaid royalties
    - Preproduction (or startup) costs
    - Inventory capital (fuel storage, consumables, etc.)
    - Initial cost for catalyst and chemicals
    - Land

The owner costs included in this study were preproduction costs and inventory capital. Land costs and prepaid royalties were not included in TCR.

Preproduction Costs

Preproduction costs cover operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel and other materials during startup. For EPRI purposes, preproduction costs are estimated as follows:

- One month fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials). In some cases this could be as high as two years of fixed operating costs due to new staff being hired two years before commissioning the plant.
- One to three months of variable operating costs (consumables) at full capacity, excluding fuel. These variable operating costs include chemicals, water, and other consumables, plus waste disposal charges.
- Twenty-five percent of full capacity fuel cost for one month. This charge covers inefficient operation during the startup period.
- Four percent of TPC. This charge covers expected changes and modifications to equipment that will be needed to bring the unit up to full capacity.

- No credit for by-products during startup.

Inventory Capital

The value of inventories of fuels, consumables, and by-products is capitalized and included in the inventory capital account. The current practice for fuel and consumables inventory is shown in Table 4-3. These assumptions will change depending on current economic conditions and the transportation bottleneck.

An allowance for spare parts of 0.5% of the TPC is also included.

Table 4-3
Fuel and Consumables Inventory

Type of Unit	Nominal Capacity Factor (%)	Fuel and Consumable Inventory Days at 100% Capacity
Baseload	85	40
Intermediate	30-50	15
Peaking	10	5

Fleet Strategy

While a single unit project schedule and start-up is quite common, multiple unit projects are favored in some cases where the demand for power is quite substantial with a high growth rate and the economy of scale lends itself to favorable contracting terms, thus lowering overall project costs. In such a scenario, a sequential and staggered approach to project schedule with a second and third unit project start-up a year or two after the first unit and operation following a similar order is normal. The sequential approach serves two purposes:

- The borrowing costs are staggered, thus eliminating a huge lump sum borrowing upfront, resulting in a lower interest during construction.
- The revenue starts flowing earlier with each of the units going into production sequentially rather than waiting to complete all the units to start production.

For the purpose of this report, coal plants were built with one, two, four, and sometimes six units, and nuclear plants were built with one, two, four, and six units. It was assumed that the coal units would be built with sequential project initiation and start-up at one year intervals between units. Nuclear units were assumed to be built with sequential project initiation and start-up at two year intervals. In the summary tables accompanying the results, the expense schedule for a single unit is presented as well as the full project expense schedule, which normalizes the individual unit's construction for the full length of the project.

The following diagrams demonstrate the six unit construction and start-up schedule for the coal and nuclear plants,

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Expense Schedule	10%	25%	45%	20%	U1 startup					
		10%	25%	45%	20%	U2 startup				
			10%	25%	45%	20%	U3 startup			
				10%	25%	45%	20%	U4 startup		
					10%	25%	45%	20%	U5 startup	
						10%	25%	45%	20%	U6 startup
Total Expense %	10%	35%	80%	100%	100%	100%	90%	65%	20%	
Normalized Expense %	2%	6%	13%	17%	17%	17%	15%	11%	3%	

Figure 4-1
Coal Plant Six Unit Expense Schedule

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Expense Schedule	15%	15%	25%	25%	10%	10%	U1 startup										
			15%	15%	25%	25%	10%	10%	U2 startup								
					15%	15%	25%	25%	10%	10%	U3 startup						
							15%	15%	25%	25%	10%	10%	U4 startup				
									15%	15%	25%	25%	10%	10%	U5 startup		
											15%	15%	25%	25%	10%	10%	U6 startup
Total Expense %	15%	15%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	35%	35%	10%	10%	
Normalized Expense %	3%	3%	7%	7%	8%	8%	8%	8%	8%	8%	8%	8%	6%	6%	2%	2%	

Figure 4-2
Nuclear Plant Six Unit Expense Schedule

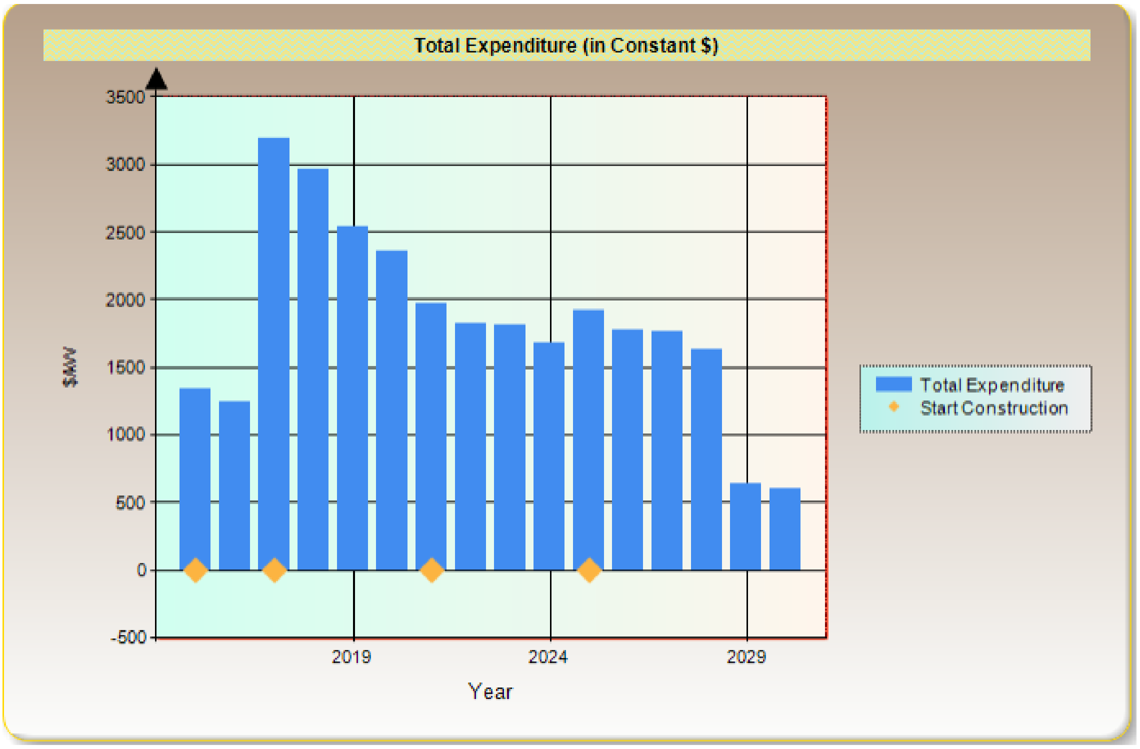


Figure 4-3
Six-Unit Nuclear Plant Total Expenditure Schedule

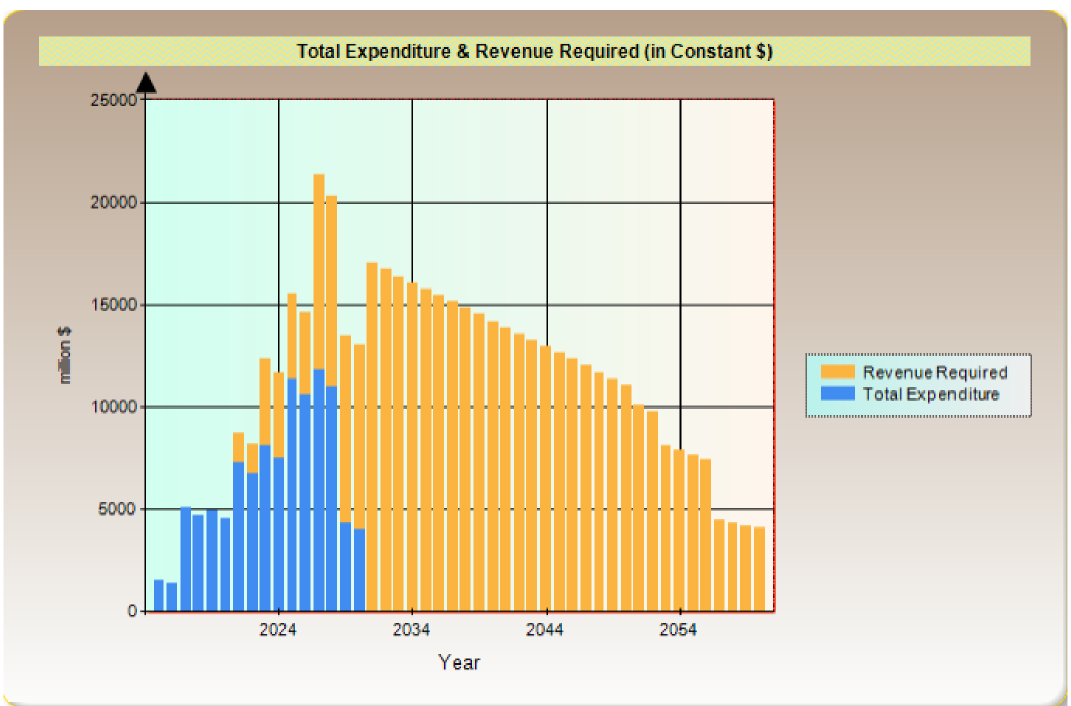


Figure 4-4
Six-Unit Nuclear Plant Total Expenditure and Revenue Required Schedule

Cost and Performance Data Uncertainties

For any technology, some degree of uncertainty is generally expected in cost and performance data, and in executing a project additional uncertainties are encountered and contribute to cost increases and schedule delays. Because new technologies do not have a history of construction or operating costs, only estimates can be used. Even for mature and commercial technologies, executing a project at a particular location may pose some challenges due to the uniqueness of technology and/or the demands of local conditions.

The tables below define the technology development and estimate uncertainties that affect the confidence level in a cost and performance estimate.

Table 4-4
Confidence Rating Based on Technology Development Status

Estimate Rating	Description
Mature	Significant commercial experience (several operating commercial units)
Commercial	Nascent commercial experience
Demonstration	Concept verified by integrated demonstration unit
Pilot	Concept verified by small pilot facility
Laboratory	Concept verified by laboratory studies and initial hardware development
Idea	No system hardware development

Table 4-5
Confidence Rating Based on Cost and Design Estimate

Estimate Rating	Description
Actual	Data on detailed process and mechanical designs or historical data from existing units
Detailed	Detailed process design (Class III design and cost estimate)
Preliminary	Preliminary process design (Class II design and cost estimate)
Simplified	Simplified process design (Class I design and cost estimate)
Goal	Technical design/cost goal for value developed from literature data

Table 4-6
Accuracy Range Estimates for Cost Data (Ranges in Percent)

Estimate Rating	Technology Development Rating				
	Mature	Commercial	Demo	Pilot	Lab and Idea
Actual	0	–	–	–	–
Detailed	-5 to +8	-10 to +15	-15 to +25	–	–
Preliminary	-10 to +15	-15 to +20	-20 to +25	-25 to +40	-30 to +60
Simplified	-15 to +20	-20 to +30	-25 to +40	-30 to +50	-30 to +200
Goal	-	-30 to +80	-30 to +80	-30 to +100	-30 to +200

All estimates in this report are based on a simplified estimate rating category. The technology maturity is listed in the next section.

In general, longer term (greater than three years duration) projects carry more risks than short term projects and technologies in the pilot or demonstration stage carry higher risks than technologies in commercial or mature stage.

Risks associated with a new coal or nuclear plant project can be considered in terms of how they affect time-related costs that are impacted by delays in the project schedule, such as interest payment on funds used during construction, and non-time-related costs, such as higher-than-expected material or labor costs.

The primary risks that affect the costs associated with the construction of a new plant are as follows:

- Project management
- Changes in the certified design (nuclear only)
- Changes in digital controls
- Availability of skilled engineering and construction personnel/labor
- Capacity factor
- Licensing processes (nuclear only)
- Availability of key equipment
- Effectiveness of the modularization construction process
- Effectiveness of construction planning/assistance software: Multi-D CAD-CM, advanced digital info systems
- Escalation in material costs
- Availability of financial incentives
- Safety goal standardization
- Design standardization within families of plants
- Radioactive waste disposal (nuclear only)

Details about these types of risks, their likelihood, and the severity of the risk are discussed in more detail in the nuclear section of the report.

Sensitivity Analysis

The uncertainty surrounding the adjustment factors used to generate South African costs, as well as the uncertainty in the baseline TPC estimates themselves, can be analyzed using the risk analysis software Crystal Ball. Using Monte Carlo simulation, Crystal Ball runs through a range of possible assumptions to reveal the range of possible outcomes (forecasts) that these assumptions can lead to, as well as the probability of these outcomes.

For this study, the assumptions made about the labor productivity, the labor rate, and the infrastructure cost were evaluated, as well as the uncertainty surrounding the baseline TPC. Each assumption was assigned a range of possible values using a triangular distribution, in which the baseline adjustment factor was the likeliest value, and a minimum and maximum value were assigned. For example, Figure 4-5 shows the probability distribution for the local labor productivity factor, with the base assumption that was used throughout the study (2.3) as the likeliest value with a maximum value of 2.45 and a minimum value of 1.9.

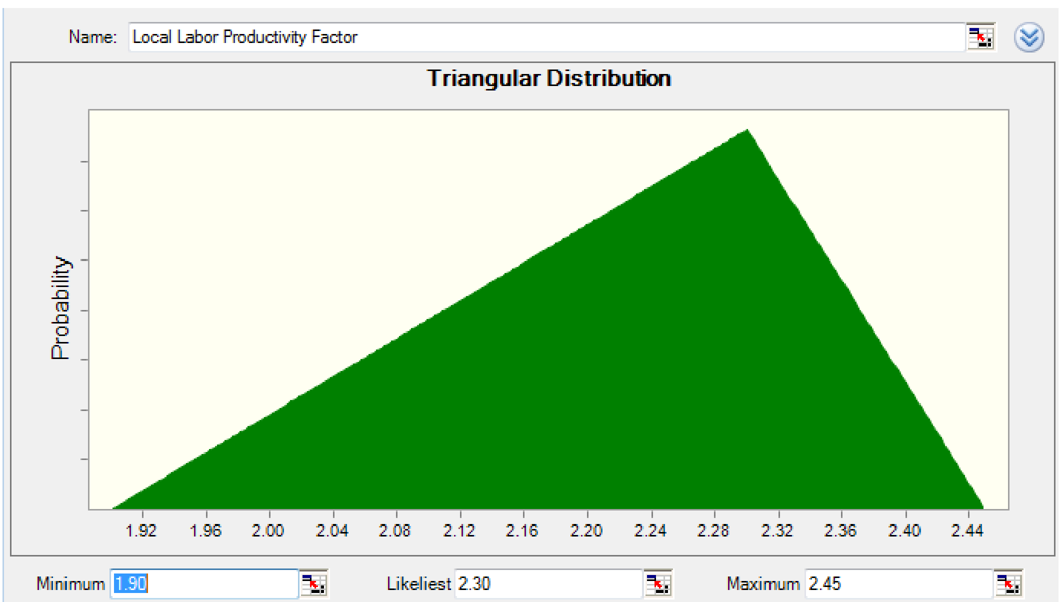


Figure 4-5
Labor Productivity Factor Distribution

Table 4-7 shows the probability assumptions used for all three conversion factors analyzed. The local labor productivity factor and local labor rate were chosen based on data provided by EPRI’s subcontractor. The infrastructure adder analyzed the assumption that it may cost more to build a plant in a more remote location, due to the need to house laborers and perhaps the need to build new roads to access the construction locations. Though not included as a factor in the base case cost adjustments, it would be applied after the adjustments for local and foreign materials, equipment, and labor just before the conversion to Rand. It was assumed that while the productivity and labor could be higher or lower than the assumption used for this study, it was not likely that the infrastructure adder would be lower than 1 and, therefore, it was only analyzed as a potential adder to the cost.

Table 4-7
Probability Assumptions

	Minimum	Likeliest	Maximum
Local Labor Productivity Factor	1.9	2.3	2.45
Local Labor Rate	0.49	0.56	0.64
Infrastructure	1	1	1.15

The sensitivity around the baseline TPC estimate was evaluated based on the technology maturity. It was assumed that those technologies that are more mature generally have more accurate estimates of plant costs, while those that are still in the demonstration or early commercial phase may not have as accurate of estimates.

Table 4-8
TPC Uncertainty Ranges

Technology	Maturity Rating	Minimum	Maximum
PC	Mature	-15%	+20%
Integrated Gasification Combined Cycle	Demonstration	-25%	+40%
FBC	Commercial	-20%	+30%
Nuclear	Demonstration	-25%	+40%
OCGT	Mature	-15%	+20%
CCGT	Mature	-15%	+20%
Wind	Mature	-15%	+20%
Parabolic Trough	Commercial	-20%	+30%
Central Receiver	Demonstration	-25%	+40%
PV – Thin Film	Commercial	-20%	+30%
PV – Concentrating	Demonstration	-25%	+40%
Biomass	Commercial	-20%	+30%

As Crystal Ball performs its analysis, it randomly selects values from within the probability distributions and calculates the TPC (forecast) associated with that set of assumptions. After running through a specified number of trials (for this study, a runtime of 10,000 trials was selected) Crystal Ball allows the user to examine the complete set of statistical values calculated, including the minimum, average, and maximum values of the entire range and the probabilities associated with values within the range.

Figure 4-6 shows the cumulative frequency for the TPC of an example PC unit. Marked on this chart are the probabilities, where P100 represents 100% probability that the cost will be higher than that value (the minimum value) and P0 represents a 0% probability that the cost will be higher than that value (the maximum value). P90 represents a 90% probability that costs will be higher than that value (10% probability that costs would be lower) and P10 represents a 10% probability that cost will be higher than that value (90% probability that costs would be lower).

For the PC unit results shown below, the minimum value is about 18% lower than the base case, the P90 value is about 6% lower than the base case, the P10 value is about 17% higher than the base case, and the maximum value is about 36% higher than the base case. This helps give a sense of the range of possible costs compared to the baseline estimate calculated in this study. Table 4-9 shows the average results for all of the different technologies (including the P50 results, which aren't shown on the figure). In all cases, the most mature technologies show the smallest range of uncertainty, while the least mature technologies demonstrate the most uncertainty.

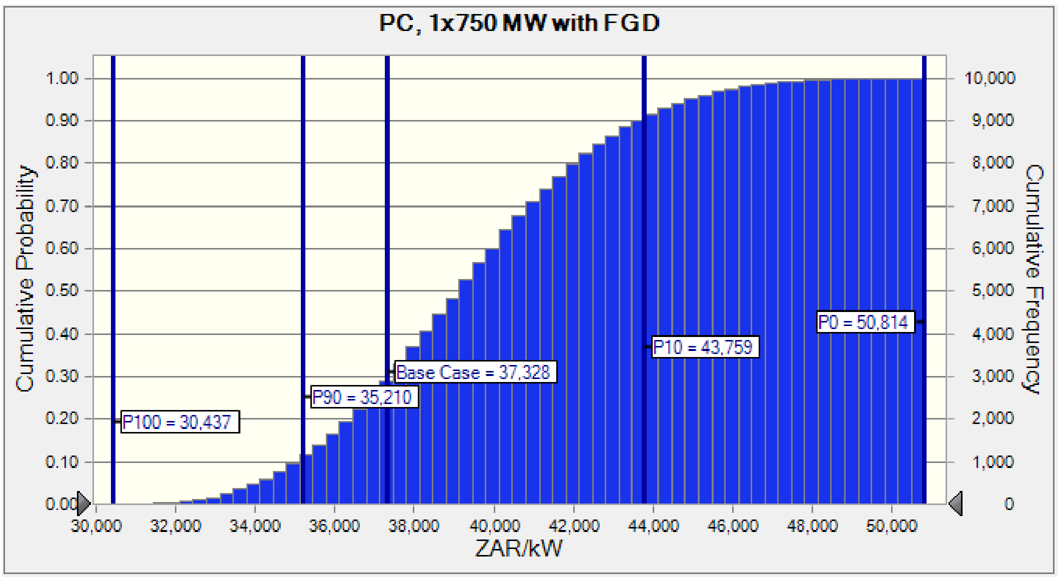


Figure 4-6
Cumulative Frequency for TPC

Table 4-9
Average Sensitivity Analysis Results for All Technologies

Technology	P100	P90	P50	P10	P0
PC	-18%	-6%	5%	17%	36%
Integrated Gasification Combined Cycle	-27%	-10%	8%	30%	61%
FBC	-23%	-8%	6%	23%	48%
Nuclear	-27%	-9%	8%	29%	62%
OCGT	-17%	-6%	5%	17%	35%
CCGT	-15%	-4%	6%	18%	34%
Wind	-15%	-4%	6%	18%	36%
Parabolic Trough	-22%	-7%	7%	23%	45%
Central Receiver	-27%	-9%	9%	30%	60%
PV – Thin Film	-19%	-6%	8%	24%	46%
PV – Concentrating	-23%	-8%	9%	31%	56%
Biomass	-24%	-7%	6%	23%	47%

In addition to wanting to understand the uncertainty surrounding the results, it is important to understand the influence that each assumption has on the forecast and which assumptions have the biggest effect on the uncertainty. Crystal Ball calculates sensitivity by computing rank correlation coefficients between every assumption and every forecast while the simulation is running. Correlation coefficients provide a meaningful measure of the degree to which assumptions and forecasts change together. If an assumption and a forecast have a high correlation coefficient, it means that the assumption has a significant impact on the forecast. Positive coefficients indicate that an increase in the assumption is associated with an increase in the forecast. Negative coefficients imply the opposite situation. The larger the absolute value of the correlation coefficient, the stronger the relationship. Contribution to variance, which is calculated by squaring the rank correlation and normalizing to 100%, shows what percentage of variance or uncertainty in the forecast is due to each assumption,

Figure 4-7 shows the contribution to variance results for the PC plant analysis discussed above. As can be seen, the TPC variation (TPC factor) has by far the biggest contribution to the variation in cost, accounting for 74.5% of the variance. The infrastructure adder contributes 14.7% to the variance, the labor productivity factor contributes 5.2% and the local labor rate factor contributes 5.6%. Table 4-10 shows the contribution to variance of the different factors for all of the technologies. For all technologies, the TPC factor contributes to over 70% of the variance, and for those technologies that are less mature and, therefore, had a higher range for the TPC factor, the contribution of the TPC factor to the variance is even more dominant, up to almost 95% in some cases.

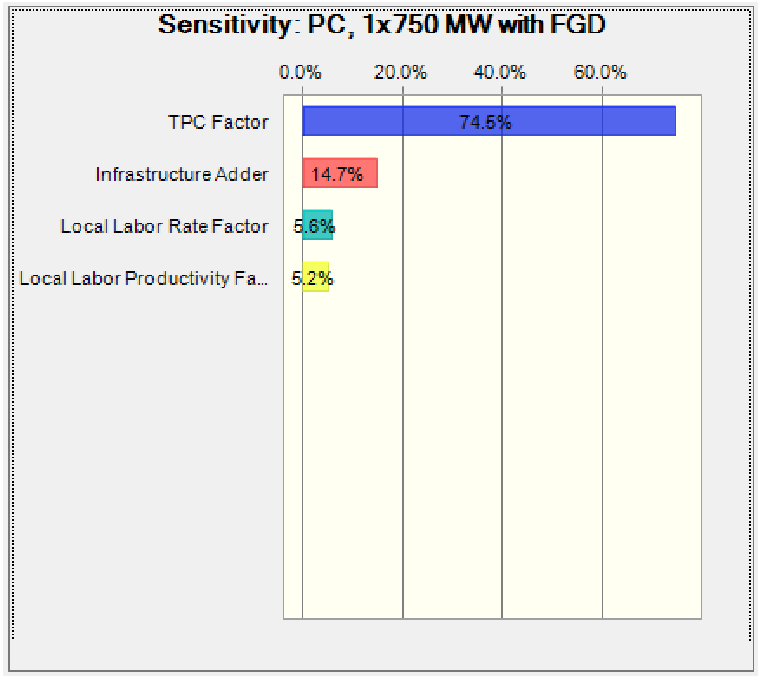


Figure 4-7
Variance Contribution

Table 4-10
Contribution to Variance for All Technologies

Technology	TPC	Infrastructure	Labor Productivity	Labor Rate
PC	74.5%	14.7%	5.2%	5.6%
Integrated Gasification Combined Cycle	90.7%	6.5%	1.3%	1.1%
FBC	84.6%	8.9%	3.5%	2.7%
Nuclear	92.3%	4.7%	1.4%	1.2%
OCGT	76.8%	15.3%	3.9%	3.6%
CCGT	81.6%	16.4%	0.8%	0.7%
Wind	82.7%	16.1%	0.5%	0.2%
Parabolic Trough	85.8%	8.8%	2.5%	2.4%
Central Receiver	91.3%	5.3%	1.6%	1.4%
PV – Thin Film	89.4%	10.0%	0.5%	0.1%
PV – Concentrating	94.1%	5.5%	0.3%	0.1%
Biomass	85.2%	8.2%	3.3%	2.9%

Future Escalate Rate Trends

Table 4-11 provides estimates of future annual escalation for a representative group of power plant-related items for the U.S markets. These average compound escalation estimates are presented as ranges. It is much more realistic to provide ranges than respective single values in order to reflect the uncertainties in the future economies of the U.S and in overseas countries.

Table 4-11
Estimated Compound Escalation Rates Trends for U.S.
(to be adapted for South Africa)

No.	Escalation Rates are Based on Bureau of Labor Statistics Producer Price Indices	Ave. Annual Compound Escalation, Jan-2005 to Jan-2015, %/yr
1	Construction Labor	3.1%
2	All Other Non-Site Labor	2.8%
3	Carbon Steel Plate, Fab'd	3.2%
4	Carbon Steel , Fab'd (Structural Steel)	2.4%
5	Carbon Steel Tubing	2.5%
6	Alloy Steel Tubing	2.8%
7	Refractory	3.5%
8	Pumps & Compressors	2.5%
9	Fans	3.6%
10	Turbomachinery	3.4%
11	Bulk Material Handling (Conveyor Belts)	2.1%
12	Pneumatic Conveying	2.4%
13	Power & Distribution Transformers	5.5%
14	Electric Switchgear	2.7%
15	Valves	5.2%
16	Electric wire & cable	4.7%
17	Process Control Instruments	2.7%
18	Fin Tube Heat Exchangers	3.3%
19	Heat Exchangers & Condensers	3.1%
20	Prefabricated Metal Bldg Systems	4.0%
21	Industrial Mineral Wool for Equipment Insulation	1.7%
22	Field Erected Metal Tanks	4.0%
23	Other Equipment	3.8%
24	Concrete	3.3%
25	Electrical Bulks	4.2%
26	All Other Bulk Items	2.9%

5
COST OF ELECTRICITY METHODOLOGY

Introduction

This section introduces the revenue requirement method, which has traditionally been used in the electric utility industry for the economic comparison of alternatives. In a rate-of-return regulatory environment, electric utilities are allowed to recover from their customers all costs associated with building and operating a facility, which are called *revenue requirements*. These costs include the annual costs of operating a plant as well as capital additions, which are in addition to the initial costs of total plant investment described in Section 4. The components of revenue requirements and how they are calculated are described, with emphasis placed on the calculation of capital-related, or fixed charge, revenue requirements—the portion of requirements related to the recovery of the booked cost. Booked costs are essentially the TCR, as defined in Section 4, as of the date the plant is placed in service and includes all capital necessary to complete the entire project. This section also describes levelized cost of electricity calculation methodology used for this study.

Table 5-1 shows the economic parameters used throughout this report for capital and cost of electricity calculations.

Table 5-1
Economic Parameters

		– – Current Dollars – –		– Constant Dollars –	
Type of Security	**% of Total**	**Cost (%)**	**Return (%)**	**Cost (%)**	**Return (%)**
Debt	60	10.0	6.0	7.3	4.4
Preferred Stock	N/A	N/A	0.0	N/A	0.0
Common Stock	40	12.2	4.9	9.4	3.8
Total Annual Return			10.9		8.2
Inflation Rate	2.5				
Federal and State Income Tax Rate	28				
Property Taxes, Insurance, and Other Taxes	2.0				
Discount Rate					
After Tax			9.19		6.93
Before Tax			10.87		8.16

The Components of Revenue Requirements

An Overview

The revenue requirement standard in the United States is defined as follows:

> ... a regulated firm must be permitted to set rates that will both cover operating costs and provide an opportunity to earn a reasonable rate of return on the property devoted to the business. This return must enable the utility to maintain its financial credit as well as to attract whatever capital may be required in the future for replacements, expansion and technological innovation, and it must be comparable to that earned by other businesses with corresponding risks.

The components of revenue requirements can be divided into two parts: (1) the *carrying charges*, also called *fixed charges*, related to the booked cost at the time the plant enters service as well as capital additions over the life of the plant and (2) the operating expenses, which include fuel and nonfuel operating and maintenance (O&M) costs (see Figure 5-1).

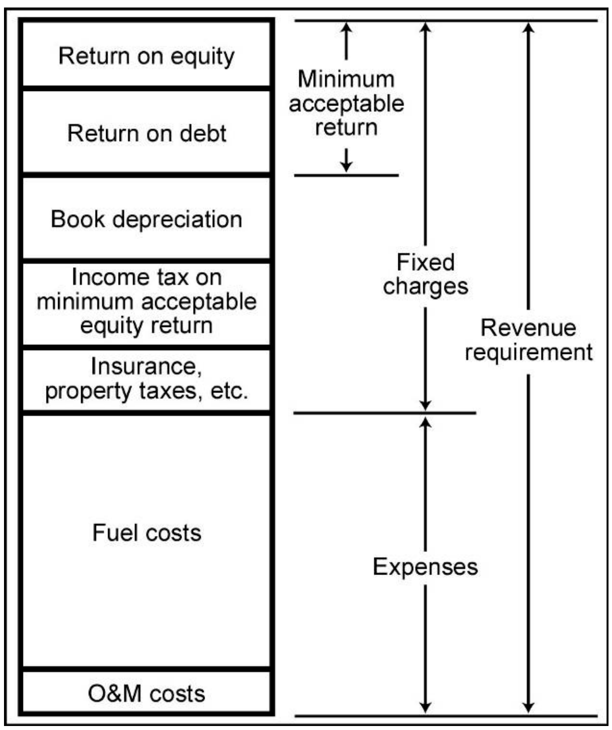


Figure 5-1
Revenue Categories for the Revenue Requirement Method of Economic Comparison

Utility investments in generation, transmission, distribution, and general plant can last 30 years or longer, and the booked costs are recovered over a period of time that is an approximation of the expected useful life for the particular investment, which is called the book life. Thus the booked costs for utility plants are recovered over roughly the period of time the investment is used in providing services to a utility's customers. The recovery of the booked costs is through an annual depreciation charge, which is a rough estimate of the extent to which an investment is used up, or obsolesces, each year of its useful life. The annual fixed charges include annual depreciation.

Construction expenditures are financed and accumulate allowance for funds used during construction (AFUDC), or "interest during construction." The sale of bonds and debentures as debt financing and the sale of common and preferred stock as equity financing are the primary means of financing utility investments.

Expenses are treated differently from the booked costs. They are recovered on an as-you-go basis directly through revenues collected from customers.

The Nature of Fixed Charges

Fixed charges are an obligation incurred when a utility plant is placed in service, and they remain an obligation until the plant is fully depreciated. The fixed charges must be collected from customers regardless of how much or how little the facility is used or how the market value of the facility changes.

The difference between the new book value (unamortized portion of the investment) and the current market value of the plant is called the sunk cost. The important characteristic of sunk costs is that they cannot be affected by management decisions. They are obligations that must be met irrespective of management decisions other than, of course, bankruptcy. Thus, the retirement of a utility plant, for example, will not affect the obligation of the utility to pay the fixed charges. Future capital additions and expenses to operate the plant are determined by management decisions. These costs are referred to as *incremental costs.*

The fixed charges themselves can, however, change. Changes in the cost of money, income tax rates, property tax rates, property assessment, or insurance rates would result in changes in fixed charges. For example, if changes in financial markets lead to lower interest rates and return on equity, the fixed charges would decline.

The Components of Fixed Charges

Annual fixed charges include the following components:

- Book depreciation
- Return on equity
- Interest on debt
- Income taxes
- Property taxes, insurance, and other taxes

Depreciation

There are two types of depreciation. The first is *book depreciation*, which is a measure of the extent to which a utility plant is used up or becomes obsolete. Book depreciation is used in setting rates and is charged directly to customers. The second is *tax depreciation*, which is used for computing income taxes and affects the fixed charges indirectly through income taxes.

While there are a number of ways of determining book depreciation and collecting the charges from customers, the straight-line method is used in this study. The annual depreciation is the booked cost divided by the book life of the plant. The book life for fossil, nuclear, solar thermal, and biomass plants in this study is 30 years, for PV plants is 25 years, and for wind plants is 20 years, as shown in Table 5-2. For this study, it is assumed that the net salvage value is zero—the salvage value of a utility plant just equals the cost of reclaiming the site. Thus annual depreciation is 3.33% of initial investment for fossil, nuclear, solar thermal, and biomass plants, 4% for PV plants, and 5% for wind plants.

Table 5-2
Book Lives and Book Depreciation for Utility Plant

Plant Type	Book Life (Years)	Annual Depreciation (%)
Fossil /Nuclear/Solar Thermal/Biomass	30	3.33
PV Plants	25	4.00
Wind Plants	20	5.00

In regulated utility economics, depreciation charges would be used to purchase the debt and equity initially used to finance construction of a project. Within the context of a utility company facing a need to expand a utility plant, depreciation represents one of the sources of funds for investment.

Tax depreciation differs from book depreciation in two respects. First, the federal government can allow for the recovery of investment for tax purposes over a period shorter than the book life of the utility plant. Second, the schedules for tax depreciation may allow for a larger portion of the recovery in the earlier years than is allowed with book depreciation. Straight-line tax life depreciation was assumed for this South African study with the assumption that the tax life is the same as the book life.

Return on Equity

Equity financing is selling ownership in the utility by issuing preferred or common stock. Equity holders earn a return on their investments in a utility plant. The return is set by the public service commission and is supposed to be (1) sufficient for a utility to maintain its financial credit, (2) capable of attracting whatever capital may be required in the future, and (3) comparable to the rate earned by other businesses facing similar risks. The return is earned only on the portion of the unamortized investment—that is, the portion that has not been depreciated.

Interest on Debt

Money from debt financing is acquired by mortgaging a portion of the physical assets of the company through *mortgage bonds* or by issuing an IOU without providing physical assets as collateral through *debentures*. Both mortgage bonds and debentures carry an obligation to pay a stated return. These interest payments take precedence over returns to equity holders. As with return on equity, interest is earned only on the unamortized investment. The key characteristics of equity and debt are summarized in Table 5-3.

Table 5-3
Key Characteristics of Utility Securities

Offering	Type	Life	Obligation to Pay Return	Relative Level of Return	Vote at Annual Meeting	Liquidation Priority
First mortgage bond	Mortgage on physical assets	30-35 years	First (fixed)	Lowest	No	First
Debenture	Unsecured obligation	10-50 years	Second (fixed)	Second lowest	No	Second
Preferred stock	Part owner of company	Usually perpetual	Third (usually fixed)	Second highest	Sometimes	Third
Common stock	Part owner of company	Perpetual	Last (variable)	Highest	Yes	Last

Income Taxes

Income taxes are the product of the income tax rate and taxable income. The tax rate represents a composite of the federal and, if applicable, state income tax rates. The income tax rate used for this study is 28%.

Because book and tax depreciation rates typically differ over the book life of a utility plant, there can be a difference between income taxes actually paid and those that *would be paid* if book depreciation were used for computing income taxes. This difference is referred to as *deferred taxes*. Deferred taxes increase over the tax life and then decline to zero by the end of the book life. The effect of accelerated depreciation for tax purposes is to shift the tax burden to the later years of operation.

Property Taxes and Insurance

Property taxes and insurance are calculated as the product of the insurance and tax rate and the TCR.

Calculating Annual Capital Revenue Requirements

The fixed charge components discussed above combine to make up the capital revenue requirement. The capital revenue requirement is the amount of income that must be recovered by the utility to pay off the capital costs and the return to investors, as well as income and property taxes. The annual capital revenue requirement represents the annual charges customers would have to pay each year so that the utility recovers its capital-related revenue requirements. The annual capital, or fixed, charge is the sum of the book depreciation, return on equity, interest on debt, income taxes, and property taxes and insurance for a given year. Table 5-4 shows an example of the annual capital revenue requirement of a plant, broken down into the different fixed charges using the financial parameters outlined in Table 5-1. In this table and throughout the section, costs are given for illustrative purposes and are not an estimate of actual plant costs.

Table 5-4
Annual Capital Revenue Requirements by Component

TPC (overnight cost), $/kW:	1,000
Plant Capacity:	750 MW
Plant Construction period:	4 years
AFUDC amount, $/kW:	114
Total Plant Investment, $/kW:	1,114
Startup, Inventory, Land, $/kW:	100
TCR, $/kW:	1,214

Year	Interest on Debt	Preferred Stock Dividends	Return on Common Equity	Capital Recovery	Income Taxes	Other Taxes and Insurance	Annual Capital Revenue Requirement
	--- Dollars per Kilowatt (Constant Dollar Analysis) ---						
1	$ 53.17	$ 0	$ 51.46	$ 40.47	$ 14.41	$ 24.28	$ 183.79
2	$ 51.39	$ 0	$ 49.74	$ 40.47	$ 13.93	$ 24.28	$ 179.83
3	$ 49.62	$ 0	$ 48.03	$ 40.47	$ 13.45	$ 24.28	$ 175.86
4	$ 47.85	$ 0	$ 46.31	$ 40.47	$ 12.97	$ 24.28	$ 171.89
5	$ 46.08	$ 0	$ 44.60	$ 40.47	$ 12.49	$ 24.28	$ 167.92
6	$ 44.30	$ 0	$ 42.88	$ 40.47	$ 12.01	$ 24.28	$ 163.96
7	$ 42.53	$ 0	$ 41.17	$ 40.47	$ 11.53	$ 24.28	$ 159.99
8	$ 40.76	$ 0	$ 39.45	$ 40.47	$ 11.05	$ 24.28	$ 156.02
9	$ 38.99	$ 0	$ 37.74	$ 40.47	$ 10.57	$ 24.28	$ 152.05
10	$ 37.22	$ 0	$ 36.02	$ 40.47	$ 10.09	$ 24.28	$ 148.08
11	$ 35.44	$ 0	$ 34.31	$ 40.47	$ 9.61	$ 24.28	$ 144.12
12	$ 33.67	$ 0	$ 32.59	$ 40.47	$ 9.13	$ 24.28	$ 140.15
13	$ 31.90	$ 0	$ 30.88	$ 40.47	$ 8.65	$ 24.28	$ 136.18
14	$ 30.13	$ 0	$ 29.16	$ 40.47	$ 8.17	$ 24.28	$ 132.21
15	$ 28.36	$ 0	$ 27.45	$ 40.47	$ 7.68	$ 24.28	$ 128.24
16	$ 26.58	$ 0	$ 25.73	$ 40.47	$ 7.20	$ 24.28	$ 124.28
17	$ 24.81	$ 0	$ 24.01	$ 40.47	$ 6.72	$ 24.28	$ 120.31
18	$ 23.04	$ 0	$ 22.30	$ 40.47	$ 6.24	$ 24.28	$ 116.34

Table 5-4 (continued)
Annual Capital Revenue Requirements by Component

Year	Interest on Debt	Preferred Stock Dividends	Return on Common Equity	Capital Recovery	Income Taxes	Other Taxes and Insurance	Annual Capital Revenue Requirement
	--- Dollars per Kilowatt (Constant Dollar Analysis) ---						
19	$ 21.27	$ 0	$ 20.58	$ 40.47	$ 5.76	$ 24.28	$ 112.37
20	$ 19.49	$ 0	$ 18.87	$ 40.47	$ 5.28	$ 24.28	$ 108.41
21	$ 17.72	$ 0	$ 17.15	$ 40.47	$ 4.80	$ 24.28	$ 104.44
22	$ 15.95	$ 0	$ 15.44	$ 40.47	$ 4.32	$ 24.28	$ 100.47
23	$ 14.18	$ 0	$ 13.72	$ 40.47	$ 3.84	$ 24.28	$ 96.50
24	$ 12.41	$ 0	$ 12.01	$ 40.47	$ 3.36	$ 24.28	$ 92.53
25	$ 10.63	$ 0	$ 10.29	$ 40.47	$ 2.88	$ 24.28	$ 88.57
26	$ 8.86	$ 0	$ 8.58	$ 40.47	$ 2.40	$ 24.28	$ 84.60
27	$ 7.09	$ 0	$ 6.86	$ 40.47	$ 1.92	$ 24.28	$ 80.63
28	$ 5.32	$ 0	$ 5.15	$ 40.47	$ 1.44	$ 24.28	$ 76.66
29	$ 3.54	$ 0	$ 3.43	$ 40.47	$ 0.96	$ 24.28	$ 72.70
30	$ 1.77	$ 0	$ 1.72	$ 40.47	$ 0.48	$ 24.28	$ 68.73

A common way of expressing the capital related revenue requirements is as a fixed charge rate. Fixed charge rates can be measured as annual fixed charge rates or levelized fixed charge rates.

Annual fixed charge rates express the annual capital revenue requirements as a percentage of the booked costs. For example, in Table 5-4 the booked cost of the plant is $1,214/kW. The annual capital revenue requirement divided by the booked plant cost gives the annual fixed charge rate for the plant. The annual fixed charge rates decline over time as the annual capital revenue requirements decline.

Levelized fixed charge rates translate the booked cost into an annual dollar charge that is constant over the years with the same present value as the actual annual capital revenue requirements. Levelized fixed charge rates are used for comparing generating alternatives on the basis of levelized costs. To calculate the lifetime revenue requirement of a plant, the present value of these annual capital charges is calculated for each year and summed to determine the total present value. The present value is calculated based on the weighted average cost of capital (WACC) or discount rate, which is the product of the cost of debt (or interest rate) and the percentage of debt financing plus the product of the cost of equity and the percentage of equity financing. For example, in this study, the real before tax discount rate is calculated as:

(% debt) x (cost of debt) + (% equity) x (cost of equity) = discount rate
60% x 7.3%/year + 40% x 10.6%/year = 8.6%/year

The present value for each year is calculated using the equation:

P/F = 1/(1 + i)n **Equation 5-1**

where P is the present value, F is the annual capital cost for the given year, *i* is the discount rate, and n is the year of the capital cost minus the year to which the costs are being presently valued. For example, if the year of the cost is 2030 and the costs are discounted to 2010, then n = 20. Table 5-5 shows the annual fixed charge rate, present value factor, and the annual present value capital charges for the example shown in Table 5-4.

Table 5-5
Annual Fixed Charge Rate and Levelized Charge Rates

Year	Annual Capital Revenue Requirement	Annual Fixed Charge Rate	Present Value Factor	Present Value Capital Charges
1	$ 183.79	0.151	0.921	$ 169.21
2	$ 179.83	0.148	0.848	$ 152.43
3	$ 175.86	0.145	0.780	$ 137.24
4	$ 171.89	0.142	0.718	$ 123.50
5	$ 167.92	0.138	0.661	$ 111.08
6	$ 163.96	0.135	0.609	$ 99.85
7	$ 159.99	0.132	0.561	$ 89.70
8	$ 156.02	0.128	0.516	$ 80.54
9	$ 152.05	0.125	0.475	$ 72.26
10	$ 148.08	0.122	0.438	$ 64.80
11	$ 144.12	0.119	0.403	$ 58.06
12	$ 140.15	0.115	0.371	$ 51.98
13	$ 136.18	0.112	0.341	$ 46.50
14	$ 132.21	0.109	0.314	$ 41.56
15	$ 128.24	0.106	0.289	$ 37.12
16	$ 124.28	0.102	0.266	$ 33.12
17	$ 120.31	0.099	0.245	$ 29.52
18	$ 116.34	0.096	0.226	$ 26.28
19	$ 112.37	0.093	0.208	$ 23.37
20	$ 108.41	0.089	0.191	$ 20.76
21	$ 104.44	0.086	0.176	$ 18.41

Table 5-5 (continued)
Annual Fixed Charge Rate and Levelized Charge Rates

Year	Annual Capital Revenue Requirement	Annual Fixed Charge Rate	Present Value Factor	Present Value Capital Charges
22	$ 100.47	0.083	0.162	$ 16.31
23	$ 96.50	0.079	0.149	$ 14.42
24	$ 92.53	0.076	0.138	$ 12.73
25	$ 88.57	0.073	0.127	$ 11.22
26	$ 84.60	0.070	0.117	$ 9.86
27	$ 80.63	0.066	0.107	$ 8.66
28	$ 76.66	0.063	0.099	$ 7.58
29	$ 72.70	0.060	0.091	$ 6.61
30	$ 68.73	0.057	0.084	$ 5.76

The present values for each year are then summed to calculate the total present value for the plant. Using this total present value and the discount rate, the annual capital payment required for the plant can be calculated using the equation:

A/P = [i(1+i)n] / [(1+i)n – 1] **Equation 5-2**

where A is the regular annual payment, P is the present value, *i* is the discount rate, and n is the number of years over which the payments are being made. For the example above, the total present value (P) is $1,580.4/kW and the annual payment factor is 0.094, resulting in an equivalent annual payment (A) of $148.63/kW.

The equivalent payment that must be made each year to cover the capital costs of the plant, or the annual revenue requirement, has now been calculated. This is often expressed as a levelized fixed capital charge rate, which is calculated as the annual payment divided by the booked cost, just like the annual fixed charge rate. For this example, the levelized capital charge rate is 0.122.

Calculating Cost of Electricity

Cost of electricity calculations combine the capital and O&M costs of a plant with the expected performance and operating characteristics of the plant into a cost per megawatt-hour basis. This procedure allows for comparison of technologies across a variety of sizes and operating conditions and allows for the comparison of the cost of electricity of a new plant with that of an existing plant. The cost of electricity typically consists of three cost components: the capital cost, the O&M cost, and the fuel costs. When presented independently, these cost components typically have different units. However, they must all have the same cost unit basis when combined to calculate the cost of electricity, typically $/MWh (or for South Africa, ZAR/MWh).

Annual Megawatt-Hours Produced

The amount of electricity produced by a plant in a given year is a key piece of information for calculating the levelized cost of electricity. The maximum number of megawatt-hours that a plant could produce in one year would occur if the plant operated at full load 24 hours a day for 365 days a year (8760 hours per year). In reality, a plant will be shut down at times during the year, either for maintenance or because the electricity is not needed and it would be uneconomical to operate the plant. The capacity factor is the ratio of the actual amount of electricity produced by the plant over the maximum amount that could be produced.

To calculate annual electricity production, the net capacity of the plant is multiplied by the number of hours that it operates (the capacity factor of the plant multiplied by 8760 hours/year). For example, a 500 MW plant that operates with an 85% capacity factor produces 3,723,000 MWh per year. A plant that operates for more hours in a year ultimately has more hours of electricity generation over which to spread its annual revenue cost requirements.

Constant vs. Current Dollars

Cost of electricity is often presented on a levelized basis. Like the annual revenue requirement presented above, this is the consistent cost of electricity that would be necessary to be collected annually to achieve the same present value as the actual capital and operating expenses of the plant. Levelized cost of electricity can be presented in two ways: constant (or real) dollars and current (or nominal) dollars. In a constant dollar analysis, the effects of inflation are not taken into account when looking at future costs, while in current dollar analysis, the effects of inflation are taken into account. While both methods are completely valid, it is important to know which method has been used when comparing cost results. Current dollar analysis results are always higher than constant dollar results because they account for year-by-year inflation in the cost of fuel, O&M, and the cost of money. This report uses constant dollar analysis.

Capital Contribution to Cost of Electricity

Capital costs in this report are presented in rand per kilowatt. Using the annual revenue requirement calculations described above, the cost in ZAR/kW is multiplied by the overall size of the plant to determine the cost on a dollar basis. This revenue requirement is then divided by the number of megawatt-hours produced to determine the capital cost on a ZAR/MWh basis.

O&M Contribution to Cost of Electricity

Fixed O&M costs throughout this report have been presented on a rand per kilowatt-year basis. Costs can be converted to a rand basis by multiplying the cost on a rand per kilowatt-year basis by the unit size. For a current-dollar analysis, the year-by-year costs are calculated using general inflation. In constant-dollar analysis, as was performed in this study, inflation is not taken into account; and, therefore, the fixed O&M cost remains the same throughout the life of the plant. The rand-per-year fixed O&M costs are then divided by the annual output of the plant to calculate the fixed O&M cost of electricity.

Variable O&M is often already presented as ZAR/MWh costs and, therefore, do not need to be converted to find the cost of electricity contribution. As with fixed O&M, for current-dollar analysis, the year-by-year costs are calculated using general inflation while for constant-dollar analysis, the variable O&M cost remains the same throughout the life of the plant.

Fuel Contribution to Cost of Electricity

The annual cost of fuel is calculated by multiplying the fuel cost in rand per gigajoule by the heat rate of the plant. Once again, for current-dollar analysis, the year-by-year costs are calculated using general inflation while in constant-dollar analysis, the cost remains the same throughout the life of the plant.

6
TECHNOLOGY DESCRIPTIONS

Coal Technologies

Pulverized Coal

The PC type of boiler dominates the electric power industry, producing about 50% of the world's electric supply. PC power generation starts by crushing coal into a fine powder that is fed into a boiler where it is burned to create heat. The heat generates steam that is expanded through a steam turbine to produce electricity.

The heat of the steam determines the relative efficiency of the power plant. Subcritical units produce steam at temperatures around 538°C (1,000°F) and pressures around 16.5 MPa (2,400 psig). Present day supercritical units generate steam at pressures of at least 24.8 MPa (3,600 psig) with steam temperatures of 565-593°C (1,050-1,100°F).

Subcritical units are more suitable for power plants intended to meet fluctuating electricity demand at different times of day. Supercritical units work best when operated at full-load, around-the-clock to deliver "baseload" electricity. The initial cost of subcritical units is 1 to 2% lower than that of supercritical units. Supercritical units operate at about two percentage points higher efficiency than subcritical units (i.e., increasing from 36.5 to 38.5% efficiency on a higher heating value basis for plants with wet cooling towers).

For both the subcritical and supercritical plant configurations, the major components of a PC-fired plant include coal-handling equipment, steam generator island, turbine generator island including all balance of plant (BOP) equipment, bottom and fly ash handling systems, as well as emission control equipment.

The steam generator island includes coal pulverizers, burners, waterwall-lined furnace, superheater, reheater, economizer heat transfer surface, soot blowers, Ljungstrom air heater(s), and forced-draft and induced-draft fans. The turbine-generator island includes the steam turbine, power generator plus the main, reheat, and extraction steam piping, feedwater heaters, boiler feedwater pumps, condensate pumps, and a system for condensing the low pressure steam exiting the steam turbine. For the conditions in South Africa, a dry cooling system (i.e., an air cooled condenser) is used for the base cases developed for this study. However, cost and performance estimates were also developed for a PC plant with a wet cooling system (i.e., a closed-loop wet cooling tower) for comparison purposes.

The water/steam loop starts at the condensate pumps. The water is pumped through low pressure feedwater heaters and moderately heated before entering the feedwater pumps. Here the pressure is increased and the feedwater is sent to the deaerator for oxygen removal and then through the high pressure feedwater heaters. The pre-heated feedwater enters the economizer section of the steam generator, recovers heat from the combustion gases exiting the steam generator, and then the heated water passes to water-wall circuits enclosing the furnace. After passing through the water-wall circuits, steam is then further heated in the convective sections and is superheated before exiting the steam generator. The high pressure, high temperature steam is then expanded through the high pressure steam turbine section. The cooler exiting steam is then returned to the steam generator for reheating to elevated temperatures and then sent to the intermediate pressure and low pressure steam turbine where it is expanded and exits at low temperature and vacuum pressure. The steam is then condensed in either an air cooled condenser or a wet cooling tower and the water collected and pumped forward to start the circuit again.

The PC plant evaluated in this study is a supercritical plant operating at 24.8 MPa (3,600 psig) with main steam and reheat steam temperatures of 565°C (1,050°F). A schematic diagram of a PC supercritical generating unit is shown in Figure 6-1.

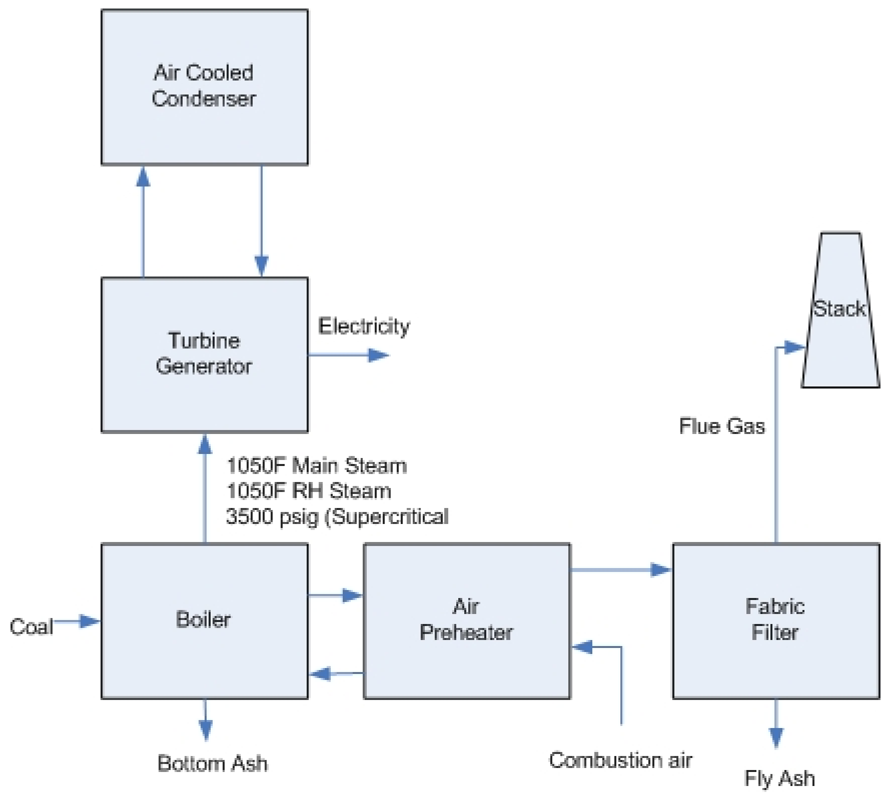


Figure 6-1
Simple Schematic of PC (Supercritical) Generating Unit

The first supercritical coal power plant was built in the late 1950s. Since then hundreds of units have been built around the world. Since 1990 more than 230 supercritical boilers representing more than 147 GW of power have been ordered, and in 2005 supercritical designs captured over 40% of worldwide orders for coal-fired boilers.[15] Research and development continues to advance the supercritical technology and has resulted in improved reliability, fuel flexibility, and wider load range operation. In the U.S., Europe, and Japan, programs are in place to develop boiler and steam turbine materials to accommodate higher steam conditions in the range of 700-

[15] Black, S., and N. Mohn, “Clean Coal Combustion – Competitive Solutions for Near Zero Emissions”, Coal-Gen Conference, Cincinnati, Ohio, August 2006.

760°C (1,290-1,400°F), which could significantly increase plant efficiency and reduced coal consumption.

Because of regulations in the U.S., Europe, and Japan, environmental controls for PC plants are progressing to near-zero emissions for SO_2, NO_X, particulate (including condensables), mercury, and several other hazardous air pollutants such as lead and arsenic. It is becoming more certain that in a few years time, emissions of CO_2 will also have to be reduced. In this study, PC plants are considered both with and without FGD units for environmental controls on top of pulse jet fabric filters (FF) for particulate control. In cases that include CO_2 capture, a selective catalytic reduction (SCR) system is also included for NO_X removal.

A limestone forced oxidation (LSFO) wet scrubber is the most widely used FGD system and is the system utilized in this study. The LSFO system uses a variety of gas-liquid contacting devices that have the capability to remove more than 95% of the inlet SO_2 and produce a disposable or wallboard-grade gypsum byproduct. This gypsum is able to be marketed in the U.S., though market analysis should be performed to properly assess the potential for a market for FGD-produced gypsum in South Africa.

The removal of particulate matter, or ash, is accomplished through use of FFs housed in structures referred to as baghouses that are located downstream of the air preheaters. FFs are porous cloth media that collect particulate as dust cakes on their surface. Pressure losses are incurred through the baghouse and increase as the particulate collects on the filter, placing an increased demand on fans. The baghouse is regularly pulsed to remove the particulate from the fabric filter for disposal.

In plants that include CO_2 capture, a small portion of the NO_X present in the flue gas (NO_2, which makes up about 5% of the NO_X produced from a coal plant) will react with the amine solvent, forming heat stable salts. While SCR is not necessarily required for a PC plant with capture, if it is not included then the plant will have higher O&M costs as a result of the loss and disposal of solvent. Therefore, SCR has been included for plants with CO_2 capture in this study. In the SCR system, ammonia is injected into the hot flue gas before passing over a catalyst. The ammonia mixes with the hot gases such that when passing over the catalystic surface, NO_X is reduced to nitrogen and oxygen.

The post-combustion carbon capture technology considered for PC plants in this study is an amine-based process. After the SO_2, NO_X, and particulates have been removed, the flue gas passes through an absorber where it interacts with a lean amine solution, monoethanolamine (MEA). The amine absorbs the CO_2 and the cleaned flue gas is emitted from the plant stack. The amine solution, which is now rich in CO_2, is pumped into a stripper in order to separate the amine and the gas, where steam provides the energy needed to desorb the CO_2 from the solution. The CO_2 is then removed from the absorber to be dried and compressed for transportation and storage.

Dry Cooling System

In a dry cooling system turbine exhaust steam is ducted directly to an air-cooled condenser. Heat rejection to the environment takes place in a single step in which steam is condensed in finned tube bundles, which are cooled by air blown across the exterior finned surfaces.

The dry system considered consists of the following major equipment:

- Multi-bay air cooled condenser
- Steam ducting from turbine exhaust to air cooled condenser
- Instrumentation and controls
- Electrical distribution
- Structures

A conceptual diagram is illustrated below.

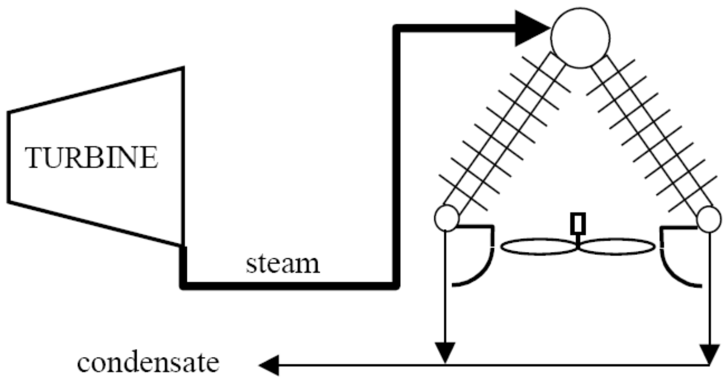


Figure 6-2
Conceptual Diagram of a 100% Dry Cooling System

IGCC

An integrated gasification combined cycle, or IGCC, is a technology that turns coal into synthesis gas or syngas. The gasification plant then removes impurities from the raw syngas before it is combusted. This results in lower emissions of sulfur dioxide, particulates, and mercury.

The plant is called “integrated” because heat recovery in the gasification unit is integrated with the plant's combined cycle. Additionally, the GT compressor provides pressurized air used in the air separation unit (ASU) that produces oxygen for the gasification process. The syngas produced is used as fuel in a GT which produces electrical power. To improve the overall process efficiency, heat is recovered from both the gasification process and also the GT exhaust in a HRSG producing steam. This steam is then used in steam turbines to produce additional electrical power.

A schematic diagram of the IGCC power plant is shown in Figure 6-4. It is the integration of the system components that brings the most important advantage of IGCC plants.

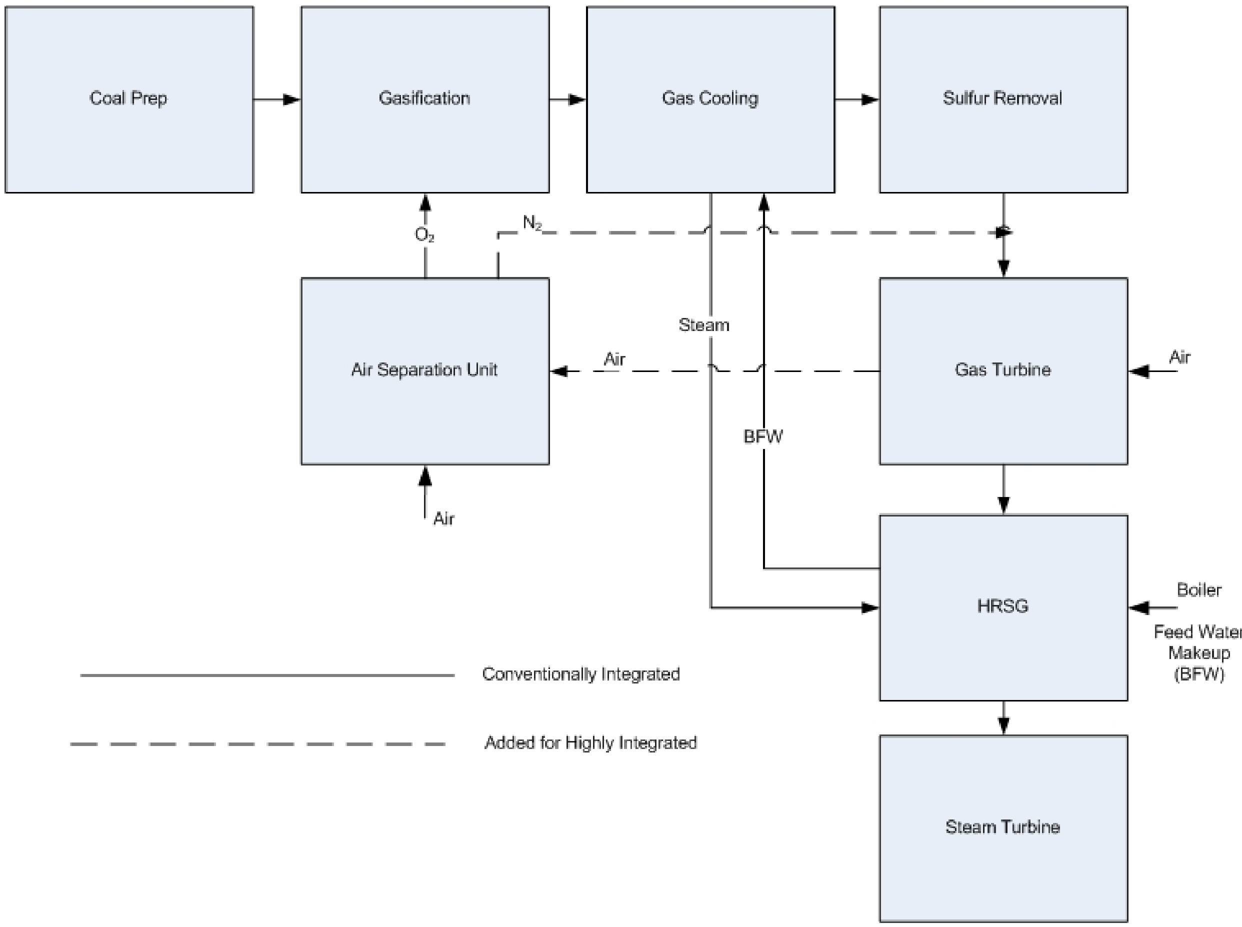


Figure 6-3
Schematic of an IGCC Power Plant

Major components are contained in two groupings, commonly referred to as the "gasification island" and the "power island." Typically, the capacity of the gasification system is selected to match the fuel needs of the GT, along with design decisions regarding spare gasification capacity, which may be used to increase plant availability or to allow supplemental firing to increase steam production for the steam turbine or process use.

The gasification island of an IGCC plant may resemble any of a number of different stand-alone gasification plants; gasification islands from different suppliers share many common elements but are also technically distinct in several ways. Elements common to IGCC gasification islands generally include a coal preparation area, a gasification reactor, an ASU, gas cooling and clean up, and a water-shift reactor if CO_2 capture is included.

The coal preparation area is where coal is pulverized and dried or slurried as necessary for feed to the specific type of gasification reactor. Additives may be added to adjust flow characteristics. Lime or another source of CaO may be added to optimize ash melting point and flow characteristics.

The gasification reactor receives dry or slurried coal, oxygen or air, and in some cases steam, and converts it to raw fuel gas composed chiefly of carbon monoxide, hydrogen, and methane. The reactor may incorporate one or more vessels and have one or two stages of reaction. Dry-feed reactors generally require lock hoppers for feed and for slag discharge. Slurry feed reactors may have a slag discharge hopper.

The ASU provides high purity oxygen when the gasifier is oxygen-blown. High-pressure air for the ASU may be provided from the GT compressor or from a separate compressor. Typically, the nitrogen by-product of the ASU is fed back to the combustor for dilution to reduce NOx formation and increase working gas volume.

Gas cooling generally serves double-duty by preheating boiler feedwater and/or generating part of the steam for the steam turbine, in addition to adjusting temperature as required for acid gas clean-up equipment. Gas clean-up removes solids, sulfur, mercury, and other undesired compounds before the fuel gas goes to the combustor(s). A water-shift reactor and CO_2 absorber may be added to enable CO_2 separation for sequestration and/or to provide hydrogen-rich syngas for other purposes. A major advantage of gasification-based energy systems relative to conventional coal combustion is that the CO_2 produced by the process is in a concentrated high-pressure gas stream. The partial pressure of CO_2 in the syngas, following the water-gas shift reaction step, is much higher than that in post combustion flue gas. This is especially true for oxygen-blown gasifiers, though air-blown gasifiers also provide a higher partial pressure of CO_2 than in ambient-pressure flue gas. This higher pressure makes it easier and less expensive to separate and capture CO_2 from syngas than from flue gas.

The power island of an IGCC plant uses the same basic components as a combined cycle power plant fired with natural gas or distillate oil. Modifications to these components may be made to suit a specific gasification technology. Three major components form the basis of the combined cycle: the GT, the HRSG, and the steam turbine.

The GT is at the heart of the combined cycle power plant. A multi-stage, axial-flow compressor draws in ambient air and raises its pressure for delivery to the combustor(s). In IGCC, a portion of this air may be redirected to the gasifier (air-blown gasifier) or to an air separation unit (oxygen-blown gasifier). One or more combustors mix fuel with air and combust it to create a high-pressure, high-temperature gas working fluid.

The working fluid exits the combustor(s) and flows through the multi-stage, axial-flow power turbine, which converts its heat energy and kinetic energy into rotational energy. Temperature and stress limits of blade materials in the power turbine are typically the limiting factor in the advancement of GT design for efficiency and power capacity. GTs firing low-heating value syngas often have higher fuel mass flow and lower flame temperatures than the comparable turbine firing natural gas or distillate. In many cases, despite the lower firing temperature, the higher mass flow allows an increase in GT power rating. Some turbine designs are modified with stronger drive shafts and larger generators to take advantage of this capacity.

Exhaust gas from the power turbine is directed to an HRSG. The HRSG typically will produce steam at two or three pressures and may incorporate a reheat loop. For IGCC, the gas cooler(s) in the gasification cycle may augment some of the heat exchange surface in the HRSG and/or take the place of feedwater heaters.

Steam from the HRSG is directed to a multi-stage steam turbine. In a single-shaft combined cycle, the steam turbine and the combustion turbine are installed on a common shaft, driving a single generator. In a dual-shaft combined cycle, the steam turbine is installed separately. In larger plants, it is common to have two or three GT/HRSG trains providing steam for a single large steam turbine. Typically, the power output from the steam turbine is about one-third to half of the output from the GT(s). As with conventional combined cycles, the steam turbine will be designed to match characteristics of the combustion turbine, HRSG, and condenser. The different heat, steam, and water requirements of the gasification system will further influence steam turbine and HRSG design.

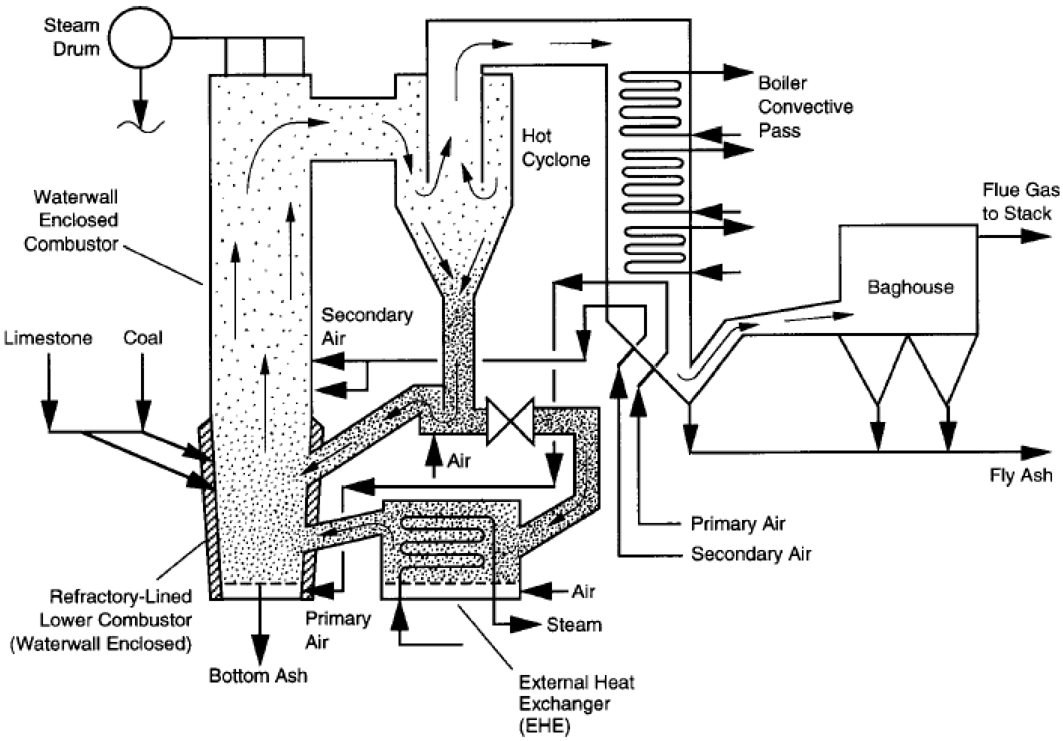
The South African coal used in this study has a high ash content and low heating value compared to U.S. coals often analyzed for gasification and IGCC applications. The major coal gasification processes available for commercial license are mostly entrained flow gasifiers (GE, COP, and Shell) that operate in the high temperature slagging region. While these entrained flow gasification processes could run the South African coal, the economics would be very adversely affected by the high ash content and lower grade coal. The slurry fed gasifiers of GE and COP would be particularly affected in this regard since achievable energy content of the slurry would probably be even lower than for the U.S. PRB coal, and it is doubtful that GE or COP would offer their process for this coal.

The dry coal fed entrained gasifiers (Shell and Siemens) could handle South African coal, and its low moisture content would prevent the drying costs from being too large. Fluid bed gasifiers such as KBR Transport could also run South African coal; however, the relatively low volatile matter content and the high ash content suggest that the reactivity may not be very high and that the carbon conversion would likely be considerably lower than has been experienced with the low rank more reactive U.S. coals and lignites. IGCC cost and performance estimates for this study are based on a Shell gasifier as a representative of commercially available gasifiers that could be used for this application.

There is an additional economic challenge for IGCC technology because of the high elevation of the mine-mouth power plant sites. The power output of a GT is markedly affected by elevation since the compressor is a constant volume machine. At an elevation of 1800 m, the IGCC net power output would be reduced by about 13% from that at sea level. The syngas required would also be less; however, there would be an increase in cost of electricity because some of the economies of scale would be lost.

FBC

In FBC plants, coal and limestone are fed into a bed of hot particles suspended in turbulent motion (fluidized) by combustion air, blown in through a series of distribution nozzles. The limestone is calcined to form free lime, a portion of which reacts with SO_2 to form calcium sulfate. The bed consists of unburned fuel, limestone, free lime, calcium sulfate, and ash. In-situ sulfur capture is most efficient between 825 and 875°C (1,520 and 1,610°F), and the boiler is usually designed to operate in this temperature range. The furnace enclosure is a waterwall construction and a convection pass for heat recovery from the flue gas is included. In this respect, the design is similar to that of a conventional PC boiler. Figure 6-5 shows a schematic of an FBC boiler system. As with a PC plant, the heat from combustion heats water in the walls of the boiler, generating steam that is expanded through a steam turbine to produce electricity. The FBC plant evaluated in this study is a subcritical plant with main steam at 16.5 MPa (2,400 psig) and both main steam and reheat steam at 565°C (1,050°F).



Source: SFA Pacific, Inc.

Figure 6-4
Schematic of an FBC Boiler system

FBC boilers operate at gas velocities high enough to entrain the majority of the bed material between 3.7 to 9.1 m/s (12 to 30 ft/s). Typically, a high-efficiency cyclone at the furnace exit is used to separate the entrained material and recycle it back to the bed. To prevent erosion damage in the lower regions of the furnace there are no in-bed tubes and the water walls are lined with refractory. To achieve the required heat duty, in-furnace heat transfer surface (wing walls, panels, etc.) is added to the water walls which may require an increased furnace height. Some designs provide the additional heat transfer surface with an external heat exchanger (EHE), where boiler tubes are immersed in a bed of the hot solids captured by the cyclone that are fluidized at a velocity sufficiently low to avoid tube erosion. The cooled solids leaving the EHE are then recycled to the foot of the furnace.

As there are no tubes in the bed, air staging is possible in an FBC, which results in lower NOx emissions. Staging means that the lower portion of the bed is supplied typically with 70% of the stoichiometric air required and operates under reducing conditions, which inhibit NOx formation. The remaining air is added approximately one fifth of the way up the reactor, just above where the refractory lining ends. Although NOx is reduced, staging increases the amount of CO formed to levels well above those achieved in PC units.

High combustion efficiency is maintained despite the low operating temperature by the use of recycle to extend the in-bed residence time of the fuel particles. This measure also lowers sorbent demand by increasing its percent utilization. An additional advantage of the low combustion temperature is that it prevents or limits the slagging of coal ash, thus greatly reducing the fouling of heat transfer surfaces. Hence, FBCs can handle a wide variety of fuels including those difficult to burn in PC boilers, such as high-ash, slagging/fouling coals, and coal wastes. However, this fuel flexibility is assured only if the boiler is designed for the full range of fuels that are intended for use.

If present as separate particles, crushing high ash coal has provided some challenges to operation of FBC units. Crushing the harder ash to achieve the required size distribution for circulation can result in the coal being too fine with it being elutriated from the bed before burning out. This either reduces combustion efficiency or results in fires in the cyclones. Alternatively crushing the coal to the required size distribution for combustion can result in the ash being too coarse to be elutriated into the cyclones and recirculated back to the furnace. It is believed that this issue is being addressed by use of two-stage crushing in preference to the more commonly used single-stage process.

UCG

UCG is a method of converting unworked coal - coal still in the ground - into a combustible gas which can be used for industrial heating, power generation, or the manufacture of hydrogen, synthetic natural gas, or diesel fuel.

UCG technology allows countries that are endowed with coal to fully utilize their resource from otherwise unrecoverable coal deposits in an economically viable and environmentally safe way. UCG turns this resource into high value products:

- Clean power
- Liquid fuels
- Syngas
- Fertilizers and other chemical feedstocks.

UCG uses a similar process to surface gasification. The main difference between both gasification processes is that in UCG the cavity itself becomes the reactor so that the gasification of coal takes place underground instead of at the surface.

The cost and performance data for the production of synthesis gas (syngas – mixture of CO and H_2) from UCG as well as the subsequent generation of electricity are not well defined for a commercial scale operation. Whereas the cost and performance data for surface coal gasification process is defined well, including the production of syngas in a gasifier, the important aspect of UCG is in the sustained burn and production of syngas. Hence, the focus here is on the production of syngas from UCG.

UCG Process

The basic UCG process involves drilling two wells into the coal, one for injection of the oxidants (water/air or water/oxygen mixtures) and another well some distance away to bring the product gas to the surface. The resulting high-pressure syngas stream is returned to the surface, where the gas is separated and contaminants are removed.

Coal has considerable variation in its resistance to flow, depending on its age, composition, and geological history, so simply relying on the natural permeability of the coal to transport the gas is generally not satisfactory. High pressure break-up of the coal with water (hydrofracking), electric-linkage, and reverse combustion have all been used with success in both pilot and commercial scale operations. The technique is best suited to deep coal seams, 500 meters plus, and can be undertaken both on and off-shore.

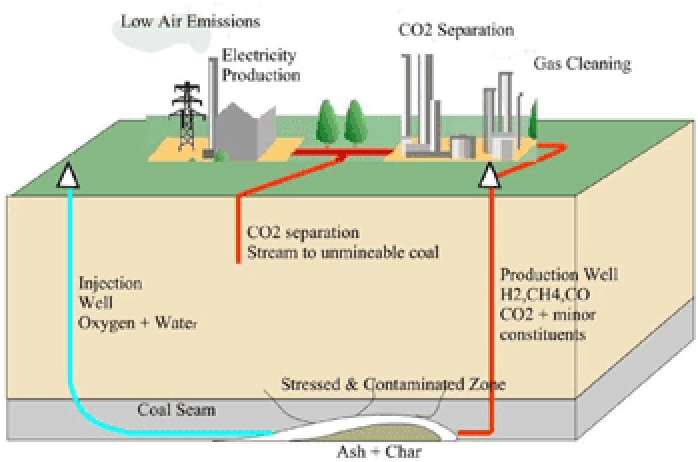


Figure 6-5
UCG Process

The coal at the base of the first well is then heated to temperatures that would normally cause the coal to burn. However, through careful regulation of the oxidant flow, the coal does not burn but rather separates into the syngas. The syngas is then drawn out of the second well. Two different methods of UCG have evolved and are commercially available:

- Vertical wells combined with methods for opening the pathway between the wells.
- Inseam boreholes using technology adapted from oil and gas production that can move the injection point during the process

Tests in Europe in the late 1990s demonstrated it was possible to have greater control of deep drilling, to create larger cavities in the coal seam for the gases, and to provide more efficient combustion. In addition, while the process had previously been criticized for generating large quantities of hydrogen as a useless by-product, hydrogen is now in demand as a feedstock for the chemical industry and shows potential as an alternative fuel for vehicles.

The advantages in the use of this technology - especially in the emerging markets of China, India, and South Africa - are the low plant costs (as no surface gasifiers are required) and the absence of coal transport costs.

Different Methods - Two different methods of UCG have evolved, both are commercially available. The first, based on technology from the former Soviet Union, uses vertical wells and a ‘reverse’ combustion to open up the internal pathways in the coal. The process was successfully tested in Chinchilla, Australia (1999-2003) using air and water as the injected gases. The second, tested in European and American coal seams, creates dedicated in-seam boreholes, using drilling and completion technology adapted from oil and gas production. It has a moveable injection point known as controlled retraction injection point (CRIP) and generally uses oxygen or enriched air for gasification.

In-seam and Directional Drilling

In-seam drilling was identified at an early stage as an option, but steerable drilling in coal only started to become available in the latter stages of the U.S. program of UCG (1975-1990). The breakthrough came when directional in-seam drilling was combined with CRIP. This arrangement provided an unobstructed path for the departing gases.

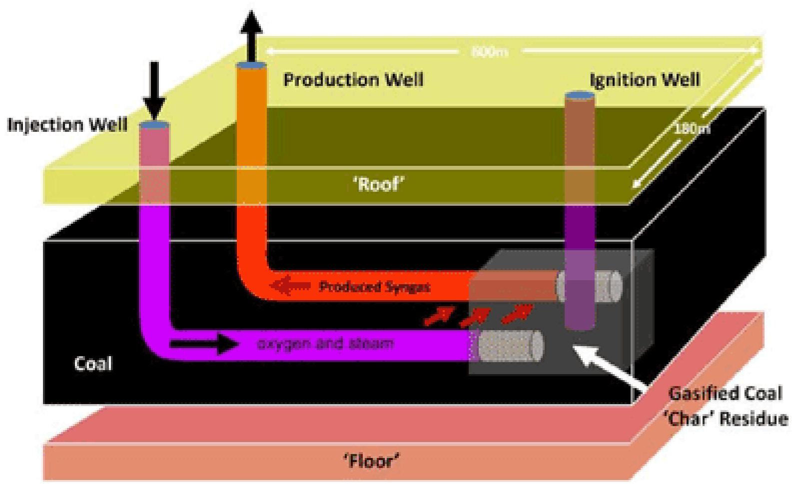


Figure 6-6
Controlled Retractable Ignition Point (CRIPs)

Site Selection

Site selection is paramount to a successful UCG project. The characteristics of the coal seam, the permeability and fault structure of the local strata and the geology and hydrogeology of the area which surrounds the target coal seam must be fully understood. This requires the drilling of pilot bore holes to coal seam depth for coring and seam characterization, and a good quality seismic survey (preferably 3D) of the whole area. The same method is used when assessing the suitability of an area for CCS and may offer synergies for UCG and CCS. Modeling of the hydrogeology will be required to meet ground water requirements. This detailed exploration work is one of the major upfront costs of UCG, as it is for all conventional mining projects.

Development History and Present UCG Activities

Development History

The technology of UCG is quite old as it was already developed in the 1920s and 1930s in the former Soviet Union. Large-scale operations (>1GW) were developed by the Soviets in the 1970s and one plant in Uzbekistan still operates today. Low natural gas prices in the 1990s eliminated much of the ongoing development in the U.S., although in Europe, a substantial program of development in deeper seams was maintained until the present day. Extensive trials in Europe, the U.S., Russia, and Australia, have proven the technology on many occasions.

U.S. Trials

There have been over thirty trials in the U.S., divided into four sections:

- The first series from 1973-1976 were commissioned to evaluate the methods being used in Russia. The projects were carefully researched and extensively monitored and vertical wells formed the basis of the process, usually drilled quite close together.
- The second series from 1976 - 1979 was conducted by Lawrence Livermore National Laboratory (LLNL) and the U.S. Department of Energy facility at Hoe Creek.
    - These tests provided the basis for a number of developments which included the validation of the CRIP scheme, the validation of subsidence models, and the first oxygen/steam injection experiments in the U.S. A wide range of instruments and monitoring tools were used, including the use of chemical (gas) tracers.
    - The tests also gave rise to the first recognition of possible groundwater hazards. In Hoe Creek I, where explosive fracturing was used, the test continued for 11 days with using air injection. Approximately 7% of the gas was lost into the rock formation. Hoe Creek II used reverse combustion, and gasification lasted for 43 days. Water influx significantly lowered the gas quality. To decrease the water inflow the operating pressure in the burn zone was increased. This resulted in a significant amount of gas (approximately 20%) being lost into the rock formation. Much of this loss is thought to have occurred when the burn zone collapsed, exposing the overlying Felix No 1 coal seam, which was at a lower hydrostatic pressure. This event which happened in strata would now be classed as having high environmental risk (and would therefore not be considered for development of any kind), which gave UCG an unjustified reputation as a potential hazard.
- The third series was conducted at Rawlins, in Wyoming in 1979, using steeply dipping seams, and was successful in producing high quality gas, with lower oxygen demand than was the case in horizontal strata.
- The fourth series (Centralia and Rocky Mountain trials) occurred from 1984 -1989 and was a direct comparison between the CRIP method and the enhanced Soviet (vertical borehole) method. Rocky Mountain Trial gasified 14,000 tons of coal in 93 days.

Present UCG Activities

The technology has gained substantial interest in the last ten years as fossil fuel prices increased and concerns over rising fossil fuel imports in Europe have grown. UCG in combination with CCS shows considerable promise as a low cost solution to carbon abatement. The composition of the syngas is particularly suited to CO_2 capture and the high pressure from deep UCG will require a smaller and less costly plant. The possibility of storing CO_2 in nearby coal seams is a further option which is currently being researched. So far the results look very promising.

There are a number of pilot projects either operating or in the planning stage in more than 25 countries, including the U.K., Australia, the U.S., South Africa, and China. Some of the highlights are:

Eskom UCG Project

Eskom's Majuba UCG pilot plant, based on Ergo Exergy's proprietary ***e*UCG™** technology, was the first in the African continent. The pilot plant, operated from January 2007 until September 2011, produced syngas from unminable coal deposit to supply fuel to the 4,200 MWe Majuba power plant. With syngas production capacity at 15,000 Nm^3/hr, the Majuba UCG project was unprecedented in its scale, geological complexity, and pioneering nature. The UCG syngas was co-fired with coal and contributed 3MW to the Majuba power station's existing electricity production of approximately 650MW.

The Majuba power station was originally supplied by an adjacent underground coal mine with a design capacity of 15 million t/a. The mine, which was targeting a 3.5 meter thick coal seam at a depth of approximately 300m, was closed and abandoned due to frequent dolerite intrusions in the coal, creating difficult mining conditions.

The pilot facility successfully proved that the ***e***UCG™ technology works in complex geological settings to extract coal from the unminable coal deposit by converting it into gas for power generation, without experiencing the problems that caused closure of the conventional mine. Planned expansion of the gas production facility will ultimately see all boilers firing on a mixture of coal and ***ε***UCG™ Syngas. It is anticipated that approximately 30% of the plant's fuel will be eventually provided by ***ε***UCG™ syngas, producing approximately 1,200 MWe of electricity. Furthermore, Eskom has initiated development plans for a UCG demonstration facility with production capacity of 250,000 Nm3/hr. The syngas will supply fuel to a 100 to 140 MWe gas turbine plant. When combined with Ergo Exergy's ***ε***UCG™ process, such gas plants can reach efficiencies of up to 40%, providing for a significantly reduced carbon footprint.

Additionally, in 2013 Eskom and Sasol New Energy signed a research agreement to jointly explore UCG technology development in South Africa.

Linc Energy UCG Projects

From 1999 to 2013 Linc Energy developed and tested five successive UCG designs at the Chinchilla demonstration facility in Australia. The facility was the first of its kind in the western world to operate multi-panel UCG gasifiers. With the completion of UCG Gasifier 5 at Chinchilla, the company has successfully demonstrated the technology and now focuses on the commercial roll-out of UCG in strategic locations around the world.

In September 2014 the U.S. Environmental Protection Agency (EPA) granted final approval of Linc Energy's UCG R&D License, allowing the company build and operate a UCG demonstration facility in one of the richest coal resources in the world, Wyoming's Powder River Basin (PRB). The project will employ Gasifier 6 (G6), the next generation gasifier incorporating technology enhancements from Linc Energy's Gasifiers 1 – 5 tested at Chinchilla. The gasifier is designed to gasify the Wyodak coal at a depth of 1100 feet (335 m) for 90-100 days while proving no subsidence, decommissioning procedures and UCG operations and monitoring. The G6 project will utilize state of the art drilling techniques, equipment selection, modular surface facilities, gasifier operations and engineering.

The company is also developing UCG projects in Europe and Africa. In July 2014, Linc Energy was granted initial approval from the Polish Ministry of the Environment to commence a UCG project in Poland. Stage one of the Polish UCG project involves gas production trials and process verification. The trials are precursor to the development of a commercial UCG project, with an expected capacity of 1bcm of syngas per year.

In Africa, Linc Energy signed its first commercial UCG license in 2013 with Exxaro Resources, one of South Africa's largest diversified coal resource groups, to develop UCG projects in Sub-Saharan Africa. The deal allows for the joint pursuit of UCG to develop energy solutions in the region, including utilizing syngas for power generation and gas-to-liquids.

China

China has the largest UCG program worldwide, with about 30 projects in different phases of preparation that use underground coal gasification. One of China's current UCG projects is a joint venture between SinoCoking Coal and Coke Chemical Industries. In October 2014 the companies commenced phase one of the construction of a UCG facility near SinoCoking Coal's mines in Henan Province. The UCG project employs the patented underground coal gasification (UCG) and carbon capture and storage (CCS) processes developed and jointly owned by SinoCoking's two technology partners – the Institute of Process Engineering of the Chinese Academy of Sciences and the North China Institute of Science and Technology. This project will be the first commercial venture in China to deploy both UCG and CCS technologies.

In phase one, the UCG facility will produce 60,000 cubic meters of syngas per hour when completed in March 2015. The second phase of the UCG project, scheduled to begin construction in April 2015, is expected to achieve 120,000 cubic meters of syngas per hour. In the long term, SinoCoking targets a syngas production of up to 21 million cubic meters per hour from a full industrial-scale project.

Summary of UCG Project Test Sites

The tests and trials to date, along with the main conclusions from each one, are summarized in the table below. Many of these projects were conducted in thin, low quality seams which contributed to the low gas quality produced. The data on the test and projects is limited but it is known that experiments into air and oxygen injection rates were made as well as heating the input air by passing it through previously gasified panels. The Lisichansk project undertook important design work in gasifying steeply dipping seams.

Table 6-1
UCG Project Test Sites

TEST SITE	COUNTRY	YEAR	COAL TYPE	SEAM THICKNESS (m)	SEAM DEPTH (m)	DIP (DEGREES)	COAL GASIFIED (t)	SYNGAS CV (MJ/m^3)
Lisichansk	Russia	1934-36	Bit	0.75	24	N/A	N/A	3 - 4
Lisichansk	Ukraine	1943-63	Bit	0.4	400	0	N/A	3.2
Gorlovka	Russia	1935-41	N/A	1.9	40	N/A	N/A	6 - 10
Podmoskova	Russia	1940-62	SBB	2	40	0	N/A	6 with O_2
Bois-la-Dame	Belgium	1948	Anthracite	1	N/A	N/A	N/A	N/A
Newman Spinney	UK	1949-59	SBB	1	75	N/A	180	2.6
Yuzhno-Abinsk	Russia	1955-89	Bit	2-Sep	138	60	c 2 mt	9 - 12.1
Angren	Uzbekistan	1965-now	SBB	4	110	N/A	Over 10 mt?	3.6
Hanna 1	USA	73-74	HVC	9.1	120	0	3130	
Hanna 2	USA	75-76	HVC	9.1	84	0	7580	5.3
Hoe Creek 1	USA	1976	HVC	7.5	100	0	112	3.6
Hanna 3	USA	1977	HVC	9.1	84	0	2370	4.1
Hoe Creek 2A	USA	1977	HVC	7.5	100	0	1820	3.4
Hoe Creek 2B	USA	1977	HVC	7.5	100	0	60	9.0
Hanna 4	USA	77-79	HVC	9.1	100	0	4700	4.1
Hoe Creek 3A	USA	1979	HVC	7.5	100	0	290	3.9
Hoe Creek 3B	USA	1979	HVC	7.5	100	0	3190	6.9
Pricetown	USA	1979	Bit	1.8	270	0	350	6.1
Rawlins 1A	USA	1979	SBB	18	105	63	1330	5.6
Rawlins 1B	USA	1979	SBB	18	105	63	169	8.1
Rawlins 2	USA	1979	SBB	18	130-180	63	7760	11.8
Brauy-en-Artois	France	1981	Anthracite	1200	N/A			
Thulin	Belgium	1982-84	Semi-anthracite	860	N/A			
Centralia Tono A	USA	84-85	SBB	6	75	14	190	9.7
Centralia Tono B	USA	84-85	SBB	6	75	14	390	8.4
Haute-Duele	France	1985-86	Anthracite	2	880			

Table 6-1 (continued)
UCG Project Test Sites

TEST SITE	COUNTRY	YEAR	COAL TYPE	SEAM THICKNESS (m)	SEAM DEPTH (m)	DIP (DEGREES)	COAL GASIFIED (t)	SYNGAS CV (MJ/m^3)
Thulin	Belgium	1986-87	Semi-anthracite	6	860		157	
Rocky Mountain 1A	USA	87-88	SBB	7	110	0	11200	9.5
Rocky Mountain 1B	USA	87-88	SBB	7	110	0	4440	8.8
El Tremedal	Spain	1997	SBB	2	600			
Eskom	South Africa	2007-2011		3.5	280-300		34663 (2007-2011)	4.2
Chinchilla	Australia	1999 - 2013					19300 (2011-2012)	6.2 – 10.2

KEY
Coal Types
HVC - High Vol Bit
SBB - Sub Bituminous
Bit – Bituminous

Results from the numerous global tests and projects have provided valuable information, relating to methodology, site selection, and environmental restrictions. The key findings to date are summarized as follows:

There are three primary methods for undertaking UCG projects:

- The vertical well (Soviet) method
- The enhanced vertical well method with wells linked by horizontal boreholes
- The CRIP methodology

Of these, many believe the CRIP method offers the best opportunity providing better process control by injecting the oxygen or air where needed and offering the ability to exploit deeper seams which would not be economic using vertical wells.

On site selection, there are clear conclusions that can be drawn from the work to date:

- Shallow seams are not suitable for gasification because of high gas losses, potential breakthrough to surface and possible contamination of ground waters.
- Thin seams, less than 3m thick, will be difficult to exploit economically unless in a multi-seam environment.
- Thick seams work well using the CRIP method.
- Lignite and sub bituminous coal are ideal for gasification, as is bituminous coal provided no significant swelling characteristics exist.

- Deeper coals offer the opportunity to have much higher pressures in the reactor resulting in higher methane content and resultant higher heat value gas.
- CVs in the range of 12-14 MJ/m^3 are recorded when using oxygen feed, and this may be slightly increased as the process develops at a greater depth.
- The CRIP concept has lead to the highest gasification efficiency in terms of oxygen usage and will allow subsidence to be minimized or possibly eliminated by using wider barrier pillars between panels.

While LLNL had already shown that coal gasification using the CRIP technology produced better quality gas than linked vertical wells, the importance of El Tremedal was that it proved deep coals could be successfully gasified. This meant that with the use of oxygen and the higher pressures in the reactor, deep coals produced a far better product while opening up a significantly large resource base of coal that was unsuitable to be exploited by conventional mining.

In addition, the greater depth significantly reduced the risk of groundwater contamination and minimized the impact of surface subsidence, while preventing any possible breakthrough to surface that could offer an uncontrolled exposure to air intake. The future of UCG will probably focus on gasifying deeper coals, below 250m, and with a thickness of over 4m which means a substantial resource base is available on a global basis.

Meeting Environmental Challenges

The new field pilots will also provide key data for the environmental models being developed by a team of environmental scientists at LLNL. Although most of the previous UCG pilots did not produce significant environmental consequences, LLNL's 1970s test site at Hoe Creek, Wyoming, unfortunately resulted in contaminated groundwater, as did one pilot in Carbon County, Wyoming. At Hoe Creek, operation of the burn cavity at pressures higher than that in the surrounding rock strata pushed contaminants away from the cavity, which introduced benzene, a carcinogen, in potable groundwater. The contamination has required an expensive and long-term cleanup effort at the site.

Since these problematic tests in the 1970s, environmental scientists have learned a great deal about the behavior and types of contaminant compounds produced by UCG as well as about contaminant transport and environmental risk assessment. Several steps can be taken to avoid groundwater pollution. One is balancing operating conditions to minimize the transport of contaminants from overpressurized burn zones. Another is to locate a UCG site where natural geologic seals isolate the burn zone from surrounding strata. Isolating the site from current or future groundwater sources and understanding how UCG affects the local hydrogeology are essential. This knowledge greatly benefited the Chinchilla project. "Chinchilla is an excellent example of how to plan a site and operate a UCG plant," says LLNL scientist. "The operators maintained negative pressure in the combustion cavity so that contaminants could not flow beyond the cavity."

The LLNL team is creating the first detailed models of contaminant flow and transport specifically for UCG operations. LLNL scientists feel that the standard types of hydrologic models used for environmental assessments do not consider the full effects of UCG operations. UCG requires integrated simulations that capture the complex geochemical, geomechanical, and geohydrological processes occurring during a burn. Initially, LLNL groundwater specialists created and tested a modified version of the groundwater-modeling tool Flex to generate simple models of contaminant transport from UCG combustion. The models included thermal buoyancy effects on contaminant plume migration.

Another environmental concern is that the void created by gasification may cause the land surface to subside. Subsidence is likely to be more of a problem if gasification occurs in a shallow coal seam, closer to the surface. This phenomenon also often occurs above long-wall underground coal mines but is less of a problem if the seam is deep.

UCG for the Future

Although the potential of UCG as a transformational technology for coal has been rediscovered globally, its future maturation depends on the success of the pilot tests that are just beginning. The U.S. government has declared "clean coal" a critical goal for the near term, and the state of California and other government entities have mandated the reduction of CO_2 emissions. LLNL scientists note that the successful implementation of UCG requires that the right tools are available to accurately assess the economic viability and environmental consequences of UCG in all phases, from planning to operations to site closure.

The recent successful attempts to produce natural gas by "fracking" has dramatically increased the economically recoverable reserves in the U.S. and the availability of natural gas at low prices. As the practice of "fracking" extends to other countries, and if the attempts are successful, it is quite unpredictable at this time what this may do to the UCG potential.

Steam Augmentation with Concentrating Solar Power (CSP)

Concentrating solar power systems utilize solar thermal energy for the generation of electric power. This characteristic makes a solar CSP/conventional coal based generation hybrid fairly easy to understand. When the sun is shining, solar heat contributes a portion of the energy used to produce electricity. Such hybridization offers a pathway to a greater penetration of solar energy, while reducing emissions associated with coal power generation. In addition, the combination of fossil and solar generation enables a partially renewable resource to be dispatch-able. From an economic perspective, if an existing facility is retrofitted with CSP steam augmentation, EPRI research[16] suggests that the strategy could achieve reductions of approximately 30% in the levelized cost of electricity.

Two CSP technologies have been investigated for suitability for steam augmentation and are included for discussion in this report – parabolic troughs and solar central receivers. Based on research conducted by the National Renewable Energy Laboratory (NREL) and EPRI[17], central receivers offer a better option due to their ability to achieve higher steam temperatures compared to the parabolic trough technology. However, from a project risk perspective, parabolic troughs are associated with less risk because of the number of plants deployed.

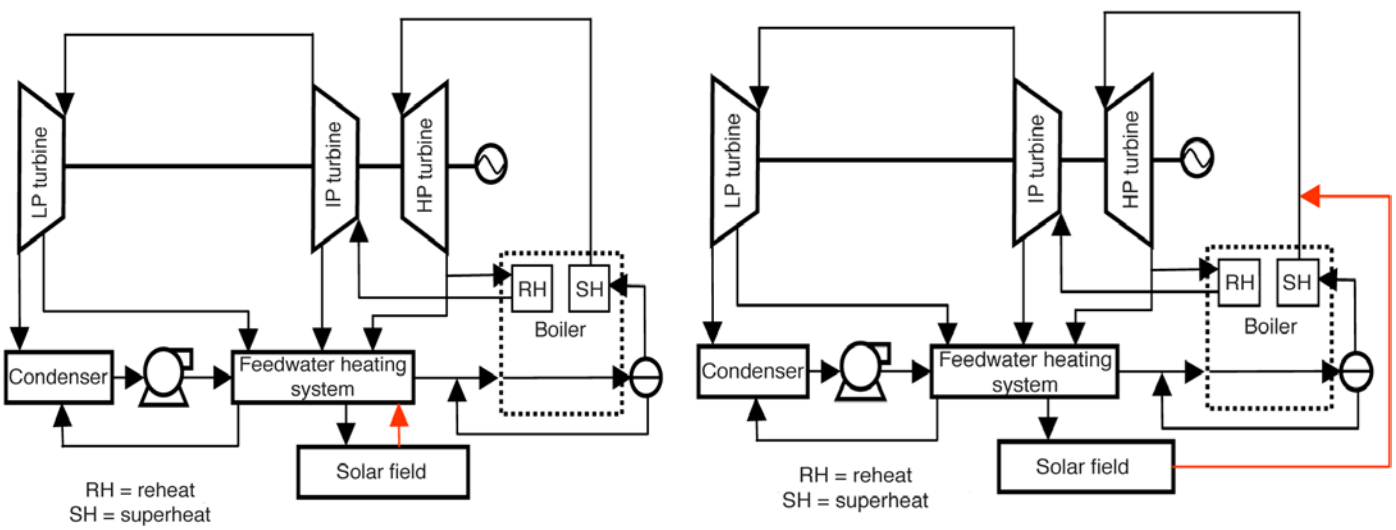
In integrating the CSP technologies into the steam cycle, the steam cycle conditions were selected to match the typical steam pressure conditions expected in the coal-fired power plant at

[16] "Solar Augmentation at the Coal-Fired Cameo Generating Station". Cerezo, Luis and Paul Meagher. EPRI, September 2011.
[17] "Solar-Augment Potential of US Fossil-Fired Power Plants." Turchi, Craig; Langle, Nicholas, Langle; Bedilion, Robin; and Cara Libby. National Renewable Energy Laboratory, February 2011.

both before and after the superheaters. The steam conditions and integration points are outlined in the table below. Simplified schematics show the point of integration in Figure 6-7.

Table 6-2
Steam Conditions and Integration Points for Solar-augmentation

Solar Technology	Integration Point	Solar Steam Conditions
Parabolic Trough	Feedwater Heater	165 bar, 371°C
Central Receiver	Main Steam System	165 bar, 538°C



Simplifed Diagram of Solar Integration into a Coal-fired Plant: Integration into the Feedwater System (Left) and Integration into the Main Steam Line (Right)

The Kogan Creek Solar Boost project in Queensland, Australia is currently underway. Construction on the project utilizing Areva's Solar Boost compact linear fresnel reflector system began construction 2011 and was set expected to be complete in 2013. The project has encountered delays due to equipment suppliers and unspecified commercial issues. Commercialization is now slated for 2015. The 44 MW solar addition will enable the 750 MW coal-fired power station to produce more electricity with the same amount of coal. The project budget is $105m (AU$) or $2,386/kW.

Tucson Electric Power in the United States began construction in April 2014 of 5 MW plant at its 400 MW dual-fueled Sundt Generating Station. The solar addition project was originally scheduled to begin in 2012, but the project was delayed due to permitting issues. The project's total cost is estimated at $7.8m (US$) or $1,560/kW. Although the project began when both coal and natural gas were being used at the facility, in August 2015, TEP announced that the plant will no longer burn coal. Part of that decision was based on the recent US EPA's recent Clean Power Plan that penalizes coal facilities.

Nuclear Technologies

The current fleet of nuclear power plants is a fairly mature technology representing approximately 20% of the electricity generated in the U.S. and over 16% of the electricity generated in the world. It is well suited for large scale stationary applications as well as naval vessels such as submarines and ships. It is especially attractive to countries with limited access to fossil fuels. The major factors driving interest in nuclear power include projected growth in electricity demand, a desire to reduce greenhouse emissions and move away from reliance on fossil fuels, increasing fossil fuel prices, and energy security. However, the Fukushima Daiichi accident caused by an earthquake and tsunami in March 2011 has possibly reduced interest in nuclear power, at least in some areas of the world. It will take time to understand the full effect of this accident on the nuclear power industry.

Compared to other large scale central stations, nuclear plants are typically more expensive to construct but less expensive to operate. High construction costs are mostly due to the safety and security requirements, including both design/construction requirements and the lengthy licensing process. Low operating costs are a result of low fuel costs (on a per kWh basis). Therefore, they can be cost effective when construction costs are kept in check and when the plant is to be operated at high capacity for many years. Due to the low operating costs of nuclear reactors, the electricity generation costs are expected to be more stable than those of coal or natural gas-fired plants. They produce no gaseous emissions, although they do generate nuclear waste that poses its own problems. Therefore, CO_2 emissions regulations would also tend to make nuclear power economically favorable.

Nuclear power is generated through a fission chain reaction. The heat produced during fission is transferred via gas or liquid to produce steam. Light water reactors (LWR) use standard water as the heat transfer medium and moderator. The moderator turns fast neutrons into thermal neutrons by reducing the neutron’s velocity. The thermal neutrons are then capable of sustaining the fission chain reaction in neighboring uranium atoms. Less commonly used moderators are heavy water and graphite. Fast neutron reactors do not require a moderator, and they utilize a variety of coolants.

Nuclear fuel typically consists of uranium dioxide enriched to 3-5% (by weight) using the uranium-235 isotope. Natural uranium, MOX consisting of both plutonium and enriched uranium oxides, thorium, and actinides are also used as nuclear fuel. Uranium prices have been increasing over the last several years due mostly to renewed interest in construction of nuclear power plants and recent mining production problems associated primarily with flooding of mines. However, nuclear fuel prices have stabilized recently and compared to other power plant fuel sources, nuclear fuel cost is quite low and has much less volatility.

Generation I nuclear reactors include plants that were developed in the 1950s and 1960s. These reactors typically used unenriched uranium as the fuel and graphite as the moderator. There are only two still in commercial operation in the United Kingdom; both are scheduled for closure within the next few years.

Generation II nuclear reactors include LWR of two primary types – pressurized water reactors (PWR) and boiling water reactors (BWR). PWRs utilize pressurized water as the coolant, with another cooling loop driving the steam turbine. This design contains the radioactivity within the reactor and the primary cooling loop. BWRs allow the water in the cooling loop to boil, and this steam is then used to drive the steam turbine. These Generation II reactors began to be installed in the 1970s and comprise the vast majority of reactors in operation today. They generally utilize enriched uranium fuel. The advanced gas-cooled reactor (AGR) utilizes graphite as the moderator and natural uranium for fuel. The CANDU reactor also utilizes natural uranium fuel and uses heavy water as its moderator. These reactors include active safety features.

Generation III and III+ nuclear reactors are being constructed and continue to undergo some development. The first was constructed in Japan and has been operating since 1996. They are known as the advanced reactors, and are similar to the Generation II reactors with notable economic and safety advancements. Most of them employ passive safety features rather than active ones, with controls using gravity or natural convection. These reactors are expected to also have reduced nuclear waste and fuel consumption due to higher fuel burn-up. Anticipated lifetime for these reactors is approximately 60 years.

Additionally, several Generation IV nuclear reactor designs are under various stages of development and are expected to become commercially available in the 2030 timeframe. In addition to higher thermal efficiency, the major feature for these reactors will be their ability to integrate into a closed fuel cycle. That is, the long-lived actinides that are currently being treated as nuclear waste could be used as a fuel in many of these reactors. This may help to reduce waste and cost, while ensuring the fuel associated with these reactors is more resistant to nuclear proliferation. It is also expected that these reactors will be capable of supporting high temperature hydrogen production, high temperature water desalination, and other high temperature process heat applications

Although, this study is focused on two Generation III/III+ reactors: Areva's evolutionary pressurized reactor (EPR) and Westinghouse's AP1000, it is worth mentioning, the Russian-designed Water-Water Energetic Reactor (VVR). The model ranges in size from 300 MW to 1,700 MW. Installations are in Russian China, India, Ukraine, Finland, Germany, and Iran. Recent activity includes commissioning of two units, one at the Rostov nuclear power plant in Volgodonsk and the other at the Kudankulam nuclear power station. In addition, toward the end of 2014, Russian signed two separate intergovernmental agreements with Iran and India to construct new reactors in each country. Much of the data on capital expenditures for nuclear power generation that is in this report is based on plants in the United States. Since the VVR plan design has not received certification by the US nuclear regulatory agencies, the data to support this study was not as readily accessible. However, based upon a review of external sources the capital cost for the VVR design ranges. Research conducted by Clemson University indicates that the VVR design consistently ranked lowest among other designs. The average of installation costs of VVRs constructed in other countries outside of Russia was $2,121/kW (2015$). The study goes on to suggest that the difference could like in the segmentation of cost estimates, i.e. providers of the data not including design costs in the estimate[18]. A recent report from the International Energy Agency lists an estimate of $6,215/kW for nuclear generation cost based on a VVE-1200 reactor. Without further data to support the most probably cost estimate for the VVR design, it will not be included in the analysis portion of this report. Again, this report focuses on Areva's EPR and Westinghouse's AP1000.

[18] "Minatom Export Control Behavior: Economic Factors & Motivattions." Maloney, Michael T. and Oana Diaconu. Clemson University, John E. Walker Department of Economics. June 2003.

Areva EPR

The Areva EPR is based on the PWR design. The first reactor of this type is currently under construction in Finland, with another underway in France. In addition, there are two EPRs planned for Taishan, China in the Guangdong province. There is a U.S. version of this design known as the U.S. EPR that is rated at 1,600 MW, which is under review by the Nuclear Regulatory Commission for licensure. Areva EPR cost estimates for this study are based on the U.S. EPR design.

The U.S. EPR has 241 fuel assemblies surrounded by a neutron reflector to optimize fuel utilization and protect the pressure vessel from radiation damage. The key features of this advanced PWR are an improvement in economy, safety, and reliability. The U.S. EPR has an optimized core design and higher overall efficiency with savings on uranium consumption which reduces the costs of the entire fuel cycle.

The plant is designed to cost 10% less to operate than most of the conventional nuclear plants in service today. The U.S. EPR has been greatly simplified as compared with existing plants. The plant has 47% fewer valves, 16% fewer pumps, 50% fewer tanks, and 44% fewer heat exchangers than the current PWR design. The plant design also has only those features and materials that have shown superior performance over the last 40 years of nuclear power plant operation, improving both reliability and O&M costs.

The reactor can use various types of fuel, such as low enriched uranium (i.e., up to 5%) or MOX fuel. The U.S. EPR design also allows for a flexible operating cycle (i.e., 12 to 24 months). Another feature of the U.S. EPR that makes it very reliable is that many maintenance and inspection tasks can be completed while the reactor is operating. This in turn also minimizes downtime and maximizes plant efficiency.

The U.S. EPR has four pressurized water coolant loops. The reactor coolant system (RCS) is composed of the reactor vessel that contains the fuel assemblies, a pressurizer including control systems to maintain system pressure, one reactor coolant pump per loop, one steam generator per loop, associated piping, and related control and protection systems. The RCS is contained within a concrete containment building. The reactor containment building has two cylindrical walls with separate domes. The inner wall is made of pre-stressed concrete, the outer of reinforced concrete, and both walls are 1.3 meters thick, designed to withstand postulated external hazards (e.g., airplane crash).

The reactor building is surrounded by four safeguard buildings and a fuel building. The internal structures and components within the reactor building, fuel building, and two safeguard buildings (including the plant control room) are protected against aircraft hazard and external explosions. The other two safeguard buildings are not protected against aircraft hazard or external explosions; however, they are separated by the reactor building, which restricts damage from these external events to a single safety division.

The U.S. EPR has four 100% separate safety systems and uses the latest digital instrumentation that performs continuous self-checking functions. Each safety system is capable of performing the entire safety function for the reactor. This divisional separation is provided for electrical and mechanical safety systems. With four divisions, one division can be out-of-service for maintenance and one division can fail to operate, while the remaining two divisions are available to perform the necessary safety functions even if one is ineffective due to the initiating event.

In the event of a loss of off-site power, each safeguard division is powered by a separate emergency diesel generator (EDG). In addition to the four safety-related diesels that power various safeguards, two independent diesel generators are available to power essential equipment during a postulated station blackout event-loss of off-site AC power with coincident failure of all four EDGs.

Water storage for safety injection is provided by the in-containment refueling water storage tank. Also inside containment, below the reactor pressure vessel (RPV), is a dedicated spreading area for molten core material following a postulated worst-case severe accident.

The fuel pool is located outside the reactor building in a dedicated building to simplify access for fuel handling during plant operation and handling of fuel casks. The fuel building is protected against aircraft hazard and external explosions. Fuel pool cooling is assured by two redundant, safety-related cooling trains. Each train consists of two pumps installed in parallel, a heat exchanger cooled by the component cooling water system, and associated piping and valves. The pipe penetrations to the spent fuel pool are above the required level of water that must be maintained over the spent fuel, while providing the required pump suction head. The pipes that penetrate the pool are equipped with siphon breakers to limit water loss resulting from a leak in the piping system.

Figure 6-8 shows the plant layout of the U.S. EPR and Figure 6-9 shows a simplified flow diagram of the EPR.

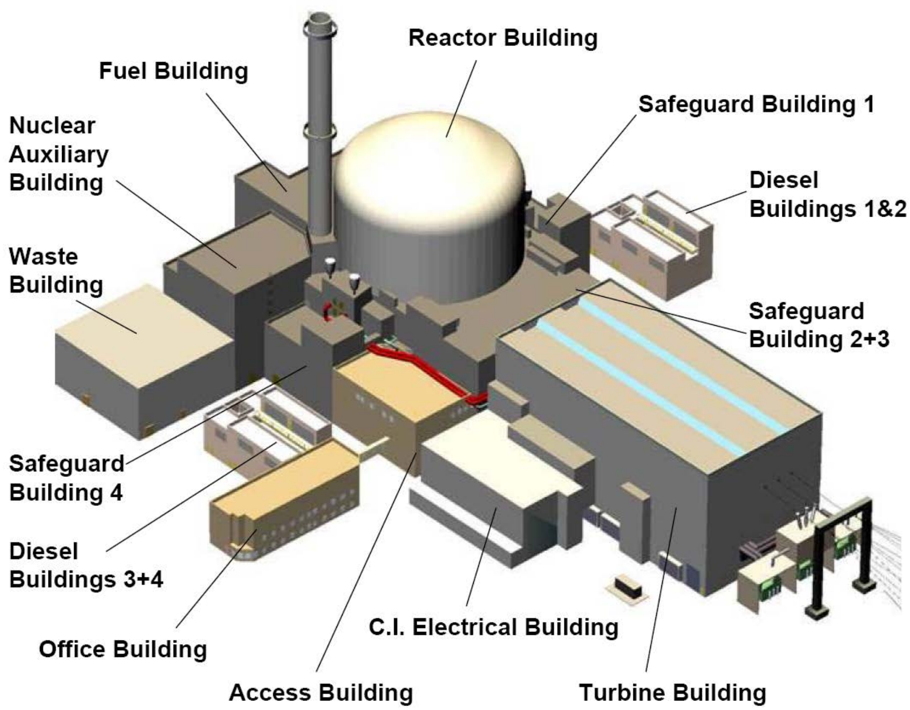


Figure 6-8
Example Plant Layout of the U.S. EPR (provided by AREVA NP)

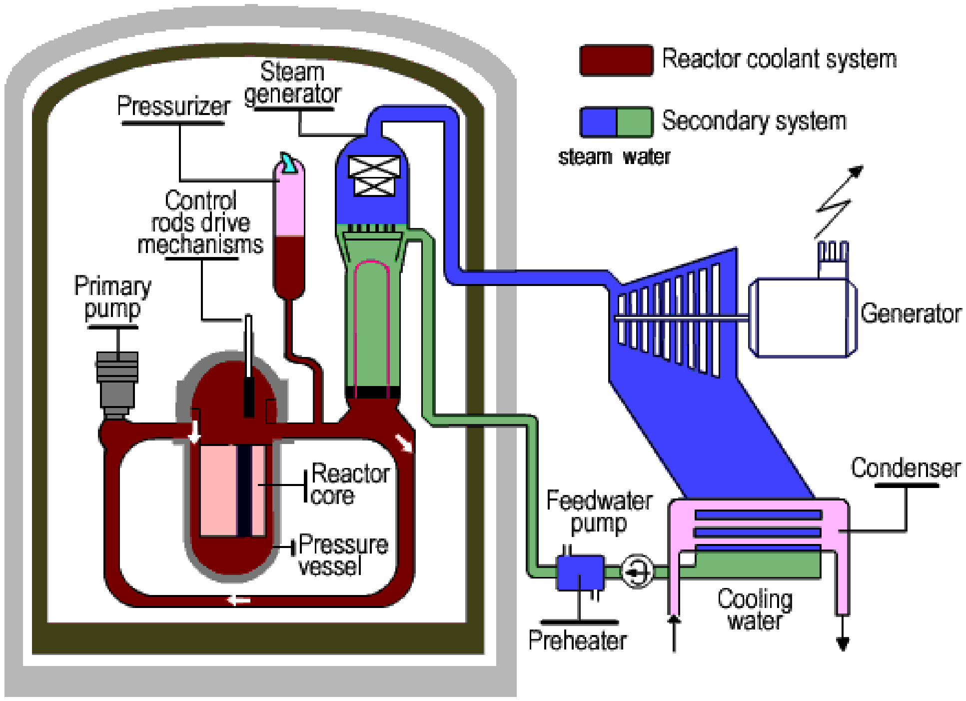


Figure 6-9
Simplified Process Flow Diagram for the EPR (provided by AREVA NP)

Westinghouse AP1000

The Westinghouse AP1000 is a 1,200 MWe (1,115 MWe net) advanced PWR reactor developed with passive safety systems. The AP1000 power plant is designed as a single unit with a stand-alone configuration. Westinghouse manufactures the AP1000 units in modules for rail and/or barge shipment upon order, which could allow for constructing many modules in parallel with each AP1000 unit virtually identical. The cost estimates within this study are presented for a single unit with a six year project duration from initial engineering to procurement start-up. The schedule and cost for two units, four units, and six units constructed in parallel with an eight year, 12 year, and 16 year project duration, respectively, is also discussed.

The AP1000 power plant has approximately 87% less control cable, 83% less piping (safety grade), 50% fewer valves, 50% less seismic building volume, and 35% fewer pumps than a similarly sized conventional generation II LWR plant. This decrease not only reduces plant costs but also reduces construction schedules. Construction time is further reduced since the AP1000 power plant utilizes a modularization technique for construction.

The AP1000 power plant fuel design is based on a design used successfully at plants in the U.S. and Europe, which is the 17x17 fuel assembly design. It can operate with enriched uranium dioxide of less than 4.95% enrichment. Studies have also shown that the AP1000 power plant can operate with a MOX fuel type. The AP1000 has an 18-month fuel cycle and a 17-day refueling outage duration.

The AP1000 uses reduced-worth control rods (termed “gray” rods) to achieve daily load follow without requiring changes in the soluble boron concentration. The use of gray rods, in conjunction with an automated load follow control strategy, eliminates the need for processing thousands of gallons of water per day to change the soluble boron concentration. As a result, systems are simplified through the elimination of boron processing equipment (such as evaporator, pumps, valves, and piping). With the exception of the neutron absorber materials used, the design of the gray rod assembly is identical to that of a normal control rod assembly. The turbine generator is intended for base load operation but also has load follow capability.

A typical site plan for a single unit AP1000 has a power block complex which consists of five principal building structures: the nuclear island, the turbine building, the annex building, the diesel generator building, and the radwaste building. Each of these building structures is constructed on individual base mats. The nuclear island consists of the containment building, the shield building, and the auxiliary building, all of which are constructed on a common base mat. A multi-unit plant would consist of multiple single-unit plants with no shared systems.

The AP1000 power plant design is a two-loop, four-reactor coolant pump plan that uses a reactor vessel, internals and fuel similar to those currently used in Westinghouse reactors. The reactor is water cooled and moderated and utilizes enriched uranium fuel. The reactor coolant pumps are designed as canned-type pumps in order to reduce the probability of leakage and to improve reliability. The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor and is designed to provide a high degree of integrity throughout operation of the plant.

The AP1000 steam turbine consists of a double-flow, high-pressure cylinder and three double-flow, low-pressure cylinders that exhaust to individual condensers. It is a six flow tandem-compound, 1,800 rpm machine (1,500 rpm for 50 HZ applications). The turbine generator is intended for base load operation but also has load follow capability.

Figure 6-10 is a simplified process flow diagram for a typical PWR like the AP1000.

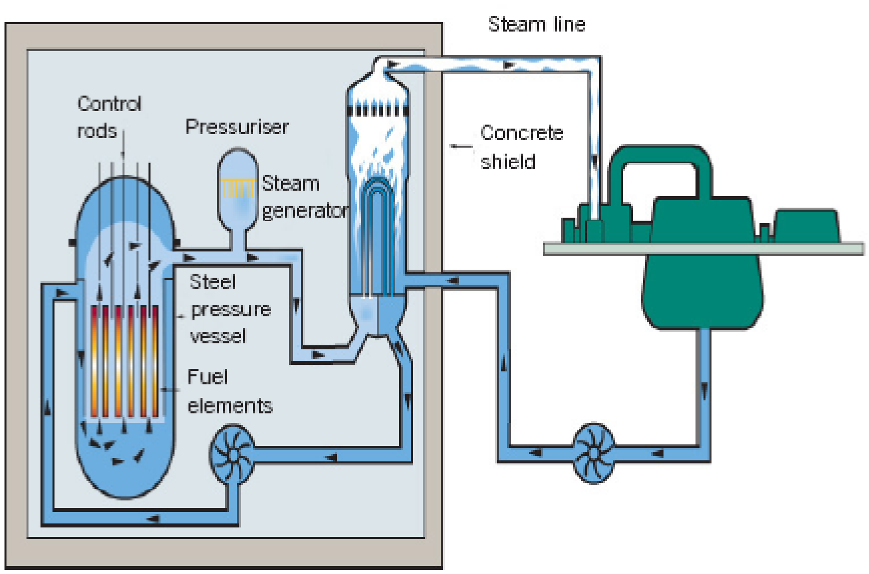


Figure 6-10
Typical Process Flow Diagram for a PWR

The AP1000 is designed to achieve a high safety and performance record. The design is conservatively based on proven PWR technology, but with an emphasis on safety features that rely on natural forces. To achieve a high safety and performance record, safety systems use natural driving forces such as pressurized gas, gravity flow, natural circulation flow, and convection rather than active components (such as pumps, fans, or diesel generators), and are designed to function without safety-grade support systems (such as AC power, component cooling water, service water, or HVAC). The AP1000 passive safety systems are significantly simpler than typical PWR safety systems since they contain appreciably fewer components, reducing the required tests, inspections, and maintenance. They require no active support systems, and their readiness is easily monitored.

The number and complexity of operator actions required to control the safety systems are also minimized. The approach is to eliminate operator action rather than automate it. A few simple valves align and automatically actuate the passive safety systems. To provide high reliability, these valves are designed to actuate to their safeguard positions upon loss of power or upon receipt of a safeguards actuation signal. They are supported by multiple, reliable power sources to avoid unnecessary actuations.

The AP1000 passive safety-related systems include:

- The passive core cooling system
- The passive containment cooling system
- The main control room emergency habitability system
- Containment isolation

These passive safety systems provide a major enhancement in plant safety and investment protection as compared with conventional plants. They establish and maintain core cooling and containment integrity indefinitely, with no operator or AC power support requirements. The passive systems are designed to meet the single-failure criteria, and probabilistic risk assessments are used to verify their reliability. Off-site power has no safety-related function due to the passive safety features incorporated in the AP1000 design. Therefore, redundant off-site power supplies are not required. The design provides a reliable off-site power system that minimizes challenges to the passive safety system.

The passive containment cooling system is shown in Figure 6-11.

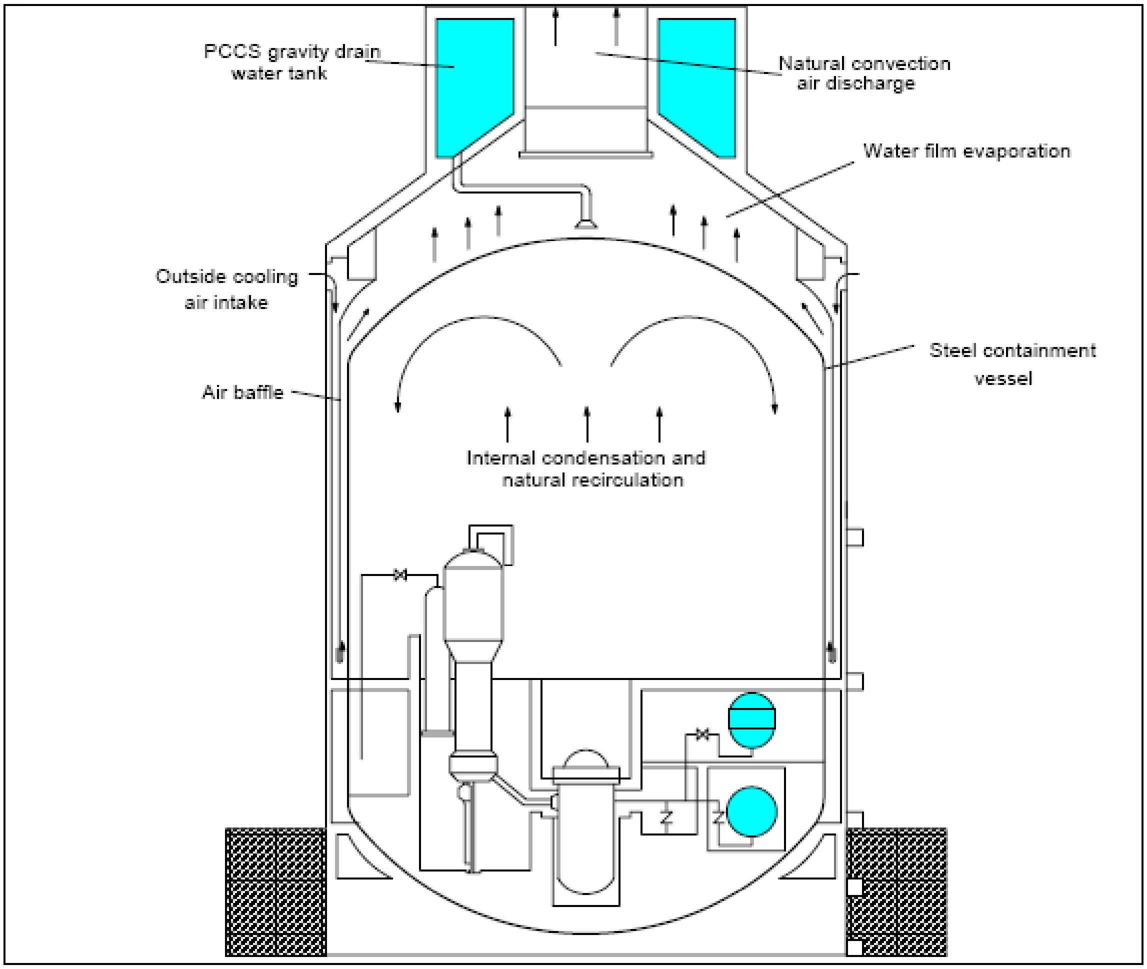


Figure 6-11
AP1000 Passive Containment Cooling System (provided by Westinghouse Electric Co., LLC)

Hualong One

China has an aggressive nuclear deployment schedule, with 24 plants under construction and 59 plants planned. See the figure below for a forecast of the growth of China's nuclear fleet. Of the plants under construction, most utilize the CPR-1000 nuclear power plant design. The first CPR-1000 unit was commissioned in 2010. The last two CPR-1000 installations, Hongyanhe 3 and Nindge 3, were commissioned both in March 2015.

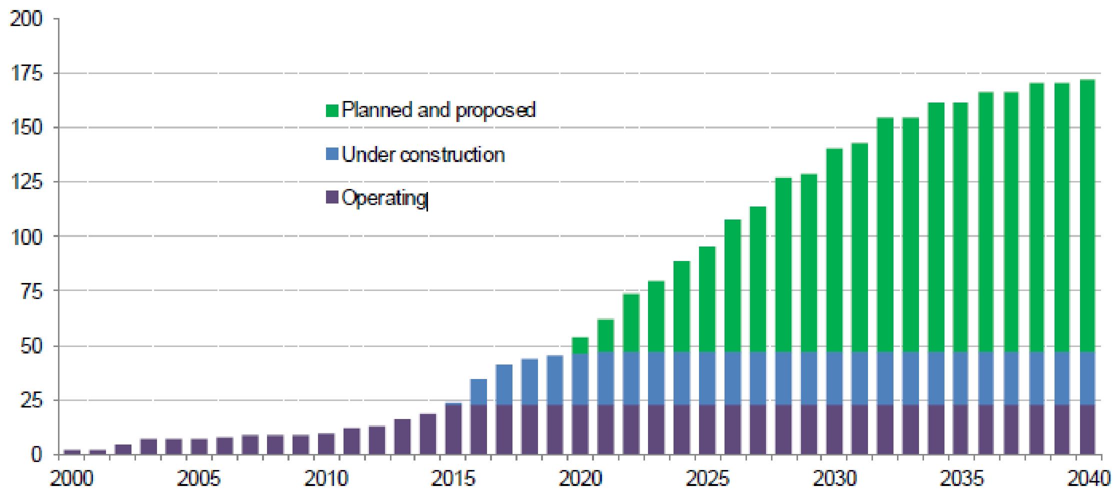


Figure 6-12
China's Nuclear Power Plant Generation (Bloomberg New Energy Finance, 2015)

Unlike recent nuclear projects in other countries, China has been able to construct nuclear projects quickly and less expensively. Hongyanhe 3's schedule (from the first concrete pour to grid connection) was 60 months, while Nindge 3 took only 63 months. That in comparison to the Finnish EPR project that currently suggests a construction term of 120 – 156 months. Another point of comparison is the construction of 2 EPR units in China, both taking 84 to 96 months for construction. In both examples, the construction schedule of the CPR-1000 units is quite favorable.

The 59 nuclear power plants that are being planned are based on one of three designs: AP1000, EPR, or Hualong One (also known as HPR1000). The Hualong One reactor, Generation III nuclear design, is an indigenous nuclear power plant design developed by the China National Nuclear Corporation (CNNC) and the China General Nuclear Power Group (CGNPG). The gross capacity is 1,150MW_e. The Hualong One design features include double containment and active safety systems with some passive elements, and a 60-year design life.

The design successfully completed the Generic Reactor Safety Review (GRSR) governed by the International Atomic Energy Agency (IAEA's) in December 2014. The international use of the design will still depend on meeting country-specific standards and requirements, but passing the IAEA safety review should make this process easier.

Figure 6-13
China's Hualong One Plant *(http://gbtimes.com/china/china-nuclear-reactor-design-possibility-uk)*

The pilot Hualong nuclear power design will be at the Fuqing Power station – units 5 & 6. Construction on unit 5 began in May 2015. Construction is scheduled to be competed in 2019. In August of 2015, Pakistan relaunched its 2013 ground-breaking for the Karahci Coastal twin units. China, who has invested heavily in energy projects in Pakistan, is providing financial assistance for the Karachi project. Future additional units that will be based on the Hualong One design are Fangchenggang 3 & 4. China is hoping to build a strong nuclear export market based on the success of its initial units. Argentina has expressed interest in building a nuclear facility based on the Hualong One design; it has postponed closing the deal unit later to see how Fuqing 5 & 6 units fare. China has already started actively marketing its design in Northern Africa, Saudi Arabia, Egypt, Sudan, and South America.

The target cost in China is $2,500/kW per the World Nuclear Association. According to Francois Morin, the China Director of the World Nuclear Association, the price is about 10 – 15% lower than the AP1000 on a $/kW basis. The estimated cost for the 2,300MW project underway in Pakistan is $9.6B, or approximately $4,200/kW.
The Areva EPR is based on the PWR design. The first reactor of this type is currently under construction in Finland, with another underway in France. In addition, there are two EPRs planned for Taishan, China in the Guangdong province. There is a U.S. version of this design known as the U.S. EPR that is rated at 1,600 MW, which is under review by the Nuclear Regulatory Commission for licensure. Areva EPR cost estimates for this study are based on the U.S. EPR design.

APR1400

South Korea currently has 24 operating reactors. The country is currently constructing multiple APR1400 reactors, South Korea's advanced PWR design. The reactor design was jointly developed by the Korea Electric Power Corporation (KEPCO) and the Korea Hydro o and Nuclear Power (KHNP). The APR1400 is a Gen III design with a 60 year life. The gross electrical capacity is 1,400MW$_e$. Main design features include reinforced seismic design basis, shortened construction schedule due to the integrated manufacture of the core support barrel and lower support structures, and improved economic efficiency with a longer refueling cycle greater than 18 months.

Figure 6-14
APR1400 Plant Layout *(02APR1400-Technical Summary-2010.pdf)*

Shin-Kori 3 & 4 and Shin-Ulchin 1 & 2 are under construction and expected to be commercial between 20176 and 2020. Two additional units are planned for Shin-Kori 5 & 6. The schedule for Shin Kori 3 & 4 has slipped. Shin-Kori 3 began construction in October 2008 and was expected to be commercial at the end of 2013, with Shin-Kori coming on-line in the fall of 2014. The current date for commercialization of Shin-Kori 3 is mid-2016, followed by Shin-Kori in early 2017. Outside of the country there are four units planned in the United Arab Emirates (UAE).Two of the units are under construction. All four are scheduled to be in operation by 2020, with unit 1 projected to commercial in 2017. The current estimate for the UAE project is approximately $3,571/kW ($20 billion/5,600MW).

As with China, Korea has its sights on achieving big gains in the export market. The United States' Nuclear Regulatory Commission (NRC) accepted the application from KEPCO and KHNP to complete the US design certification of the APR1400. Plans for the APR+ are underway as well. In August 2014, the Nuclear Safety and Security Commission approved the standard design for the APR+, the 1,550MW evolution of the AP1400. Its modular construction is expected to reduce the construction time from 52 months to 36 months. There are also additional safety features.

Gas Technologies

CCGT

CCGT technology provides some of the highest plant efficiencies currently attainable among the various technologies examined in this study. This technology is based on generating power by combining GT and steam turbine technologies (Brayton and Rankine cycles). Power is first generated as gas is combusted, and the combustion products flow through the GTs (Brayton cycle). The exhaust heat of the GT is then recovered in an HRSG which provides steam to the steam turbine for generating additional power (Rankine Cycle). A simple schematic of a CCGT arrangement is shown in Figure 6-15.

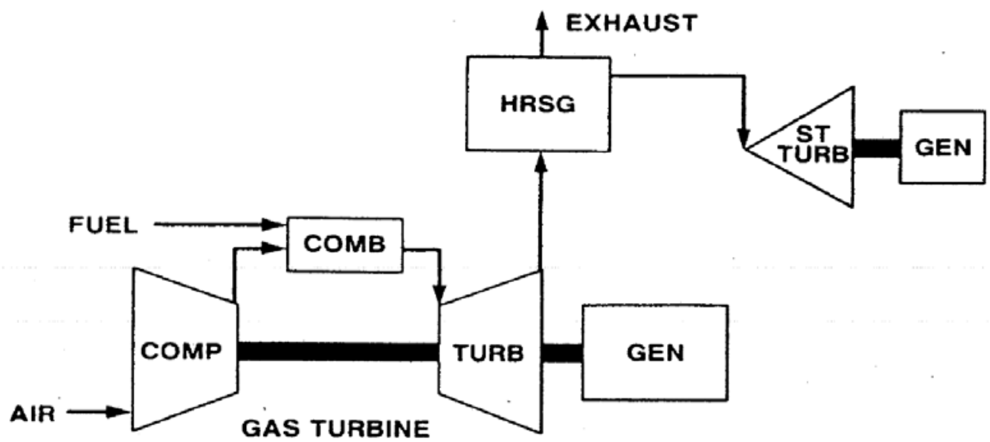


Figure 6-15
Simple Schematic of CCGT

A GT includes an air compressor, a combustor, and an expansion turbine. Gaseous or liquid fuels are burned under pressure in the combustor, producing hot gases that pass through the expansion turbine, driving the air compressor. The shaft of the GT is coupled to an electric generator which is driven by the mechanical energy produced by the GT.

The hot exhaust gas exits the GT at temperatures between 538°C and 593°C (1000°F and 1100°F) and passes through an HRSG where it exchanges heat with water producing steam at two or three pressures and may incorporate a reheat loop. The exhaust gas is cooled down to between 80°C and 135°C (176°F and 275°F) before exiting through the HRSG stack. Depending on the selected GT and its associated exhaust temperatures, the high pressure steam conditions from the HRSG range anywhere between 4.32-17.23 MPa(g) (700-2500 psig) with temperatures of 482-565°C (900-1050°F).

The steam produced in the HRSG is used to drive a steam turbine generator. In larger plants, it is common to have two or three GT/HRSG trains providing steam for a single large steam turbine. Usually about two-thirds of the total power is produced from the GTs and one-third from the steam turbine. The steam from the steam turbine is condensed using an air-cooled condenser or a closed-loop cooling tower, and the condensate is returned to the HRSG by condensate pumps.

There are various types and categories of GTs available in the market today. These include the earlier designed E- or lower-class turbine models, the state-of-the-art heavy-duty F-, G- and H-class turbine models, and the aeroderivative GTs that are generally used in power, combined heat and power (CHP), and industrial applications. These GTs are available in given sizes or ratings. Their efficiencies are strongly influenced by several factors such as inlet mass flow, compression ratio, and expansion turbine inlet temperature. The earlier design of heavy duty GTs had maximum turbine inlet temperatures ranging anywhere between 815-1093°C (1500-2000°F). More recent state-of-the-art heavy-duty GT designs have turbine inlet temperatures that reach over 1315-1371°C (2400-2500°F). These turbines are designed with innovative hot gas path materials and coatings, advanced secondary air cooling systems, and enhanced sealing techniques that enable higher compression ratios and turbine inlet temperatures. The advancements made in the newer GTs by the manufacturers are generally down-flowed into the earlier models for efficiency and power output improvements.

Combined cycle plants can operate with both conventional and advanced GTs. With GTs running at higher turbine inlet temperatures that result in higher exhaust temperatures, it is possible to include a reheat stage in the steam turbine. This further increases the efficiency in the bottoming cycle.

The combined cycle can be built up from the discrete size GT. The HRSG and steam turbine are sized to the exhaust energy available from the GT. There are various configurations of combined cycles with various numbers of HRSG pressure levels. The best heat rates are obtained in combined cycles in which the steam cycle requirements are matched by maximizing the recoverable energy from the GT exhaust. Therefore, various optimized combined cycles can be constructed from a combination of the basic components. The combined cycle plants can be further characterized by the steam cycle (i.e., reheat or non-reheat), HRSG pressure levels (i.e., single pressure, two-pressure, or three-pressure), and the number of turbine generator shafts/arrangement (such as single shaft or multi-shaft).

The combined cycle configuration for the purposes of this report will be a multi-shaft, reheat, three-pressure cycle based on the GE 9FA GT. It will consist of two 9FA GTs, each exhausting into a separate HRSG, and a common steam turbine-generator.

OCGT

An OCGT is one in which the working fluid remains gaseous throughout the thermodynamic cycle (Brayton cycle). This thermodynamic cycle consists of an adiabatic compression, isobaric heating, adiabatic expansion, and isobaric cooling. In the expansion turbine section of the GT the energy of the hot gases is converted into work. This conversion actually takes place in two steps. In the nozzle section of the turbine, the hot gases expand and a portion of the thermal energy is converted into kinetic energy. In the subsequent bucket section of the turbine, a portion of the kinetic energy is transferred to the rotating buckets and converted to work.

The GT includes an air compressor, a combustor, and an expansion turbine. Air is compressed and then mixed with gaseous or liquid fuels to be burned under pressure in the combustor, producing hot gases that pass through the expansion turbine. The shaft of the GT is coupled to both the air compressor and an electric generator such that mechanical energy produced by the GT drives the electric generator as well as the air compressor. Typically, more than 50% of the work developed by the turbine sections is used to power the axial flow compressor, while the remainder is available as useful work to drive the generator.

There are various types of GTs such as heavy-duty industrial, aeroderivative, and advanced heavy-duty GTs. Unit sizes are available in a wide range (from 2 MW and smaller to 330 MW and larger). They also have different shaft arrangements. A single-shaft configuration has one continuous shaft between the compressor and the expansion turbine, such that all compressor and expansion turbine stages operate at the same speed. These units are typically used for generator-drive applications where significant speed variation is not required. In a two-shaft configuration, the low-pressure or power turbine rotor is mechanically separated from the high-pressure turbine and compressor rotor. This unique feature allows the power turbine to be operated at a wide range of speeds, and makes two-shaft GTs ideally suited for variable-speed applications. All of the work developed by the power turbine is available to drive the load equipment, since the work developed by the high-pressure turbine supplies all the necessary energy to drive the compressor.

The main advantages of open cycle GTs include flexibility in siting, low emission levels with natural gas fuel, low capital cost, and short construction time. These advantages make them attractive for peaking duty applications. Peaking duty open cycle site arrangements can be designed to allow for later conversion to combined cycle through staged development.

The performance of a GT is affected by a number of factors, including ambient temperature, relative humidity, fuel type, inlet pressure drop, outlet pressure drop, and site elevation. Higher ambient temperatures or lower ambient pressures (higher altitudes) result in less dense air while lower ambient temperatures or higher ambient pressures (lower altitudes) result in more dense air. Because a GT operates at a fixed volume, lower air density results in reduced mass flow of intake air through the compressor and turbine. Figure 6-16 shows a typical Open Cycle Compressor Inlet Temperature performance curve. This shows the correction factors for open cycle heavy duty GTs to be applied to generated output, heat rate, exhaust flow, and heat consumption based on the inlet air temperature. An open cycle altitude correction curve (Figure 6-17) shows the effect of site elevation on GT output and fuel consumption.

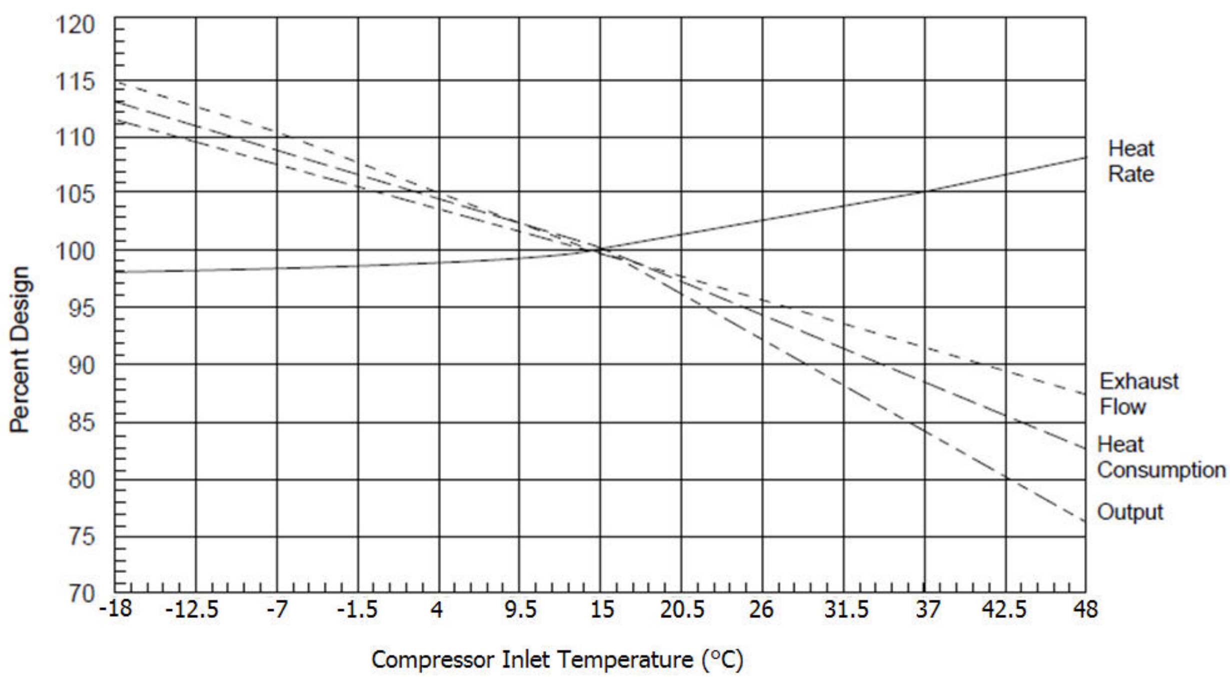


Figure 6-16
Open Cycle Compressor Inlet Temperature Performance Curve

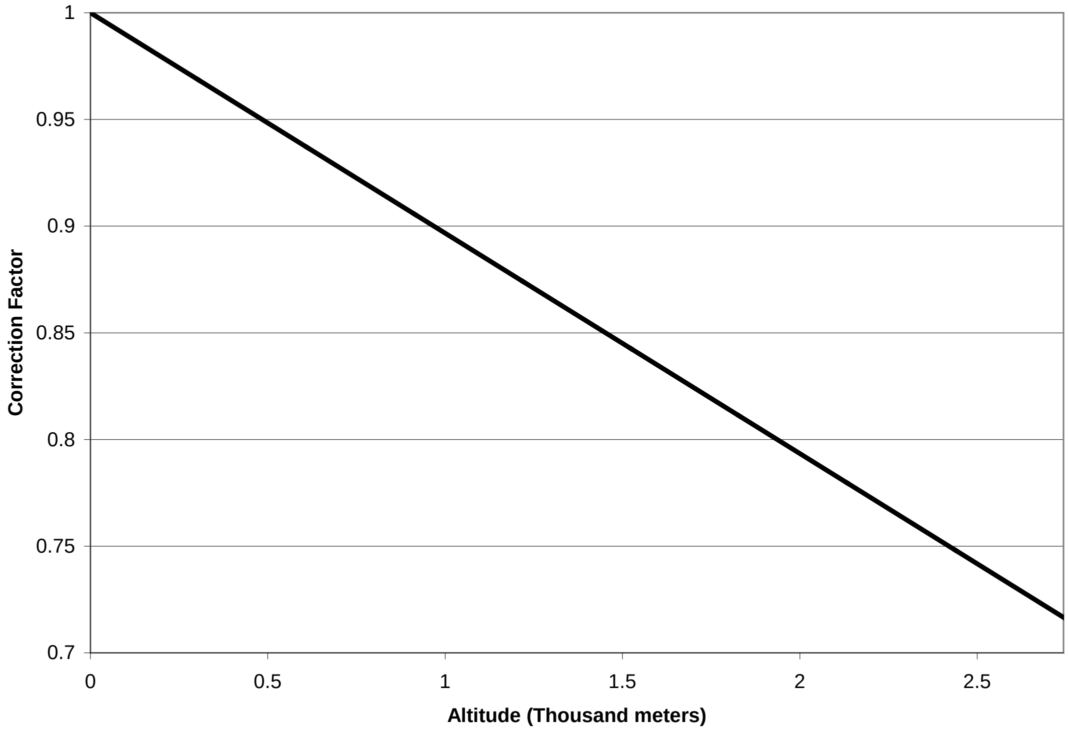


Figure 6-17
Open Cycle Altitude Correction Curve

As can be seen, the power output of a GT is very sensitive to ambient temperature. Maximum power typically drops about 0.4% for each degree Fahrenheit increase in ambient temperature. For example, a GT with an output rating of about 160 MW at 15ºC ambient temperature at sea level drops to about 140 MW at 32ºC ambient. The reference site conditions (as per ISO standards) for data presented are 15ºC, 60% relative humidity, and sea level elevation.

The GT evaluated in this study is the GE 9E.04 heavy duty model operated in peaking service with an annual capacity factor of 10%. An E-class GT was used for this open cycle peaking unit due to its better start/stop characteristics compared to the F-class GT that is used for combined cycles.

Internal Combustion Engine (ICE)

Gas Supply

Natural gas is supplied to the engine through a gas-regulating unit that filters the gas and regulates the pressure. The maximum pressure needed by large engines is approximately 65 psia. Many gas supply networks have natural gas pressure sufficient to supply engine-generators without need for natural gas compressors.

Engine Process

Internal combustion engines in large, stationary power generation applications are 4-stroke, spark-ignited (SI) engines. The four strokes in a power cycle are 1) intake, 2) compression, 3) expansion, and 4) exhaust stroke.

Small natural gas engines typically use natural aspiration for their air-intake. Large natural gas engines have a turbocharger to boost air flow. The turbocharger utilizes exhaust gas energy in the expansion turbine to drive the air compressor. With more air flow comes more fuel, resulting in higher output. A waste gate is in place to (partially) bypass the turbocharger in order to control air flow. The higher compression ratio as a result from turbo charging, also impacts NOx formation - at higher pressure, the timing accuracy for air in-flow is improved, thus achieving optimal low-NOx combustion conditions.

Compression ratios in the large bore engine class are in the range of 11:1 to 12:1. The compression ratio is limited since a higher compression ratio could lead to auto-ignition of the fuel which can damage the engine (knock). Diesel engines require higher compression ratios, up to 17:1, in order to achieve a temperature increase that is sufficient for ignition.

In order to achieve low NOx emission levels, a lean-burn concept is used. For lean-burn, the air-to-fuel ratio is higher than in a stoichiometric mixture. In lean combustion, the combustion temperature is reduced, and subsequently less NOx is produced. These lean air-fuel mixtures, typical for ICE in large stationary power applications, require a pre-combustion chamber. In this staged combustion process, the spark-ignition occurs in a chamber on the cylinder head. A rich mixture of fuel and air is ignited and shoots into the cylinder, providing enough energy to ignite the lean mixture. The lean combustion method for NOx control is comparable to lean burners in combustion turbines.

Cooling

Water-cooling is applied to the cylinders (jacket cooling), the lube oil system, and the charge air (intercoolers and after coolers). Waste heat is dissipated to the atmosphere through radiators in a closed loop system. For large multi-engine power plants radiators are generally located in a bank outside the engine building (outdoors) and are arranged in horizontal banks. The electricity from the ICE plants covered in this chapter comes strictly from the close loop cooled engine-generator. As a result, these plants have extremely low water makeup requirements. Makeup consists primarily of potable water for plant employees and floor wash-down water.

Renewable Technologies

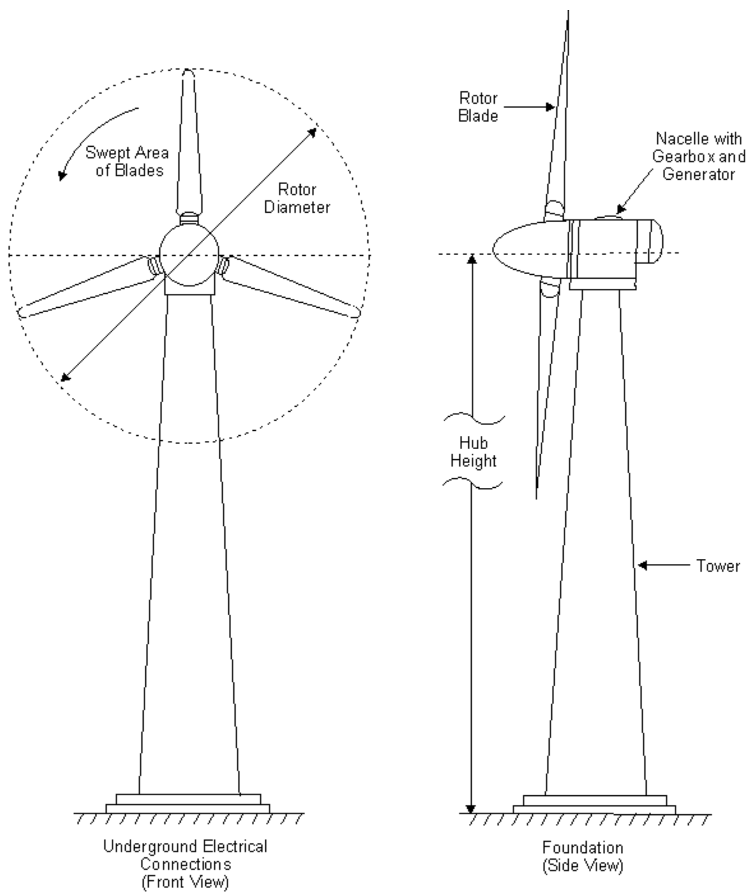
Wind

In recent years, wind has been the fastest growing form of electricity generation in the world. The World Wind Energy Association reports that installed wind capacity worldwide by the end of 2014 reached 370,000 MW. Almost all wind power capacity installed to date is on-shore wind. However, the superior wind resources available off-shore along coastlines has led to considerable research and development of larger off-shore wind turbines and the construction of a few off-shore wind farms.

On-Shore Wind

During the past 20 years of development, numerous wind turbine design configurations have been proposed and tested, including vertical- and horizontal-axes, upwind and downwind rotors, two or three blades, direct and gearbox-drive train, and fixed-speed, two-speed, and variable-speed generators. Today, the most common wind turbine configuration is the three-blade, upwind, horizontal-axis design with a three-stage gearbox, variable-speed generator and power electronics to generate 50 or 60 Hz power.

The primary components of an on-shore wind turbine include the tower and foundation, the rotor, the nacelle and drive train, rotor pitch and yaw systems, power electronics, and electrical controls, all of which are described in more detail below. Figure 6-18 shows a typical wind turbine.



(Source: U.S. Department of Energy. Energy Information Administration. “Forces Behind Wind Power”. Renewable Energy 2000: Issues and Trends. DOE/EIA-0628. February 2001.)

Figure 6-18
Wind Turbine Front and Side View

The tower is the base that holds the nacelle and the rotor. Typically, turbine towers are constructed from steel. To support the tower, the rotor, and the nacelle, as well as the dynamic structural loads created by the rotating turbine, a large steel-reinforced concrete foundation designed for the site and soil conditions is typically required.

For large-scale electricity production, multiple wind turbines are typically arranged in single or multiple rows, which are oriented to maximize generation when the wind is from the prevailing direction. The wind turbines must be arranged to minimize the impact of wake turbulence on other downwind turbines. To do this, they are often separated by five to 15 rotor diameters downwind and three to five rotor diameters in the direction perpendicular to the wind. Because individual wind turbines require a minimal area for the foundation, only 5-10% of the total land covered by the wind farm is used for the turbines and the remaining land area is available for crop production, grazing land for livestock, or other uses.

At the top of the tower, the rotor blades capture the wind and transfer its power to the rotor hub, which is attached to the low-speed drive shaft. In modern wind turbines, the pitch of the rotor blades is controlled by individual mechanisms that rotate the blade about its long axis to control the wind load on the turbine in high winds. The blade pitch is controlled to maximize energy production as wind speed varies. The rotor also helps to maintain a constant power output and limit drive train overload.

The rotor blades are conventionally fabricated from fiberglass composites. However, the wind industry seems to be moving towards carbon composite blades, which have a much higher length to weight ratio, allowing longer blades to be used as rated capacity increases without making the dynamic loads at the top of the tower proportionately bigger. The rotor blades are attached to the hub, which is typically made from cast iron or steel.

As the rotor blades capture the wind, they rotate the hub and the low-speed shaft of the turbine. Some turbine designs use direct-drive multiple-pole generators, and most use a three-stage gearbox to increase the rotation speed and drive the generator to produce electricity. Contrary to typical electrical generators, the rotor, gearbox, and generator are designed to efficiently capture wind energy at both low and high wind speeds. Efficiency is less important at higher wind speeds above the rated wind speed, where the blade pitch is adjusted to spill some of the wind in order to maintain the rated power. The nacelle serves as the housing for the gearbox and the electrical generator and is typically fabricated using fiberglass composites.

The electronic controller monitors the wind turbine's condition. It controls the yaw mechanism, which uses an electric motor to rotate the hub and rotor blades so that the turbine is optimally facing into the wind. It also starts and stops the turbine based on wind speed and shuts down the turbine if there is a malfunction.

Wind turbines are designed to operate within a wind speed window, which is bound by a "cut-in" speed and a "cut-out" speed. When the wind is below the cut-in speed, the energy in the wind is too low to utilize. When the wind reaches the turbine's cut-in speed, the turbine begins to operate and produce electricity. As the wind speed increases, the power output of the turbine increases until it reaches its rated power. After this, the blade pitch is controlled to maintain the rated power output, even as the wind speed increases, until the wind reaches its cut-out speed. At the cut-out speed, the turbine is shut down to prevent mechanical damage.

Wind plants typically are operated unattended and are monitored and controlled by a supervisory control and data acquisition (SCADA) system. Using onboard computers, wind turbines start up when the wind reaches its cut-in speed and shut down when the wind exceeds its cut-out speed or drops back below the cut-in speed. The system is also designed to shut down the turbine if there are any mechanical or electrical failures detected, and maintenance crews will be notified.

Off-Shore Wind

Some countries have begun to investigate placing wind farms off-shore. The primary difference between off-shore and on-shore wind turbines is the size and foundation requirements. Due to the high cost of off-shore wind turbine foundations and undersea electric cables, off-shore wind turbines are typically larger than their on-shore counterparts in order to take advantage of economies of scale. In addition to the difference in size, off-shore wind turbines have been modified in a number of ways to withstand the corrosive marine environment, such as implementation of a fully-sealed or positive-pressure nacelle to prevent corrosive saline air from coming in contact with critical electrical components, structural upgrades to the tower to withstand wave loading, and enhanced condition monitoring and controls to minimize service trips.

Currently, commercial off-shore wind farms are installed in water depths of up to 30 m with foundations fixed to the seabed. The most common foundation type for shallow depths is the steel monopole foundation, which is drilled or driven 25 to 30 m into the seabed. Other types of fixed foundations include steel or concrete gravity bases, which rest on top of the seabed and rely on the weight of the structure to provide stability. Bucket foundations are large-diameter hollow steel structures that are partially driven into the subsea structure by suction and filled with soil and rock to stabilize the foundation. Future developments in off-shore wind turbine foundation technology include fixed turbine foundations for transitional depths of 30 m to 60 m and floating turbine foundations for deepwater sites of 60 m to 200 m.

Currently, off-shore wind farms are installed at distances from shore ranging from 0.8 km to 20 km. Undersea cables connect the wind turbines within a project to an off-shore substation and from the substation to the mainland. Most off-shore wind farms utilize high voltage AC transmission lines to transmit power from the off-shore substation to the mainland. High voltage DC transmission is a new technology that experiences lower electrical line losses than high voltage AC; however, rectifier and inverter losses are introduced when converting from AC to DC at the off-shore substation and from DC back to AC at the on-shore grid connection point. The lower line losses are expected to outweigh the additional electrical conversion losses and cost differential only for projects located a significant distance from shore.

This study focused on cost and performance data for on-shore wind.

Solar Thermal

Solar thermal technologies use sunlight to heat a medium and then use the medium to drive a power generation system. Using mirrors, the sun’s energy can be concentrated up to 1,000 times. The concentrated sunlight is then focused onto a receiver containing a gas or liquid that is heated to high temperatures and used to generate steam to drive a power generation system.

The technologies described below are based on the concept of concentrating direct normal irradiation or insolation (DNI) to produce steam used in electricity generating steam turbine cycles. In these technologies, the solar power generating systems use glass mirrors that continuously track the position of the sun while absorbing its solar radiation energy. The absorbed solar energy can be harnessed and transferred in two ways: indirectly or directly. The indirect method uses a heat transfer fluid (HTF) which absorbs solar radiation energy and transfers the heat to water via a series of solar steam generator heat exchangers, thus indirectly producing steam. The direct method eliminates the HTF step by circulating water directly through the concentrated solar radiation path, thus directly producing steam. Both solar thermal technologies investigated in this study use the indirect method with either a synthetic oil HTF (parabolic trough) or a molten salt HTF (central receiver).

Thermal Energy Storage

The coupling of concentrating solar power technologies with thermal energy storage (TES) has the ability to extend the production of electricity from solar power beyond daylight hours. It essentially eliminates the variability associated with solar energy technologies, allowing for dispatch-ability. As outlined in the previous sections, some heat gathered during the day when solar is at its peak can be stored using molten salts. The heat captured in the salts can later be used to produce steam after sunset.

The integration of TES with each CSP technology is discussed further below in the respective sections. See the figure below for a generic load profile and the impact of thermal energy storage. The yellow line represents the thermal heat (primary y-axis) that is collected during the entire day. The orange line represents the net electricity that is produced with storage. They key observation is the power generation system's ability to produce long after the sun has set, i.e. the loss of direct normal irradiation.

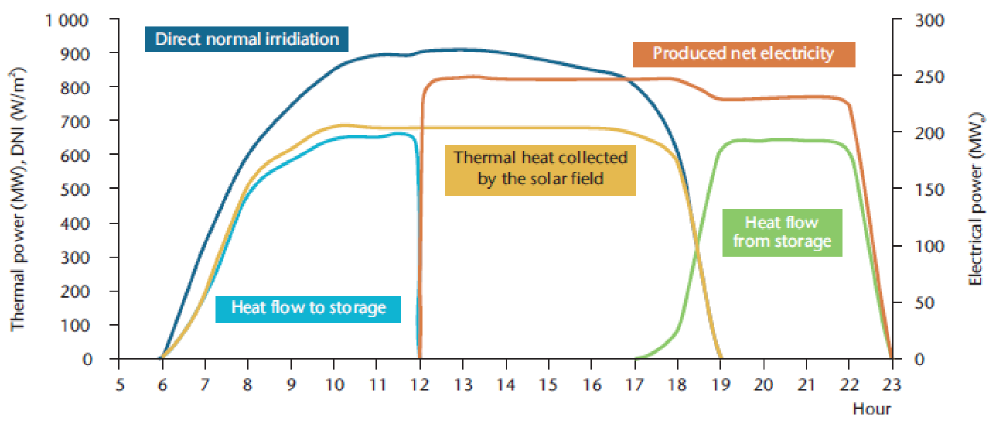


Figure 6-19
Use of Storage for Shifting Production to Cover Evening Peaks

The use of TES has been demonstrated to significantly improve the energy production significantly. Torresol Energy's Gemasolar plant outside of Seville, Spain began operating in 2011 and was the first large scale solar tower power plant to use molten salt storage. The 20MW facility set a record of operating 24/7 for 36 consecutive days in 2013. The figure below displays the energy production from Gemasolar. The top graph was developed from production during the summer months. The bottom graph was taken during the winter months. During the winter months, energy is reduced but production continues. It should be noted that Gemasolar is outfitted with 15-hour storage capability to achieve this level of production.

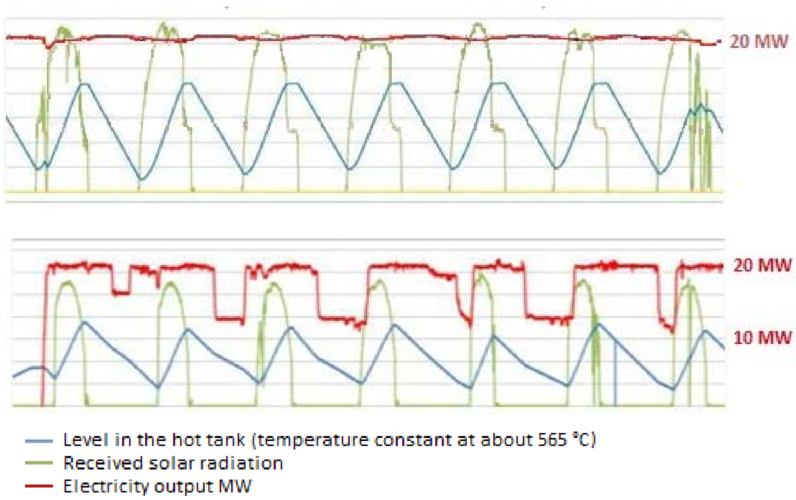


Figure 6-20
Weekly Energy Production for Gemasolar CSP Plant

Parabolic Trough

Trough technology uses single-axis tracking, parabolic trough-shaped reflectors to concentrate DNI onto a vacuum absorber pipe or heat collection element (HCE) located at the focal line of the parabolic surface (Figure 6-21). The solar field consists of several hundred to several thousand parabolic trough solar collectors, known as solar collector assemblies (SCAs). Rows of SCAs are aligned on a north-south axis, allowing the single-axis troughs to track the sun from east to west during the day (Figure 6-22). A high temperature HTF such as synthetic oil absorbs the thermal energy as it flows through the HCE. Heat collected in the solar field is transported to a series of shell-and-tube heat exchangers – collectively termed a solar steam generator (SSG). The superheated steam generated in the SSG then expands through a conventional steam turbine to generate electricity. Steam temperatures are generally limited to ~370ºC due to degradation temperature limitations of the synthetic oil.

Parabolic trough systems can be coupled with thermal energy storage to enhance the dispatchability of the power plant. The current viable TES technology is the indirect molten salt two-tank system. These systems consist of a “cold” tank and a “hot” tank to hold the molten salt and a heat exchanger. During peak hours of solar insolation, some of the heat collected from the solar field in the synthetic oil HTF passes through the heat exchanger of the storage system, transferring heat to molten salt passing from the cold tank to the hot tank. The heated salt is then stored in the hot tank until additional thermal energy is required for the steam cycle. At this time, the hot salt passes back through the heat exchanger, this time heating the synthetic oil HTF, and returns to the cold tank. The heated HTF can then enter the SSG to generate steam for the steam turbine of the power cycle.

Storage rating is a design based on the amount of heat to run the turbine at full output for a specified length of time, for example 125 MW for three hours. This specification sizes the storage tanks, piping, pumps, etc. The actual performance of the storage system is based on many parameters including, but not necessarily limited to, the solar multiple used for sizing the field, the operating scheme, the available solar energy, ambient temperatures, etc. The largest factor is the solar multiple, which is the ratio of the solar energy collected at the design point DNI to the amount of solar energy required to generate the rated turbine gross power, and dictates the total amount of heat that can be created by the solar field at any given DNI value. Choosing a solar multiple is a trade off between capital expense and incremental electricity generated. There are times when there will be insufficient energy to charge the storage and run the turbine at full load. There will be other times when parts of the solar field will need to be defocused due to too much heat being available. The concept of solar multiple has been studied extensively, and the solar multiples represented in this study's designs attempt to strike the best balance between capital expenditure and incremental energy production.

Some important site requirements for a parabolic trough system include having a land slope between 1% and 3% to minimize the trough tilt angle, and a large square to rectangular-shaped land area allowing for north-south SCA row arrangement.

Generation profiles for parabolic trough units with various storage capacities are shown in Figure 6-23.

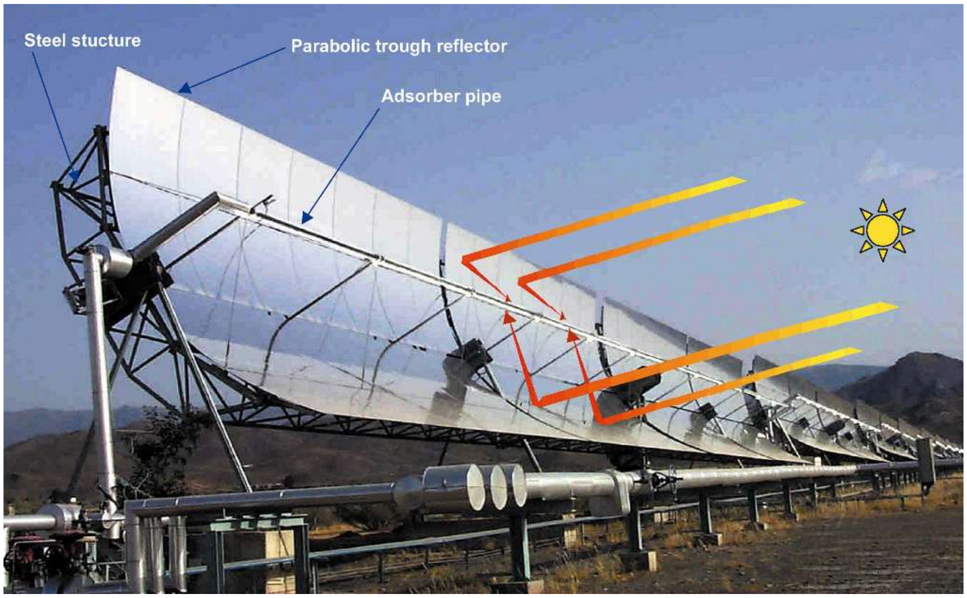
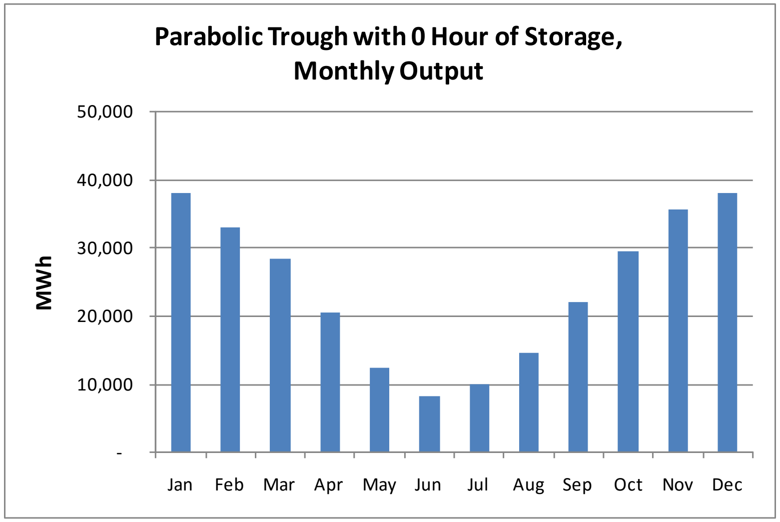


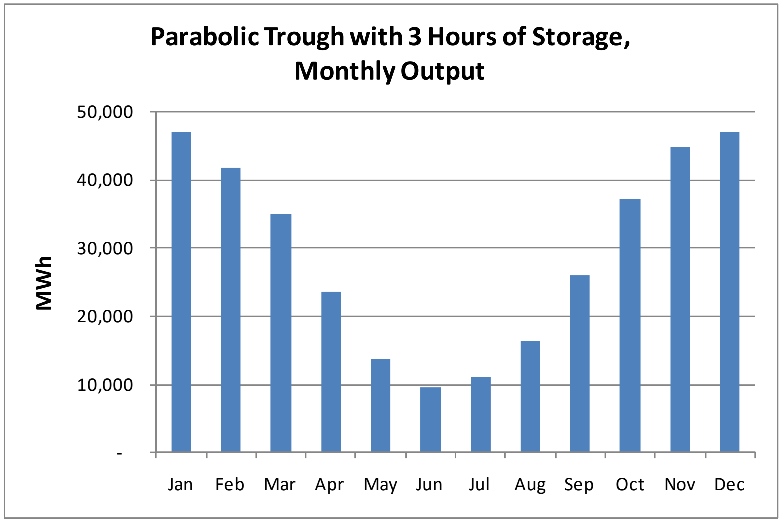
Figure 6-21
Parabolic Trough

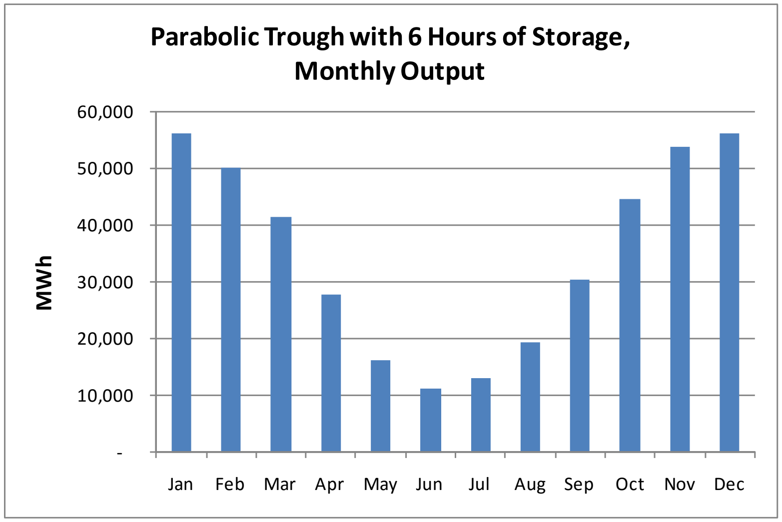
Figure 6-22
Parabolic Trough North-South Axis View

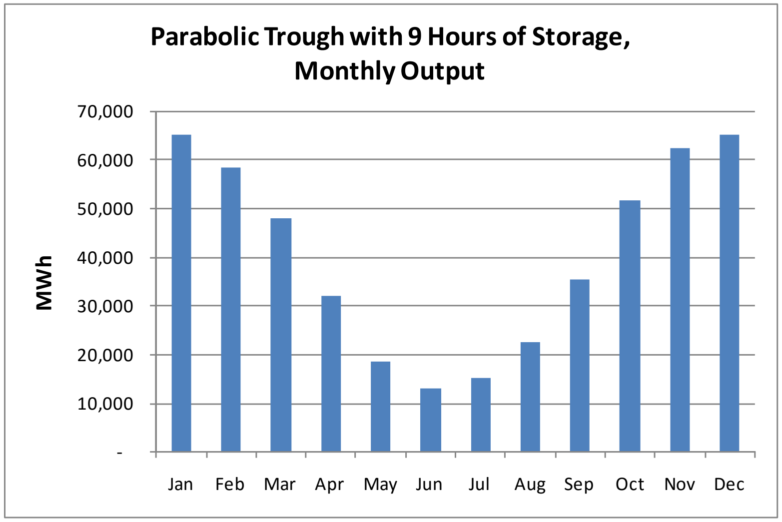
Figure 6-23
Parabolic Trough Generation Profiles

Note: Generation profiles shown are based on interpretation of similar units located in Las Vegas, NV, with direct normal insolation value of 2600 kWh/m^2









Central Receiver

A central receiver uses two-axis sun-tracking mirrors called heliostats to redirect DNI to a receiver at the top of a tower (Figure 6-24 and Figure 6-25). Molten nitrate salt HTF at 287ºC is pumped out of the "cold" tank, through the receiver, and into the "hot" tank at 565ºC. The "hot" tank delivers the molten salt to the SSG where superheated steam is produced and expanded through a conventional steam turbine producing electricity. Currently, molten nitrate salt has been used as the common HTF because of its superior heat transfer and energy storage capabilities.

Figure 6-24
Picture of Central Receiver Plant

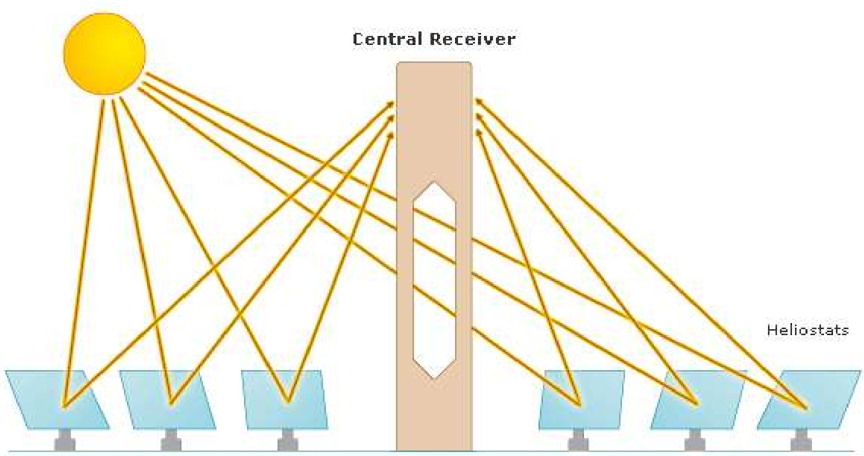


Figure 6-25
Heliostat to Receiver Sun Path

The ability of molten salt HTF to be heated to 565ºC and generate steam at 538ºC results in relatively higher cycle efficiencies than achievable with the lower temperature steam of the typical synthetic oil HTF parabolic trough plant. The elimination of oil also reduces environmental risks due to leaks and reduces consumable costs because salt is typically significantly cheaper than synthetic oil. However, molten salt has a relatively high freezing point at 221ºC. To maintain salt in the liquid state a significant electrical freeze protection system must be employed. Another disadvantage of this technology is that each mirror must have its own dual-axis tracking control; as a result, tower plants also have larger parasitic loads associated with mirror tracking relative to parabolic trough systems.

Unlike the synthetic oil HTF parabolic trough system, power tower technology using molten salt allows for direct TES, where the HTF is the same fluid as the storage media, allowing for substantial cost reduction of the TES system compared to an indirect TES system because oil to salt heat exchangers are eliminated. Figure 6-26 shows a schematic diagram of the primary flow paths in a molten-salt solar central receiver plant with an integrated two-tank TES system.

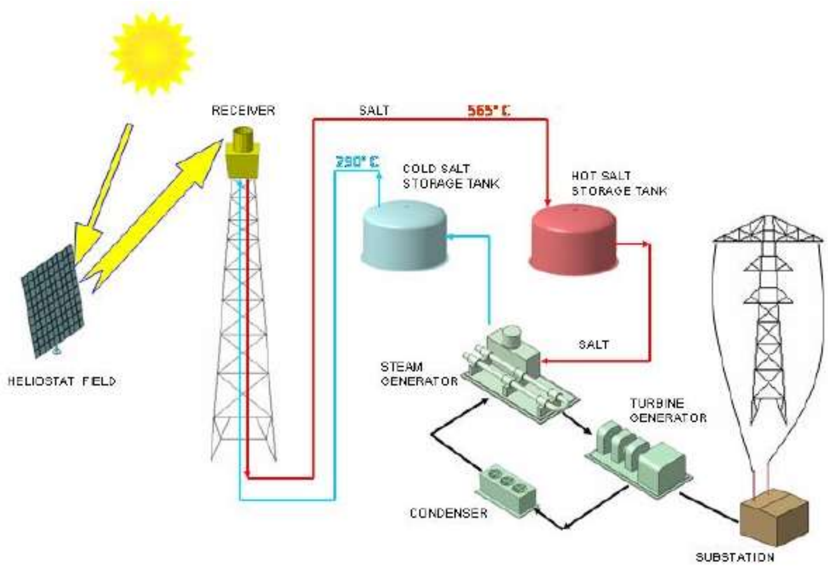


Figure 6-20
Schematic of Molten-Salt Power Tower System

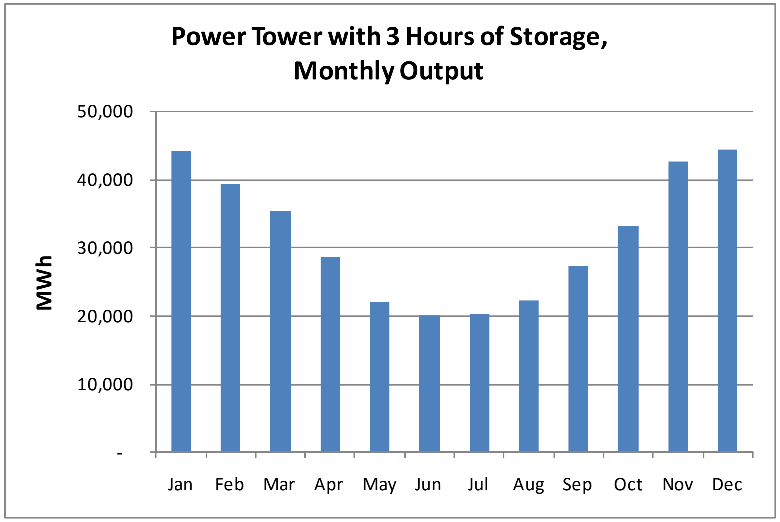
Typically, central receiver designs have a fixed number of heliostats (solar field size) and a fixed tower height, with the alternating plant design variables being the steam turbine/power block and storage capacities. More specifically, with a larger turbine the plant output is higher at peak solar insolation periods, but less energy is available for storage, whereas a smaller turbine allows for more stored energy, and thus a higher capacity factor, but less peak output to the grid. The optimum balance is highly dependent upon the planned dispatch profile.

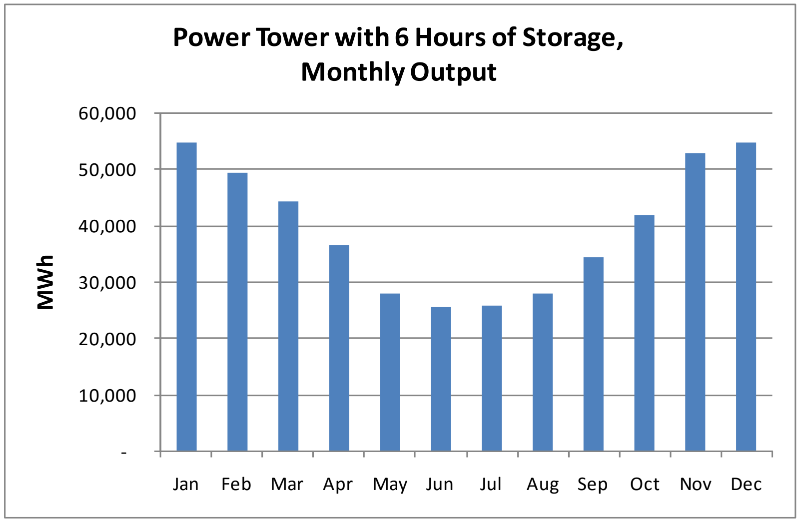
Some important site requirements include having a level land area; however, the requirements are less stringent than with the trough design, in principle, because of the two-axis mirror tracking. Having a continuous parcel of land able to accommodate an ovular-shaped footprint is also a valuable feature. The footprint of tower systems is relatively larger than a trough-based plant.

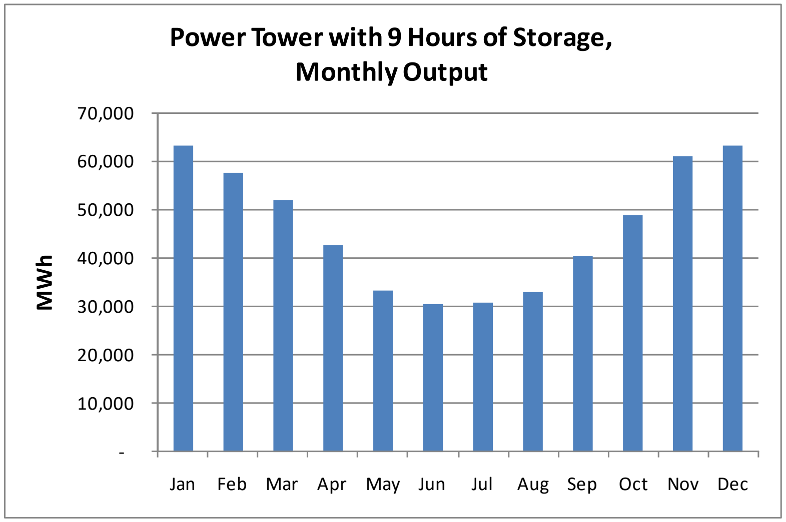
Generation profiles for power tower units with various storage capacities are shown in Figure 6-27.

Figure 6-21
Power Tower Generation Profiles

Note: Generation profiles shown are based on interpretation of similar units located in Las Vegas, NV, with direct normal insolation value of 2600 kWh/m^2







Solar PV

Solar PVs are rapidly becoming a viable utility scale renewable technology option. This technology converts sunlight into electrical power and has been through various levels of commercialization since its development in the 1950s. One of the first applications of solar PV technology was to power remote equipment such as satellites, buoys, and telecommunication equipment in combination with batteries to maintain a backup of energy. As costs have decreased and government incentives and mandates have proliferated, applications now span grid-connected homes, buildings, and large ground mounted systems.

The market for solar PVs is growing rapidly. According to the International Energy Agency, the global cumulative solar PV capacity amounted to 177 GW at the end of 2014, with incremental global capacity additions totaling approximately 39 GW for that year. Asia was the leading solar PV region in the world in 2014, with China reaching over 10 GW in installed capacity while Japan added 9.7 GW. In North America, the U.S. installed over 6 GW of capacity, while Canada, Mexico, and Chile also grew. South Africa became the first African country to install close to 1 GW in 2014, while many more countries across the continent have a number of projects in various stages of planning and construction. The European market, however, continued to decline in 2014, in spite of the UK's growth throughout 2014, which has established itself as the leading European market with over 2 GW capacity additions.

PV technologies convert sunlight directly into electricity using semiconductor materials that produce electric currents when exposed to light. Semiconductor materials used for PV cells are typically silicon doped with other elements that have either one more or one less valence electron to alter the conductivity of the silicon. For example, if the silicon is doped with an element having one more valence electron, such as phosphorus, then the resulting material will have an extra electron available for conduction. This material is called an n-type semiconductor. Conversely, when the silicon is doped with an element having one less valence electron, such as boron, then the p-type semiconductor that is produced has an electron vacancy, or hole. When adjacent layers of n-type and p-type materials are illuminated, a voltage develops between them, which can cause a DC electric current to flow in an external circuit.

One characteristic of solar PV that sets it apart from other renewable technologies is its modular nature, which makes it applicable to small distributed systems as well as large utility-scale power plants. The building block of a solar PV system is the PV module, illustrated in Figure 6-28. The solar module consists of multiple solar cells connected in series, and it generates the electrical energy in the form of direct current power. Modules are connected in series to form a string in order to increase the voltage of the system. Higher system voltage results in reduced resistance losses across DC collection system wiring distances.

The multiple strings of a PV system are connected in parallel at a combiner box and fed to an inverter, a power electronics device that converts the DC power into AC power. Utility scale systems make use of multiple inverters; for example, a 10-MW plant could have twenty 500-kW inverters. Depending on the technology, the land area required for a 10-MW power plant varies between 40 and 80 acres or more. Therefore, the distance between the inverters and the point of interconnection to the grid can be significant. To increase the distribution efficiency of the electrical AC energy generated by the inverters in a utility scale system, it is typical to step up the voltage after the inverter to the maximum distribution voltage possible before connecting to a substation for transmission over power lines.

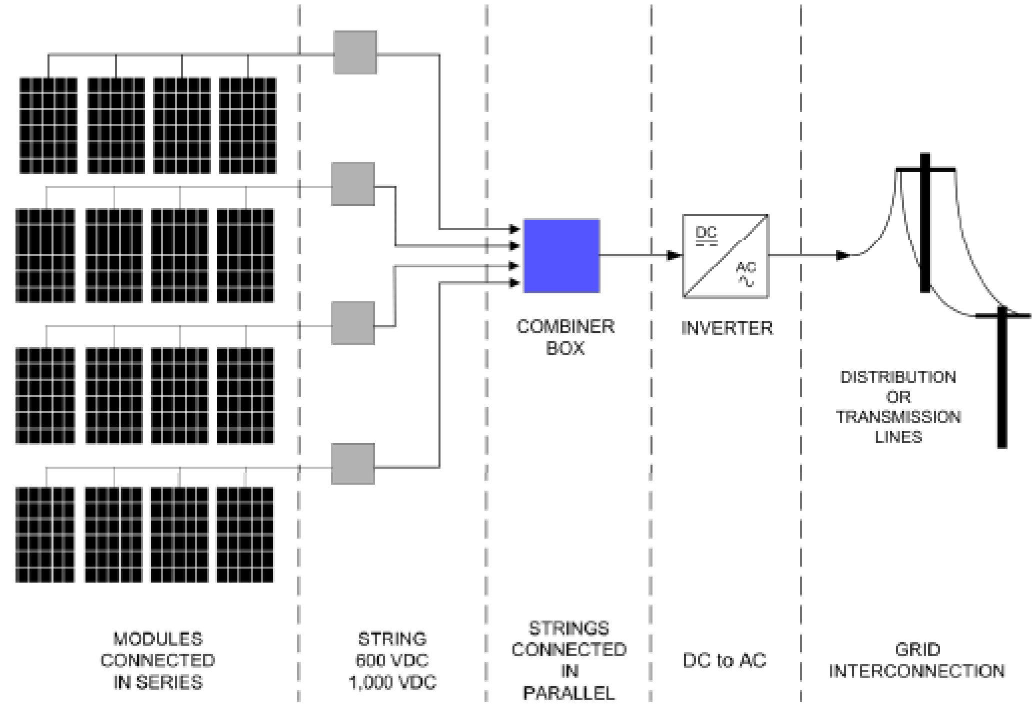


Figure 6-22
Conceptual Overview of Solar PV System

The nominal power rating of flat plate modules is based on the power output under Standard Test Conditions (STC). STC defines an input energy density of 1,000 W/m^2 and a cell temperature of 25° C. The STC rating test is conducted indoors using a solar light simulator that flashes a pulse of controlled and calibrated light over the module. The STC conditions rarely occur in real applications, but the test is relatively easy to replicate and has become the standard to report the nominal power of modules. In solar PV terminology, the power rating is reported as Watt Peak (Wp), to reflect the DC power output of the module under the ideal STC conditions. Two modules with the same power rating may operate with different conversion efficiencies and, therefore, the less efficient module will require a larger active surface area to achieve the same power rating as the more efficient module. The efficiency of the solar PV modules varies from technology to technology. The efficiency of the module has an impact on the land area and balance of system component requirements for a given rated project power. As the efficiency of the modules increases, there is a corresponding decrease in the amount of land area and components such as mounting structures and wiring that are required for a given power generation capacity.

Three array configurations are used for PV systems: fixed-tilt arrays that are stationary and are either mounted flat or oriented to tilt towards the equator for maximum sun exposure, single-axis tracking that tracks the sun’s movement from east to west, and two-axis tracking that tracks the sun to remain perpendicularly oriented to the sun’s rays. There are also three main types of PV technology: flat plate c-Si, thin film, and concentrated PV (CPV). This study focused on fixed-tilt thin film PV, fixed-tilt c-Si PV, and two-axis tracking CPV for commercial- and utility-scale systems.

Flat Plate PV

There are two predominant types of flat plate solar PV technologies on the market: c-Si and thin film. C-Si cells are the most widely used technology to date and is what one traditionally pictures when envisioning a solar panel. However, thin film modules are being commercialized and are challenging the dominance of c-Si in the PV market. To date, c-Si cells have achieved the greatest efficiency of non-concentrating technologies, but the manufacturing process remains relatively slow and energy intensive. One of the main drivers behind the cost competitiveness of the thin films is the simpler manufacturing process, reduced use of semiconductor materials, and lower manufacturing energy requirements in comparison with c-Si cells.

The manufacturing process of c-Si cells involves sawing thin wafers of extremely pure silicon ingots, exposing the wafers to several chemical and physical treatments, and completing the process by adding an aluminum conducting mask and an anti-reflective coating that creates the distinctive dark metal blue color of the cells. The manufacturing process for thin film modules typically consists of depositing thin layers of semiconductors on a sheet of glass. Thin film solar cells are made from layers of semiconductor materials only a few micrometers thick; hence the term “thin film”. This process eliminates the ingot growth and wafer sawing steps that are characteristic of c-Si, activities with high energy demand and high semiconductor material waste. A streamlined manufacturing process and a drastic reduction in semiconductor raw material give thin film technologies a cost edge.

Silicon is an abundant, non-toxic element, which gives c-Si PV technology a relatively stable feedstock. C-Si can be grown in two main forms: mono-crystalline silicon and poly-crystalline silicon. Mono-crystalline silicon has an ordered crystalline structure with each atom arranged in a regular pattern. These cells yield a slightly higher efficiency and a better temperature coefficient (the power output derate is less steep vs. temperature increase) than poly-crystalline silicon. However, mono-crystalline silicon is more expensive than poly-crystalline silicon because of the high processing control required and high energy consumption during manufacture. The manufacturing process requirements for poly-crystalline ingots are less strict; therefore, more ingots can be produced per unit time, reducing cost. At present, the flat plate PV market is dominated by traditional poly-crystalline technology. Poly-crystalline technology has been successful largely due to the technology’s ability to use scrap material, processing equipment, and know-how from the semiconductor industry to help reduce commercial risks. C-Si, either mono or poly, is a well understood technology with many years of experience.

Cadmium telluride (CdTe) is a well-developed technology that is competing for and expanding the thin film market share based on its efficiency and competitive cost. One of the major advantages of CdTe is the relatively simple manufacturing process compared to other thin film technologies, which translates into lower equipment capital costs and subsequently lower module costs. The two largest drawbacks to this technology are the toxicity of cadmium and the rarity of tellurium. Elemental cadmium is a well-known toxic substance, but it is not known to be toxic in a stable compound form, such as in CdTe. Tellurium is one of the rarest stable solid elements in the earth’s crust, and could become a feedstock bottleneck in the future.

Copper indium gallium (di) selenide, also known as CIGS, is a thin film technology just now entering the market. CIGS has a long track record in the field, but it is only now beginning to be commercialized on a large scale. It promises a higher efficiency than other thin film technologies. However, the technology has some drawbacks, such as the use of the rare element indium and a relatively complex manufacturing process. Other thin film technologies currently in development include dye sensitized solar cells, high-efficiency flexible solar cells, and organic solar cells. Development of these technologies could potentially achieve dramatic reductions in cell cost, but likely will achieve efficiencies on the lower end of the range for solar PV cells.

This study focused on fixed-tilt cadmium telluride thin film and c-Si technologies.

It is worth noting that single axis tracking technologies are beginning to change the landscape of installed solar PV projects. Including tracking in utility-scale solar photovoltaic (PV) installations has historically been uneconomic for most project owners. Put simply, the increase in daily, seasonal, and annual plant energy production provided by one- and two-axis trackers has not financially justified the cost premium associated with the resulting rise in system complexity and required O&M effort. As a result, relatively few single-axis tracking (SAT) and dual-axis tracking PV plants have been installed. This situation appears to be changing, however, particularly for SAT systems.

Adding tracking to a PV system increases the energy yield by allowing the modules to follow the sun daily (east to west) in single-axis applications and both daily and seasonally in dual- axis applications. In addition to generating more energy annually (relative to same-capacity fixed flat-plate plants) tracking PV systems alter the shape of the daily output profile thus, in effect, modifying PV resource availability.

Two-axis tracking results in the highest annual energy production, but at a higher capital cost. Concentrating PV (CPV) systems, for example, require either one-axis or two-axis tracking, depending on whether the system is line focus or point focus. According to GTM Research, tracking adds an estimated ~$0.20-$0.25/W to the capital cost of projects, though these premiums may be smaller for very large projects. Tracking also increases O&M expenses by introducing complexity in the racking system via motors, actuating mechanisms and control systems.

Per Figure 6-29, the addition of tracking can increase energy production by over 30% relative to a horizontal, fixed PV system. However, it is best to compare incremental tracking gains to a fixed flat-plate PV system at latitude tilt because it is more typical of utility-scale ground-mount plants. This approach derives a more modest energy production — perhaps an increase of around 7% that is offset by an additional roughly 5% in capital costs. System performance improvements with trackers is most pronounced at sites with high quality solar resources (e.g., desert locations) and can, in turn, have a greater impact in reducing a PV plant's levelized cost of electricity (LCOE).

				
	Horizontal	**Fixed Tilt**	**Single-Axis Tracking**	**Two-Axis Tracking**
Indicative Energy Boost Relative to Fixed Horizontal System	0%	15%	22%	32%
Increased Capital Cost per m^2 of Panel Relative to Fixed Horizontal System	0%	10%	15%	20%

Figure 6-23
Effects of Tracking on Annual Energy Production and CAPEX

Concentrating PV

CPV systems make use of optical devices (mirror or lenses) to concentrate the incoming sunlight and deliver it to a PV cell. The increased energy per unit area allows for a reduction in the surface area of the cell to generate the same amount of power that, without concentration, would have required a cell with a larger surface area. In any PV system, the PV cell is the most expensive component. Hence, the main motivation for the development of CPV technologies is to reduce the amount of semiconductor material, while providing an increased power per unit area and using significantly less expensive materials. CPV technologies typically make use of high efficiency tandem or multi-junction cells. Common cell alloys are indium gallium phosphide and GaAs on a germanium substrate. Other materials are being investigated.

Many of the companies working on CPV technologies are still relatively small and early in development. There has been a flood of investments both by private and public entities to commercialize CPV technologies and prove their merit on a large scale. There are also a handful of companies developing low concentration linear concentrators. In addition, some companies that focused on making high efficiency cells for space applications are now developing products for terrestrial systems.

This study focused on high concentration CPV utilizing high efficiency multi-junction cells.

Biomass

Biomass fuels are produced by living plant and animal matter. The use of these fuels, which are typically considered renewable fuels, provides electricity generators with dispatchable, non-intermittent renewable power due to the fact that, for the most part, biomass fuels can be produced, concentrated, and stored for use when it is economic to do so.

Biomass fuels exhibit certain fundamental differences from other fossil fuels. Typically, biomass fuels are either gathered up or harvested from diffuse sources and concentrated at a given location. Consequently, there are practical limitations on the quantities that can be obtained at any location without experiencing significant cost pressures. This is in distinct contrast to the fossil fuels that are produced in centralized locations—e.g., coal—and distributed to users such as power plants.

Fuels currently used as biomass fuels are, almost exclusively, residues from other processes. They may be wood processing residues such as hog fuel, bark, sawdust, or spent pulping liquor. They may be agricultural and agribusiness residues such as bagasse. They may be methane-rich gases generated from wastewater treatment plants, landfills, or anaerobic digestion of animal manure. Fractions of MSW—paper, wood waste, food waste, yard waste—are also forms of biomass fuel. These are all commodities that are presently outside the commercial mainstream. In some cases these commodities have both material and energy value. Wood waste markets, for example, can include mulch for urban areas, bedding for livestock and poultry, feedstocks for materials such as particleboard, and feedstocks for niche chemical and related products. As a result, fuel pricing is highly sensitive to locale and the competitive pressures of local and regional economies.

This study focused on forestry residue, MSW, landfill gas, and biogas.

Forestry Residue

The traditional wood-fired boiler used in electricity generation is a stoker boiler. Producing electricity using biomass boilers is a well-proven technology. Stoker grate boilers utilizing biomass were developed in the 1920-30s. The stoker grate technology is well proven in the biomass power generation industry and is commercially available. It is effective in burning solid fuels that contain fuel particles of sufficient size that they must rest on a grate to burn as well as finely sized particles. Solid fuel is introduced into the furnace using pneumatic or mechanical spreaders, which “stokes” (feeds) the furnace. If the stoker feeds fuel into the furnace by flinging it mechanically or pneumatically over the top of the grate, the stoker is referred to as a spreader stoker. The spreader stoker technology allows for the finely sized particles of the fuel to burn in suspension, while the larger solid fuel particles fall on the grate where they burn to completion. Spreader stokers with oscillating, pulsating, or traveling grates have been widely used for biomass power plants because many of the designed systems have the ability to burn a wide variety of solid fuels simultaneously.

Steam conditions in wood-fired boilers are a function of the design capacity of the boiler. For lower-capacity boilers (e.g., 113,400 kg/hr (250,000 lb/h) steam), 4.1 MPa/400°C (600 psig/750°F) conditions are common. For medium-capacity boilers, the steam conditions are often 5.9 MPa/440°C (850 psig/825°F), and higher capacity units typically use 8.6 MPa/510°C (1,250 psig/950°F) and 10 MPa/540°C (1,450 psig/1,000°F) steam conditions. The larger units use more feedwater heaters to improve the thermal efficiency of the unit.

Turbines are selected based on unit capacity and whether the system is designed as a stand-alone power-only plant, or whether it is a cogeneration or CHP plant. Steam turbines can be designed with automatic extractions for process steam or as backpressure turbines exhausting process steam at 345 kPa (50 psig), 1035 kPa (150 psig), or other conditions depending upon the plant requirements. Alternatively, the turbines can be designed and supplied to exhaust steam at 6.7 to 10.2 kPa (2 to 3 in HgA) if power is the exclusive product.

Air pollution equipment for solid biomass-fired systems includes either FFs or electrostatic precipitators (ESP) for particulate control. To meet NOx emission standards, stoker grate boiler systems typically include staged combustion systems and accurate combustion control. Combustion is carried out at about 40% excess air, where overfire air accounts for about half the total. Typically, three fans provide the necessary combustion control: one for under-grate combustion air, one for overfire air, and one for pneumatic fuel distributors. Modern stoker boilers also include either SCR or selective noncatalytic reduction (SNCR) systems to reduce NOx up to a maximum reduction of 50 %. Acid gas scrubbers are not required due to the compositions of typical solid biomass fuels.

MSW

Unprocessed MSW and refuse derived fuel (RDF) are used to generate electricity by burning them in a boiler to produce steam and drive a steam-turbine generator. This study focused on mass burn MSW, which does not process the MSW prior to combustion as is done with RDF. It was chosen for this study because it is the predominant technology for recovering energy and generating electricity from MSW. However, both mass burn MSW and RDF are described for informational purposes.

Unprocessed MSW typically has a lower heating value than RDF; however, the fuel cost is also lower due to the reduced fuel preparation costs. RDF typically consists of pelletized or fluff material that is the byproduct of a resource recovery operation to remove ferrous and nonferrous materials, such as aluminum and steel cans, glass from bottles and other sources, grit, and other materials that are not combustible. The remaining material is then sold as RDF.

MSW is burned directly in a mass burn boiler. RDF is burned in one of several configurations, including:

- Dedicated RDF boilers designed with traveling grate spreader-stokers;
- Cofiring with coal or oil in multi-fuel boilers;
- Dedicated RDF fluidized boiler.

Various qualities of RDF can be produced, depending on the needs of the user or market. A high quality RDF would possess higher heating value and lower moisture and ash contents. Processed engineered fuel (PEF), for example, is high quality RDF in which toxic and high-ash components have been removed, as well as metals, rock, glass, electronics, sheet rock, plaster, and other high ash non-combustible components. PEF exists as a fluff, while densified PEF (dPEF) is the same product packed as cubes or pellets for easy storage and transportation.

PEF composite fuels can be formulated to substitute for other solid fuels without modification to the combustion system. E-Fuel is an example of a commercial PEF made with a mixture of 70% paper making waste sludge, 25% waste from a low density polyethylene plastic used to line food cartons, and 5% coal fines. This mixture is blended and then pelletized. Other PEF fuels come in the form of briquettes made from coal fines and other waste materials such as wood.

RDF has relatively high concentrations of paper and plastics, both of which have a high calorific value. In comparison with most coals, it also may contain materials that have a relatively high percentage of ash, can be damaging to burners and boilers, and can impact quality of exhaust gases. For example, RDF typically contains materials with substantial concentrations of chlorides that may induce a corrosive effect on boiler tubes. The presence of small particles of metal and of glass fines in RDF can present problems in the combustion system. Moreover, the exclusion of these small particles in RDF is difficult.

Ash production resulting from combustion of MSW or RDF can be four to six times that which would be experienced with the combustion of coal. Consequently, when using RDF in cofiring with coal, some provisions must be made for handling the additional burden of ash.

An important pre-requisite for the successful combustion of RDF/PEF in a combustion system, whether fired solely or in combination with another fuel, is the development of the proper fuel specification. The fuel specification should be provided to the RDF supplier by the combustion system supplier. The need for compatibility of the RDF with all the applicable elements of the combustion system cannot be over emphasized. For financial reasons, optimum performance of the combustion process and thermal conversion system is required. Therefore, the properties of the RDF must be carefully evaluated and selected. These requirements apply to dedicated RDF plants and to cofiring with coal.

RDF composites hold strong potential for both reducing emissions from coal fired boilers and reducing fuel costs. In order to realize both potentials, sources of low cost feedstock must be converted into solid fuel that can be used in existing coal boilers without the need for a capital intensive boiler retrofit or a high increase in fuel purchase, transportation, handling, and storage costs. Gasification and pyrolysis technologies can convert MSW into energy sources. However, these technologies are less proven in operation, even at relatively modest scale.

Landfill Gas

Gases released from the decomposition of MSW in landfills are also considered a form of biomass. Solid waste landfills are the largest source of human-related methane emissions in the United States. Landfill gas composition is typically 50% methane, 50% carbon dioxide, and small amounts of other organic compounds. Landfill gas is extracted from landfills using a series of wells and a blower/flare (or vacuum) system. This system directs the collected gas to a central point where it can be processed and treated depending upon the ultimate use for the gas. From this point, the gas can be simply flared or used to generate electricity, replace fossil fuels in industrial and manufacturing operations, fuel greenhouse operations, or be upgraded to pipeline quality gas.

Many sites produce electricity by burning landfill gas in internal combustion engines, small combustion turbines, boilers coupled with steam turbines, and microturbines. Other developing technologies that can use landfill gas are Stirling engines, organic Rankine cycle (ORC) engines, and fuel cells. Thermal applications include packaged boilers, dryers, kilns, greenhouses, water heating for aquaculture, etc. In limited instances, landfill gas has also been compressed and converted to a high-energy gas comparable to pipeline quality natural gas, to liquid fuel, or to feedstock for methanol production. Actively collecting the landfill gas and using it for power generation and thermal uses reduces the contribution of methane to greenhouse gas emissions, reduces the potential for buildup of explosive/toxic releases of methane, and offsets a portion of the natural gas recovered from underground deposits. In this study, the landfill gas is combusted in spark ignition reciprocating engines, which is currently the most common technology used for generating electricity from landfill gas.

Cost of LFG Power Generators

As with other forms of power or energy generation, capital costs vary considerably as a function of location, plant size, generating technology, construction labor wages, owner's philosophy, and other factors. While there is published information on the costs of LFG projects, it should be considered as a general (order-of-magnitude) indicator of plant cost, not a cost that can be applied to the cost of LFG generators in a "blanket" fashion. The reason is that the capital cost of what appears to be the same project (e.g., "5-MW LFG engine project") can vary substantially, due to project-specific issues such as:

- Amount of LFG collection piping included (i.e., from the landfill to the engines).
- Whether a blower/compressor and flare are included.
- LFG quality and the extent of gas cleanup equipment required.
- Other site specific issues:
  - Electrical interconnection
  - Civil/foundation work
  - Local labor rates
- Whether soft costs, such as owner's costs, are included in a reported project cost figure.

Additionally, O&M costs can vary with issues such as:

- Whether a service agreement is purchased from the equipment manufacturer (or if the owner can handle most of the inspection and routine maintenance work with his own staff).
- The quality of LFG filtering included with the original installation. If the initial LFG filtering is marginal, the maintenance costs will rise.
- Operating issues relating with the landfill operator. For example, if waste of a different composition is buried in the landfill, the LFG quality could change. (One example was in a landfill that accepted a large amount of gypsum drywall after a storm, which increased the level of sulfur in the LFG.)

Table 6-3 summarizes indicative costs of the various power generation technologies, based on the LMOP 2009 handbook.

Table 6-3
Typical Costs of Power Generation Technologies

(per EPA LMOP handbook and database, note 1)

	Micro-Turbines	**Reciprocating Engines**	**Gas Turbines**	**Combined Cycle**	**Boiler/Steam Turbine**	**Sterling Engines**
Quantity of Projects	16	347	30	8	18	2

% of Electricity Generation Projects	3.8	82.4	7.1	1.9	4.3	0.5
Average MW per Project	0.4	3	5.6	11.2	9	< 500 kW
Typical Project Capacity Range	Less than 500 kW	500 kW to 6.0 MW	4.5 to 10 MW	10 - 30 MW	8 to 50 MW	< 500 kW
Typical Capital Costs, $/kW	5,500	1,700 - 2,300	1,400	Note 2	Note 2	Note 2
O&M Costs, Cents/kwh	3.8	1.8 - 2.1	1.3	Note 2	Note 2	Note 2

Notes:

1. The data from “LFG Energy Project Development Handbook,” 2009.
2. Typical capital cost data for boiler/steam turbine, combined cycle, and Sterling engine arrangements is not indicated in LMOP handbook.

Technical Issues for LFG Power Production

The heating value of LFG can range from 350-600 Btu per cubic foot, while natural gas contains about 1000 Btu per cubic foot. One benefit of LFG is that because it is generated 24 hours a day, it is always available for power generation. EPA has estimated that utilizing LFG for energy projects will effectively reduce significant amounts of CO_2 emissions to the atmosphere. As indicated in previous discussion and tables, LFG has been burned primarily in reciprocating engines, combustion turbines, and boilers.

For LFG-fired power generation systems, the extraction, collection, compression and treatment of the gas are the primary challenges. Burning the gas in a combustion turbine, reciprocating engine or boiler is relatively straightforward once the fuel is processed and made available to the generation system. Many of these LFG turbines are designed to use 100% LFG, but can also use diesel oil or natural gas as backup fuels. If the power generation system is off line, the LFG stream must be flared to comply with environmental regulations. Non-productive flaring can be minimized or avoided by the use of multiple LFG power generating units, with efficient turn-down capability.

The LFG collection system at a landfill typically consists of an interconnected system of horizontal and vertical collection pipes made of high-density polyethylene. Once collected in the pipes, the gas is moved to a central compression and treatment system. It is critical to the project development to properly estimate the available flow to an LFG project utilizing a state-of-the-art computer model such as the EPA’s LandGEM program. The program can estimate the LFG production flow over the long term (20-30 years of LFG generation life) based on inputs such as waste tonnage and age, and other site-specific characteristics of the landfill. As noted above, a collection efficiency factor should be applied to the predicted LFG production rate to conservatively estimate the available LFG flow to the project.

Dry LFG is composed of 50% methane, 30% CO_2, 10% N_2 (N_2 drawn into the landfill during extraction from the atmosphere), and 10% water and other compounds. Halogen compounds in LFG can combine with the water in the gas to form acids that attack process equipment. Pretreatment systems can consist of coalescers and intercoolers/condensers to reduce the water content of the gas. Other pretreatment steps are sometimes used to prevent impacts on the power generator life and performance. Packaged LFG treatment/conditioning systems are available on the market. A two stage system, consisting of a rotary blower followed by a screw compressor, is used to first extract the gas from the landfill and then compress it to more than 200 psi for firing combustion turbines. Compression requirements are much lower for reciprocating engines and boilers.

The allowable emissions level is a key aspect of the project development process. Of the power generation technologies considered herein, reciprocating engines have comparatively high emissions. As noted in Table 6-4, today's LFG engines can easily meet the federal New Source Performance Standards (NSPS) for spark-ignition engines; but the emission limits included in state-issued permits can be more stringent.

Table 6-4
Federal NSPS and State Permitted Emissions Limits for Spark Ignition Engines

(grams/BHP-hour)

	NO_X	**CO**	**VOC**
Federal NSPS Limits for LFG Engines	3.0 (Note 2)	5.0	1.0
Recent State Permitted LFG Engine Projects (without catalysts) (Note 3)	0.5 – 0.6	2.5 – 3.0	0.16 - 0.80

Notes:

1. Recently permitted project information was sourced from EPA's RBL Clearing house data list. (RBL = RACT/BACT/LAER, where RACT = Reasonably Achievable Control Technology; BACT = Best Available Control Technology; and LAER = Lowest Achievable Emission Rate).
2. The NO_X standard will be reduced to 2.0 grams/BHP/hour after the following manufacture dates: July 1, 2010 for engines ≥500 HP; January 1, 2011 for engines <500 HP.
3. The ranges listed pertain to those indicated in permits in the past 7 years, as indicated in the EPA database.

As indicated in Table 6-4, individual state permitting requirements are often more stringent than the federal NSPS levels especially in non-attainment zones. Non-attainment zones in the U.S. are classified by the EPA as "any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for the pollutant." The EPA maintains a database of non-attainment zone locations. Typically, emissions from a new project in a non-attainment zone will be permitted at lower levels than in attainment zones. Therefore, in limited cases, selective catalytic reduction (SCR) systems (for NO_X removal) and/or CO catalysts have been considered for LFG projects, which would add significant capital and O&M expense. Additionally, regarding O&M, a concern with using post-combustion emission catalysts in LFG projects is the possibility of contamination due to some trace elements in the LFG that pass through the power generator. The project developer should confirm the allowable emission levels for the specific project site, the anticipated technology (e.g., gas turbine, reciprocating engine, etc.), and size of project early in the development process. Costs and technical progress in the use of SCR and CO catalysts in LFG projects should be monitored if they might be required for a project under consideration.

Operating Impacts of Burning LFG

With regard to operating reciprocating engines and combustion turbines, one contaminant that has caused serious operating problems is the formation of silanes and silicones (often referred to as “siloxanes”) on the surfaces of the engines and turbine blades and potentially, in downstream emissions control systems such as SCR catalyst. These compounds tend to form a hard coating on equipment surfaces that cannot be easily removed. Siloxanes are a constituent of most LFG in varying concentrations, originating from typical MSW products, such as cosmetics and some types of detergents. Additionally, there are several molecular forms of siloxanes. When burned, they produce a white abrasive powder that can damage downstream equipment, including the turbine, engines, or heat recovery steam generator (HRSG). A second contaminant of concern is the presence of hydrogen sulfide in the LFG. This compound gives the LFG a noxious odor and also contributes to the SO_2 emissions from the combustion system. Other contaminants include the halogen species that can cause corrosion of process equipment.

Reciprocating engines are the most common form of LFG energy use. LFG clean up or pretreatment is also required prior to burning in reciprocating engines. Reciprocating engines can suffer from build up of materials similar to combustion turbines. This may result in cylinder wear. However, the costs of repairs are less than for combustion turbines-piston rings, which can be replaced at least once with oversize rings at a modest cost. These new oversize rings will allow the engine to maintain proper cylinder pressure.

One type of system that is offered commercially for LFG conditioning/pretreatment is termed an alternating evaporator/chilling system. In the case of reciprocating engine system, the gas is first compressed to 40-50 psig. This raises the temperature to around 200°F and air coolers then reduce the gas temperature to around 100°F. This is followed by a refrigeration system, which cools the gas to about 40°F allowing contaminants to condense. The gas is reheated to about 70°F prior to injection into the engine. The chilling system will remove moisture, and a percentage of siloxanes and other impurities in the LFG. The percentage removal depends on the concentration and the forms of the impurities in the raw LFG.

A second option is the use of adsorption systems of carbon or other media, which can also be added downstream of a chiller, depending on the impurities in the raw LFG. The chilling and/or adsorption systems can remove the harmful contaminants from the LFG, but each requires additional capital investment and operating cost. Removal efficiencies of 99% for siloxane, H_2S, SO_2, moisture, halogens and other contaminants have been achieved using these types of systems. These two types of systems are predominantly employed when the LFG is burned in reciprocating engines, combustion turbines, or boilers.

Since the replacement of the adsorption media is expensive, suppliers now offer carbon beds that can be regenerated on site. While the initial cost of this arrangement is more than the non-regenerating approach, it could be economically feasible on a total life cycle cost basis for LFG projects with high content of siloxanes or other impurities in the raw LFG.

For higher-purity LFG conditioning, other systems are available. Applications where LFG is processed to pipeline quality natural gas for use in fuel cells or as fuel in automobiles require processes that increase the Btu content by separating the CO_2 from the methane. An example is the Selexol process, which uses amine separation technology.

Biogas

There are six sources of raw material for biogas: organic waste, sewage, restaurant waste, municipal waste, agricultural residues and landfill. For the purpose of this subsection, the organic waste from cattle and the restaurant waste will be the main topics for discussion on a qualitative basis with some reference to design and cost estimate basis. The landfill gas has been discussed separately as the design basis and cost estimate basis have been defined much better than for the other two cases.

The biogas concept has been adapted on a very small scale, suitable for individual households in developing countries such as India, China other parts of Asia and South America with food waste and animal waste. In Europe it has been adapted on a medium scale with animal waste and slaughter house waste and dairy farm waste. In the U.S., medium to large scale dairy farms and slaughter houses as well as facilities using restaurant food waste have adapted the biogas concept. The basic process is the same in all cases.

In this process, called an “anaerobic digester,” the action begins when organic waste material is loaded into the system. (“Organic” means it’s made from plants and animals. In this case, the waste material is food scraps from restaurants and animal secretions in a feed lot and other animal waste discarded in a dairy farm and slaughter house). The restaurant waste biogas discussion is based on a California Energy Commission funded project with University of California, Davis, California. Under oxygen-free (anaerobic) conditions, naturally occurring bacteria break the waste down into organic acids and water. At this stage, some hydrogen is produced, drawn off, and is ready for use as fuel. Next, the water containing organic acids is mixed with other bacteria to produce methane (natural gas). The methane is then captured, cleaned, and compressed for use in natural-gas buses, cars, and trucks. It also may be burned in an engine.

The APS-Digester system combines favorable features of both batch and continuous biological processes in a single biological system and makes it possible to achieve efficient and stable production of both hydrogen and methane gases from a variety of organic solid and liquid wastes, including grass clippings, food leftovers, food processing byproducts, crop residues, and animal wastes. The pilot digester system is housed in the newly developed UC Davis Biogas Energy Plant and has a capacity of treating three to eight tons per day organic waste with expected biogas production of producing 11,400-22,900 ft^3 per day biogas. It has employed innovative design features and state of the art equipment and control technologies that provide optimum conditions for fast microbial degradation of organic wastes and efficient material handling. At present, the biogas is used for electricity and heat generation. One of the primary goals of the project is to generate electricity from the produced biogas. It will be considered a design goal to deliver about 22 kW (528 kWh per day) of electric energy to the grid. The electrical energy delivered to the grid will be measured by the instrumentation and metering equipment installed on the Cummins generator system. The generator system will be operated on a full-time basis when feasible, but may not continuously provide power to the project. During demonstrations or daily operations, the material processing and loading equipment may be operated using power from the generator and/or the electric grid. The nominal electrical generating capacity of the system is anticipated to be 528 kWh per day, with some reduction as required to meet thermal loads during peak heat requirements. The capital cost of the project was estimated to be about U.S.$1.8million (14.4 million Rand).

Operation and maintenance of the digester system may require handling high temperature water (140 °F), explosive gases (methane), and noxious gases (hydrogen sulfide, and carbon dioxide).

Air emission and odors are potential concerns when the feedstock is loaded into the digestion reactor vessels, and the effluent liquids and solids are removed.

Biogas from animal waste

Biogas systems use bacteria to break down wet organic matter like animal dung, human sewage, or food waste. This produces biogas, which is a mixture of methane and carbon dioxide, and also a semi-solid residue. The biogas is used as a fuel for cooking, lighting, or generating electricity. Using biogas can save the labor of gathering and using wood for cooking, minimize harmful smoke in homes, and cut deforestation and greenhouse gas emissions. Biogas plants can also improve sanitation, and the residue is useful as a fertilizer.

Individual biogas systems are already benefitting several million households in Nepal, India, China, and elsewhere. Larger systems are also used, for instance to process farm waste in Germany, and at sewage treatment works in the UK.

How biogas works

A simple biogas plant has a container to hold the decomposing organic matter and water (slurry), and another to collect the biogas. There must also be systems to feed in the organic matter (the feedstock), to take the gas to where it will be used, and to remove the residue.

In fixed dome biogas plants (the most common type), the slurry container and gas container are combined, so that the gas collects under a rigid dome over the slurry. As the slurry breaks down, the biogas which is produced pushes some of the slurry into a separate reservoir. When the biogas is taken off, the slurry flows back.

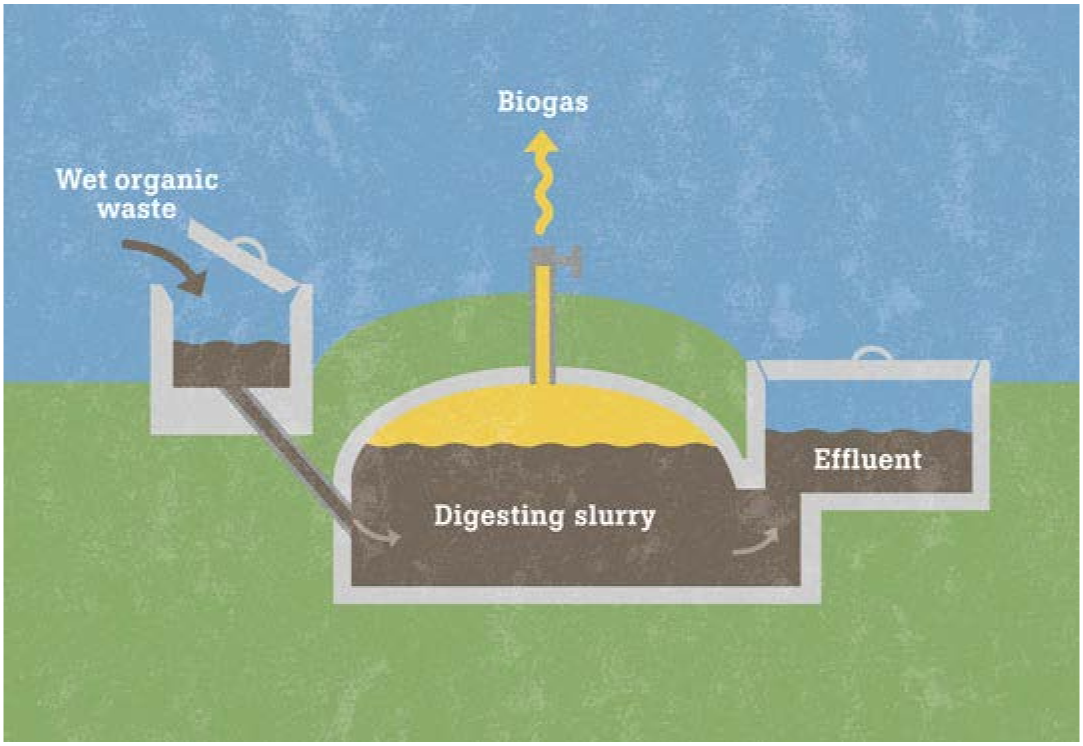


Figure 6-30
Biogas Process

In floating dome plants, the gas container floats in the slurry. The gas container gradually rises up as biogas is produced, and sinks back down as the biogas is used.

Anaerobic digesters convert the energy stored in organic materials present in manure into biogas. Biogas can be fed directly into a gas-fired combustion turbine. The type of turbine most often used for small-scale electricity production is the microturbine. Combustion of biogas converts the energy stored in the bonds of the molecules of the methane contained in the biogas into mechanical energy as it spins a turbine. The mechanical energy produced by biogas combustion in an engine or microturbine spins a turbine that produces a stream of electrons, or, electricity. In addition, waste heat from these engines can provide heating or hot water for use on farm.

As a fuel, biogas composed of 65% methane yields about 650 Btu per cubic foot. Often used when designing systems for the anaerobic digestion of manure, these energy estimates can predict the amount of power production per animal. General estimates predict one kilowatt of electricity production requires five to eight dairy cows.

A biogas plant needs some methane-producing bacteria to get it started. Once the plant is producing biogas, the bacteria reproduce and keep the process going. Cattle dung contains suitable bacteria, and a small amount of cattle dung is often used as the ‘starter’ for a biogas plant, even when it is not the main feedstock.

How biogas plants are used

Rural families often use animal dung as the feedstock for a biogas plant. The dung from two to four cows (or five to ten pigs) can produce enough gas for all cooking, and sometimes lighting too. The family needs to feed the plant once each day with a mixture of dung and water. Ashden

Award winner BSP-Nepal coordinates a program which has sold over 170,000 fixed-dome plants throughout rural Nepal.

Food waste can also be used as the feedstock. Food waste breaks down and produces gas more quickly than dung, so the slurry does not need to be held for as long; these plants are therefore smaller and more suitable for urban homes. A family or community using just their own food waste can replace between 25% and 50% of their cooking fuel.

Larger-scale biogas schemes can produce sufficient gas to generate electricity. This is frequently done in sewage treatment plants in the UK, and there are a number of large farm-based plants in Germany and elsewhere. BIOTECH in Kerala, South India, supplies plants to manage the waste from vegetable markets, and produce gas for electricity generation.

Biogas plants can work well for many years, provided that they are constructed well and checked regularly. If the plant is made from masonry, care must be taken to make sure that the structure is water-tight and gas-tight. The slurry needs to be kept at a temperature of about 35°C for the bacteria to work effectively, and feedstock must be added regularly so that they continue to multiply.

What are the benefits of using biogas?

The immediate benefit of biogas is replacing other fuels for cooking. In rural areas, biogas usually replaces fuelwood, which is often in short supply. Studies by BSP-Nepal show that households with biogas plants save three hours per day on average, because collecting dung and feeding it to a biogas plant takes much less time than collecting fuelwood and preparing a cooking fire. Biogas is available whenever it is needed and cooks food quickly, so it is easier to prepare hot food before children go to school.

Biogas reduces indoor air pollution because it burns with a clean flame. This means that women do not have to breathe wood smoke, which is a major cause of respiratory and eye disease and responsible for an estimated 1.6 million deaths each year.

If the fuelwood source is unsustainable (i.e., not re-growing fast enough to keep up with use) then a biogas plant reduces deforestation and cuts CO_2 emissions. CO_2 is also saved when biogas replaces kerosene or LPG for cooking.

The residue from dung-based biogas plants makes a good fertilizer with minimal smell. The fertilizer value can be improved by composting the residue with crop waste, and feeding the compost to earthworms for additional processing (vermicomposting).

Cost

The cheapest, fixed-dome biogas plants are made mainly of masonry, either brick or concrete. A 6 m^3 plant using cattle dung to provide gas for a single family costs about U.S. $500.

Steel and plastic are used in some floating-dome plants. These can be pre-fabricated and thus installed very quickly. BIOTECH sells prefabricated plants for suburban homes with the gas container made of fiberglass-reinforced-plastic and the slurry container from ferrocement, and a 1m^3 plant costs about U.S. $220.

The economic viability of biogas depends on the cost of the fuel being replaced, and whether there are other financial benefits (for instance, avoided waste disposal costs, or income from selling compost). For example, BIOTECH plant users can pay back the cost of a plant in about three years through savings in LPG.

The potential of biogas plants to reduce greenhouse gases (including methane from uncontrolled dung and sewage management as well as carbon dioxide) means that carbon-offset finance is becoming a significant source of funding.

Numbers

The number of domestic biogas plants currently in use is difficult to estimate. Nepal, with about 170,000 biogas plants in 2008 has the largest per capita use. India had an estimated 2 million plants in use in 2000. Around 8 million plants were installed in China in the early 1980s, but quality was poor and many fell into disuse. The program in China is now continuing with a better quality design but at a slower rate. Biogas programs are growing in many other parts of the world, such as Vietnam, Brazil, and Tanzania.

Manure Fuels Texas Ethanol Plant

Texas is the leading cattle state in the U.S., with an abundance of animal waste that can be used to create energy. Because transporting dry manure far distances to power plants is impractical, it is most often used as a fuel regionally. Hereford, located in the Texas Panhandle, is known as the cattle capitol of the world with more than one million head of cattle and 100,000 dairy cows located within a 100-mile radius of the town. The area is supplying a new ethanol plant with fuel in the form of manure from cattle feedyards, eliminating the need to burn expensive natural gas.

In 2005, Panda Ethanol began construction on a $120 million ethanol plant on a 380-acre site in Hereford. The Hereford plant is a fine example of what can be achieved when the ethanol and livestock industries work together for the benefit of both the industries and the community. Projected energy savings are equivalent to 1,000 barrels of oil per day and transportation costs are greatly reduced as well. To take advantage of another waste resource, Panda is using gray water from the city wastewater facility.

The Hereford ethanol plant brings new jobs and an increased tax base to the community. The plant is expected to produce 100 million gallons of ethanol fuel each year.

Manure for Fuel

The development of large feedlots for livestock has created economic opportunity for agribusiness in Texas. Hogs, beef and dairy cattle, and poultry are often fed in close proximity to maximize efficient production and keep costs low. At the same time, however, this practice produces large amounts of animal manure that may emit odors, methane, nitrous oxide, carbon dioxide, antibiotics, and ammonia. Manure can also produce water pollution from uncontrolled runoff of phosphorus and nitrates.

Growing environmental concerns coupled with higher energy prices have led to a renewed interest in using animal manure, also known as feedlot biomass, to produce power. This can be accomplished either by burning manure directly for fuel, gasifying it with heat, or by turning it into “biogas” through biological decomposition. The best approach to using animal wastes for power depends on the amount of moisture and essentially non-biodegradable solid materials including dirt (generally called ash) mixed with the manure to be used as a feedstock. Each of these methods disposes of large accumulations of manure while mitigating its possible negative environmental effects.

Environmental benefits to processing manure into fuel include cleaner air and water. Methane has a global warming effect that is 21 times that of carbon dioxide, so using the methane for energy production significantly reduces greenhouse gas emissions. And because manure that is used in the biogas plant is not washed off land surfaces into local rivers and streams, the local watershed also benefits.

Manure also can be used to reduce emissions from traditional fuels. A recent scientific study by the Texas Engineering Experiment Station and Texas Agricultural Experiment Station found that co-firing coal plants with manure lowers their emissions of nitrous oxide (NO_X). The reburning process involves a second combustion process to reduce these air emissions.

Manure-based power plants can boost rural economic development and provide dairy farmers and feedlot operators with another source of revenue, or at least cut their disposal costs. Although Texas is a leading beef and dairy cattle producer, use of manure for energy is just beginning in Texas. There are promising new plants in Central Texas and the Panhandle both under construction and on the drawing board which have the potential to bring jobs and income to rural Texas, although there are no estimates of the current or potential effects available.

Dry Manure for Fuel

Dry manure has long provided heating and cooking fuel for rural societies. If the water content of manure is low enough (less than 20%), dry manure can be burnt directly. Solid, dry manure includes manure from beef feedlots and dairy drylots. Burning dry manure can also release energy for the production of biogas. While supplying its own energy needs, a cattle feedlot operation could also solve its manure disposal problem, reduce odors, provide jobs, and increase the local tax base - all by installing a manure-to-energy generator on site.

Wet Manure for Fuel

Many livestock operations flush animal pens with water and store the manure in waste lagoons, or ponds. Wet manure that is produced from dairy cattle and hogs produces biogas when confined in enclosed areas. This is called *Anaerobic Digestion*. The biogas produced by anaerobic digestion contains about 60% methane, which is a primary component of natural gas and an important source of energy. To take advantage of this, a growing number of livestock operations are placing floating covers on their lagoons to capture the biogas. The gas is then used to run an engine/generator to produce electricity.

In addition, biogas from manure can be captured and purified to yield pipeline grade methane that is chemically the same as natural gas. Pipeline grade methane can be transported by pipeline for sale to the local power grid to run electric generators.

The U.S. Environmental Protection Agency (EPA) has established a voluntary program to reduce methane emissions in the livestock industry. This program, known as the AgSTAR Program, encourages adoption of anaerobic digestion technologies that recover and combust biogas (methane) for odor control or as an on-farm energy resource.

Anaerobic Digestion and Methane Recovery

In the anaerobic digestion process, manure is collected and broken down by bacteria in a low-oxygen environment which generates methane emissions (biogas).

Anaerobic digesters (or methane digesters) such as airtight digester tanks or covered anaerobic lagoons are used for this process.

Anaerobic digesters are available at competitive rates and are currently in use on farms across the country. At the beginning of 2008, there were 111 anaerobic digesters operating across the U.S. that produce electricity or gas to fuel boilers.

Anaerobic Digester Tank

The air-tight anaerobic digester tank converts biomass waste to methane. Capping and channeling the methane into a productive use, instead of releasing it into the atmosphere, helps to mitigate global warming while producing a renewable energy that can be used for heating, electricity, or operation of an internal combustion engine.

The material drawn from the anaerobic digester is called sludge, or effluent. It is rich in nutrients (ammonia, phosphorus, potassium, and more than a dozen trace elements) and is an excellent soil conditioner. It can also be used as a livestock feed additive when dried.

Methane digesters particularly appeal to dairy farmers because they:

- Add revenue to dairy operations;
- Cut waste management costs;
- Provide electricity and power needs;
- Reduce manure odor by as much as 95%;
- Reduce pesticide costs;
- Reduce surface and groundwater contamination;
- Help minimize run-off and other water quality issues;
- Capture methane, sulfur compounds, and other gases, which would otherwise have been released into the atmosphere; and,
- Create nutrient-rich fertilizer, compost, livestock feed additive, and cow bedding out of the leftover byproducts.

References

1. Underground Coal Gasification Association - http://www.ucgassociation.org/index.php
2. Lawrence Livermore National Laboratory – "Fire in the Hole" - *Julio Friedmann* (friedmann2@llnl.gov).
3. Exergy – Ergo Exergy Technologies, Inc – http://www.ergoexergy.com/
4. Linc Energy - http://www.lincenergy.com/
5. Anaerobic Phased Solids Digester Pilot Demonstration Project – California Energy Commission – http://www.energy.ca.gov/
6. BIOTECH – http://www.biotech-india.org/showonweb.pps
7. SECO – State Energy Conservation Office, Texas - http://www.seco.cpa.state.tx.us/
8. Solar Thermal Electricity Technology Roadmap. International Energy Agency, 2014.
9. APR1400 – Technical Summary. KEPCO, 2010.
10. Capacity Market Database. Bloomberg New Energy Finance, 2015.
11. "H1 APAC Nuclear Market Outlook". Bloomberg New Energy Finance, June 2015.

7
COAL TECHNOLOGIES PERFORMANCE AND COST

PC

Table 7-1
PC without FGD Cost and Performance Summary

Technology	1x750 MW, No FGD	2x750 MW, No FGD	4x750 MW, No FGD	6x750 MW, No FGD
Rated Capacity, MW Gross	804	1,608	3,216	4,824
Rated Capacity, MW Net	750	1,500	3,000	4,500
Plant Cost Estimates (January 2017)				
Total Overnight Cost, ZAR/kW	36,983	35,043	33,104	32,134
Lead-times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year (ZAR/GJ)	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, HHV, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	789	746	695	670
Variable O&M, ZAR/MWh	65.9	65.9	65.9	65.9
Availability Estimates, %				
Equivalent Availability	91.7	91.7	91.7	91.7
Maintenance	4.8	4.8	4.8	4.8
Unplanned Outages	3.7	3.7	3.7	3.7
Performance Estimates				
Economic Life, years	30	30	30	30

Table 7-1 (continued)
PC without FGD Cost and Performance Summary

Technology	1x750 MW, No FGD	2x750 MW, No FGD	4x750 MW, No FGD	6x750 MW, No FGD
Heat Rate, kJ/kWh				
Average Annual	9,707	9,707	9,707	9,707
100% Load	9,664	9,664	9,664	9,664
75% Load	9,844	9,844	9,844	9,844
50% Load	10,371	10,371	10,371	10,371
25% Load	12,524	12,524	12,524	12,524
Net Plant Efficiency, %	37.1	37.1	37.1	37.1
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	33.4	33.4	33.4	33.4
Sorbent (Limestone) Usage				
Per Unit of Energy, kg/MWh	0	0	0	0
Air Emissions, kg/MWh				
CO_2	930.2	930.2	930.2	930.2
SOx	9.03	9.03	9.03	9.03
NOx	1.91	1.91	1.91	1.91
Particulates	0.13	0.13	0.13	0.13
Solid Wastes, kg/MWh				
FGD solids	0.0	0.0	0.0	0.0
Fly ash	166.2	166.2	166.2	166.2
Bottom ash	3.3	3.3	3.3	3.3

Table 7-2
PC with FGD Cost and Performance Summary

Technology	1x750 MW, with FGD	2x750 MW, with FGD	4x750 MW, with FGD	6x750 MW, with FGD
Rated Capacity, MW Gross	813	1,626	3,252	4,878
Rated Capacity, MW Net	750	1,500	3,000	4,500
Plant Cost Estimates (January 2017)				
Total Overnight Cost, ZAR/kW	46,092	43,667	41,243	40,031
Lead-times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year (ZAR/GJ)	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, HHV, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	1,229	1,162	1,081	1,044
Variable O&M, ZAR/MWh	90.3	90.3	90.3	90.3
Availability Estimates				
Equivalent Availability	91.7	91.7	91.7	91.7
Maintenance	4.8	4.8	4.8	4.8
Unplanned Outages	3.7	3.7	3.7	3.7
Performance Estimates				
Economic Life, years	30	30	30	30

Table 7-2 (continued)
PC with FGD Cost and Performance Summary

Technology	1x750 MW, with FGD	2x750 MW, with FGD	4x750 MW, with FGD	6x750 MW, with FGD
Heat Rate, kJ/kWh				
Average Annual	9,812	9,812	9,812	9,812
100% Load	9,780	9,780	9,780	9,780
75% Load	9,970	9,970	9,970	9,970
50% Load	10,529	10,529	10,529	10,529
25% Load	12,872	12,872	12,872	12,872
Net Plant Efficiency, %	36.7	36.7	36.7	36.7
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	231	231	231	231
Sorbent (Limestone) Usage				
Per Unit of Energy, kg/MWh	15.8	15.8	15.8	15.8
Air Emissions, kg/MWh				
CO_2	947.3	947.3	947.3	947.3
SOx	0.46	0.46	0.46	0.46
NOx	1.94	1.94	1.94	1.94
Particulates	0.13	0.13	0.13	0.13
Solid Wastes, kg/MWh				
FGD solids	25.2	25.2	25.2	25.2
Fly ash	168.0	168.0	168.0	168.0
Bottom ash	3.3	3.3	3.3	3.3

Table 7-3
PC with CCS Cost and Performance Summary

Technology	1x750 MW, with CCS	2x750 MW, with CCS	4x750 MW, with CCS	6x750 MW, with CCS
Rated Capacity, MW Gross	941	1,882	3,764	5,646
Rated Capacity, MW Net	750	1,500	3,000	4,500
Plant Cost Estimates (January 2017)				
Total Overnight Cost, ZAR/kW	85,800	82,454	79,107	77,434
Lead-times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year (ZAR/GJ)	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, HHV, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	2,045	1,951	1,834	1,780
Variable O&M, ZAR/MWh	166.6	166.6	166.6	166.6
Availability Estimates				
Equivalent Availability	91.7	91.7	91.7	91.7
Maintenance	4.8	4.8	4.8	4.8
Unplanned Outages	3.7	3.7	3.7	3.7
Performance Estimates				
Economic Life, years	30	30	30	30
Heat Rate, kJ/kWh				
Average Annual	14,106	14,106	14,106	14,106
100% Load	13,990	13,990	13,990	13,990
75% Load	14,496	14,496	14,496	14,496
50% Load	15,815	15,815	15,815	15,815
25% Load	23,580	23,580	23,580	23,580

Table 7-3 (continued)
PC with CCS Cost and Performance Summary

Technology	1x750 MW, with CCS	2x750 MW, with CCS	4x750 MW, with CCS	6x750 MW, with CCS
Net Plant Efficiency, %	25.5	25.5	25.5	25.5
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	320	320	320	320
Sorbent (Limestone) Usage				
Per Unit of Energy, kg/MWh	22.8	22.8	22.8	22.8
Air Emissions, kg/MWh				
CO_2	136.2	136.2	136.2	136.2
SOx	0.66	0.66	0.66	0.66
NOx	0.42	0.42	0.42	0.42
Particulates	0.18	0.18	0.18	0.18
Solid Wastes, kg/MWh				
FGD solids	36.2	36.2	36.2	36.2
Fly ash	241.5	241.5	241.5	241.5
Bottom ash	4.8	4.8	4.8	4.8

Plant Cost Estimates

The total overnight cost for a PC plant ranges from 32,134 ZAR/kW to 36,98 ZAR/kW for the plants without FGD, from 40,031 ZAR/kW to 46,092 ZAR/kW for plants with FGD, and from 77,434 ZAR/kW to 85,800 ZAR/kW for plants with CCS, depending on the number of units. It is expected that a plant with multiple units would have a cost advantage over a single unit due to some shared support buildings and infrastructure, as well as the possibility of cost negotiations with contractors for larger purchases. The cost of adding an FGD unit can add about 25% to the cost of the plant on a ZAR per kilowatt basis, due to a combination of the cost of the FGD equipment as well as a slight increase in auxiliary load. The addition of carbon capture increases the cost of the plant by 130% due to the additional capture equipment and the large increase in auxiliary load, which in turn requires an increase in the size of the boiler and turbine to maintain plant output.

A PC unit would have about a four year expense and construction period. Early in the project, costs will include preliminary design, project siting, and permitting. Later in the project, equipment will be procured, delivered, and installed. This will be when the majority of the expenditures take place. The final stage of the project will be the commissioning of the plant. Based on this schedule, the expected expense schedule is 10% in year 1, 25% in year 2, 45% in year 3, and 20% in year 4. For a multi-unit plant, it is expected that the construction and start-up of each unit would be staggered by a year, such that the first unit would start after four years, and a new unit would start-up each subsequent year.

Fuel Cost Estimates

The cost of the South African coal used in this study is estimated to be 31.1 ZAR/GJ with an energy content of about 17,850 kJ/kg before drying. The price of the coal is not expected to increase beyond general inflation.

O&M Cost Estimates

The fixed O&M costs for a PC plant are between 670-789 ZAR/kW-yr for a plant without FGD, between 1,044 -1,229 ZAR/kW-yr for a plant with FGD, and between 1,780 -2,045 ZAR/kW-yr for a plant with carbon capture, depending on the number of units. For this study, both maintenance labor and material costs are considered to be fixed O&M costs. The variable O&M costs are 65.9 ZAR/MWh for the plant without FGD, 90.3 ZAR/MWh for the plant with FGD, and 166.6 ZAR/MWh for the plant with carbon capture. The FGD unit increases O&M costs both due to increased labor needs (fixed O&M) as well as the additional cost of limestone used in the LSFO FGD unit (variable O&M). The addition of carbon capture increases O&M for the same reasons: additional labor needs and the addition of amine costs.

Availability and Performance Estimates

The PC plants have an expected equivalent availability of 91.7% and a capacity factor of 85%. The annual heat rate of the plants without an FGD unit is about 9,700 kJ/kWh and the plants with an FGD unit have an annual heat rate of about 9,810 kJ/kWh. The increased heat rate is due to the added auxiliary load of the FGD unit. The plants with carbon capture have an annual heat rate of 14,100 kJ/kWh due to the large auxiliary load of the capture unit and the need to divert steam from the steam turbine to the capture unit for amine regeneration.

An economic life of 30 years is assumed for the PC plants for cost of electricity calculations; however, the operating life of a coal plant can extend well beyond 30 years.

Cost of Electricity

Table 7-4 through Table 7-6 show a representative levelized cost of electricity for the PC plants. These assume sequential start-up so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single start-up at the end of the project would result in a significantly higher AFUDC, resulting in a higher capital expense and higher cost of electricity. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 7-4
PC without FGD Levelized Cost of Electricity

Technology	1x750 MW, No FGD	2x750 MW, No FGD	4x750 MW, No FGD	6x750 MW, No FGD
Rated Capacity, MW Net	750	1,500	3,000	4,500
Fuel Cost (ZAR/MWh)	301.8	301.8	301.8	301.8
O&M (ZAR/MWh)	171.9	166.1	159.2	155.9
Capital (ZAR/MWh)	727.6	689.7	651.9	632.9
LCOE (ZAR/MWh)	**1,201.2**	**1,157.6**	**1,112.8**	**1,090.6**

Table 7-5
PC with FGD Levelized Cost of Electricity

Technology	1x750 MW, with FGD	2x750 MW, with FGD	4x750 MW, with FGD	6x750 MW, with FGD
Rated Capacity, MW net	750	1,500	3,000	4,500
Fuel Cost (ZAR/MWh)	305.2	305.2	305.2	305.2
O&M (ZAR/MWh)	255.4	246.4	235.5	230.5
Capital (ZAR/MWh)	906.2	858.8	811.5	787.8
LCOE (ZAR/MWh)	**1,466.8**	**1,410.5**	**1,352.1**	**1,323.5**

Table 7-6
PC with CCS Levelized Cost of Electricity

Technology	1x750 MW, with CCS	2x750 MW, with CCS	4x750 MW, with CCS	6x750 MW, with CCS
Rated Capacity, MW net	750	1,500	3,000	4,500
Fuel Cost (ZAR/MWh)	438.5	438.5	438.5	438.5
O&M (ZAR/MWh)	441.3	428.6	413.0	405.7
Capital (ZAR/MWh)	1,684.1	1,618.7	1,553.4	1,520.7
LCOE (ZAR/MWh)	**2,563.9**	**2,485.8**	**2,404.9**	**2,365.0**

Water Usage

Because the steam cycles of the base case plants evaluated are air-cooled, the only water usage for the plant without FGD is for makeup water to the boiler, which is about 33.4 L/MWh. The addition of wet FGD increases water consumption to 231.0 L/MWh. The addition of carbon capture increases the water consumption to 320.2 L/MWh.

Emissions

Both the air and solid emissions of the PC plants evaluated in this study are listed in the summary table above. The installation of an FGD unit drastically reduces the SOx emissions of the plant, though it does slightly increase CO_2 and ash emissions due to the slight increase in heat rate and, therefore, coal consumption. The addition of carbon capture significantly decreases CO_2 emissions. The inclusion of an SCR unit to prevent amine degeneration due to NO_2 reduces NO_X emissions for the plant with carbon capture. However, SO_X emissions increase slightly due to the heat rate increase.

Integrated Gasification Combined Cycle

Table 7-7
IGCC Cost and Performance Summary

Technology	One 2x2x1 Shell IGCC	Two 2x2x1 Shell IGCC	Four 2x2x1 Shell IGCC	Six 2x2x1 Shell IGCC
Rated Capacity, MW gross	789	1,578	3,156	4,734
Rated Capacity, MW net	644	1,288	2,576	3,864
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	62,142	58,414	54,684	52,820
Lead Times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year, ZAR/GJ	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	1,606	1,318	1,141	1,071
Variable O&M, ZAR/MWh	85.1	85.1	85.1	85.1
Availability Estimates				
Equivalent Availability	85.7	85.7	85.7	85.7
Maintenance	4.7	4.7	4.7	4.7
Unplanned Outages	10.1	10.1	10.1	10.1

Table 7-7 (continued)
IGCC Cost and Performance Summary

Technology	One 2x2x1 Shell IGCC	Two 2x2x1 Shell IGCC	Four 2x2x1 Shell IGCC	Six 2x2x1 Shell IGCC
Performance Estimates				
Economic Life, years	30	30	30	30
Heat Rate, kJ/kWh				
Average Annual	9,758	9,758	9,758	9,758
100% Load	9,652	9,652	9,652	9,652
75% Load	10,328	10,328	10,328	10,328
50% Load*	12,258	12,258	12,258	12,258
25% Load	15,502	15,502	15,502	15,502
Net Plant Efficiency, %	36.9	36.9	36.9	36.9
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	256.7	256.7	256.7	256.7
Air Emissions, kg/MWh				
CO_2	930	930	930	930
SOx (as SO_2)	0.18	0.18	0.18	0.18
NOx (as NO_2)	0.23	0.23	0.23	0.23
Particulates	0.38	0.38	0.38	0.38
Solid Wastes kg/MWh				
Ash as Slag	182.3	182.3	182.3	182.3

* The heat rate penalty could be mitigated by designing for approximately 50% load on the gasification/ASU system and turn off of one GT.

Table 7-8
IGCC with CCS Cost and Performance Summary

Technology	One 2x2x1 Shell IGCC with CCS	Two 2x2x1 Shell IGCC with CCS	Four 2x2x1 Shell IGCC with CCS	Six 2x2x1 Shell IGCC with CCS
Rated Capacity, MW gross	905	1,810	3,620	5,430
Rated Capacity, MW net	644	1,288	2,576	3,864
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	82,929	77,953	72,978	70,489
Lead Times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year, ZAR/GJ	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	1,991	1,664	1,459	1,378
Variable O&M, ZAR/MWh	144.5	144.5	144.5	144.5
Availability Estimates				
Equivalent Availability	85.7	85.7	85.7	85.7
Maintenance	4.7	4.7	4.7	4.7
Unplanned Outages	10.1	10.1	10.1	10.1
Performance Estimates				
Economic Life, years	30	30	30	30

Table 7-8 (continued)
IGCC with CCS Cost and Performance Summary

Technology	One 2x2x1 Shell IGCC with CCS	Two 2x2x1 Shell IGCC with CCS	Four 2x2x1 Shell IGCC with CCS	Six 2x2x1 Shell IGCC with CCS
Heat Rate, kJ/kWh				
Average Annual	12,541	12,541	12,541	12,541
100% Load	12,404	12,404	12,404	12,404
75% Load	13,274	13,274	13,274	13,274
50% Load*	15,753	15,753	15,753	15,753
25% Load	19,923	19,923	19,923	19,923
Net Plant Efficiency, %	28.7	28.7	28.7	28.7
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	1,027	1,027	1,027	1,027
Air Emissions, kg/MWh				
CO_2	120	120	120	120
SOx (as SO_2)	0.23	0.23	0.23	0.23
NOx (as NO_2)	0.29	0.29	0.29	0.29
Particulates	0.65	0.65	0.65	0.65
Solid Wastes kg/MWh				
Ash as Slag	234.3	234.3	234.3	234.3

* The heat rate penalty could be mitigated by designing for approximately 50% load on the gasification/ASU system and turn off of one GT.

Plant Cost Estimates

The total overnight cost for the IGCC plant evaluated in this study ranges from 52,820 ZAR/kW to 62,142 ZAR/kW for the plant without carbon capture and from 70,489 ZAR/kW to 82,929 ZAR/kW for the plant with carbon capture, depending on the number of units. It is expected that a plant with multiple units would have a cost advantage over a single unit due to some shared support buildings and infrastructure, as well as the possibility of cost negotiations with contractors for larger purchases. The addition of carbon capture increases the plant cost on a per kilowatt basis by about 33% due to added equipment and increased auxiliary load. However, incrementally this is less of an increase than in the PC plant with carbon capture.

An IGCC unit would have about a four year expense and construction period. Early in the project, costs will include preliminary design, project siting, and permitting. Later in the project, equipment will be procured, delivered, and installed. This will be when the majority of the expenditures take place. The final stage of the project will be the commissioning of the plant. Based on this schedule, the expected expense schedule is 10% in year 1, 25% in year 2, 45% in year 3, and 20% in year 4. For a multi-unit plant, it is expected that the construction and start-up of each unit would be staggered by a year, such that the first unit would start after four years, and a new unit would start-up each subsequent year.

Fuel Cost Estimates

The cost of the South African coal used in this study is estimated to be 31.1 ZAR/GJ with an energy content of about 17,850 kJ/kg before drying. The price of the coal is not expected to increase beyond general inflation.

O&M Cost Estimates

The fixed O&M cost for an IGCC plant ranges from 1,071 ZAR/kW-yr to 1,606 ZAR/kW-yr for plants without carbon capture and 1,378 ZAR/kW to 1,991 ZAR/kW for plants with carbon capture. For this study, both maintenance labor and material costs are considered to be fixed O&M costs. The Shell gasifier has a membrane wall, resulting in a maintenance cost that is slightly lower than for refractory-lined gasifiers. The total staffing requirement for an IGCC is slightly more than for an equivalent sized PC plant due to the more complex processing facilities and is higher for a plant with carbon capture than for a plant without carbon capture. The variable O&M cost is 85.1 ZAR/MWh for a plant without capture and 144.5 ZAR/MWh for a plant with capture. No credit was assumed for sulfur by-product or for the ash, which is recovered as a glassy, non-leachable slag that can be sold for various building material or roadbed uses. There is an increase in variable O&M costs from the previous year's study to this year's update. The increase in the variable O&M costs for the IGCC plant is due to the updated costs of consumables for the sulfur removal and CO_2 removal units.

Availability and Performance Estimates

The IGCC plant evaluated in this study has an expected equivalent availability of 85.7%. This is lower than the expected availability of the other fossil technologies evaluated in this study, largely due to the less mature nature of an IGCC plant and an expected unplanned outage rate of over 10%.

Though the boiler-fired coal plants are unaffected by the higher elevation of the mine-mouth location, the output of the IGCC plant at 1800 m is about 13% lower than the same plant at sea-level. This is because the reduced density of the air at higher elevation reduces the mass flow through the GTs. However, the effect of altitude on an IGCC plant is less dramatic than that of a natural-gas fired plant due to the available N_2 from the ASU that can be used to add mass through the turbine. The annual heater rate of the IGCC plant is expected to be about 9,760 kJ/kWh, which is similar to the PC units evaluated. At decreased loads, the GTs operate less efficiently and the heat rate increases more dramatically than the other coal fired units. However, if the plant is designed correctly, this heat rate penalty can be mitigated by turning off one GT and operating the other at full load if the plant is reduced to 50% load. The annual heat rate of an IGCC with carbon capture is expected to be about 12,540 kJ/kWh. This performance penalty is less severe than a PC unit due to the higher partial pressure of the CO_2 captured from the syngas stream before combustion and the integrated design of the IGCC.

An economic life of 30 years is assumed for the IGCC plants for cost of electricity calculations; however, it is expected that the operating life of an IGCC could extend well beyond 30 years.

Cost of Electricity

Table 7-9 and Table 7-10 show representative levelized cost of electricity for the IGCC plants evaluated in this study. These assume sequential start-up so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single start-up at the end of the project would result in a higher AFUDC, resulting in a higher capital expense and higher cost of electricity. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 7-9
IGCC Levelized Cost of Electricity

Technology	One 2x2x1 Shell IGCC	Two 2x2x1 Shell IGCC	Four 2x2x1 Shell IGCC	Six 2x2x1 Shell IGCC
Rated Capacity, MW net	644	1,288	2,576	3,864
Fuel Cost (ZAR/MWh)	303.3	303.3	303.3	303.3
O&M (ZAR/MWh)	300.9	262.1	238.5	229.0
Capital (ZAR/MWh)	1,224.9	1,151.9	1,079.0	1,042.5
LCOE (ZAR/MWh)	**1,829.2**	**1,717.4**	**1,620.8**	**1,574.9**

Table 7-10
IGCC with CCS Levelized Cost of Electricity

Technology	One 2x2x1 Shell IGCC with CCS	Two 2x2x1 Shell IGCC with CCS	Four 2x2x1 Shell IGCC with CCS	Six 2x2x1 Shell IGCC with CCS
Rated Capacity, MW net	644	1,288	2,576	3,864
Fuel Cost (ZAR/MWh)	389.9	389.9	389.9	389.9
O&M (ZAR/MWh)	411.9	368.1	340.6	329.4
Capital (ZAR/MWh)	1,632.5	1,535.3	1,438.0	1,389.4
LCOE (ZAR/MWh)	**2,434.3**	**2,293.2**	**2,168.5**	**2,108.7**

Water Usage

The IGCC plant requires water for makeup water to the steam cycle as well as water for steam injection into the gasifier to promote the gasification reactions, resulting in a water consumption rate of about 257 L/MWh for the plant without capture. The use of an air-cooled condenser significantly reduces the water consumption compared to a wet-cooled plant, though it increases cost and decreases output. For an IGCC with carbon capture, the water consumption rate increases significantly to over 1,000 L/MWh due primarily to the water used in the water shift.

Emissions

Both the air and solid emissions of the IGCC plant evaluated in this study are listed in the summary table above. The gas cleanup process required before sending the syngas to the GT results in very low SOx and NOx emissions without the need for post-combustion clean up. The addition of CO_2 capture leads to a significant reduction in CO_2 emissions, though SO_X emissions increase slightly due to the increased heat rate.

FBC

Table 7-11
Fluidized Bed without FGD Cost and Performance Summary

Technology	1x250 MW, No FGD	2x250 MW, No FGD	4x250 MW, No FGD	6x250 MW, No FGD
Rated Capacity, MW gross	270	540	1,080	1,620
Rated Capacity, MW net	250	500	1,000	1,500
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	47,458	44,611	41,763	40,340
Lead Times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year, ZAR/GJ	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	695	649	593	566
Variable O&M, ZAR/MWh	149.7	149.7	149.7	149.7
Availability Estimates				
Equivalent Availability	90.4	90.4	90.4	90.4

Table 7-11 (continued)
Fluidized Bed without FGD Cost and Performance Summary

Technology	1x250 MW, No FGD	2x250 MW, No FGD	4x250 MW, No FGD	6x250 MW, No FGD
Maintenance	5.7	5.7	5.7	5.7
Unplanned Outages	4.1	4.1	4.1	4.1
Performance Estimates				
Economic Life, years	30	30	30	30
Heat Rate, kJ/kWh				
Average Annual	10,749	10,749	10,749	10,749
100% Load	10,702	10,702	10,702	10,702
75% Load	10,901	10,901	10,901	10,901
50% Load	11,485	11,485	11,485	11,485
25% Load	13,869	13,869	13,869	13,869
Net Plant Efficiency, %	33.5	33.5	33.5	33.5
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	33	33	33	33
Sorbent (Limestone) Usage				
Per Unit of Energy, kg/MWh	0	0	0	0
Air Emissions, kg/MWh				
CO_2	1,003	1,003	1,003	1,003
SOx (as SO_2)	10.00	10.00	10.00	10.00
NOx (as NO_2)	0.28	0.28	0.28	0.28
Particulates	0.14	0.14	0.14	0.14
Solid Wastes kg/MWh				
Fly ash	144.5	144.5	144.5	144.5
Bottom ash	43.2	43.2	43.2	43.2
Gypsum	0.0	0.0	0.0	0.0

Table 7-12
Fluidized Bed with FGD Cost and Performance Summary

Technology	1x250 MW, with FGD	2x250 MW, with FGD	4x250 MW, with FGD	6x250 MW, with FGD
Rated Capacity, MW gross	273	546	1,092	1,638
Rated Capacity, MW net	250	500	1,000	1,500
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	48,319	45,420	42,521	41,072
Lead Times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year, ZAR/GJ	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	702	656	599	572
Variable O&M, ZAR/MWh	195.4	195.4	188.7	195.4
Availability Estimates				
Equivalent Availability	90.4	90.4	90.4	90.4
Maintenance	5.7	5.7	5.7	5.7
Unplanned Outages	4.1	4.1	4.1	4.1
Performance Estimates				
Economic Life, years	30	30	30	30
Heat Rate, kJ/kWh				
Average Annual	10,788	10,788	10,788	10,788
100% Load	10,740	10,740	10,740	10,740
75% Load	10,940	10,940	10,940	10,940
50% Load	11,526	11,526	11,526	11,526
25% Load	13,918	13,918	13,918	13,918

Table 7-12 (continued)
Fluidized Bed with FGD Cost and Performance Summary

Technology	1x250 MW, with FGD	2x250 MW, with FGD	4x250 MW, with FGD	6x250 MW, with FGD
Net Plant Efficiency, %	33.4	33.4	33.4	33.4
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	33	33	33	33
Sorbent (Limestone) Usage				
Per Unit of Energy, kg/MWh	41	41	41	41
Air Emissions, kg/MWh				
CO_2	1,003	1,003	1,003	1,003
SOx (as SO_2)	0.50	0.50	0.50	0.50
NOx (as NO_2)	0.28	0.28	0.28	0.28
Particulates	0.14	0.14	0.14	0.14
Solid Wastes kg/MWh				
FGD Solids	36.2	36.2	36.2	36.2
Fly ash	145.0	145.0	145.0	145.0
Bottom ash	43.3	43.3	43.3	43.3
Gypsum	0	0	0	0

Table 7-13
Fluidized Bed with CCS Cost and Performance Summary

Technology	1x250 MW, with CCS	2x250 MW, with CCS	4x250 MW, with CCS	6x250 MW, with CCS
Rated Capacity, MW gross	355	709	1,420	2,130
Rated Capacity, MW net	250	500	1,000	1,500
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	84,705	80,891	77,078	75,171
Lead Times and Project Schedule, years	4	5	7	9
Single Unit Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	3%, 9%, 20%, 25%*, 23%, 16%, 5%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%
Fuel Cost Estimates				
First Year, ZAR/GJ	31.1	31.1	31.1	31.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, kJ/kg	17,850	17,850	17,850	17,850
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	1,055	995	920	886
Variable O&M, ZAR/MWh	257.3	257.3	257.3	257.3
Availability Estimates				
Equivalent Availability	90.4	90.4	90.4	90.4
Maintenance	5.7	5.7	5.7	5.7
Unplanned Outages	4.1	4.1	4.1	4.1
Performance Estimates				
Economic Life, years	30	30	30	30
Heat Rate, kJ/kWh				
Average Annual	15,518	15,518	15,518	15,518
100% Load	15,451	15,451	15,451	15,451
75% Load	15,737	15,737	15,737	15,737
50% Load	16,581	16,581	16,581	16,581
25% Load	20,022	20,022	20,022	20,022

Table 7-13 (continued)
Fluidized Bed with CCS Cost and Performance Summary

Technology	1x250 MW, with CCS	2x250 MW, with CCS	4x250 MW, with CCS	6x250 MW, with CCS
Net Plant Efficiency, %	23.2	23.2	23.2	23.2
Plant Load Factor				
Typical Capacity Factor	85%	85%	85%	85%
Maximum of Rated Capacity	100%	100%	100%	100%
Minimum of Rated Capacity	25%	25%	25%	25%
Water Usage				
Per Unit of Energy, L/MWh	50	50	50	50
Sorbent (Limestone) Usage				
Per Unit of Energy, kg/MWh	59	59	59	59
Air Emissions, kg/MWh				
CO_2	150	150	150	150
SOx (as SO_2)	0.72	0.72	0.72	0.72
NOx (as NO_2)	0.41	0.41	0.41	0.41
Particulates	0.20	0.20	0.20	0.20
Solid Wastes kg/MWh				
FGD Solids	52.0	52.0	52.0	52.0
Fly ash	208.6	208.6	208.6	208.6
Bottom ash	62.3	62.3	62.3	62.3
Gypsum	0	0	0	0

Plant Cost Estimates

The total overnight cost for the FBC plants evaluated in this study ranges from about 40,340 ZAR/kW to 47,458 ZAR/kW for the plant without FGD, from about 41,072 ZAR/kW to 48,319 ZAR/kW for the plant with FGD, and from about 75,171 ZAR/kW to 84,705 ZAR/kW for the plant with CO_2 capture. Implementing FGD at the plant by adding limestone to the combustion bed increases TPC by ~2%. Adding carbon capture increases the plant cost by about 78% on a per kilowatt basis.

The expected expense and construction period for a single FBC unit is about four years. Early in the project, costs will include preliminary design, project siting, and permitting. Later in the project, equipment will be procured, delivered, and installed. This will be when the majority of the expenditures take place. The final stage of the project will be the commissioning of the plant. Based on this schedule, the expected expense schedule is 10% in year 1, 25% in year 2, 45% in year 3, and 20% in year 4. For a multi-unit plant, it is expected that the construction and start-up of each unit would be staggered by a year, such that the first unit would start after four years, and a new unit would start-up each subsequent year.

In comparing this report to the previous one completed in 2010, the increase in the FBC total capital cost was largely attributed to the increase in the costs of the dry cooling system, the steam generator island, and the turbine island. The FBC Cost Program was used to develop cost estimates for the FBC plants. The 2010 and 2012 cost estimates were developed using an older version of the program, whereas the 2015 estimates were based on the newest version which includes the most current equipment, commodity and labor cost data for the FBC plants.

Fuel Cost Estimates

The cost of the South African coal used in this study is estimated to be 31.1 ZAR/GJ with an energy content of about 17,850 kJ/kg before drying. The price of the coal is not expected to increase beyond general inflation.

O&M Cost Estimates

The fixed O&M costs for the FBC plants are about 566 ZAR/kW-yr to 695 ZAR/kW-yr for the plant without FGD and 572 ZAR/kW-yr to 702 ZAR/kW-yr for the plant with FGD. The major O&M cost difference between the plant without FGD and the plant with FGD occurs in the variable O&M due to the additional limestone consumption: variable O&M is 149.7 ZAR/MWh for the plant without FGD and 195.4 ZAR/MWh for the plant with FGD. For this study, both maintenance labor and material costs are considered to be fixed O&M costs. In the previous edition of this report, the numbers of maintenance personnel were assumed to be similar to that of the PC coal plant. However, in the latest version of the CFB Cost Program, the numbers of maintenance personnel were less than what were previously assumed in the 2012 Study. This resulted in a decrease in the fixed O&M cost in the 2015 Study. Limestone use is less efficient in an FBC plant compared to a PC unit, resulting in a more dramatic increase in consumable costs for an FBC plant. The addition of carbon capture results in larger increases in both fixed and variable O&M due to additional maintenance labor and materials and additional consumable consumption: fixed O&M is 886 ZAR/kW to 1,055 ZAR/kW and variable O&M is 257.3 ZAR/MWh.

Availability and Performance Estimates

The equivalent availability of the FBC plant evaluated in this study is expected to be about 90.4% and a capacity factor of 85%. The heat rate is 10,749 kJ/kWh for the plant without FGD and 10,788 kJ/kWh for the plant with FGD. There is a slight increase in auxiliary load for the plant with FGD due to the handling of more solids with the addition of limestone, but compared to the emission controls on other fossil plants, the addition of FGD to this plant through the inclusion of limestone in the combustion bed does not adversely affect the heat rate. The inclusion of carbon capture has a much larger adverse effect on heat rate, increasing the annual heat rate to 15,518 kJ/kWh. In the previous 2010 and 2012 studies, the heat rate for the dry cooling FBC cases was estimated based on the heat rate penalty extrapolated from TAGWeb data available at the time. In this study, the heat rate was developed using the CFB Cost Program, in which the result showed that the heat rate for the FBC plant with dry cooling was higher than previously estimated in the 2010 and 2012 studies.

An economic life of 30 years is assumed for the FBC plants for cost of electricity calculations; however, the operating life of a coal plant can extend well beyond 30 years.

Cost of Electricity

Table 7-14 through Table 7-16 show representative levelized costs of electricity for the FBC plants evaluated in this study. These assume sequential start-up so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single start-up at the end of the project would result in a higher AFUDC, resulting in a higher capital expense and higher cost of electricity. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 7-14
Fluidized Bed without FGD Levelized Cost of Electricity

Technology	1x250 MW, No FGD	2x250 MW, No FGD	4x250 MW, No FGD	6x250 MW, No FGD
Rated Capacity, MW net	250	500	1,000	1,500
Fuel Cost (ZAR/MWh)	334.1	334.1	334.1	334.1
O&M (ZAR/MWh)	243.0	237.0	229.3	225.8
Capital (ZAR/MWh)	933.0	877.5	821.9	794.1
LCOE (ZAR/MWh)	**1,510.2**	**1,448.7**	**1,385.4**	**1,354.0**

Table 7-15
Fluidized Bed with FGD Levelized Cost of Electricity

Technology	1x250 MW, with FGD	2x250 MW, with FGD	4x250 MW, with FGD	6x250 MW, with FGD
Rated Capacity, MW net	250	500	1,000	1,500
Fuel Cost (ZAR/MWh)	335.4	335.4	335.4	335.4
O&M (ZAR/MWh)	289.7	283.4	269.0	272.3
Capital (ZAR/MWh)	950.8	894.2	837.6	809.3
LCOE (ZAR/MWh)	**1,575.9**	**1,513.0**	**1,442.0**	**1,417.0**

Table 7-16
Fluidized Bed with CCS Levelized Cost of Electricity

Technology	1x250 MW, with CCS	2x250 MW, with CCS	4x250 MW, with CCS	6x250 MW, with CCS
Rated Capacity, MW net	250	500	1,000	1,500

Fuel Cost (ZAR/MWh)	482.5	482.5	482.5	482.5
O&M (ZAR/MWh)	398.9	390.9	380.8	376.1
Capital (ZAR/MWh)	1,663.6	1,589.3	1,514.9	1,477.6
LCOE (ZAR/MWh)	**2,545.0**	**2,462.7**	**2,378.1**	**2,336.2**

Water Usage

Because the steam cycles of the base case FBC plants evaluated are air-cooled, the only water usage is for makeup water to the boiler, which is about 33.3 L/MWh for the plants without capture and about 50.0 L/MWh for the plants with capture. The addition of in-bed desulfurization does not increase water consumption since it is a totally dry process. The use of an air-cooled condenser significantly reduces water consumption; however, it will increase the heat rate and the plant cost compared to a wet-cooled plant.

Emissions

The air and solid emissions of the FBC plants evaluated in this study are shown in the summary table above. The addition of limestone to the combustion bed significantly reduces the SO_x emissions from the plant, though some additional CO_2 is released from calcination of the limestone. A gypsum byproduct is also produced, which could possibly be sold if a gypsum market is available, or could result in an additional disposal cost. The addition of carbon capture significantly reduces CO_2 emissions, though SO_X and NO_X emissions increase due to the increased heat rate and fuel consumption.

8

NUCLEAR TECHNOLOGY PERFORMANCE AND COST

Table 8-1
Nuclear Areva EPR Technology Performance and Cost Summary

Technology	1 Unit	2 Units	4 Units	6 Units
Rated Capacity, MW net	1,600	3,200	6,400	9,600
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	98,079	96,881	94,427	92,128
Lead Times and Project Schedule, years	6	8	12	16
Single Unit Expense Schedule, % of TPC per year	15%, 15%, 25%, 25%, 10%, 10%	15%, 15%, 25%, 25%, 10%, 10%	15%, 15%, 25%, 25%, 10%, 10%	15%, 15%, 25%, 25%, 10%, 10%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	15%, 15%, 25%, 25%, 10%, 10%	7%, 7%, 20%, 20%, 18%, 18%*, 5%, 5%	4%, 4%, 10%, 10%, 13%, 13%*, 12%, 12%, 9%, 9%, 2%, 2%	3%, 3%, 7%, 7%, 8%, 8%*, 8%, 8%, 8%, 8%, 8%, 8%, 6%, 6%, 2%, 2%
Fuel Cost Estimates				
First Year, ZAR/GJ	9.1	9.1	9.1	9.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, GJ/kg	1,299	1,299	1,299	1,299
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	933	774	695	650
Variable O&M, ZAR/MWh	52.3	52.3	52.3	52.3
Availability Estimates				
Equivalent Availability	92.1	92.1	92.1	92.1
Maintenance	2.5	2.5	2.5	2.5
Unplanned Outages	5.5	5.5	5.5	5.5

Table 8-1 (continued)
Nuclear Areva EPR Technology Performance and Cost Summary

Technology	1 Unit	2 Units	4 Units	6 Units
Performance Estimates				
Economic Life, years	60	60	60	60
Heat Rate, kJ/kWh	10,340	10,340	10,340	10,340
Net Plant Efficiency, %	34.8	34.8	34.8	34.8
Water Usage				
Cooling (once-through sea water), L/MWh	6,814	6,814	6,814	6,814
Boiler Makeup, L/MWh	Negligible	Negligible	Negligible	Negligible

Table 8-2
Nuclear AP1000 Technology Performance and Cost Summary

Technology	1 Unit	2 Units	4 Units	6 Units
Rated Capacity, MW net	1,117	2,234	4,468	6,702
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	75,271	74,355	72,520	70,669
Lead Times and Project Schedule, years	6	8	12	16
Single Unit Expense Schedule, % of TPC per year	15%, 15%, 25%, 25%, 10%, 10%	15%, 15%, 25%, 25%, 10%, 10%	15%, 15%, 25%, 25%, 10%, 10%	15%, 15%, 25%, 25%, 10%, 10%
Full Project Expense Schedule, % of TPC per year (* indicates commissioning year of first unit)	15%, 15%, 25%, 25%, 10%, 10%	7%, 7%, 20%, 20%, 18%, 18%*, 5%, 5%	4%, 4%, 10%, 10%, 13%, 13%*, 12%, 12%, 9%, 9%, 2%, 2%	3%, 3%, 7%, 7%, 8%, 8%*, 8%, 8%, 8%, 8%, 8%, 8%, 6%, 6%, 2%, 2%
Fuel Cost Estimates				
First Year, ZAR/GJ	9.1	9.1	9.1	9.1
Expected Escalation (beyond inflation)	0%	0%	0%	0%
Fuel Energy Content, GJ/kg	1,299	1,299	1,299	1,299
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	1,254	1,027	914	850
Variable O&M, ZAR/MWh	31.2	31.2	31.2	31.2

Table 8-2 (continued)
Nuclear AP1000 Technology Performance and Cost Summary

Technology	1 Unit	2 Units	4 Units	6 Units
Availability Estimates				
Equivalent Availability	92.1	92.1	92.1	92.1
Maintenance	2.5	2.5	2.5	2.5
Unplanned Outages	5.5	5.5	5.5	5.5
Performance Estimates				
Economic Life, years	60	60	60	60
Heat Rate, kJ/kWh	10,973	10,973	10,973	10,973
Net Plant Efficiency, %	32.8	32.8	32.8	32.8
Water Usage				
Cooling (once-through sea water), L/MWh	6,814	6,814	6,814	6,814
Boiler Makeup, L/MWh	Negligible	Negligible	Negligible	Negligible

Table 8-3
Performance and Cost Summary for Multiple Nuclear Units with the Same Commercial Service Date

Technology	6x1600 MW, Areva	8x1117 MW, AP1000
Rated Capacity, MW Net	9,600	8,936
Plant Cost Estimates (January 2017)		
Total Overnight Cost, ZAR/kW	92,128	68,951
Lead-times and Project Schedule, years	10	10
Expense Schedule, % of TPC per year	5%, 5%, 13%, 13%, 17%, 17%, 12%, 12%, 3%, 3%	5%, 5%, 13%, 13%, 17%, 17%, 12%, 12%, 3%, 3%
Fuel Cost Estimates		
First Year (ZAR/GJ)	9.1	9.1
Expected Escalation (beyond inflation)	0%	0%
Fuel Energy Content, HHV, GJ/kg	1,299	1,299
Operation and Maintenance Cost Estimates		
Fixed O&M, ZAR/kW-yr	650	685
Variable O&M, ZAR/MWh	52.3	31.2
Availability Estimates		
Equivalent Availability	92.1	92.1
Maintenance	2.5	2.5
Unplanned Outages	5.5	5.5

Table 8-3 (continued)
Performance and Cost Summary for Multiple Nuclear Units with the Same Commercial Service Date

Technology	6x1600 MW, Areva	8x1117 MW, AP1000
Performance Estimates		
Economic Life, years	60	60
Heat Rate, kJ/kWh	10,340	10,973
Net Plant Efficiency, %	34.8	32.8
Water Usage		
Cooling (once-through sea water), L/MWh	6,814	6,814
Boiler Makeup, L/MWh	Negligible	Negligible

Plant Cost Estimates

The total overnight cost for the Areva EPR is estimated to be between 92,128 ZAR/kW and 98,079 ZAR/kW, and the total overnight cost for the AP1000 is estimated to be between 70,669 ZAR/kW and 75,271 ZAR/kW, depending on the number of. Construction of multiple units shown in Table 8-1 and Table 8-2 is assumed to occur sequentially, with construction and start-up of each new unit occurring every two years. While the idealized construction period is four years for the Areva EPR and three years for the AP1000, it is expected that the construction of a single unit would be closer to a six year project duration from initial engineering and procurement to construction and start-up. Because of some long lead times for procurement of equipment, much of the project cost is incurred in the earlier years of the project, with a total expense profile of 15% in year 1, 15% in year 2, 25% in year 3, 25% in year 4, 10% in year 5, and 10% in year 6.

Table 8-3 shows the cost data for multiple units being built all at once. The total overnight cost for 6 Areva EPR units (9600 MW net) is estimated to be 92,128 ZAR/kW, and the total overnight cost for 8 AP1000 units (8900 MW net) is estimated to be 68,951 ZAR/kW. The idealized construction period is assumed to be 10 years due to equipment and other critical material lead times.

Nuclear Cost Uncertainty Risks

As mentioned in the Capital Cost Estimating Basis discussion of cost uncertainty, risks associated with a new nuclear plant project can be considered in terms of how they affect time-related costs that are impacted by delays in the project schedule, such as interest payment on funds used during construction, and non-time-related costs, such as higher-than-expected material or labor costs. While the risks described below focus primarily on nuclear plant construction, they can apply to the other technologies evaluated in this study as well.

Lack of effective project management represents the greatest risk to overall nuclear project costs in terms of both likelihood and severity effect. Although the reference plants provide a level of confidence in the technical design and construction approach to the facility, the applicability of project management experience is not clear. The available resources of nuclear suppliers are expected to be in great demand in the future. Utility management will need to ensure that the proposed project team for the construction of a new nuclear power plant has acceptable expertise, commitment, and support from the parent companies.

Changes in certified design, digital controls, and the availability of skilled labor for nuclear plant construction have medium to high severity with medium likelihood. The process of submittal and approval of changes to certified design is untested in the U.S. Examples are upgrades like digital controls and site-specific limitations that may not match certified design. In addition to the risks related to the licensing process, changes in the digital controls have technical risks. Control room work is often a critical path for a project during the latter stages of construction. Implementing a new software base and licensing dependent control system may cause potential commissioning delays after construction is substantially complete.

Skilled labor in various engineering disciplines and crafts (welders, electrical, etc.) will likely be limited due to other nuclear projects and non-nuclear projects that compete for resources; though, as the demand becomes more certain, supply will expand to meet the increase in demand. One example of how supply meets demand is the BWX Technologies facility in Mount Vernon, Indiana, USA, which once produced large, heavy components for the nuclear industry and recently (2006) had its American Society of Mechanical Engineers' "N-stamp" certification – a crucial requirement for fabricating commercial nuclear-grade components – reinstated. The BWXT facility plans to revive manufacturing of large, heavy nuclear components if new plant orders materialize. In the meantime, it is manufacturing replacement components, including reactor vessel heads for existing plants.

Several risks associated with nuclear plant projects have a low likelihood of occurring, but medium to high impact (increased cost). The highest potential impact of these low probability risks is the performance of the unit once completed, as measured by capacity factor. The proposed plants should be able to achieve an industry capacity factor goal of above 90%. However, in the past plants have encountered unexpected equipment or regulatory problems and have been forced into extended outages (six months to three years). This potential is very real for a new plant design.

Other risks associated with a nuclear project have medium likelihood, but low impact. Radioactive waste disposal is an example of such a risk. Although few environmental risks are considered to be associated with the construction and operation of a nuclear power plant due to their low emissions and overall performance of the current U.S. domestic fleet, radioactive waste disposal does represent an environmental risk for new plants. The low-level and high-level waste disposal options and storage requirements for the new plants do not differ from operating U.S. plants in a significant way. Both old and new plants are planned for a limited amount of on-site storage, after which the material would have to be sent to a long-term disposal facility. The availability of disposal options for both low-level and high-level radioactive waste, and associated long term storage requirements, is uncertain. This could require additional investment in short term storage. The risk is considered to have a medium likelihood of occurring, but has a low severity relative to overall project cost.

The primary impact of the risks related to the construction of a nuclear power plant is increased capital costs due to construction delays and uncertainties in initial cost estimates. Some of the risks can be mitigated through effective planning and contracting strategies. However, all the risks cannot be wrapped into the project engineering, procurement, and construction contracts as they are not within the contractor's control, such as licensing and availability of material and qualified personnel. A significant number of causes of the delays and cost overruns associated with building the current U.S. fleet of nuclear plants have been addressed by structural changes in the design and licensing process. These risks are not project specific, so mitigation strategies need to be aligned with industry programs and efforts to build new nuclear plants. Some of the risks, however, are project specific, although they are impacted by industry issues, and can be expected to be borne or shared by the contractors. For example, risks related to effective project management, modularization construction techniques, and effective implementation of approved design changes are more within the contractors' control than generic licensing issues. Accordingly, corresponding mitigation strategies should be project specific and can be addressed during the project development, planning, and contracting stages of the project.

Fuel Cost Estimates

The fuel cycle for Areva EPR is expected to be between 12 and 24 months. For the AP1000, refueling is expected to occur every 18 months with a 17-day fueling outage. The cost of uranium is estimated to be 9.1 ZAR/GJ.

O&M Cost Estimates

It is expected that manpower requirements for modern nuclear plants will be reduced due the reduction in equipment and focus on passive safety features. Furthermore, advances in on-line diagnostic equipment and control room interfaces will reduce maintenance time. Fixed O&M costs are estimated to be 650 ZAR/kW-yr to 933 ZAR/kW-yr for the Areva EPR and 850 ZAR/kW-yr to 1,254 ZAR/kW-yr for the AP1000. Variable O&M costs are estimated to be 52.3 ZAR/MWh for the Areva EPR and 31.2 ZAR/MWh for the AP1000. The data presented in this report represent the latest variable O&M data for the AP1000 nuclear plant provided by EPRI's contractor, Sargent & Lundy. It appears that the difference may be more of an accounting issue. Although the variable O&M cost is less than previous years' studies, the consolidated O&M cost presented in this study is in-line with estimates developed by the International Energy Agency's report, *Projected Costs of Generating Electricity* that was published in 2015.

Availability and Performance Estimates

Availability of nuclear plants has continued to improve over the years as maintenance practices have been refined and on-line diagnostic equipment has developed. Availability of the nuclear plants is expected to be about 92%.

Though operating licenses are currently issued for 40 years in the United States, it is expected that nuclear plants will have an economic life of 60 years or longer, based on the service life of the reactor vessel.

The heat rate is estimated to be 10,340 kJ/kWh for the Areva EPR and 10,973 kJ/kWh for the AP1000. These plants are expected to operate primarily at full load, but are designed to allow for some load follow capability.

Cost of Electricity

Table 8-4 and Table 8-5 show the levelized cost of electricity of the Areva EPR and the AP1000 nuclear plants. These assume sequential start-up so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single start-up at the end of the project would result in a significantly higher AFUDC, resulting in a higher capital expense and higher cost of electricity. Table 8-6 shows the levelized cost of electricity of multiple Areva EPR and AP1000 nuclear plants with the same commercial service date. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 8-4
Nuclear Areva EPR Levelized Cost of Electricity

Technology	1 Unit	2 Units	4 Units	6 Units
Rated Capacity, MW net	1,600	3,200	6,400	9,600
Fuel Cost (ZAR/MWh)	93.9	93.9	93.9	93.9
O&M (ZAR/MWh)	170.6	150.5	140.5	134.8
Capital (ZAR/MWh)	1,979.4	1,955.1	1,905.5	1,859.1
LCOE (ZAR/MWh)	**2,243.8**	**2,199.4**	**2,139.8**	**2,087.8**

Table 8-5
Nuclear AP1000 Levelized Cost of Electricity

Technology	1 Unit	2 Units	4 Units	6 Units
Rated Capacity, MW net	1,117	2,234	4,468	6,702
Fuel Cost (ZAR/MWh)	99.6	99.6	99.6	99.6
O&M (ZAR/MWh)	190.2	161.6	147.2	139.0
Capital (ZAR/MWh)	1,520.0	1,501.2	1,464.1	1,426.6
LCOE (ZAR/MWh)	**1,809.8**	**1,762.4**	**1,710.9**	**1,665.2**

Table 8-6
Levelized Cost of Electricity for Multiple Nuclear Units with the Same Commercial Service Date

Technology	6x1600 MW, Areva	8x1115 MW, AP1000
Rated Capacity, MW net	9,600	8,936
Fuel Cost (ZAR/MWh)	93.9	99.6
O&M (ZAR/MWh)	134.8	118.1
Capital (ZAR/MWh)	2,119.0	1,586.3
LCOE (ZAR/MWh)	**2,347.6**	**1,804.0**

Water Usage

It was assumed that the nuclear plants in this study are cooled using a once-through cooling seawater condenser. This condenser has a water requirement of about 6,814 L/MWh, but the water is returned to the ocean after it has cooled the condenser, and there is no net consumption of water for cooling purposes. The water makeup necessary for the steam cycle is negligible.

9
GAS TECHNOLOGIES PERFORMANCE AND COST

Table 9-1
GT Cost and Performance Summary

Technology	OCGT	CCGT without CCS	CCGT with CCS
Rated Capacity, MW gross	133	751	751
Rated Capacity, MW net	132	732	635
Plant Cost Estimates (January 2017)			
TPC, Overnight, ZAR/kW	9,226	10,131	22,262
Lead Times and Project Schedule, years	2	3	3
Expense Schedule, % of TPC per year	90%, 10%	40%, 50%, 10%	40%, 50%, 10%
Fuel Cost Estimates			
First Year, ZAR/GJ	63.9	63.9	63.9
Expected Escalation (beyond inflation)	0%	0%	0%
Fuel Energy Content, MJ/SCM	39.3	39.3	39.3
O&M Cost Estimates			
Fixed O&M, ZAR/kW-yr	181	187	444
Variable O&M, ZAR/MWh	2.7	24.7	38.4
Availability Estimates			
Equivalent Availability	88.8	88.8	88.8
Maintenance	6.9	6.9	6.9
Unplanned Outages	4.6	4.6	4.6
Performance Estimates			
Economic Life, years	30	30	30

Table 9-1 (continued)
GT and ICE Cost and Performance Summary

Technology	OCGT	CCGT without CCS	CCGT with CCS
Heat Rate, kJ/kWh			
Average Annual	11,519	7,395	8,900
100% Load	11,184	7,180	8,642
75% Load	12,419	7,818	9,410
50% Load	14,960	7,941	9,559
25% Load	21,043	8,389	10,097
Net Plant Efficiency, %	31.3	48.7	40.5
Plant Load Factor			
Typical Capacity Factor	10%	50%	50%
Maximum of Rated Capacity	100%	100%	100%
Minimum of Rated Capacity	20%	20%	20%
Water Usage			
Per Unit of Energy, L/MWh	0.0	12.8	19.3
Air Emissions, kg/MWh			
CO2	574	367	42
SOx (as SO2)	0.00	0.00	0.00
NOx (as NO2)	0.30	0.17	0.21
CO	0.24	0.14	0.15
Particulates	0.05	0.03	0.04

Table 9-2
ICE Cost and Performance Summary

Technology	Internal Combustion Engine (ICE)	Internal Combustion Engine (ICE)
Rated Capacity, MW gross	1.93	9.57
Rated Capacity, MW net	1.90	9.4
Plant Cost Estimates (January 2017)		
TPC, Overnight, ZAR/kW	14,394	15,427
Lead Times and Project Schedule, years	1	1
Expense Schedule, % of TPC per year	100%	100%
Fuel Cost Estimates		
First Year, ZAR/GJ	63.9	63.9
Expected Escalation (beyond inflation)	0%	0%
Fuel Energy Content, MJ/SCM	39.3	39.3
O&M Cost Estimates		
Fixed O&M, ZAR/kW-yr	476	536
Variable O&M, ZAR/MWh	79.0	135.9
Availability Estimates		
Equivalent Availability	88.8	88.8
Maintenance	6.9	6.9
Unplanned Outages	4.6	4.6
Performance Estimates		
Economic Life, years	30	30

Table 9-1 (continued)
GT and ICE Cost and Performance Summary

Technology	Internal Combustion Engine (ICE)	Internal Combustion Engine (ICE)
Heat Rate, kJ/kWh		
Average Annual	9,477	8,780
100% Load	9,200	8,525
75% Load	9,696	8,894
50% Load	10,413	9,422
25% Load	12,365	11,068
Net Plant Efficiency, %	38.0	41.0
Plant Load Factor		
Typical Capacity Factor	50%	50%
Maximum of Rated Capacity	100%	100%
Minimum of Rated Capacity	20%	20%
Water Usage		
Per Unit of Energy, L/MWh	0	0
Air Emissions, kg/MWh		
CO2	491	455
SOx (as SO2)	0.00	0.00
NOx (as NO2)	1.34	0.11
CO	2.68	0.27
Particulates	0.00	0.00

Plant Cost Estimates

The total overnight cost for the OCGT is 9,226 ZAR/kW and for the CCGT is 10,131 ZAR/kW for the plant without capture and 22,262 ZAR/kW for the plant with capture. The total overnight cost for the 1.9 MW ICE unit is 14,394 ZAR/kW, and 15,427 ZAR/kW for the 9.4 MW ICE unit. The low cost of the open cycle plant is important for its economic viability as a peaking unit – because it operated infrequently, its annual electricity production is low and it, therefore, has fewer megawatt-hours over which to recover capital expenses.

The expected expense and construction period for an OCGT plant is about two years. The first year will include the majority of design, equipment procurement, and construction while the second year will involve the commissioning of the plant, leading to an expected expense schedule of 90% in the first year and 10% in the second year. The CCGT has an expected expense and construction period of about three years. The first year will involve permitting at the beginning followed by equipment procurement, delivery, and installation in the latter part of the year and into the second year, while the final year of the project will involve commissioning of the plant, leading to an expected expense schedule of 40% in year 1, 50% in year 2, and 10% in year 3. Lastly, the ICE unit has an expected expense and construction period of about one year.

Fuel Cost Estimates

The cost of the LNG used in this report is estimated to be 63.9 ZAR/GJ with a fuel energy content of 39.3 MJ/SCM. The price of natural gas is not expected to increase beyond general inflation.

O&M Cost Estimates

The fixed O&M cost is about 181 ZAR/kW-yr for the OCGT plant, about 187 ZAR/kW-yr for the CCGT plant without carbon capture, and about 444 ZAR/kW-yr for the CCGT plant with capture. For the ICE unit, the fixed O&M is about 476 ZAR/kW-yr for the 1.9 MW unit, and 536 ZAR/kW-yr for the 9.4 MW unit. For this study, both maintenance labor and material costs are considered to be fixed. The assumed coastal location of the GT plants could possibly increase these maintenance costs because salty air could be detrimental to the GT life and could affect filtration systems differently from air in a non-coastal location.

The variable O&M for the OCGT is relatively low because consumables are used in a negligible amount. The variable O&M is 24.7 ZAR/MWh for the CCGT without carbon capture and 38.4 ZAR/MWh for the CCGT with carbon capture. The addition of carbon capture results in larger increases in both fixed and variable O&M due to additional maintenance labor and materials and additional consumable consumption. The variable O&M for the 1.9 MW ICE unit is 79 ZAR/MWh, and 136 ZAR/MWh for the 9.4 MW unit.

Availability and Performance Estimates

The equivalent availability of both GT plants evaluated in this study is expected to be about 88.8% and both are expected to have an economic life of at least 30 years. The annual heat rate of the OCGT is 11,519 kJ/kWh, and the plant becomes much less efficient when it is run at part-load. The combined cycle plant without capture has a heat rate of 7,395 kJ/kWh. This is the most efficient fossil fuel plant due to its utilization of the waste heat exiting the GT for use in the steam turbine. The CCGT with capture has a heat rate of 8,900 kJ/kWh. The ICE unit has a heat rate of 9,477 kJ/kWh. As a peaking plant, the OCGT has an expected capacity factor of 10% while the combined cycle has a capacity factor of 50%.

Cost of Electricity

Table 9-2 shows a representative levelized cost of electricity for the GT and ICE plants evaluated in this study. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 9-3
GT and ICE Levelized Cost of Electricity

Technology	OCGT	CCGT without CCS	CCGT with CCS	ICE	ICE
Rated Capacity, MW net	132	732	635	1.90	9.4
Fuel Cost (ZAR/MWh)	736.5	472.8	569.0	605.8	561.3
O&M (ZAR/MWh)	210.2	67.5	139.8	187.8	258.4
Capital (ZAR/MWh)	1,513.9	339.1	743.0	423.9	454.2
LCOE (ZAR/MWh)	**2,460.5**	**879.4**	**1,451.8**	**1,217.5**	**1,274.0**

Water Usage

In the previous edition of this report, it was assumed that water injection was needed for NO_x control. The estimated water requirement was 19.8 L/MWh. However, in this report, the OCGT water usage is based on dry low emission (DLE) combustors without having to inject water or steam. Therefore, in Table 9-1, the required water usage for OCGT is stated as zero.

A small amount of makeup water is needed for the steam cycle of the combined cycle plant. However, air-cooling of the combined cycle plant greatly reduces water consumption compared to a wet-cooled plant. The water use is 12.8 L/MWh in the combined cycle without capture, and 19.3 L/MWh in the CCGT plant with carbon capture. The water consumption of the ICE plants is zero.

Emissions

The air emissions of the GT and ICE plants evaluated in this study are shown in the summary table above. Natural gas is a much less carbon intensive fuel than coal, resulting in much lower CO_2 emission on a per MWh basis than the coal-fired plants. The addition of carbon capture to the CCGT reduces the CO_2 emissions even further.

10
RENEWABLE TECHNOLOGIES PERFORMANCE AND COST

Wind

Table 10-1
Wind Technology Performance and Cost Summary

Technology	10 x 2 MW	25 x 2 MW	50 x 2 MW	100 x 2 MW
Rated Capacity, MW net	20	50	100	200
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	33,475	31,363	29,251	28,194
Lead Times and Project Schedule, years	2-3.5	2.5-4	3-5	3-6
Expense Schedule, % of TPC per year	5%, 5%, 90%	2.5%, 2.5%, 5%, 90%	5%, 5%, 10%, 80%	2.5%, 2.5%, 5%, 15%, 75%
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	710	700	684	675
Availability Estimates	94-97%	94-97%	94-97%	94-97%
Performance Estimates				
Economic Life, years	20	20	20	20
Capacity Factor	See Table 10-2			

Plant Cost Estimates

The total overnight cost for the wind technology ranges from 28,194 ZAR/kW for a 200 MW plant to 33,475 ZAR/kW for a 20 MW plant. It is expected that the total project schedule for a wind farm, including preconstruction siting and lead times as well as construction, would be two to three and a half years for a 20 MW plant, two and a half to four years for a 50 MW plant, three to five years for a 100 MW plant, and three to six years for a 200 MW plant. It is expected that most of the costs in the earlier months of the project will be permitting, while the equipment procurement and installation will be in the latter months, leading to a heavier weighting of expenses later in the project.

O&M Cost Estimates

First year O&M costs for wind turbines range from 675 ZAR/kW-yr for a 200 MW plant to 710 ZAR/kW-yr for a 20 MW plant. These costs include both maintenance labor and materials. Due to the lack of consumables or disposal costs for wind farms, variable O&M is zero. O&M costs typically increase during the project life by 1-2% per year as major components wear and require more maintenance. As with capital costs, larger projects typically experience economies of scale with O&M costs.

Availability and Performance Estimates

Wind farms are expected to have an availability in the range of 94-97%. A major factor contributing to this high availability is the fact that maintenance can be performed on a single turbine while the remainder of the plant remains in service. The economic life of a wind turbine is expected to be about 20 years.

The performance of a wind turbine depends primarily on the wind resource available. Table 10-2 shows the capacity factor of a wind turbine at various wind speed. While the wind resource map in Figure 3-2 shows the wind speeds across South Africa at 10 meter measurement height, this study assumed a hub height of 80 meters.

Table 10-2
Wind Turbine Capacity Factors

Average Wind Speed (m/s @ 80-meter hub height)	5.0	6.0	7.0	8.0
Wind Class	1	2	4	6
Average Net Capacity Factor, %	21.6	27.4	37.2	46.0

Cost of Electricity

Table 10-3 through Table 10-6 show representative levelized costs of electricity of the wind plants at different wind classes. These are shown for illustrative purposes only and will vary based on financial assumptions. It can be seen that higher wind classes result in improved levelized costs of electricity.

Table 10-3
Wind Levelized Cost of Electricity – 10 x 2 MW Farm

Technology	**Wind**			
Rated Capacity, MW net	20			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	361.9	282.9	208.5	168.2
Capital (ZAR/MWh)	2539.3	1986.0	1463.3	1180.7
LCOE (ZAR/MWh)	**2,901.2**	**2,269.0**	**1,671.8**	**1,348.9**

Table 10-4
Wind Levelized Cost of Electricity – 25 x 2 MW Farm

Technology	Wind			
Rated Capacity, MW net	50			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	365.5	287.0	210.8	170.8
Capital (ZAR/MWh)	2442.2	1917.4	1408.4	1140.8
LCOE (ZAR/MWh)	**2,807.7**	**2,204.4**	**1,619.2**	**1,311.5**

Table 10-5
Wind Levelized Cost of Electricity – 50 x 2 MW Farm

Technology	Wind			
Rated Capacity, MW net	100			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	368.0	291.8	214.8	173.6
Capital (ZAR/MWh)	2372.1	1880.9	1384.5	1119.1
LCOE (ZAR/MWh)	**2,740.0**	**2,172.7**	**1,599.3**	**1,292.7**

Table 10-6
Wind Levelized Cost of Electricity – 100 x 2 MW Farm

Technology	Wind			
Rated Capacity, MW net	200			
Wind Speed, m/s	5.0	6.0	7.0	8.0
Fuel Cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	371.2	294.9	217.3	175.7
Capital (ZAR/MWh)	2346.7	1864.6	1374.1	1110.8
LCOE (ZAR/MWh)	**2,717.8**	**2,159.6**	**1,591.4**	**1,286.5**

Solar Thermal

Table 10-7
Parabolic Trough Cost and Performance Summary

Technology	0 Hours Storage	3 Hours Storage	6 Hours Storage	9 Hours Storage	12 Hours Storage
Rated Capacity, MW net	125	125	125	125	125
Plant Cost Estimates (January 2017)					
TPC, Overnight, ZAR/kW	72,524	97,641	120,542	147,877	177,182
Lead Times and Project Schedule, years	4	4	4	4	4
Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
O&M Cost Estimates					
Fixed O&M, ZAR/kW-yr	1,123	1,154	1,185	1,216	1,262
Variable O&M, ZAR/MWh	1.0	1.0	0.9	0.9	0.9
Availability Estimates	95%	95%	95%	95%	95%
Performance Estimates					
Economic Life, years	30	30	30	30	30
Capacity Factor (in Upington, SA)	25.6%	32.5%	38.0%	45.6%	53.9%
Water Usage					
Per Unit of Energy, L/MWh	319	306	298	296	296

Table 10-8
Central Receiver Cost and Performance Summary

Technology	No Storage	3 Hours Storage	6 Hours Storage	9 Hours Storage	12 Hours Storage
Rated Capacity, MW net	125	125	125	125	125
Plant Cost Estimates (January 2017)					
TPC, Overnight, ZAR/kW	71,266	87,126	107,135	121,374	135,772
Lead Times and Project Schedule, years	4	4	4	4	4
Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
O&M Cost Estimates					
Fixed O&M, ZAR/kW-yr	1,031	1,062	1,108	1,139	1,170
Variable O&M, ZAR/MWh	1.0	1.0	1.0	1.0	1.0
Availability Estimates	92%	92%	92%	92%	92%
Performance Estimates					
Economic Life, years	30	30	30	30	30
Capacity Factor (in Upington, SA)	29.3%	39.5%	51.0%	60.3%	69.7%
Water Usage					
Per Unit of Energy, L/MWh	320	310	302	300	298

Plant Cost Estimates

The total overnight cost for the parabolic trough ranges from 72,524 ZAR/kW for a plant without storage to 177,182 ZAR/kW for a plant with twelve hours of storage. For the central receiver, costs range from 71,266 ZAR/kW for a plant without storage to 135,772 ZAR/kW for a plant with twelve hours of storage.

It is expected that a parabolic trough or a central receiver plant would have a four year expense and construction period. Early in the project, costs will include preliminary design, project siting, and permitting. Later in the project, equipment will be procured, delivered, and installed. This will be when the majority of the expenditures take place. The final stage of the project will be the commissioning of the plant. Based on this schedule, the expected expense schedule is 10% in year 1, 25% in year 2, 45% in year 3, and 20% in year 4.

In comparing the previous studies to this updated report, the two contributors to the cost increase in the 2015 Study were the costs of the heat transfer system and the power block for concentrating solar parabolic trough technologies. Additionally, in the 2012 Study the Engineering and Construction Management Fees used were 5% of total process capital. For this study, EPRI's contractor, Sargent & Lundy, recommended the Engineering and Construction Management Fees of 15% of total process capital. These factors contributed to the cost increase in the 2015 Study.

For the concentrating solar central receiver technologies, the major contributor to the cost increase in the 2015 Study was the cost of the power block. Similar to the CSP parabolic rough cases, the Engineering and Construction Management Fees were also increased to 15% of total process capital in this study.

O&M Cost Estimates

First year O&M costs for parabolic troughs range from 1,123 ZAR/kW-yr for a plant without storage to 1,262 ZAR/kW-yr for a plant with twelve hours of storage. For the central receiver, O&M costs range from 1,031 ZAR/kW-yr for a plant without storage to 1,170 ZAR/kW-yr for a plant with twelve hours of storage. These costs include both maintenance labor and materials. Due to the lack of consumables or disposal costs for solar thermal plants, variable O&M is zero. It is expected that O&M holdback will remain relatively constant (in constant dollars) for the life of the plant.

Availability and Performance Estimates

Parabolic troughs are expected to have an availability of up to 95% while central receivers are expected to have an availability of 92% due to their early commercial status. It is expected that as more systems are deployed the availability of central receiver plants will converge with those of parabolic troughs. Because the solar fields do not operate at night, much of the required maintenance can take place during this down time. Furthermore, due to the modular nature of the collectors and heliostat mirrors, many repairs can take place on a single section of the solar field while the remainder remains in operation. The economic life of a solar thermal plant is expected to be about 30 years.

As the amount of storage included at a solar thermal plant increases, the annual output and capacity factor of the plant increases. The actual output of a solar thermal plant is highly dependent on the solar resource at the site, and the capacity factors presented in this study are for a plant located near Upington, South Africa. For a parabolic trough without storage, the capacity factor is expected to be about 25.6% while a plant with twelve hours of storage has a capacity factor of 53.9%. In the same manner, a central receiver without storage has a capacity factor of 29.3% while a plant with twelve hours of storage has a capacity factor of 69.7%. This increased plant output requires the additional storage equipment and additional mirrors or collectors, resulting in increased plant cost. Therefore, the costs and benefits of storage must be considered to find the optimum design.

Cost of Electricity

Table 10-9 and Table 10-10 show a representative levelized cost of electricity of the parabolic trough and central receiver for a range of storage hours. These are shown for illustrative purposes only and will vary based on financial assumptions. Central receivers are in the pre-commercial to early commercial phase of development, and any early projects, particularly with large amounts of TES, will likely have a different financial structure with a higher equity ratio and a higher cost of debt. Rather than speculate what this structure may be like, the same assumptions were used for all solar technologies to illustrate any capital and/or operational advantages of each case. It can be seen that the number of hours of storage can be optimized to find the lowest cost of electricity based on the increased output of the plant due to storage compared to the increased cost of the plant.

Table 10-9
Parabolic Trough Levelized Cost of Electricity

Technology	Parabolic Trough				
Rated Capacity, MW net	125				
Hours of Storage	0	3	6	9	12
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	501.3	405.6	356.0	304.3	267.1
Capital (ZAR/MWh)	4,702.9	4,984.8	5,259.1	5,371.9	5,447.2
LCOE (ZAR/MWh)	**5,204.1**	**5,390.4**	**5,615.1**	**5,676.1**	**5,714.3**

Table 10-10
Central Receiver Levelized Cost of Electricity

Technology	Central Receiver				
Rated Capacity, MW net	125				
Hours of Storage	0	3	6	9	12
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	402.3	307.2	248.1	215.8	191.6
Capital (ZAR/MWh)	4,040.6	3,659.9	3,485.9	3,340.6	3,230.7
LCOE (ZAR/MWh)	**4,442.9**	**3,967.1**	**3,734.0**	**3,556.4**	**3,422.3**

Water Usage

Because the plants in this study were evaluated with air cooled condensers, the primary use of water in these solar thermal plants is due to mirror washing. It is expected that about 38 liters of water is required per meter squared of mirror area per year assuming that mirrors are washed about once a week. A small amount of water will also be needed for power block make-up.

PVs

Table 10-11
CdTe PV Cost and Performance Summary – Fixed Tilt

Technology	Thin Film CdTe - Fixed Tilt			
Mounting Location	Rooftop (0° tilt)		Ground (latitudinal tilt)	
Rated Capacity, MW net	0.25	1	1	10
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	74,879	57,157	43,466	42,907

Lead Times and Project Schedule, years	1	1	1	1
Expense Schedule, % of TPC per year	100%	100%	100%	100%
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	281	281	316	316
Availability Estimates	99%	99%	99%	99%
Performance Estimates				
Economic Life, years	25	25	25	25
Capacity Factor	See Table 10-16			
Water Usage, L/yr	0	0	13,874	138,742

Table 10-12
CdTe PV Cost and Performance Summary - Tracking

Technology	Thin Film CdTe - Tracking			
Mounting Location	Single Axis Tracking		Double Axis Tracking	
Rated Capacity, MW net	1	10	1	10
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	51,545	50,986	57,357	56,798
Lead Times and Project Schedule, years	1	1	1	1
Expense Schedule, % of TPC per year	100%	100%	100%	100%
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	334	334	369	369
Availability Estimates	99%	99%	99%	99%
Performance Estimates				
Economic Life, years	25	25	25	25
Capacity Factor	See Table 10-16			
Water Usage, L/yr	16,646	166,464	17,926	179,264

Table 10-13
C-Si PV Cost and Performance Summary – Fixed Tilt

Technology	C-Si - Fixed Tilt			
Mounting Location	Rooftop (0° tilt)		Ground (latitudinal tilt)	
Rated Capacity, MW net	0.25	1	1	10

Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	73,652	55,929	37,643	37,144
Lead Times and Project Schedule, years	1	1	1	1
Expense Schedule, % of TPC per year	100%	100%	100%	100%
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	281	281	281	302
Availability Estimates	99%	99%	99%	99%
Performance Estimates				
Economic Life, years	25	25	25	25
Capacity Factor	See Table 10-17			
Water Usage, L/yr	0	0	14,478	140,069

Table 10-14
C-Si PV Cost and Performance Summary – Tracking

Technology	C-Si - Tracking			
Mounting Location	Single Axis Tracking		Dual Axis Tracking	
Rated Capacity, MW net	1	10	1	10
Plant Cost Estimates (January 2017)				
TPC, Overnight, ZAR/kW	43,336	42,837	47,457	46,956
Lead Times and Project Schedule, years	1	1	1	1
Expense Schedule, % of TPC per year	100%	100%	100%	100%
O&M Cost Estimates				
Fixed O&M, ZAR/kW-yr	320	320	354	354
Availability Estimates				
Performance Estimates				
Economic Life, years	25	25	25	25
Capacity Factor	See Table 10-17			
Water Usage, L/yr	17,376	173,759	18,709	187,090

Table 10-15
Concentrating PV Cost and Performance Summary

Technology	Concentrating PV
Rated Capacity, MW net	10
Plant Cost Estimates (January 2017)	

TPC, Overnight, ZAR/kW	56,863
Lead Times and Project Schedule, years	1
Expense Schedule, % of TPC per year	100%
O&M Cost Estimates	
Fixed O&M, ZAR/kW-yr	354
Availability Estimates	95%
Performance Estimates	
Economic Life, years	25
Capacity Factor (First Year)	24.7%
Capacity Factor (Average)	22.8%
Water Usage, L/yr	327,755

Plant Cost Estimates

The total overnight cost for CdTd PV systems ranges from 42,907 ZAR/kW for a 10 MW ground mounted plant to 74,879 ZAR/kW for a 250 kW roof mounted system. Single axis tracking CdTd PV systems range from 50,986 ZAR/kW for a 10 MW plant to 51,545 ZAR/kW for a 1 MW plant. Double axis tracking CdTd PV systems range from 56,798 ZAR/kW for a 10 MW plant to 57,357 ZAR/kW for a 1 MW plant.

For c-Si PV, the total overnight cost ranges from 37,144 ZAR/kW for a 10 MW ground mounted plant to 73,652 ZAR/kW for a 250 kW roof mounted system. Single axis tracking c-Si PV systems range from 42,837 ZAR/kW for a 10 MW plant to 43,336 ZAR/kW for a 1 MW plant. Double axis tracking c-Si PV systems range from 46,956 ZAR/kW for a 10 MW plant to 47,457 ZAR/kW for a 1 MW plant.

A 10 MW concentrating PV system is estimated to cost 56,863 ZAR/kW for a dual axis tracking system. It is expected that both the roof mounted and ground mounted systems can be sited, permitted, and constructed within a year.

O&M Cost Estimates

First year O&M costs for CdTe fixed tilt PV plants are expected to be 281 ZAR/kW-yr for the roof mounted system, 316 ZAR/kW-yr for the ground mounted system, 334 ZAR/kW-yr for the single axis tracking system, and 369 ZAR/kW-yr for the double axis tracking system.

For c-Si fixed tilt PV plants, the O&M costs are expected to be 281 ZAR/kW-yr for the roof mounted system, 302 ZAR/kW-yr for the ground mounted system, 320 ZAR/kW-yr for the single axis tracking system, and 354 ZAR/kW-yr for the double axis tracking system.

While ground mounted systems include the cost of the land purchased for the system in their capital costs, roof mounted systems typically include the annual lease cost of the roof space in the fixed O&M. However, these estimates do not include this extra cost. O&M for a two axis tracking CPV plant is expected to be 354 ZAR/kW. These fixed O&M costs include both maintenance labor and materials. Due to the lack of consumables or disposal costs for PV plants, variable O&M is zero.

Availability and Performance Estimates

The fixed tilt, single axis tracking, and double axis tracking PV systems are expected to have an availability of 99%, while the CPV system is expected to have an availability of 95%. As with solar thermal plants, the fact that the plants do not operate at night allows for some of their maintenance to take place during hours of non-operation. Furthermore, their modularity allows for individual modules to be serviced without shutting down the entire system. The economic life of PV systems is expected to be about 25 years.

The performance of a PV system is highly dependent on the solar resource available. The performance of the flat plate PV systems was evaluated in both Cape Town and Johannesburg, South Africa. The rooftop mounted panels were assumed to be installed without any tilt, while the ground mounted panels were assumed to be installed tilted at latitude, maximizing annual energy output. Experience has shown that PV modules decrease in output over time due to a number of reasons. Most manufacturers guarantee 80% of the original output at standard conditions after 25 years. This translates into a 0.8% per year energy degradation factor included in the price modeling. Capacity factors were calculated for the first year of operation, as well as the average over the 25 year life of the panels assuming degradation in panel output of 0.8% per year. Table 10-16 and Table 10-17 show the capacity factors for both locations and thin film types both for the first year and the average for 25 years.

The performance of the CPV system was evaluated for a site near Upington. The capacity factor was calculated for the first year of operation, as well as the average over the 25 year life of the CPV panels assuming a degradation in panel output of 0.7% per year. This resulted in a first year capacity factor of 24.7% and an average capacity factor of 22.8%.

Table 10-16
Thin Film Capacity Factors

Technology	**CdTe**			
Mounting Location	Rooftop (0° tilt)	Ground (latitudinal tilt)	Single Axis	Double Axis
Cape Town (1st Year)	18.2%	20.2%	24.3%	26.2%
Cape Town (Average)	16.6%	18.5%	22.4%	24.1%
Johannesburg (1st Year)	18.8%	20.9%	25.1%	27.0%
Johannesburg (Average)	17.2%	19.1%	23.1%	24.9%

Table 10-17
c-Si PV Capacity Factors

Technology	**c-Si**			
Mounting Location	Rooftop (0° tilt)	Ground (latitudinal tilt)	Single Axis	Double Axis
Cape Town (1st Year)	18.9%	21.1%	25.4%	27.3%
Cape Town (Average)	17.2%	19.3%	23.4%	25.1%
Johannesburg (1st Year)	19.6%	21.8%	26.2%	28.2%

Johannesburg (Average)	17.8%	19.9%	24.1%	26.0%

Cost of Electricity

Table 10-18 through Table 10-22 show the representative levelized costs of electricity of the PV plants. These are shown for illustrative purposes only and will vary based on financial assumptions. It can be seen that the economy of scale of the larger ground-mounted systems result in lower costs of electricity.

Table 10-18
CdTe Levelized Cost of Electricity – Fixed Tilt

Technology	**Thin Film CdTe – Fixed Tilt**			
Mounting Location	Rooftop (0^0 tilt)		Ground (latitudinal tilt)	
Rated Capacity, MW	0.25	1.0	1.0	10.0
	Cape Town			
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	176.1	176.7	178.3	178.3
Capital (ZAR/MWh)	6,547.7	5,012.5	3,416.5	3,372.6
LCOE (ZAR/MWh)	**6,723.9**	**5,189.2**	**3,594.8**	**3,550.9**
	Johannesburg			
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	170.2	170.7	172.5	172.5
Capital (ZAR/MWh)	6,327.5	4,844.1	3,304.8	3,262.5
LCOE (ZAR/MWh)	**6,497.8**	**5,014.7**	**3,477.3**	**3,435.0**

Table 10-19
CdTe Levelized Cost of Electricity – Tracking

Technology	**Thin Film CdTe - Tracking**			
Mounting Location	Single Axis		Double Axis	
Rated Capacity, MW	1.0	10.0	1.0	10.0
	Cape Town			
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	157.3	157.3	161.0	161.0
Capital (ZAR/MWh)	3,376.0	3,339.5	3,487.2	3,453.3
LCOE (ZAR/MWh)	**3,533.2**	**3,496.7**	**3,648.2**	**3,614.2**
	Johannesburg			

Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	152.1	152.1	155.8	155.8
Capital (ZAR/MWh)	3,265.7	3,230.4	3,375.3	3,342.5
LCOE (ZAR/MWh)	**3,417.9**	**3,382.5**	**3,531.0**	**3,498.2**

Table 10-20
C-Si Levelized Cost of Electricity – Fixed Tilt

Technology	**C-Si – Fixed Tilt**			
Mounting Location	Rooftop (0^0 tilt)		Ground (latitudinal tilt)	
Rated Capacity, MW	0.25	1.0	1.0	10.0
	Cape Town			
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	169.6	169.2	151.7	158.1
Capital (ZAR/MWh)	6,200.0	4,699.6	2,835.0	2,706.1
LCOE (ZAR/MWh)	**6,369.6**	**4,868.8**	**2,986.7**	**2,864.3**
	Johannesburg			
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	163.9	163.5	146.8	163.5
Capital (ZAR/MWh)	5,991.7	4,541.6	2,742.3	2,797.5
LCOE (ZAR/MWh)	**6,155.6**	**4,705.1**	**2,889.1**	**2,961.0**

Table 10-21
C-Si Levelized Cost of Electricity – Tracking

Technology	**C-Si Tracking**			
Mounting Location	Single Axis		Double Axis	
Rated Capacity, MW	1.0	10.0	1.0	10.0
	Cape Town			
Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	143.9	143.9	148.0	148.0
Capital (ZAR/MWh)	2,719.8	2,688.4	2,764.7	2,735.6
LCOE (ZAR/MWh)	**2,863.7**	**2,832.4**	**2,912.7**	**2,883.7**
	Johannesburg			

Fuel Cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	139.3	139.3	143.2	143.2
Capital (ZAR/MWh)	2,631.0	2,600.6	2,676.0	2,647.8
LCOE (ZAR/MWh)	**2,770.2**	**2,739.8**	**2,819.3**	**2,791.0**

Table 10-22
CPV Levelized Cost of Electricity

Technology	CPV
Rated Capacity, MW	10.0
Fuel Cost (ZAR/MWh)	0.0
O&M (ZAR/MWh)	163.5
Capital (ZAR/MWh)	3,660.2
LCOE (ZAR/MWh)	**3,823.7**

Water Usage

Water usage for PV plants is due to the necessity to wash the PV panels to reduce soiling effects that degrade the output of the panel. Assuming that a fixed flat plate PV system is washed twice a year and that a concentrating PV system would be washed four times per year, a fixed flat plate PV system annually requires about 1.5 liters per meter squared of panel area and a CPV system will annually require 3 liters per meter squared of panel.

Biomass

Table 10-23
Biomass Cost and Performance Summary

Technology	Forestry Residue	MSW
Rated Capacity, MW net	25	25
Plant Cost Estimates (January 2017)		
TPC, Overnight, ZAR/kW	84,040	161,424
Lead Times and Project Schedule, years	3.5-4	3.5-4
Expense Schedule, % of TPC per year	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Fuel Cost Estimates		
First Year, ZAR/GJ	36.2	0.0
Expected Escalation (beyond inflation)	0%	0%

Fuel Energy Content, kJ/kg	11,763	11,388
O&M Cost Estimates		
Fixed O&M, ZAR/kW-yr	1,868	7,303
Variable O&M, ZAR/MWh	74.7	128.9

Table 10-23 (continued)
Biomass Cost and Performance Summary

Technology	Forestry Residue	MSW
Availability Estimates		
Equivalent Availability	90.2	90.2
Maintenance	4.0	4.0
Unplanned Outages	6.0	6.0
Performance Estimates		
Economic Life, years	30	30
Heat Rate, kJ/kWh	14,243	18,991
Net Plant Efficiency, %	25.3	19.0
Plant Load Factor		
Typical Capacity Factor	85%	85%
Maximum of Rated Capacity	100%	100%
Minimum of Rated Capacity	40%	40%
Water Usage		
Per Unit of Energy, L/MWh	227	227
Air Emissions, kg/MWh		
CO_2	1243	1633
SOx (as SO_2)	0.75	0.57
NOx (as NO_2)	0.58	2.21
CO	1.47	1.91
Particulates	0.18	0.31
HCl	0.0	0.0
Solid Wastes kg/MWh		
Fly ash	20.1	106.1
Bottom ash	5.0	259.7

Table 10-24
Landfill Gas and Biogas Reciprocating Engine Cost and Performance Summary

Technology	Landfill Gas	Biogas
Rated Capacity, MW net	5	5
Plant Cost Estimates (January 2017)		
TPC, Overnight, ZAR/kW	35,048	87,242
Lead Times and Project Schedule, years	1	1
Expense Schedule, % of TPC per year	100%	100%
Fuel Cost Estimates		
First Year, ZAR/GJ	0	0
Expected Escalation (beyond inflation)		
Fuel Energy Content, MJ/SCM	18.6	18.6
O&M Cost Estimates		
Fixed O&M, ZAR/kW-yr	2,678	2,191
Variable O&M, ZAR/MWh	69.7	57.0
Availability Estimates		
Equivalent Availability	86%	86%
Maintenance	5%	5%
Unplanned Outages	10%	10%
Performance Estimates		
Economic Life, years	30	30
Heat Rate, kJ/kWh	12,302	11,999
Net Plant Efficiency, %	29.3	30.0
Plant Load Factor		
Typical Capacity Factor	85%	85%
Maximum of Rated Capacity	100%	100%
Minimum of Rated Capacity	13%	13%
Water Usage		
Per Unit of Energy, L/MWh	0	0

Table 10-24 (continued)
Landfill Gas and Biogas Reciprocating Engine Cost and Performance Summary

Technology	Landfill Gas	Biogas
Air Emissions, kg/MWh		
CO_2	806	787
SOx (as SO_2)	0.00	0.00
NOx (as NO_2)	0.61	0.59
CO	3.00	2.93
Particulates	2.59	2.32

Plant Cost Estimates

The total overnight cost for biomass plants burning forestry residue is estimated to be 84,040 ZAR/kW and 161,424 ZAR/kW for plants burning MSW. Because MSW boilers must be designed to handle a much more diverse fuel input, they are built much more robustly. MSW boilers also required a scrubber, unlike a wood-fired boiler. For these reasons, the cost of the MSW plant is considerably higher than that of the forestry residue biomass plant. In comparing previous editions of this report, the biomass forestry residue-based power plant costs presented in this report is the latest estimate for biomass plants provided by EPRI's contractor, Sargent & Lundy. It is higher than what was developed in 2010; however, it is consistent with data developed in the International Energy Agency's *Projected Costs of Generating Electricity* that was published in 2015. The total overnight cost is estimated to be 35,048 ZAR/kW for a landfill gas reciprocating engine and 87,242 ZAR/kW for a biogas reciprocating engine.

It is expected that a biomass plant would have a three and a half to four year expense and construction period. Early in the project, costs will include preliminary design, project siting, and permitting. Later in the project, equipment will be procured, delivered, and installed. This will be when the majority of the expenditures take place. The final stage of the project will be the commissioning of the plant. Based on this schedule, the expected expense schedule is 10% in year 1, 25% in year 2, 45% in year 3, and 20% in year 4.

The construction period for the landfill gas and biogas reciprocating engines is much shorter and is expected to be completed within a year. This is because the engine equipment is the bulk of the plant and requires minimal siting and construction. This timeframe does not include the development of the landfill gas facility.

Fuel Cost Estimates

Forestry residue has a fuel energy content of about 11,760 kJ/kg. MSW has a slightly lower energy content of 11,390 kJ/kg. Landfill gas and biogas have an energy content of 18.6 MJ/SCM. The cost of forestry residue is assumed to be 36.2 ZAR/GJ for this study. For MSW, the cost is assumed to be zero. In actuality, mass burn boilers are often paid to take MSW and the fuel cost can actually act as a credit for the plant. Figure 10-1 shows how the tipping fee for MSW can lead to negative fuel prices.

The landfill gas and biogas are also assumed to be zero for this study. The price of landfill gas can vary considerably and will depend on numerous variables, such as the quality, the quantity, the longevity of the gas supply, the potential of interruption of gas flow, the O&M arrangement on the gas collection and supply system, etc. The fact that a large landfill flares the landfill gas to waste if it is not utilized will depress the price that the landfill will charge the gas user substantially below the prevailing price of natural gas. Many landfill gas projects are developed and owned by the landfill owner. For such projects, there would be no fuel cost charged to the project, such as a power generation engine located on a landfill site that is owned and operated by the landfill owner.

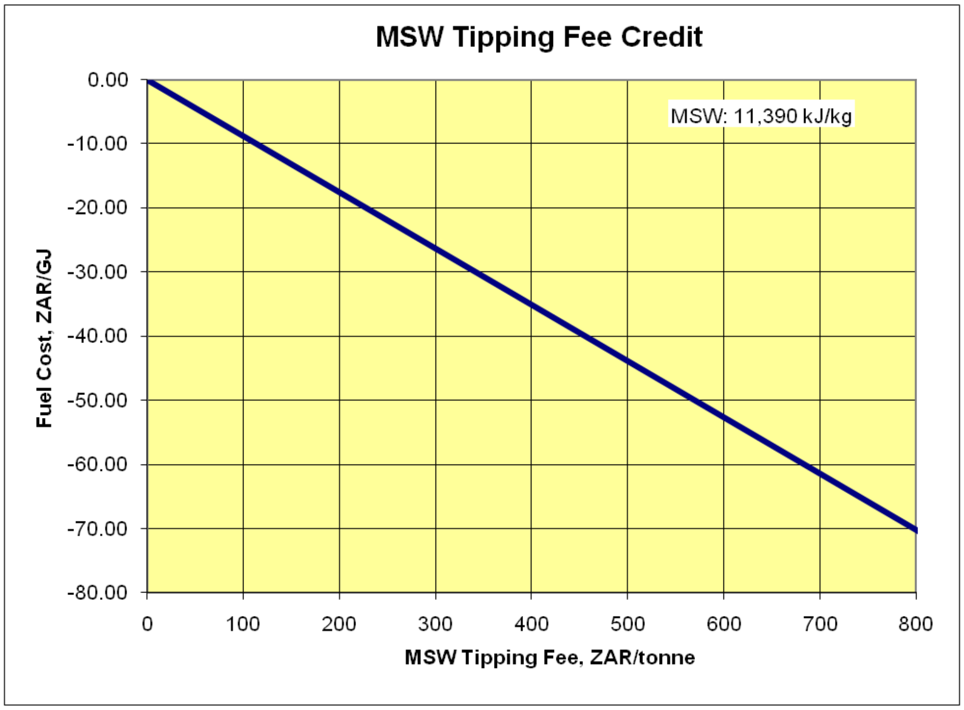


Figure 10-1
Fuel Cost for MSW Based on Tipping Fee

O&M Cost Estimates

For a wood-fired biomass boiler, the fixed O&M is expected to be 1,868 ZAR/kW-yr and the variable O&M is expected to be 74.7 ZAR/MWh. For an MSW mass burn boiler, the fixed O&M is much higher due to the increased corrosive nature of the combustion products, as well as the additional emissions equipment. Fixed O&M is expected to be 7,303 ZAR/kW-yr and variable O&M is expected to be 129 ZAR/MWh for the mass burn MSW boiler. The fixed O&M for the landfill gas engines is 2,678 ZAR/kW-yr and the variable O&M is 69.7 ZAR/MWh. For the biogas engines, the fixed O&M is 2,191 ZAR/kW-yr and the variable O&M is 57 ZAR/MWh. The O&M costs for the landfill and biogas plants are for the engines, gas filtering/clean-up, and the compressor/blower. In previous editions of this study, O&M costs were limited to only the engine. The costs developed in this report are similar in nature to costs estimated by the US-based National Renewable Energy Laboratory in the technical report, *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*[19].

Availability and Performance Estimates

Both the wood-fired and MSW-fired plants have an expected availability of 90% and an expected capacity factor of 85%. The heat rate of the wood-fired plant is 14,243 kJ/kWh, while MSW plants have a higher heat rate of 18,990 kJ/kWh. The landfill gas engines have an expected availability of 86%. This takes into consideration that at times the engines will not operate due to outages caused by the landfill gas supply company. The landfill gas engines have a heat rate of 12,300 kJ/kWh, while the biogas engines have a heat rate of 12,000 kJ/kWh. As the load fluctuates, one, two, or three of the four engines can be taken offline, resulting in the same full load heat rate at 75%, 50%, and 25% load. The economic life of all plants is expected to be about 30 years. In comparing the heat rates, the rates for the biomass forestry residue and MSW increased slightly. This report's estimates are closer to the values developed in 2010. This year's landfill gas heat rate is notably higher than previous years' reports. The estimate this year was informed by operating data taken from systems operating in the United States – mainly from data collected by the California Public Utility Commission[20].

Cost of Electricity

Table 10-22 shows the levelized cost of electricity for the biomass plants. These are shown for illustrative purposes only and will vary based on financial assumptions.

Figure 10-2
Biomass Levelized Cost of Electricity

Technology	Forestry Residue	MSW	Landfill Gas	Biogas
Rated Capacity, MW Net	25	25	5	5
Fuel Cost (ZAR/MWh)	516.0	2.6	41.2	40.2
O&M (ZAR/MWh)	325.7	1,109.8	429.3	351.1
Capital (ZAR/MWh)	1,649.1	3,155.8	637.6	1,580.6
LCOE (ZAR/MWh)	**2,490.8**	**4,268.2**	**1,108.1**	**1,971.9**

Water Usage

Because the steam cycles of these plants are air-cooled, the only water usage is for makeup water to the boiler. For both of the biomass boiler plants, this is about 227 L/MWh. The use of an air-cooled condenser reduces water consumption by over 90%. However, this leads to a derate penalty for an air-cooled plant compared to a wet-cooled plant, requiring that the rest of the plant, such as turbine generators and auxiliaries, must be larger to generate the same amount of

[19] *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*. National Renewable Energy Laboratory, November 2011.
[20] *California Energy Almanac*. http://energyalmanac.ca.gov/electricity/web_qfer/Heat_Rates.php

steam and output the same amount of electricity. Because there is no steam cycle for the landfill gas plant, there is no need for makeup water.

Emissions

Of the renewable technologies evaluated in this study, biomass plants are the only ones without zero emissions. Emissions are higher for the MSW plant than for the wood-fired plant, both because the MSW is a dirtier fuel to start with and because the higher heat rate of the MSW plant, which requires that more fuel is burned to generate the same amount of electricity. The air emissions and solid wastes, where applicable, are shown in the summary tables above.

11
GRID INTEGRATION AND INTERMITTENCY ISSUES FOR NON-THERMAL RENEWABLE TECHNOLOGIES

Managing significant quantities of renewable generation requires changes in the power delivery system at both the transmission and distribution levels. For example, at the transmission level, the variability of renewable resources will lead systems operators to redefine ancillary requirements, such as reserve requirements and ramp rates in order to operate the grid reliably. Operational changes may affect many tools and processes currently in use and will increase in importance for operators to meet reliability standards.

Because renewable technologies, especially solar and wind, are not dispatchable, the practice in the U.S. is to provide for GTs as a back-up in system reserve. In general, the regulatory agencies (Public Utility Commissions and Independent System Operators) in the U.S. assign a value of about 10% to 15% of the total installed capacity of wind farms to the reserve margin (that is a 100 MW wind farm is assigned a 10 to 15 MW reserve margin capacity). Any shortfall in reserve margin is made up with GTs. If there is regulatory stipulation that the maximum production capacity (up to 100%) of wind and solar be used this may require turning down some fossil units, which may lower their efficiency and increase emissions. Independent of this, the evaluations have only just begun on assessing the impact of the full use of renewable power generation capacity on fossil units, especially on pollution control units.

At the distribution level, the issues are different but equally important for enabling penetration of distributed generation into existing and future systems. These include evaluating interface devices, analytics, studies, applications with end-use resources, and assessment of new technology for effective interconnection and integration of renewable and other distributed generation. Recognizing the need for change and adapting the electric grid can enable higher penetration levels without reducing safety, reliability, or asset utilization effectiveness.

As a point of reference, in its 2008 Annual Report 1, the Electric Reliability Council of Texas (ERCOT, the agency responsible for managing electricity flow throughout the state of Texas) reported a peak load of 62 GW, average production of 35.6 GW, and 10 % installed capacity from wind generation. This portion of capacity represents a significant impact on the power system. Over three GW of wind capacity, at multiple locations, became operational in 2008.

ERCOT now has special operating procedures, extensive use of demand response, routine negative prices during low-load conditions, and investors, with government subsidies, are considering the introduction of energy storage pilot projects.

In its 2009 Annual Report 2, Eskom reported peak demand, not counting demand reductions, of almost 36 GW. Average production was about 20 GW out of 40 GW net maximum capacity. To reach 5% wind penetration by capacity, South Africa would need to install two GW or ten 200-MW wind farms. Technically, operational and planning impacts can be expected at this level of penetration, and the evidence suggests that, depending on policy, such impacts could be expected within the energy planning horizon.

The costs cited in earlier chapters for renewable technologies include costs for TES, power electronics, and reactive power compensation as appropriate. This chapter addresses other technologies that ease the integration of renewable energy into the electricity grid, which are mostly related to additional operating costs.

Technology Characteristics

The primary challenges for the non-thermal renewable generation technologies considered in this study are variability and predictability of energy output. This section considers wind generation and PV technologies.

Wind Integration Issues

Grid integration of significant wind energy is expected to be the most challenging of all renewable options. The basic issue is wind turbine generators simply cannot perform all the functions that are expected from traditional generation.

Wind plant output varies with the weather and, by its nature, tends to be remote from load centers. Experience to date has shown that wind output is not likely to coincide with peak load requirements and that there are interesting successes and significant challenges to absorbing higher levels of deployment. Over speed tripping due to storm fronts and under voltage tripping due to power system faults have led to some significant tripping events.

Another characteristic of wind generation is its high rate of change or ramping. Although large positive and negative changes in the wind are rare, there is a need to understand and plan for them, especially in remote and relatively weak grid conditions.

PV Solar Integration Issues

Compared to wind, solar energy may be easier to integrate into the electric grid. Good solar resources are more often close to load centers and are more likely to coincide with and be available during the daily load peak. One exception is the rapid rate of change in output that may occur as clouds pass over solar arrays.

By its nature, solar energy can be more available during the summer than winter. For most areas with summer peaking of demand, its generation profile has a good match with the load profile. Even so, seasonal and daily variations of available output affect the capacity factor and overall system economics.

Like wind, solar PV power output can be quite variable due to partly cloudy weather and storm fronts. This has been observed in desert systems as well as those located in more temperate climates. Significant changes in solar system output can occur as clouds are passing by because these systems do not normally have any built in stored energy. The ramp rates of solar PV are likely higher than those of wind generation. Due to the large volume of HTFs contained within solar thermal fields, ramp rates associated with parabolic trough and central receiver plants tend to be reduced due to thermal inertia.

As large scale PV systems are just now being deployed, the issue of ramp rates is getting considerable attention. A large ad-hoc group being led by the National Renewable Energy Lab in Golden, CO is leading this effort in conjunction with academia, solar technology providers, and utility companies.

Integration issues

When wind, solar PV, and other intermittent generation resources are part of the generation mix, operators must consider the unique characteristics of the generator when planning and operating the power system. The following six characteristics of intermittent generation are likely to require changes in planned unit commitment, economic dispatch, and operating reserves:

- Intermittency
- Ramping burdens
- Fluctuating power output
- Limited reactive power control
- Distributed generation
- Remote location of some renewable resources.

Intermittency

The output of most traditional generators can be planned, as well as controlled, even minute-to-minute to meet the expected daily load and to balance or regulate load variations. Wind power output depends on the weather and is determined by time-varying wind speeds; its output varies day to day as well as from hour to hour and even minute to minute. Two wind facilities may have the same capacity rating and annual energy production; however, different wind regimes may result in very different hourly, daily, and seasonal operating schedules. Similarly, solar PV plant output depends on the solar resource for the day or hour, and can be greatly affected by passing clouds.

Ramping Burdens

Bringing in wind generation and solar PV usually means that additional flexibility will be required in other sources of electrical generation to accommodate sub-hourly ramps.

Grid stability requires moment-to-moment balancing of the load and generation to maintain a constant frequency. Rapid changes in system loads are matched by quickly ramping generation up or down to balance load and generation in a 5-to-10-minute timeframe. Also, some units are required to ramp more quickly, following an automatic generation control (AGC) signal to maintain system balance. Operators refer to this process as regulation and the time frame is in minutes.

A substantial load change may cause sudden changes in frequency to which speed governors on individual generator units must respond. The number of plants and their capacity to provide load balancing and regulation are limited in any power system. The challenge is to have sufficient energy balancing and regulating generation with ramp rates to meet the worst-case fluctuations.

Wind power outputs have significant spatial variations; outputs from nearby wind plants are correlated, but outputs from distant wind plants are not correlated. This spatial variation can provide smoothing of output in show time frames. Short-time fluctuations of wind power can be independent regardless of distance between wind plants. However, longer-time wind power fluctuations are more likely to be correlated for nearby wind power plants.

Fluctuating Power Output

Rapid changes in power system loading or in generation can also cause small voltage fluctuations that manifest themselves as light flicker. Voltage changes of 1% to 2% can cause visible flicker. Wind turbines can cause voltage fluctuations due to a number of natural weather and machine conditions. These include fluctuations in wind speed, cut-in or cut-out transients, tower shadow effects, wind shear, and pitching errors of blades. Another factor in flicker production is the type of generator, which can include induction generators with fixed or variable poles, variable-speed through electronic power conversion with or without pitch control, directly connected synchronous generators, or synchronous generators connected through a converter.

Limited Reactive Power Control

Depending on the type of generator, reactive power supplied or absorbed by a renewable generation facility may vary along with the real power output. For example, most wind turbines use induction rather than synchronous generators and therefore require external capacitors to provide reactive power, usually switched in discrete steps. Even with switched capacitors, reactive control to match wind power generation may still be an issue. Externally switched capacitors will probably satisfy the steady-state reactive power balance requirement for the system but will not address any dynamic VAR control needs. Dispatching reactive power to maintain transmission network voltage could place new requirements on controlled generating facilities or necessitate capital investment for reactive compensation equipment. The addition of power electronics into the wind system can provide both dynamic and static reactive power control.

In the case of inverter-connected solar PV, many systems do not have reactive power control. The reactive power output varies depending on line voltage and solar output. This variation can be quite different than the real power output and may require some form of utility control and penetration levels to increase.

Distributed Generation

Wind, solar, and other renewable generation are deployed both as large projects interconnected to the transmission system and as small distributed facilities connected to the distribution system. Even though wind is considered primarily as a bulk-generation resource, a growing number of installations are being deployed on distribution systems at or near smaller load centers. Because distributed systems are designed for one-way power flow, distributed generators require special arrangements for connection and protection.

Two types of distributed wind and solar applications are common. Some facilities use local distribution to collect energy from individual units and deliver it to the distribution system. Other facilities are more dispersed and are individually connected to the system. Integration issues that may surface in these distribution scenarios are voltage regulation, coordination of protection, and interferences or harmonic flows along rights of way. In general, these are the same integration concerns that occur when any generation is added into the distribution system.

Remote Location of Some Renewable Resources

Although good quality renewable energy sites exist throughout the world, the best wind and solar resources are typically located relatively far from large load centers. In addition, sites selected for building large wind farms are likely to be away from population centers. This is not unique to wind. For example, other generation types such as hydro and coal-fired stations may also be located at significant distances from load centers. However, wind developments have tended to not consider the available transmission capacity to these sites nor include the transmission-related costs of taking the wind to market.

Integration Technologies for Distribution-Connected Renewable Generation

Today's electric distribution systems have evolved over many years in response to load growth and changes in technology. The largest single investment of the electric utility industry is in the distribution system. Most common are radial circuits fed from distribution substations designed to supply load based on customer demand requirements while maintaining an adequate level of power quality and reliability.

The system is designed to be fed from a single source. Protection is based on time-overcurrent relays and fuses that use nested time delays to clear faults by opening the closest protective device to a fault to minimize interruptions. It is designed to safely clear faults and get customers back in service as quickly as possible. In areas of high load density, network systems are common. These systems are fed by multiple transmission sources, and thereby provide high reliability. Both radial and network distribution systems have been designed to serve load, with little planning for generation connected at these levels.

Within the United States, circuit sectionalizing switches are manually controlled to restore load in unfaulted sections downstream from a failure. The system voltage is maintained in compliance with American National Standard Institute (ANSI) Std. C84-1, which specifies that service voltage be delivered within 5% of the system rated voltage. These systems are generally considered to be ready to support small PV installations without change, when the PV inverters meet appropriate standards, and the overall penetration levels are very low.

The design and technologies associated with today's distribution systems impose important limits on the ability to accommodate rooftop solar and other distributed generation, end-user load management, distributed system controls, automation, and future technologies like plug-in hybrid electric vehicles (PHEV). A number of system characteristics lead to these limitations:

- Voltage control is achieved with devices (voltage regulators and capacitor banks) that have localized controls. These schemes work well for today's radial circuits but they do not handle circuit reconfigurations and voltage impacts of local generation well. This results in limits on the ways circuits can be configured and important limits on the penetration of distributed resources. This also limits the ability to control the voltage on distribution circuits for optimizing customer equipment energy efficiency.

- There is little communication and metering infrastructure to aid in restoration following faults on the system.

- There is no communication infrastructure to facilitate control and management of distributed resources that could include renewables, other distributed generation, and storage. Without communication and control, the penetration of distributed generation on most circuits will be limited. The distributed generation must disconnect in the event of any circuit problem, limiting reliability benefits that can be achieved with the distributed generators as well.
- There is no communication to customer facilities to allow customers and customer loads to react to electricity price changes and/or emergency conditions. Customer-owned and distributed resources cannot participate in electricity markets, limiting the economic payback in many cases. Communications to the customer would also provide feedback on energy use that has been shown to help customers achieve improved energy efficiency.
- The infrastructure is limited in the capacity to support new electrical demand such as home electronics and PHEVs. These new loads have the potential to seriously impact distribution system energy delivery profiles. Communication and coordinated control will be needed to effectively serve this new demand.

At the same time, the distribution system infrastructure is aging, resulting in concerns for ongoing reliability. Utilities are struggling to find the required investment just to maintain the existing reliability, much less achieve higher levels of performance and reliability. New automation schemes are being implemented that can reconfigure circuits to improve reliability, but these schemes do not achieve the coordinated control needed to improve energy efficiency, manage demand, and reduce circuit losses.

The bottom line is that today's power distribution system has not been designed for distribution-connected PV or other high penetration of distributed generation. In the past this was not an issue, but today, with larger amounts of PV connecting to the electric system, we can expect new challenges in how distributed and variable generation can be safely and reliably interconnected.

In order to directly address the issues related to connecting large amounts of PV in the distribution system, four key areas will need to be addressed:

1. Voltage regulation practices
2. Overcurrent protection practices
3. Grounding practices
4. Switching and service restoration practices

Depending on the robustness of the existing design practices, the distribution system can handle some level of distributed renewable generation without modification. The basis for simplified interconnect rules such as California Rule 21 is that some level of robustness in existing distribution design allows connection without detailed engineering studies. Standards such as IEEE 1547-2003 and U.L. Inverter Test Standard 1741 evolved to enable connection without major design changes to the electric system.

In most areas today, distributed renewable generation is treated as negative load and the usual functions of generation are not expected or required. However, as PV deployments grow, feeder cases that cross the threshold are expected, requiring changes in operation rules such that the distribution generation will need to provide voltage support and eventually energy balancing.

This is anticipated to occur initially on individual feeders with high penetration and later on at the substation and sub-transmission level.

Integration Technologies for Transmission-Connected Renewable Generation

Transmission is normally subject to the control of system operations and balancing authorities. In deregulated markets this would be the Independent System Operator (ISO). In vertically integrated utility markets it is usually the utility that owns most of the transmission and/or generation in the region.

The transmission systems are designed and built for two-way power flow. Therefore, if capacity is available at the location of connection, renewable generation variability can be absorbed by the grid. However, with traditional generation, system operators assume that most of the available energy resources are “dispatchable” and therefore expect to be able to schedule generator output with a high probability of delivery of the specified output. For wind, solar, and other intermittent generation, this assumption is less valid.

Depending on the location and the relative size of renewable output, absorbing variable generation ultimately leads to increased cost related to the impacts of intermittency, ramping, fluctuating output, lack of control, and remote location on transmission scheduling, system dispatch, network stability, load following, and load balancing.

Variable Generation Technical and Cost Challenges

Integration for Distribution-Connected Renewable Generation

In the future, a more automated distribution system will interact with distributed energy resources including PV generation and battery systems. This will in turn enable better utilization of these resources and higher penetration. The changes in the distribution grid for high-penetration PV will likely include the following:

- Interactive Voltage Regulation and VAR Management: Utility voltage regulator and capacitor controls will be interactive with each other and the PV sources. A central controller will help manage the interactivity to ensure optimized voltage and reactive power conditions.
- Bulk System Coordination of Photovoltaic Generation for Market and Bulk System Control: Control of renewable generation from a dispatch center will be needed. This will allow renewable generation to participate and be aggregated into energy markets as well as allow for control to preserve system stability, power quality, and reliability at the bulk level.
- Protective Relaying Schemes Designed for Renewable Generation: The distribution system and sub-transmission will include more extensive use of directional relaying, communication based transfer trips, pilot signal relaying, and impedance-based fault-protection schemes (like those used in transmission). These can work more effectively with multiple sources on the distribution system.
- Advanced Islanding Control: Extensively automated switchgear and renewable generation with enhanced islanding detection to improve capability for detecting unintentional islands.

Also, these systems should be able to reconfigure the grid/renewable generation into reliability-enhancing "intentional islands."

- Interactive Service Restoration: Sectionalizing schemes for service restoration allow distributed PV and other renewable generation to pick up load during the restoration process. Once separated, these must deal effectively with overloads from cold-load pickup and the current inrush required to recharge the system.
- Improved Grounding Compatibility: Consider new devices and architectures in both renewable generation and distribution that address grounding incompatibilities between power system sensing, protection, and harmonic flows. Examples of such techniques are:
  - Control or limit ground fault overvoltage via relaying techniques or ancillary devices instead of effectively grounded renewable generation requirements.
  - Harden the power system and loads to be less susceptible to ground fault overvoltage (increase voltage withstand ratings).
  - Change protective relaying for ground faults so a high penetration of grounding sources does not affect the ground fault relaying.
  - Change feeder grounding scheme or load serving scheme back to a grounded three-wire system.
- Distributed Energy Storage: Energy storage of various forms will apply to correct temporary load/generation mismatches, regulate frequency, mitigate flicker, and assist advanced islanding functions and service restoration.

These system changes and technology upgrades represent an extensive investment on the part of electric utilities, rate payers, and equipment manufacturers, and a huge change in the way the power system is operated and designed. These changes will not come overnight and will require many decades to implement as well as considerable engineering planning and development to determine the balance of features and capabilities needed against cost and complexity of implementation. Nonetheless, these are the approaches needed to move to high-penetration PV, and the industry needs to begin work now on research and development so that the technologies, tools, and approaches will be available in a timely manner.

Integration for Transmission-Connected Renewable Generation

The impacts of intermittent wind generation on both technical operating limits and ancillary costs are summarized in the EPRI Report, S*urvey of Wind Integration Study Results* (EPRI 1011883, March 2006), covering North American sites. A related report also covers European Sites (EPRI 1012734, March 2007).

The North American report reviews the wind integration studies conducted for nine mainland systems. These studies include the following:

- NYSERDA-NYISO
- Xcel North-280 MW
- Xcel North-1500 MW
- Alberta Electric System Operator (AESO)

- Bonneville Power Administration (BPA)
- Southwest Public Service Company
- WE Energies
- Great River Energy
- PacifiCorp

The wind generation penetration levels considered in these studies range from 0.3% to 20% of system peak load. The majority of the study results show that wind penetrations up to 20% lead to regulating reserve requirements of 30% or less.

The potential increase in intra-hour load following burdens ranges from 3% to 15% with the exception of the one 49% study result. Likewise, the potential increase in inter-hour load following burden was found to range from approximately 5% to 22%. Also, the capacity credit allocated to wind generation is only addressed in two of the nine studies presented in the North America report, with the credit ranging from 15% to 27% of rated capacity.

Intra-hour load-following cost impacts are also relatively low, ranging from zero to forty cents per MWh of wind. The inter-hour load-following costs are generally more significant. For the studies where the inter-hour load-following costs were determined in isolation, the cost impacts were $2.50 - $3.50 per MWh of wind generation. In other studies, the inter-hour load following cost is embedded with the uncertainty costs determined from scheduling/unit commitment assessments, but the costs appear to be of the same general magnitude range requirements.

The associated cost impacts of the increased regulating reserve burdens vary from twenty cents to a couple of dollars per MWh of wind. Much of the variation is associated with the assumed cost of providing (or obtaining) regulating reserves.

The increase in the standard deviation for scheduling uncertainty ranges from 20% to 50%. The associated costs are in the $1.00 to $4.50 per MWh range. Only one study yielded costs in excess of $10/MWh. It should be noted that not all cost components were calculated for all studies. Nonetheless, the studies that did evaluate cost impacts for most time frames yielded costs in the same range.

Grid Planning and Operating Tools

New tools to enable grid operators to better visualize the real time status of the grid, and to anticipate contingencies, are needed to moderate additions of intermittent resources. Several tools and methods are being developed in this area:

- Forecasting tools to predict renewable energy output on a near-real timeframe and up to 24 to 72 hours in advance using measured and numerical weather wind and solar resource data and statistical techniques. The forecasts need to be accompanied by measures of uncertainty and confidence levels for grid operators to use to commit adequate capacity, plan, and schedule to meet energy requirements. Benefits include minimizing unscheduled power flows, real-time voltage and dynamic stability problems, and preventing blackouts. Research scope should include the use of time-dependent optimal power flow techniques to develop adaptive strategies for real-time operation.

- Methods to evaluate the capacity value of an aggregation of intermittent generation, energy storage, and demand response providers, which allows for the coordinated dispatch and scheduling. This would involve energy markets to help balance the economics and risks in power system operations.
- Visualization for grid operation needs to be extended to cover intermittent generation in a geographical display, together with visualization of load and demand response capabilities and the effect they have on the transmission loadings, voltages, and frequencies of the power grid. This concept, developed by EPRI, will provide greater wide-area situational awareness to operators. Control room visualization may be a key technology for increasing intermittent generation without significant cost or loss of grid reliability R&D to develop automation concepts on adaptive relay protection, and voltage instability load shedding to handle the integration of substantial amounts of intermittent generation.

References

1. Eskom 2009 Annual Report. http://www.financialresults.co.za/eskom_ar2009/ar_2009/downloads/eskom_ar_2009.pdf
2. ERCOT 2008 Annual Report. http://www.ercot.com/content/news/presentations/2010/ERCOT%25202008%2520Annual%2520Report.pdf

12 ENERGY STORAGE

Introduction

Purpose and Scope of Section

The purpose of this section is to provide a technical update on mature and commercial storage technologies. The section provides information on the cost, performance, application, and vendors of energy storage systems and covers electric energy storage technologies that can be deployed in the near-term, including the following:

- Lithium-ion
- Sodium sulfur batteries
- Lead-acid batteries and advanced lead acid batteries
- Compressed-air energy storage (CAES), including second generation, low-fuel, and adiabatic versions (although adiabatic versions may not be a near-term technology)

Approach

To assemble the information in this section, the project team reviewed and synthesized information from EPRI reports and other documents, as well as publicly available vendor information. Cost information is provided in a spreadsheet and included in this section.

Organization of Section

Each of the battery technology storage sections includes summaries of the following topics:

- A technical/process description of the technology
- Performance characteristics
- Relevant applications
- The status of development, demonstration, and commercialization
- Costs
- Vendor and supplier contacts
- References

Applications

Energy storage systems can provide a variety of application solutions along the entire value chain of the electrical system, from generation support to transmission and distribution support and end-customer uses. Table 12-1 summarizes ten key applications. This list is not comprehensive. Additional energy storage applications exist now, and others will emerge in the future and will be the subject of future research. However, these ten key applications represent the preponderance of energy storage uses and are of most interest to potential energy storage owners and operators.

Major stakeholder groups for energy storage systems include utilities, customers, independent system operators (ISOs), wholesale market participants including intermittent generators, retail service providers, ratepayers, regulators, and policymakers.

Table 12-1
Definition of Energy Storage Applications

Value Chain	Application		Description
Generation & System-Level Applications	1	Wholesale Energy Services	Utility-scale storage systems for bidding into energy, capacity and ancillary services markets
	2	Renewables Integration	Utility-scale storage providing renewables time shifting, load and ancillary services for grid integration
↓	3	Stationary Storage for T&D Support	Systems for T&D system support, improving T&D system utilization factor, and T&D capital deferral
T&D System Applications	4	Transportable Storage for T&D Support	Transportable storage systems for T&D system support and T&D deferral at multiple sites as needed
	5	DESSs	Centrally managed modular systems providing increased customer reliability, grid T&D support and potentially ancillary services
↓	6	ESCO Aggregated Systems	Residential-customer-sited storage aggregated and centrally managed to provide distribution system benefits
End-User Applications	7	C&I Power Quality and Reliability	Systems to provide power quality and reliability to commercial and industrial customers
	8	C&I Energy Management	Systems to reduce TOU energy charges and demand charges for C&I customers
	9	Home Energy Management	Systems to shift retail load to reduce TOU energy and demand charges
	10	Home Backup	Systems for backup power for home offices with high reliability value

T&D = Transmission and Distribution; C&I = Commercial and Industrial; ESCO = Energy Services Company; TOU = Time of Use

Each of these ten applications centers around a specific operational goal but provides multiple benefits. Each benefit represents a discrete use of energy storage that can be quantified and valued. Due to the current high installed capital costs of most energy storage systems, applications (for either utilities or end users) must be able to realize multiple operational uses across different parts of the energy value chain – an aggregation of complementary benefits known as “stacking.” Figure 12-1 illustrates this concept for many of the energy storage functions served by the key applications.

For purposes of comparison, Figure 12-2 illustrates the characteristics of various energy storage technology options in terms of system power rating along the x-axis and duration of discharge time at rated power on the y-axis. For both figures, these comparisons are very general and intended for conceptual purposes only; many of the options have broader duration and power ranges than shown. Table 12-2 classifies the various types of energy storage according to the status of their development.

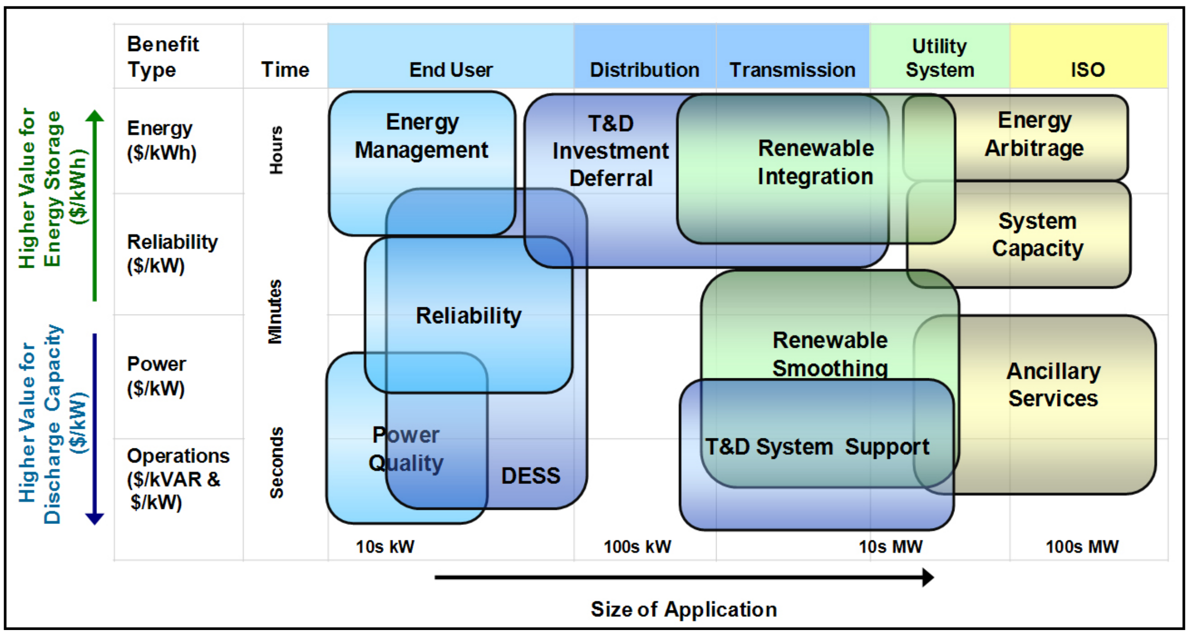


Figure 12-1
Operational Benefits Monetizing the Value of Energy Storage

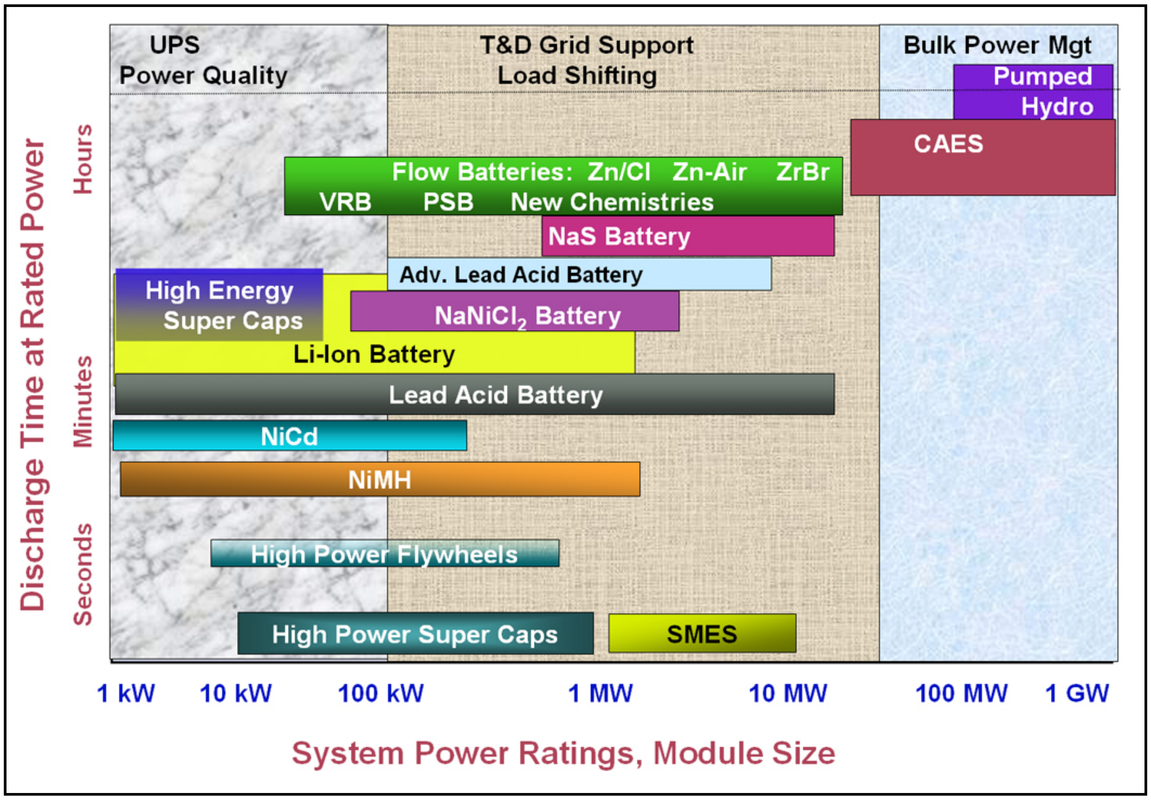


Figure 12-2
Positioning of Energy Storage Technologies

Table 12-2
Energy Storage Technologies Classified by Development Status

Letter Rating	Key Word	Example Technology Options
A	Mature	Pumped hydro, lead-acid battery
B	Commercial	CAES first generation, Lead-acid, NiCd, NaS batteries
C	Demonstration	CAES second generation, Zn-Br, vanadium redox, NiMH, advanced lead-acid, Li-ion
D	Pilot	Li-ion, Fe-Cr, $NaNiCl_2$
E	Laboratory	Zn-Air, Zn-Cl, advanced Li-ion, novel battery chemistries
F	Idea	Non-fuel (“adiabatic”) CAES, nano-supercapacitors, other novel battery chemistries

Table 12-3
Confidence Rating Based on Cost and Design Estimate

Letter Rating	Key Word	Description
A	Actual	Data on detailed process and mechanical designs or historical data from existing units
B	Detailed	Detailed process design (Class III design and cost estimate)
C	Preliminary	Preliminary process design (Class II design and cost estimate)
D	Simplified	Simplified process design (Class I design and cost estimate)
E	Goal	Technical design/cost goal for value developed from literature data

Lithium-Ion Battery Energy Storage

Technical/Process Description

The most common types of liquid Li-ion cells are cylindrical and prismatic (see Figure 12-3). They are found in notebook computers and other portable power applications. Another approach, prismatic polymer Li-ion technology, is generally only used for small portable applications such as cellular phones and MP3 players. Rechargeable Li-ion batteries are commonly found in consumer electronic products. Compared to the long history of lead-acid batteries, Li-ion technology is relatively new. There are many different Li-ion chemistries, each with specific power versus energy characteristics. Large-format prismatic cells are currently the subject of intense R&D, scale-up, and durability evaluation for near-term use in hybrid electric vehicles.

A Li-ion battery cell contains two reactive materials capable of undergoing an electron transfer chemical reaction. In order to undergo the reaction, the materials must contact each other electrically, either directly or through a wire, and must be capable of exchanging charged ions in order to maintain overall charge neutrality as electrons are transferred. A battery cell is designed to keep the materials from directly contacting each other, and to connect each material to an electrical terminal isolated from the other material's terminal. These terminals are the cell's external contacts.

Inside the cell, the materials are ionically but not electronically connected to each other by an electrolyte that can conduct ions but not electrons. This is done by building the cell with a porous insulating membrane, called the separator, between the two materials, and filling that membrane with an ionically conductive salt solution. Thus this electrolyte can serve as a path for ions, but not for electrons. When the external terminals of the battery are connected to each other through a load, electrons are given a pathway between the reactive materials, and the chemical reaction proceeds with a characteristic electrochemical potential difference or voltage. Thus there is a current and voltage (i.e. power) applied to the load.

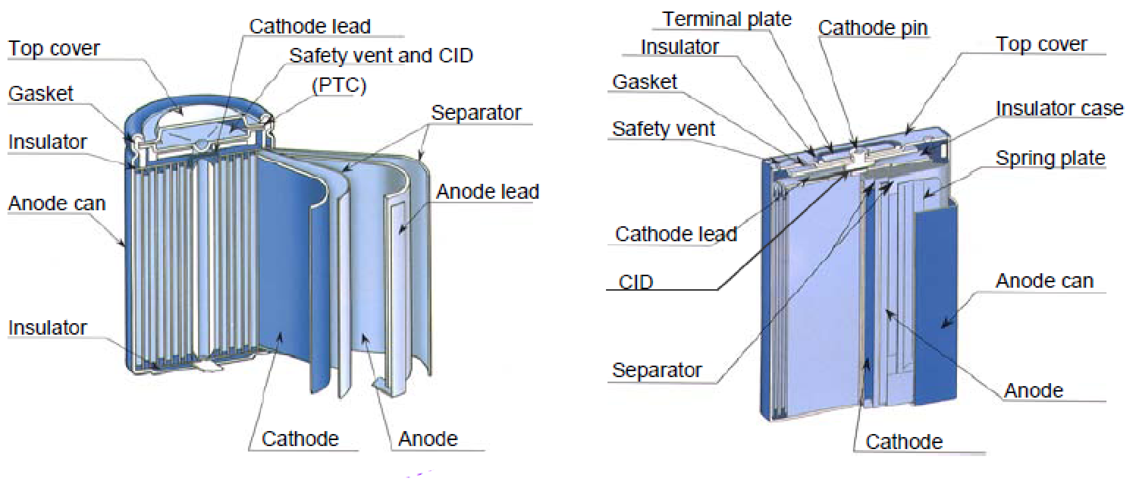


Figure 12-3
Schematics of Cylindrical and Prismatic Li-ion Cells

Currently developers are focusing investments on four main Li-ion cathode chemistries due to their applicability to portable power and vehicle applications. These cathode chemistries are: Lithium Nickel-Cobalt-Aluminum Oxide (NCA), Lithium Nickel-Cobalt-Manganese Oxide (NCM), Lithium Manganese Spinel, and Lithium Iron Phosphate. Research is also ongoing to develop lithium-based anode materials. Altair Nanotechnologies, for example, has developed a lithium titanate material, which they are using in cells designed for use in a stationary energy storage system.

Summary of Performance Characteristics

Since there are several different types of Li-ion chemistries, each with its own cost and performance capabilities, the values shown in Table 12-4 are averages of currently available systems.

Table 12-4
Performance characteristics of Li-ion in various storage applications

Li-ion (Various Chemistries)	Energy Capacity	Power	Duration (hrs)	Efficiency Percent (Total Cycles)
Distributed energy storage	50 kWh	25 kW	2	85-90 (5000)
	75 kWh	25 MW	3	
Frequency regulation	0.25-0.50 MWh	1-2 MW	0.25	85-90 >100,000)
Residential applications	18 kWh	6 kW	3	85-90 (5000)
	10 kWh	5 kW	2	
Industrial and commercial energy management	0.8 MWh	0.2 MW	4	85-90 (5000)
Storage for utility T&D grid support applications	4 MWh	1 MW	4	85-90 (5000)

Applications

The huge manufacturing scale of Li-ion batteries (estimated to be approximately 30 GWh by 2015) has resulted in lower cost battery packs – which could also be used and integrated into systems for grid-support applications, requiring less than 4 hours of energy storage duration.

The high energy density and relatively low weight of Li-ion systems make them an attractive choice for areas with space constraints. Given their attractive cycle life and compactness, in addition to high ac-to-ac efficiency that exceeds 85-90 percent, Li-ion batteries are also being considered for several utility grid-support applications such as distributed energy storage systems (DESS for community energy storage), transportable systems for grid-support, commercial end-user energy management, home back-up energy management systems, frequency regulation, and wind and photovoltaics (PV) smoothing. Many experts believe stationary markets for Li-ion batteries could exceed those for transportation. Both electric utilities and Li-ion vendors are interested in selecting one or two high value grid-support applications that offer a combination of large market size and high value to accelerate the volume production of plug-in hybrid electric vehicle (PHEV) batteries.

Potential benefits and application of Li-ion technology for power consumers include power quality and reliability, reduced time of use, and lower retail demand charges. Energy service company providers and home energy management applications are also significant markets for the technology. Uses in the distribution network include power voltage support, reduced distribution losses, lower transmission congestion, and deferred distribution investment.

Status of Technology/ Commercialization

Frequency regulation applications for energy storage continue to gain traction in the U.S. New analyses and operating methods can help determine how Li-ion storage can be optimally used, and what parameters are necessary for control by ISOs that are yet to agree on the best way of sharing signals for regulation. Other ancillary services may also become lucrative as the prices for storage technology drop. The rise of a services model for storage may allow significant opportunities for utilities to take advantage of the benefits of storage in applications such as T&D deferral, without the risk of ownership.

Table 12-5 shows a technology dashboard, which shows the status of technology development, for Lithium-ion systems.

Table 12-5
Technology dashboard: Lithium-Ion battery systems

Technology Development Status	Demonstration C	Concept Verified in Limited Field Demonstrations
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	D	-20% to +25%
Operating Field Units	~80 MW in frequency regulation application	Numerous small demonstrations in the 5-kW to 25-kW sizes are currently underway. MW-scale short-energy-duration systems are being operated in frequency regulation applications.

Process Contingency	10%	Battery management system, system integration, and cooling need to be addressed. Performance in cold climate zones needs to be verified.
Project Contingency	10%	Limited experience in grid-support applications, including systems with utility grid interface.

Sodium-Sulfur Battery Energy Storage

Technical/Process Description

NaS batteries are a commercial energy storage technology finding applications in electric utility distribution grid support, wind power integration, and high-value service applications. NaS battery technology has great potential for use in energy storage applications due to its long discharge period (approximately 6 MWh). Like many other storage technologies, it is capable of prompt, precise response to applications such as mitigation of power quality events and response to AGC signals for area regulation [3].

The normal operating temperature regime of NaS cells during discharge/charge cycles is in the range of 300°C to 350ºC. During discharge, the sodium (negative electrode) is oxidized at the sodium/beta alumina interface, forming Na^+ ions. These ions migrate through the beta alumina solid electrolyte and combine with sulfur that is being reduced at the positive electrode to form sodium pentasulfide (Na_2S_5). The sodium pentasulfide is immiscible with the remaining sulfur, thus forming a two-phase liquid mixture (see Figure 12-4) [4].

After all of the free sulfur phase is consumed, the Na_2S_5 is progressively converted into single phase sodium polysulfides with progressively higher sulfur content (Na_2S_{5-x}.). Cells undergo exothermic and ohmic heating during discharge. Although the actual electrical characteristics of NaS cells are design dependent, voltage behavior follows that predicted by thermodynamics [5].

The NaS batteries use hazardous materials including metallic sodium, which is combustible if exposed to water. Therefore, construction of NaS batteries includes airtight, double-walled stainless steel metal enclosures that contain the series-parallel arrays of NaS cells. Each cell is hermetically sealed and surrounded with sand to both anchor the cells and mitigate fire. Other safety features include fused electrical isolation and a battery management system that monitors cell block voltages and temperature. The sodium, sulfur, beta-alumina ceramic electrolyte, and sulfur polysulfide components of the battery are disposed of or recycled at the end of the NaS battery life by routine industrial processes. The manufacturer has conducted cell burning, module firing, drop, and crush safety testing to the satisfaction of regulatory authorities in Japan. The technology has a 15-year record of no accidents in Japan, and NaS battery installations are approved for use in urban areas in Japan.

NaS batteries can be installed at power generating facilities, substations, and at renewable energy power generation facilities where they are charged during off peak hours and discharged when needed.

NGK Insulators, Ltd., and Tokyo Electric Power Co. (TEPCO) jointly developed NaS battery technology over the past 25 years. “NAS” is a registered trademark for NGK’s NaS battery system, while "NaS" is a generic term used to refer to sodium-sulfur based on those elements' atomic symbols ("Na" and "S") [3].

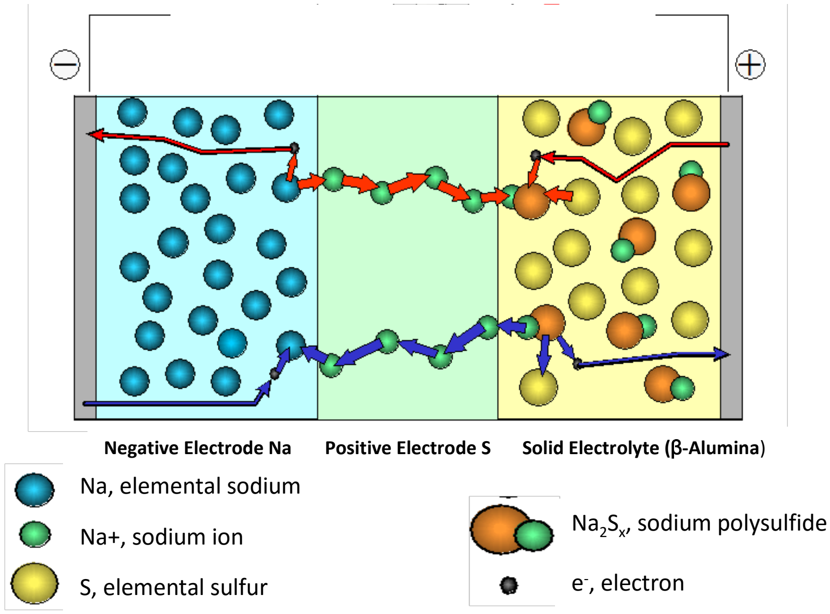


Figure 12-4
NaS Battery Technology Chemistry [4]

Summary of Performance Characteristics

Energy density by volume for NaS batteries is 170 kWh/m^3 and by weight is 117 kWh/ton. NGK projects the NAS to have a cycle life of 4500 cycles for rated discharge capacity of 6 MWh per installation MW. Rated at 4500 cycles, NAS batteries are projected have a calendar life of 15 years. This section summarizes the performance characteristics of NAS batteries provided by the manufacturer (see Table 12-6) [7].

Table 12-6
Performance Characteristics of NAS Batteries [5]

Energy Density (Volume)	170 kWh/m^3
Energy Density (Weight)	117 kWh/ton
Charge/Discharge Efficiency -Batteries (DC Base)	> 86%
Charge/Discharge Efficiency -System (AC Base)	≥ 74%
Maintenance	Low
Cycle Life	4,500 cycles at rated capacity
Calendar Life	15 yr

Applications

NaS batteries are among the most mature of so-call advanced batteries, and the NAS electrochemistry was chosen by TEPCO and NGK because it has distinct advantages over conventional lead-acid battery technologies for energy storage. NaS batteries exhibit a long service life requiring less maintenance. The battery construction has sufficient safeguards and offers a minimal environmental impact in normal operation. Because the technology can be used in peak-shaving, load-leveling, PQ mitigation and ancillary services, it is more versatile than conventional battery technologies. Additionally, NaS battery installations typically have a smaller footprint than competing batteries due to their high efficiency and energy density. Among its advantages are the financial strength of the vendor supplier and their extensive deployment of megawatt-scale installations in utility and end-use customer applications.

Disadvantages of NaS batteries in energy storage include its relatively high cost, the investment risk associated with unplanned cooldown during a loss of power event, and the fact that NGK's design has not been optimized for relocation (although many installations in Japan have been moved). As of today, there is only one supplier for the technology, NGK Insulators, Ltd., Japan.

Existing power infrastructures can utilize NaS batteries at substations to automatically subsidize increased demand or load shifting. A particularly effective load shifting application of NaS battery technology according to NGK Insulators, Ltd. is at Hitachi Automotive in Japan where NAS battery modules provide 8 MW of nominal power and 57.6 MWh of daily load shifting capacity. Sodium-sulfur (NaS) systems can also optimize existing power infrastructures by providing fast reserves, standby reserves, and frequency regulation control without the emissions created in standard generating plants.

Status of Technology/ Commercialization

NAS installations providing the functional equivalent of about 160 MW of pumped hydro storage are currently deployed within Tokyo. NAS batteries are only available in multiples of 1-MW/6-MWh units with installations typically in the range of 2 to 10 MW. The largest single installation is the 34-MW Rokkasho wind-stabilization project in Northern Japan that has been operational since August 1, 2008. There are over 300 MW (1800 MWh) of NAS installations deployed globally at 170 sites as of 2013.

Table 12-7 shows a technology dashboard, which shows the status of technology development for NaS battery energy systems.

Table 12-7
Technology Dashboard: NaS Battery Systems

Technology Development Status	Mature A	Significant Recent Commercial Experience
Confidence of Cost Estimate	A	Data based on installed systems.
Accuracy Range	B	-5% to +8%
Operating Field Units	170 sites	316 MW installed.
Process Contingency	0%	Proven battery performance
Project Contingency	1-5%	Depending on site conditions

Lead-Acid Battery Energy Storage

Technical/Process Description

For the purposes of this section, the lead-acid technologies detailed here for use as stationary energy storage technology for utility, power grid, and residential applications are divided into two types: lead-acid carbon technologies, and advanced lead-acid technologies. Lead-acid carbon technologies use a fundamentally different approach to lead-acid batteries through the inclusion of carbon, in one form or another, to improve the power characteristics of the battery and to mitigate the effects of partial states of charge. Advanced lead-acid batteries are conventional valve regulated lead-acid (VRLA) batteries with technologies that address the shortcomings of previous lead-acid products through incremental changes in the technology.

Lead-acid batteries are the oldest form of rechargeable battery technology. Originally invented in the mid 1800s, they are widely used to power engine starters in cars, boats, planes, etc. All lead-acid designs share the same basic chemistry. The positive electrode is composed of lead-dioxide, PbO_2, while the negative electrode is composed of metallic lead, Pb. The active material in both electrodes is highly porous to maximize surface area. The electrolyte is a sulfuric acid solution, usually around 37% sulfuric acid by weight when the battery is fully charged. The reaction product on both sides is lead sulfate, $PbSO^+$.

The half cell reactions are as follows:

$$\textbf{Positive:} \quad PbO_2 + 3H^+ + HSO_4^- + 2e^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} PbSO_4 + 2H_2O$$

$$\textbf{Negative:} \quad Pb + HSO_4^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} PbSO_4 + H^+ + 2e$$

The overall reaction is:

$$\textbf{Overall:} \quad PbO_2 + Pb + 2H_2SO_4 \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} 2PbSO_4 + 2H_2O$$

A notable aspect of this system is that sulfuric acid is consumed during the discharge reaction, so that the concentration of the electrolyte changes as the battery is discharged. This means that the state-of-charge of a lead-acid battery can be determined by measuring the concentration of the electrolyte, usually through a specific gravity measurement. The range of specific gravity measurement from charge to discharge is dependent on the design of the battery and the locale for which it is designed. In batteries designed for temperate climes, the electrolyte specific gravity is usually between 1.2 and 1.3 in a fully charged state and between 1.0 and 1.2 in a fully discharged state. The end of discharge occurs when the active material on either of the two electrodes is depleted, or when the concentration of sulfuric acid in the electrolyte is too small to maintain a reaction [5].

Lead-Acid Carbon

Lead-acid carbon technology exhibits a high-rate characteristic in both charge and discharge with no apparent detrimental effects as are typically experienced in traditional vented lead-acid (VLA) and VRLA batteries. This allows the lead-acid carbon batteries to deliver and accept high current rates only available with Ni-MH and Li-ion batteries [9].

Some of the developers working on the lead-acid technology are Ecoult/EastPenn and Axion Power International. Each developer has a different implementation of carbon integrated with the traditional lead-acid battery negative plate. In general, each variation is targeting a specific niche market.

According to its web site, Axion's "proprietary PbC® technology is a multi-celled asymmetrically supercapacitive lead-acid-carbon hybrid battery." The negative electrodes are five-layer assemblies that consist of a carbon electrode, a corrosion barrier, a current collector, a second corrosion barrier, and a second carbon electrode. These electrode assemblies are then combined with conventional separators and positive electrodes. The resulting battery is filled with an acid electrolyte, sealed and connected in series to other cells. Laboratory prototypes have undergone deep-discharge testing and withstood more than 1600 cycles before failure. In comparison, most lead-acid batteries designed for deep discharge applications can only survive 300-500 cycles under these operating conditions. Application-specific prototypes may offer several performance advantages over conventional lead-acid batteries, including:

- Significantly faster recharge rates
- Significantly longer cycle lives in deep discharge applications
- Minimal required maintenance [20]

Advanced Lead-Acid Technologies

While developers of lead-acid carbon technologies are improving the capability of conventional lead-acid technologies through incorporation of carbon in one or both electrodes, manufacturers such as GS Yuasa and Hitachi are taking other approaches. Advanced lead-acid products from these manufacturers focus on technology enhancements such as carbon-doped cathodes, granular silica electrolyte retention systems (GS Yuasa), high density positive active material, and silica-based electrolytes (Hitachi).

Some advanced lead batteries have "supercapacitor like" features that give them fast response similar to flywheels or Li-ion batteries. Advanced lead-acid systems from a number of companies have begun early field trial demonstrations in 2011-2012.

Summary of Performance Characteristics

Traditional VLA and VRLA batteries are typically designed for optimal performance in either a power application or an energy application, but not both. That is, a battery specifically designed for power applications can indeed deliver reasonable amounts of energy (e.g., for operating car lights), but it is not designed to deliver substantial amounts of energy (e.g., 80% deep discharges) on a regular basis. In comparison, a lead-acid carbon or advanced lead-acid battery specifically designed for energy applications can deliver high impulses of power if needed, although it is not specifically designed to do so.

In research and analysis performed in 2009-2010, EPRI compiled summaries of performance characteristics of both lead-acid carbon and advanced lead-acid batteries in a variety of energy storage applications (see Table 12-8 and Table 12-9). There are several lead-acid carbon and advanced lead-acid technologies; the values are an average of currently available systems. Each system will have its own performance characteristics.

Table 12-8
Performance Characteristics of Lead-Acid Carbon Batteries in Various Storage Applications

Lead-Acid Carbon	Energy Capacity	Power (kW)	Duration (hrs)	Efficiency Percent (Total Cycles)
Distributed energy storage	75 kWh	25	3	75-80
Frequency regulation	4 MWh	1	4	85 (4000)
Residential applications	10 kWh	5	3	75 (3000)
Energy storage for industrial and commercial	4 MWh	1	4	85 (4000)
Storage for utility T&D grid support applications	4 MWh	1	4	85 (4000)

Disposal of lead-acid batteries is an important part of the life cycle. The environmental and safety hazards associated with lead require a number of regulations concerning the handling and disposal of lead-acid batteries. Lead-acid batteries are among the most recycled products in the world. Old batteries are accepted by lead-acid manufacturers for recycling. Batteries are separated into their component parts. The lead plates and grids are smelted to purify the lead for use in new batteries. Acid electrolyte is neutralized, scrubbed to remove dissolved lead, and released into the environment. Other component parts such as plastic and metal casings are also recycled.

Table 12-9
Performance Characteristics of Advanced Lead-Acid Batteries in Various Storage Applications

<table>
<tr><th>Advanced Lead-Acid</th><th>Energy Capacity</th><th>Power (kW)</th><th>Duration (hrs)</th><th>Efficiency Percent (Total Cycles)</th></tr>
<tr><td>Distributed energy storage</td><td>800 kWh</td><td>200</td><td>4</td><td>75-80 (4500)</td></tr>
<tr><td>Frequency regulation</td><td>4 MWh</td><td>1</td><td>4</td><td>75-80 (5000)</td></tr>
<tr><td rowspan="2">Residential applications</td><td>40 kWh</td><td>10</td><td>4</td><td rowspan="2">75-78 (5000)</td></tr>
<tr><td>8 kWh</td><td>4</td><td>2</td></tr>
<tr><td>Energy storage for industrial and commercial</td><td>0.8 MWh</td><td>0.2</td><td>8</td><td>75-80 (5000)</td></tr>
<tr><td>Storage for utility T&D grid support applications</td><td>4 MWh</td><td>1</td><td>4</td><td>75-80 (4000)</td></tr>
</table>

Applications

Most lead-acid technologies are best suited for relatively limited cycle applications requiring shallow depth of discharge such as backup power and limited peak shaving. Longer duration (i.e., many cycle) applications, while possible, do not play to the strength of this technology. This is particularly the case for installations requiring many megawatts for significantly longer than four hours, where technologies such as flow batteries or compressed air energy storage (CAES) and pumped hydroelectric storage are more cost-effective on a life cycle basis. In areas where space, footprint, and land for storage is limited, lead-acid batteries may not be as attractive as other more energy-dense battery technologies such as Lithium-ion, NaS, or flow batteries.

Lead-acid carbon and advanced lead-acid batteries have demonstrated promise in a number of energy storage applications, including the following:

- Wind and solar power smoothing
- Peak-shaving
- DESSs
- Power regulation

Status of Technology/ Commercialization

Lead-acid is the most commercially mature rechargeable battery technology in the world. VRLA batteries are used in a variety of applications, including automotive, marine, telecommunications, and UPS systems. However, there have been few utility T&D applications for such batteries due to their relatively heavy weight, large bulk, cycle-life limitations, and perceived reliability issues (stemming from maintenance requirements).

Tables 12-10 and 12-11 show technology dashboards, which show the status of technology development for lead-acid batteries.

Table 12-10
Technology Dashboard: VRLA Battery Systems

Technology Development Status	Mature A	Significant Industrial and Commercial Experience
Confidence of Cost Estimate	B	Vendor quotes and system integration costs.
Accuracy Range	C	-10% to +15%
Operating Field Units	5 or more in utility energy management	Thousands of units in UPS, back-up and certain energy management applications. Limited utility grid-scale applications.
Process Contingency	5-8%	Depends on Application; limited and depth of discharge
Project Contingency	5%	Cycle life, kWh per cycle, and depth of discharge for specific application needs careful evaluation

Table 12-11
Technology Dashboard: Advanced Lead-Acid Battery Systems

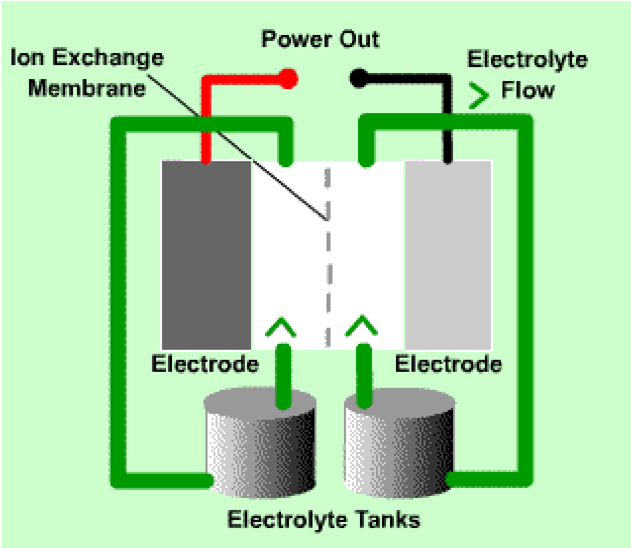
Technology Development Status	Demonstration C	Limited Field Demonstrations
Confidence of Cost Estimate	D	Vendor quotes and system installation estimates.
Accuracy Range	C	-10% to +15%
Operating Field Units	2 or more	Several wind and PV applications expected by 2011-2012
Process Contingency	10-15 %	Limited testing and filed experience
Project Contingency	10 %	Cycle life and depth of discharge for application needs careful evaluation; limited O&M cost data

Flow Batteries

A flow battery is a form of rechargeable battery in which electrolyte containing one or more dissolved electro-active species flows through an electrochemical cell that converts chemical energy directly to electricity (Figure 12-5). Additional electrolyte is stored externally, generally in tanks, and is usually pumped through the cell (or cells) of the reactor, although gravity feed systems are also known. Flow batteries can be rapidly "recharged" by replacing the electrolyte liquid (in a similar way to refilling fuel tanks for internal combustion engines) while simultaneously recovering the spent material for re-energizing. A flow battery is a special type of rechargeable battery in which the dissolution of active species in the electrolyte permits external storage of reactants thereby allowing independent scale up of power and energy density specifications. Also, external storage of reactants avoids self-discharge.

Flow batteries are emerging energy storage devices that can serve many purposes in energy delivery systems. They can respond within milliseconds and deliver power for hours. They operate much like a conventional battery, storing and releasing energy through a reversible electrochemical reaction with a large number of charging and discharging cycles. They differ from a conventional battery in two ways 1) the reaction occurs between two electrolytes, rather than between an electrolyte and an electrode and 2) they store the two electrolytes external to the battery and the electrolytes are circulated through the cell stack as required. The great advantage that this system provides is very large electrical storage capacity (MWh), the limitation being only the capacity of the electrolyte storage reservoirs.

Flow batteries essentially comprise two key elements: cell stacks, where power is converted from electrical form to chemical form, and tanks of electrolytes where energy is stored. These two elements are supplemented with circulation and control systems. An individual cell consists of a negative electrode and a positive electrode separated by an ion exchange membrane. The battery uses electrodes that cannot and do not take part in the reactions but merely serve as substrates for the reactions. There is therefore no loss of performance, as in most rechargeable batteries, from repeated cycling causing electrode material deterioration. Banks of these cells can then be linked together to create a bipolar module ‘cell stack’ where the electrodes are shared between the adjacent cells, with the cathode of the first cell becoming the anode of the next cell, etc. Linked in series, sufficient cells in a string can then form the desired voltage for the cell stack.



Source: Electricity Storage Association

Figure 12-5
Flow battery principle

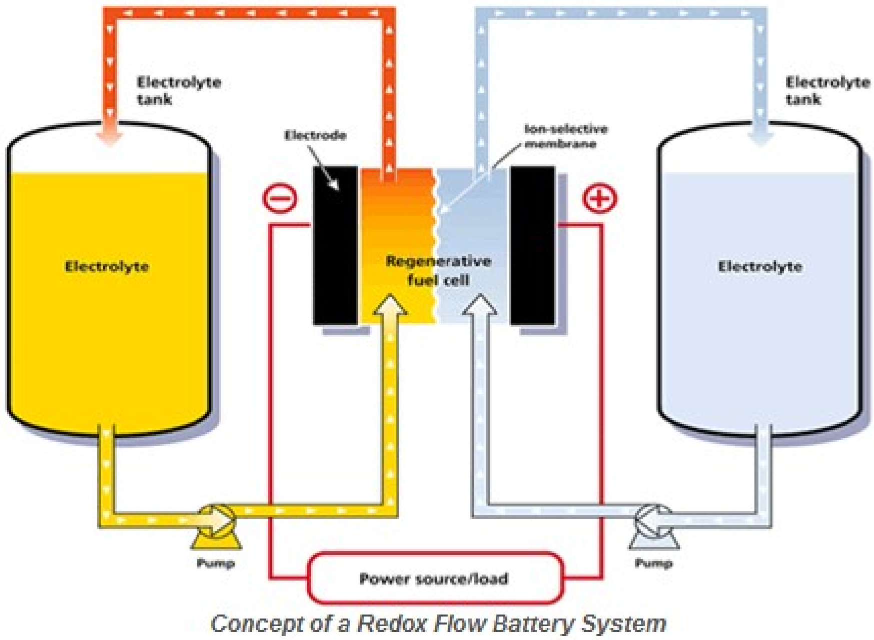
During operation, the two electrolytes flow from the separate storage tanks to the cell stack for the reaction, with ions transferred between the two electrolytes across the ion exchange membrane; after the reaction, the spent electrolytes are returned to the storage tanks. During recharging, this process is reversed.

The flow battery technologies provide very high power and very high capacity batteries for load leveling applications on the national electricity grid system.

Many different varieties of flow batteries are in existence undergoing further development. They are categorized by the chemistry of the electrolytes. Four chemistries have evolved; Vanadium Redox, Zinc Bromine, Polysulfide Bromide, and Cerium/Zinc. The first three of these are the major ones. The major flow batteries are described in the following paragraphs.

Vanadium Redox Flow Battery - The Vanadium Redox Battery Energy Storage System (VRB-ESS) is an electrical energy storage system based on the patented vanadium-based redox regenerative fuel cell that converts chemical energy into electrical energy. Energy is stored chemically in different ionic forms of vanadium in a dilute sulfuric acid electrolyte. The electrolyte is pumped from separate storage tanks into flow cells across a proton exchange membrane (PEM) where one form of electrolyte is electrochemically oxidized and the other is electrochemically reduced. This creates a current that is collected by electrodes and made available to an external circuit. The reaction is reversible allowing the battery to be charged, discharged and recharged.

The principle of the VRB is shown in Figure 12-6. It consists of two electrolyte tanks, containing active vanadium species in different oxidation states: positive redox couple on the right and negative redox couple on the left. These energy-bearing liquids are circulated through the cell stack. The stack consists of many cells, each of which contains two half-cells separated by a membrane. In the half-cells the electrochemical reactions take place on inert carbon felt polymer composite electrodes from which current may be used to charge or discharge the battery.



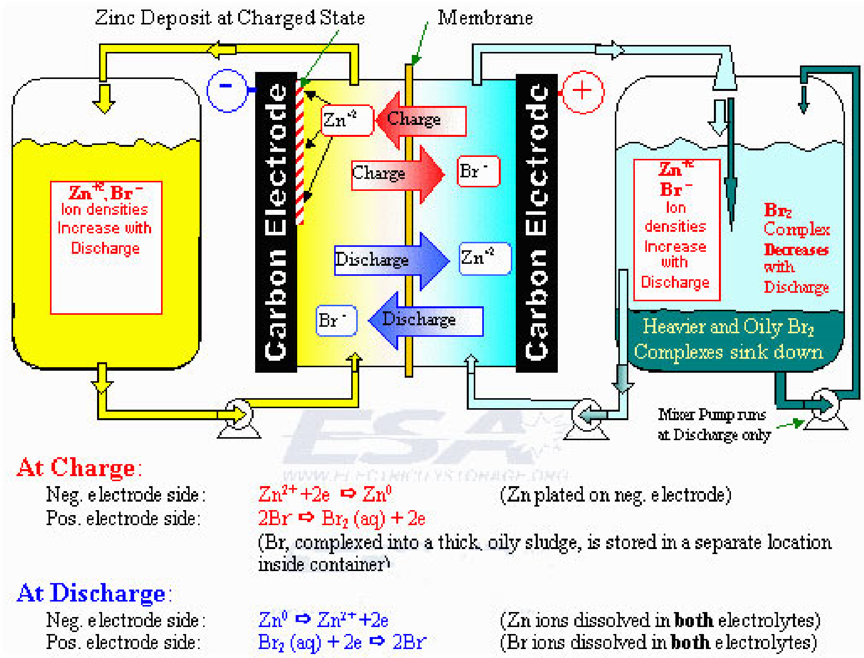
Source: Sandia National Laboratory

Figure 12-6
Redox flow battery operating principle

The VRB-ESS employs vanadium ions in both half-cell electrolytes. Therefore, cross-contamination of ions through the membrane separator has no permanent effect on the battery capacity, as is the case in redox flow batteries employing different metal species in the positive and negative half-cells. The vanadium half-cell solutions can even be remixed bringing the system back to its original state.

Zinc-Bromine Flow Battery is a modern example of a flow battery. It is based on the reaction between two commonly available chemicals, zinc and bromine. The battery consists of a zinc negative electrode and a bromine positive electrode separated by a micro-porous separator (Figure 12-7). An aqueous solution of zinc bromide is circulated through the two compartments of the cell from two separate reservoirs. The other electrolyte stream in contact with the positive electrode contains bromine. The bromine storage medium is immiscible with the aqueous solution containing zinc bromide.

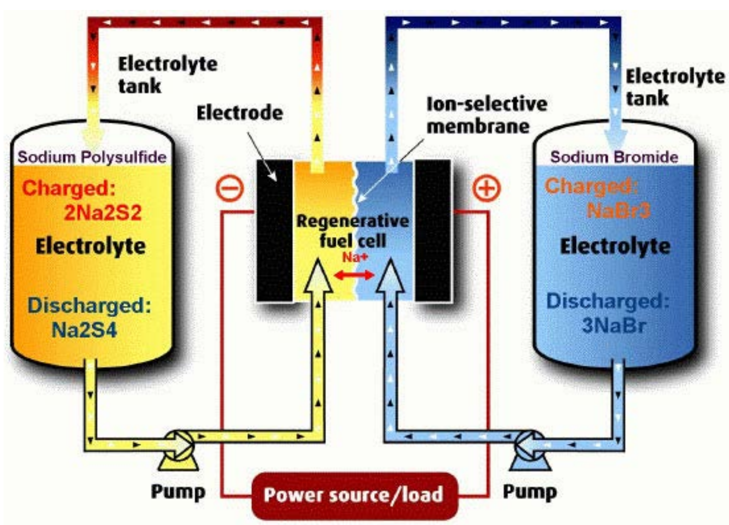
The battery uses electrodes that do not take part in the reactions but merely serve as substrates for the reactions. There is therefore no loss of performance, as in most rechargeable batteries, from repeated cycling causing electrode material deterioration. When the zinc-bromine battery is completely discharged, all the metallic zinc plated on the negative electrodes is dissolved in the electrolyte. The zinc is deposited again when the battery is charged. In the fully discharged state the zinc-bromine battery can be left indefinitely.



Source: Sandia National Laboratory

Figure 12-7
Zinc-Bromine battery operating principle

Sodium Polysulfide Bromine (PSB) is another example of a flow battery. The operating principle of polysulfide bromine batteries is shown in Figure 12-8. The principle is essentially similar to Zn-Br batteries except that the electrolytes are sodium polysulfide and sodium bromide.



Source: Electricity Storage Association

Figure 12-8
Sodium polysulfide bromine battery operating principle

Compressed Air Energy Storage (CAES)

Technical/Process Description

CAES is the only commercial, bulk energy storage plant available today, other than pumped hydro. CAES plants use off-peak electricity to compress air into an underground reservoir, surface vessel, or a piping air storage system. When electricity is needed, the air is withdrawn, heated via combustion with fuel, and passed through an expansion turbine to drive an electric generator (Figure 12-9). These "first generation" CAES plants burn about one-third the premium fuel of a conventional combustion turbine and produce about one-third the pollutants per kWh generated.

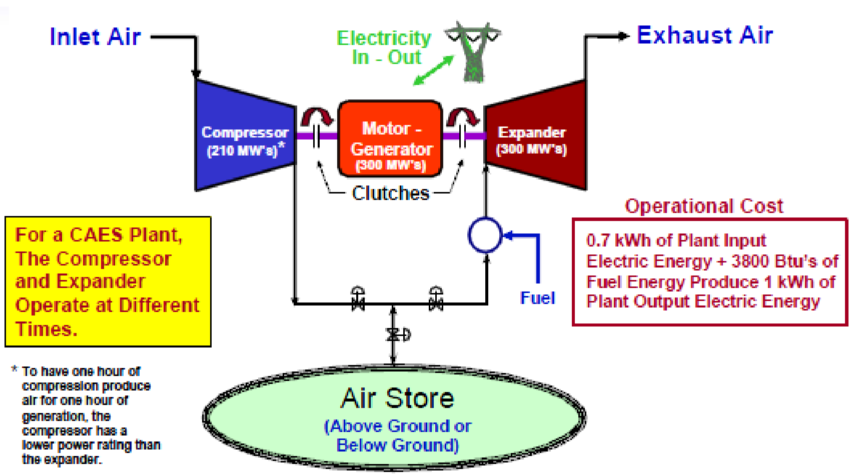


Figure 12-9
Compressed air energy storage system

The compressed air can be stored in several types of underground media, including porous rock formations, depleted gas/oil fields, and salt or rock cavern formations. The compressed air can also be stored in above ground or near surface pressurized air vessels/pipelines, including those used to transport high pressure natural gas.

Underground CAES storage systems are most cost-effective with storage capacities up to 400 MW and discharge times of 8 to 26 hours. Siting such plants involves finding and verifying the air storage integrity of a geologic formation appropriate for CAES in a given utility's service territory.

CAES plants employing above-ground air storage will typically be smaller than plants with underground storage because of the limited capacity of the storage reservoir, with capacities on the order of 3 to 15 MW and discharge times of 2 to 4 hours. Above-ground CAES plants are easier to site but more expensive to build (on a $/kW basis) than CAES plants utilizing underground air storage systems, primarily due to the incremental additional cost associated with above-ground storage.

Summary of Performance Characteristics

Table 12-12 summarizes the minimum functional requirements for a below-ground, second generation CAES plant used to establish a cost basis.

Table 12-12
CAES minimum functional requirements

Module Size Range (Net Power)	100-150 MW
Ratio of Load versus Generation Capacity (MW/MW)	1.0
Minimum Discharge Time @ Maximum Generation	8 hours
Minimum Compression System Discharge Pressure	1200 psi
Maximum Cavern Pressure Required for Full Generation	900 psi
Maximum Heat Rate & Energy Ratio at Full Generation	4200 Btu/kWh (LHV) and 0.80
Maximum NOx Emissions at Full Generation Capacity	2 ppm
Cold (or Warm Standby) Start Time to Full generation Capacity	< 10 minutes
Synchronized at Minimum Load to Full Generation Capacity	< 5 minutes
Minimum System Ramp Rate – Generation	±20 percent/min **
Minimum System Ramp Rate – Compression	±20 percent/min **
Operating Availability	98 percent
Maximum Land Usage (footprint)	2 acre per 100 MW's (below ground air)
Blackstart Capability	Yes
Remote Operation Capability	Yes
Generator Step-UP (GSU) Transformer Output	60 hz and 13,800 volts
Minimum Cycle Life*	50,000 charge/discharge cycles
Minimum Calendar Life	30 years
Sound Emissions @ 300ft from machinery	85 dbA
Cooling Medium for Compression Cycle	Water @ 60°F
Fuel Type for Generation	Methane or Natural Gas @ 300 psi
Plant Site Conditions	60°F and 14.7 psi
Maximum Storage (Air) Losses in 24 hour period	1 percent

* With proper maintenance, and periodic critical component refurbishment or replacement, according to mfr inspection criteria.

** When synchronized at all load conditions.

CAES plants can be built in modular fashion by adding capacity in 100 MW increments – such as 100 MW, 200 MW, or 400 MW sizes with ten hours of storage. The required turbomachinery is available off-the-shelf from a number of vendors. The standard configuration with ten hours of storage can be easily enhanced to facilitate twenty or thirty hours of storage if the operating economics allow. Additional storage can be charged during weekends or holidays when electricity prices are off-peak. Lack of cavern space is usually not considered a barrier to expanding the storage hours, since the volume required to store compressed air for a CAES plant is usually only a small part of the typical geological cavern structure used. Storage volumes on the order of tens of millions of cubic feet are required for CAES plants. In contrast, natural gas storage that uses similar geological structures usually contains on the order of billions of cubic feet of capacity.

Applications

A CAES plant can help to compensate for the variability of wind generation. Wind generation varies during the day and is often highest at nighttime when the energy is not needed. The CAES plant can charge the storage reservoir during off-peak periods when excess, low-cost energy is available and discharge the reservoir to produce electricity during on-peak hours. In this way, peak demand energy is delivered from CAES storage during on-peak hours using stored, nighttime wind energy, which enables better asset utilization of wind/renewable energy. Advanced CAES plants can work in concert with local wind farms and operate as both a peaking and an intermediate duty plant. The CAES plant can be thought of as a "shock absorber," providing damping to accommodate the impact of hour-by-hour fluctuations from variable wind and solar resources. In this way, the plant enables higher penetration of intermittent renewable and non-emitting baseload generation to substantially reduce carbon emissions and better manage the impact of power fluctuations from variable wind resources.

- CAES plants can provide some or all of the following capacity and ancillary services:
- Load shifting and peak shaving
- Rapid ramping power (up ramp and down ramp) when demand increases at a higher rate than most other generating sources can accommodate
- Frequency regulation ancillary service because of extremely fast response time capabilities and the ability to efficiently run at part load
- Addition or subtraction of VAR (Volts-Amp-Reactive), acting as a synchronized condenser system
- Low-cost synchronous and non-synchronous spinning reserve
- Capacity credits that can be valued at either the market price for firm capacity in an ISO/RTO environment, or the cost of alternate capacity in a system planning situation
- Black start credit, reaching full output from an off-line state in minutes
- Renewable energy credits if applicable
- CO_2 credits – If a system of providing dollar credits to utilities for CO_2 reduction is established, this plant could provide significant revenue because of CO_2 reductions from high efficiency operation.

Status of Technology/ Commercialization

There are two operating first-generation CAES systems: one in Germany and one in Alabama. First generation CAES plant design uses a complex set of turbomachinary and customized high pressure combustor. The 110-MW CAES plant at PowerSouth Energy Cooperative (formerly Alabama Electric Cooperative) has operated reliably for 18 years, and has successfully demonstrated the technical viability of this early design. This plant requires additional auxiliary equipment to meet NOx emission standards. A 290-MW Huntorft plant in Germany, in operation since December 1978, has demonstrated strong performance with 90 percent availability and 99 percent starting reliability. This plant uses two man-made, solution-mined salt caverns to store the air.

In the past several years, improved second-generation CAES systems have been defined and are being designed that have potential for lower installed costs, higher efficiency, and faster construction time than first-generation systems. In one second generation approach called a “chiller option” (see Figure 12-10), no fuel is used to heat the air before it is passed through the expansion turbine, since the air is heated with exhaust of a combustion turbine (CT), which is part of the CAES plant. New compressor designs and advanced turbomachinery are also leading to improved non-CT based CAES systems.

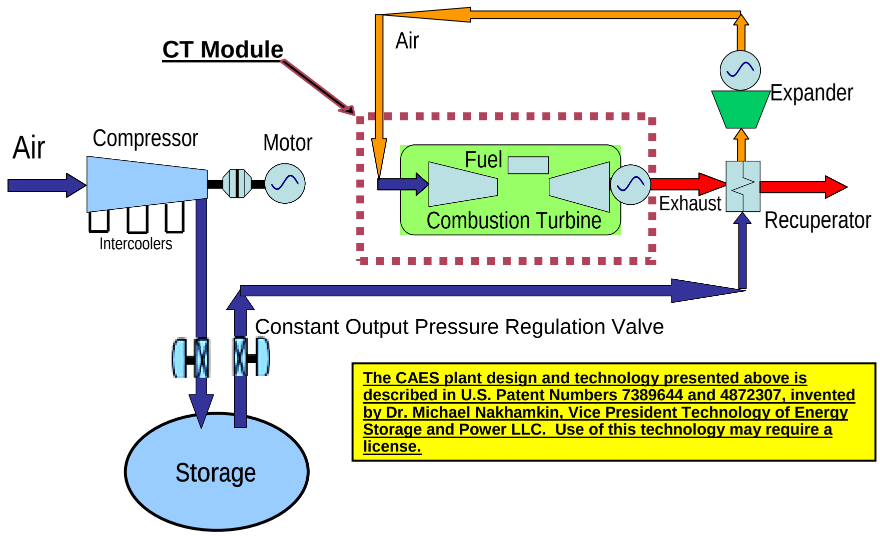


Figure 12-10
CAES second generation “chiller” arrangement

The above “fuel-based” CAES designs have a low heat rate compared to combustion turbines, combined cycles, and coal fired plants. However, fuel-based CAES is subject to future natural gas price volatility and potential carbon dioxide emission charges. Alternative CAES cycles seek to reduce or eliminate fuel usage. For example, Low-Fuel CAES (LFCAES) is a near-term technology that seeks to capture and store heat produced during the compression process, to provide initial heating for the compressed air during power production mode, thereby reducing fuel usage of the CAES cycle. No-Fuel CAES (NFCAES), also known as adiabatic CAES, will provide carbon-free operation through different methods, such as capturing and storing higher grade compression heat from high-temperature compressors (see Figure 12-11). However, NFCAES requires technology development and greater capital investment than LFCAES. Both of these CAES cycles will look increasingly attractive as wind penetration levels increase, fuel prices rise, and/or CO_2 emission charges are implemented.

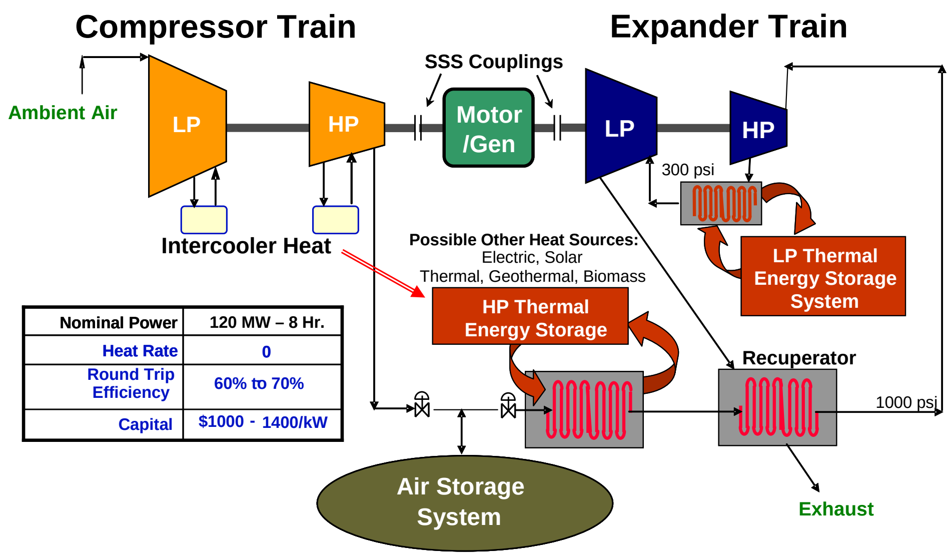


Figure 12-11
Adiabatic or "no fuel" CAES uses various heat recovery and thermal storage arrangements to eliminate combustion of fuel

Table 12-13 shows a technology dashboard, which shows the status of technology development, for second generation CAES.

Table 12-13
Technology dashboard: CAES (second generation)

Technology Development Status	Pre-Commercial	System to be Verified by Demonstration Unit
Confidence of Cost Estimate	C	Preliminary
Accuracy Range	C	-20% to +25%
Operating Field Units	None	Two of first generation type
Process Contingency	15%	Key components and controls need to be verified for second-generation systems
Project Contingency	10%	Plant costs will vary depending underground site geology

Risk Management

There are several risks associated with a CAES project. However, for each risk, strategies and/or tactics can be applied to minimize the risk. Geologic risks associated with CAES projects are extremely low because compressed air can be stored in a pre-existing underground reservoir; many of these have been successfully used in the past to store propane and natural gas at similar pressures. Technical risk normally associated with equipment is minimal, as all system components and equipment will be operating at temperatures and in conditions that have been tried and tested before in both the Alabama and German CAES plants. Several environmental permits are required, including water, NO_X, and building permits, and some risk is associated with securing the necessary environmental permits on time to ensure the plant will be commissioned on schedule. To minimize the risk of exceeding project timeframes, a dedicated project team that specializes in securing permits can be assigned. Scheduling risk is small because the McIntosh Alabama CAES plant was designed and constructed in three years. CAES systems must be able to earn revenues in the ancillary services markets. Hence, they must be able to respond to ISO 4-second signals in order to capture attractive frequency regulation market values. Plant designs and associated control systems will need to accommodate this capability.

Energy Storage Cost Estimates

Table 12-14
Battery Storage Cost and Performance Summary

Technology	Lithium-Ion	
System Size, MW	3	3
Storage Capacity, hrs	1	3
Energy Storage, MWh	3	9
Plant Cost Estimates (January 2017)		
Total Overnight Cost, ZAR/kW	11,165	27,432
Lead-times and Project Schedule, years	1	1
Single Unit Expense Schedule, % of TPC per year	100%	100%
Operation and Maintenance Cost Estimates		
Fixed O&M, ZAR/kW-yr	697	697
Variable O&M, ZAR/MWh	3.6	3.6
Availability Estimates		
Equivalent Availability	94.2	94.2
Maintenance	1.9	1.9
Unplanned Outages	4.0	4.0
Energy Requirements, (I/O Ratio)	1.11	1.11
Round Trip AC/AC Efficiency, %	89%	89%
Duty Cycle		
Cycles/Year	300	300
Hours/Cycle	1	3
Minimum Load	0%	0%
Economic Life, years	20	20

Table 12-15
CAES Cost and Performance Summary

Technology	CAES (Below Ground)
System Size, MW	180
Storage Capacity, hrs	8
Energy Storage, MWh	1,440
Plant Cost Estimates (January 2017)	
Total Overnight Cost, ZAR/kW	27,646
Lead-times and Project Schedule, years	4
Single Unit Expense Schedule, % of TPC per year	25%, 25%, 25%, 25%,
Fuel Cost Estimates	
First Year, ZAR/GJ	63.9
Expected Escalation (beyond inflation)	0%
Fuel Energy Content, MJ/SCM	39.3
Operation and Maintenance Cost Estimates	
Fixed O&M, ZAR/kW-yr	240
Variable O&M, ZAR/MWh	2.7
Availability Estimates	
Equivalent Availability	97.2
Maintenance	2.3
Unplanned Outages	0.5
Performance Estimates	
Economic Life, years	40
Heat Rate, kJ/kWh	4,465
Energy Charge Ratio, (kWh in/ kWh out)	0.68-0.75
Duty Cycle	
Cycles/Year	No Limit
Hours/Cycle	8
Minimum Load	0%

Table 12-15 (continued)
CAES Cost and Performance Summary

Technology	CAES (Below Ground)
Air Emissions, kg/MWh	
CO_2	574
SO_x (as SO_2)	0.00
NO_x (as NO_2)	0.30
CO	0.24
Particulates	0.05
Water Usage	
Per Unit of Energy, L/MWh	0

Plant Cost Estimates

The total overnight cost for the Li-ion battery systems ranging from 11,165 ZAR/kW to 27,432 ZAR/kW depending on the storage capacity. As “mega” battery supply factories are being built in the U.S., the Li-ion battery costs are expected to drop by 30% or more over the next five years. The total overnight cost for the CAES system is 27,646 ZAR/kW. For CAES, the cost of power plant equipment above ground is fairly straightforward, however, the cost of the underground storage can be highly uncertain as the process of cavern development is complex. Cavern development costs are estimated to range from 10% to 7% of the plant cost.

The expected expense and construction period is one year for the Li-ion battery system and four years for the CAES facility. Early in the project, costs will include preliminary design, project siting, and permitting. Later in the project, equipment will be procured, delivered, and installed. The final stage of the project will be the commissioning of the plant.

Fuel Cost Estimates

The cost of the LNG for the CAES plant is estimated to be 63.9 ZAR/GJ with a fuel energy content of 39.3 MJ/SCM. The price of natural gas is not expected to increase beyond general inflation.

O&M Cost Estimates

The fixed O&M cost is about 697 ZAR/kW-yr for the Li-ion battery system, and 240 ZAR/kW-yr for CAES. Reserved funds for battery and inverter replacement, controls upgrade, and battery disposal are included in the fixed O&M cost for the battery system. Staffing of the CAES plant is assumed to be the similar to that of the OCGT plant.

The variable O&M is 3.6 ZAR/MWh for the Li-ion battery system, and 2.7 ZAR/MWh for CAES. In general, the variable O&M costs for an energy storage facility are low because these plants are designed for remote and unattended operation.

Availability and Performance Estimates

The equivalent availability of the Li-ion battery system evaluated in this study is expected to be about 94% and is expected to have an economic life of 20 years. The CAES plant is expected to have the equivalent availability of 97% and the annual heat rate of 4,465 kJ/kWh.

Cost of Electricity

Table 12-6 shows a representative levelized cost of electricity for the Li-ion and CAES systems. The levelized costs include the cost of device charging using power from wind. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 12-16
Energy Storage Levelized Cost of Electricity

Technology	Li-ion	Li-ion	CAES
System Size, MW	3	3	180
Storage Capacity, hrs	1	3	8
Fuel Cost (ZAR/MWh)	0.0	0.0	285.5
Charging Cost (ZAR/MWh)	1,382.8	1,382.8	919.3
O&M (ZAR/MWh)	2,327.2	778.1	88.1
Capital (ZAR/MWh)	4,944.7	3,980.4	1,445.5
LCOE (ZAR/MWh)	**8,654.7**	**6,141.3**	**2,738.5**

Water Usage

The water use in both the Li-ion battery and CAES facilities are zero.

Emissions

The air emissions of the CAES plant evaluated in this study are shown in the summary table above. In this study, the CAES power plant is assumed to utilize similar equipment as that of the OCGT plant.

References

1. EPRI draft report. *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits.* Palo Alto, CA: September 2010.
2. EPRI Seminar. *Electric Energy Storage Options for the Electric Enterprise*. Palo Alto, CA: October 6, 2009.
3. *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications.* EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC: 2003. Report number 1001834.
4. EPRI report. *1 MW/7.2 MWh NaS Battery Demonstration and Case Study Update.* Palo Alto, CA: December 2009.
5. EPRI Presentation. *Energy Storage Overview*. EPRI, Palo Alto, CA: September, 2008.
6. EPRI report. *Best Practice Guidelines for Deploying NAS Energy Storage Systems.* EPRI, Palo Alto, CA: December 2008.
7. NGK Insulators, Ltd. NAS Web site 2010: http://www.ngk.co.jp/english/products/power/nas/application/index.html
8. Wind-to-Battery Project. Xcel Energy, Xcel Energy Web site 2010: http://www.xcelenergy.com/SiteCollectionDocuments/docs/wind-to-battery.pdf
9. EPRI Report. *Energy Storage and Distributed Generation Technology Assessment: Assessment of Lead-Acid-Carbon, Advanced Lead-Acid, and Zinc-Air Batteries for Stationary Application.* Palo Alto, CA: 2009.

A
ACRONYM LIST

AEO – Annual Energy Outlook

AGC – automatic generation control

AGR – advanced gas-cooled reactor

ASU – air separation unit

BOP – balance of plant

BWR – boiling water reactor

CHP – combined heat and power

CPV – concentrating photovoltaic

CR – central receiver

CSP – concentrating solar power

CCGT – combined cycle gas turbine

CCS – carbon capture and sequestration

CT – combustion turbine

DNI – direct normal insolation

dPEF – densified processed engineered fuel

DSG – direct steam generation

EDG – emergency diesel generator

EIA – U.S. Energy Information Administration

EHE – external heat exchanger

EPR – evolutionary pressurized reactor

ERCOT – Electric Reliability Council of Texas

ESP – electrostatic precipitators

FBC – fluidized bed combustion

FF – fabric filters

FGD – flue gas desulfurization

GT – gas turbine

GW – gigawatt

HCE – heat collection element

HRSG – heat recovery steam generator

HTF – heat transfer fluid

IGCC – integrated gasification combined cycle

ISO – Independent System Operator

LCOE – levelized cost of electricity

LFG – landfill gas

LNG – liquefied natural gas

LSFO – limestone forced oxidation

LWR – light water reactor

MEA – monoethanolamine

MOX – mixed oxide

MSW – municipal solid waste

MW – megawatt

NERSA – National Energy Regulator of South Africa

NREL – National Renewable Energy Laboratory

OCGT – open cycle gas turbine

O&M – operation and maintenance

PC – pulverized coal

PEF – processed engineered fuel

PHEV – plug-in hybrid electric vehicles

PV – photovoltaic

PWR – pressurized water reactor

RCS – reactor coolant system

RDF – refuse derived fuel

RPV – reactor pressure vessel

SAM – Solar Advisor Model

SCA – solar collector assembly

SCADA – supervisory control and data acquisition

SCR – selective catalytic reduction

SNCR – selective noncatalytic reduction

SSG – solar steam generator

STC – standard test conditions

TCR – total capital required

TES – thermal energy storage

TMY – typical meteorological year

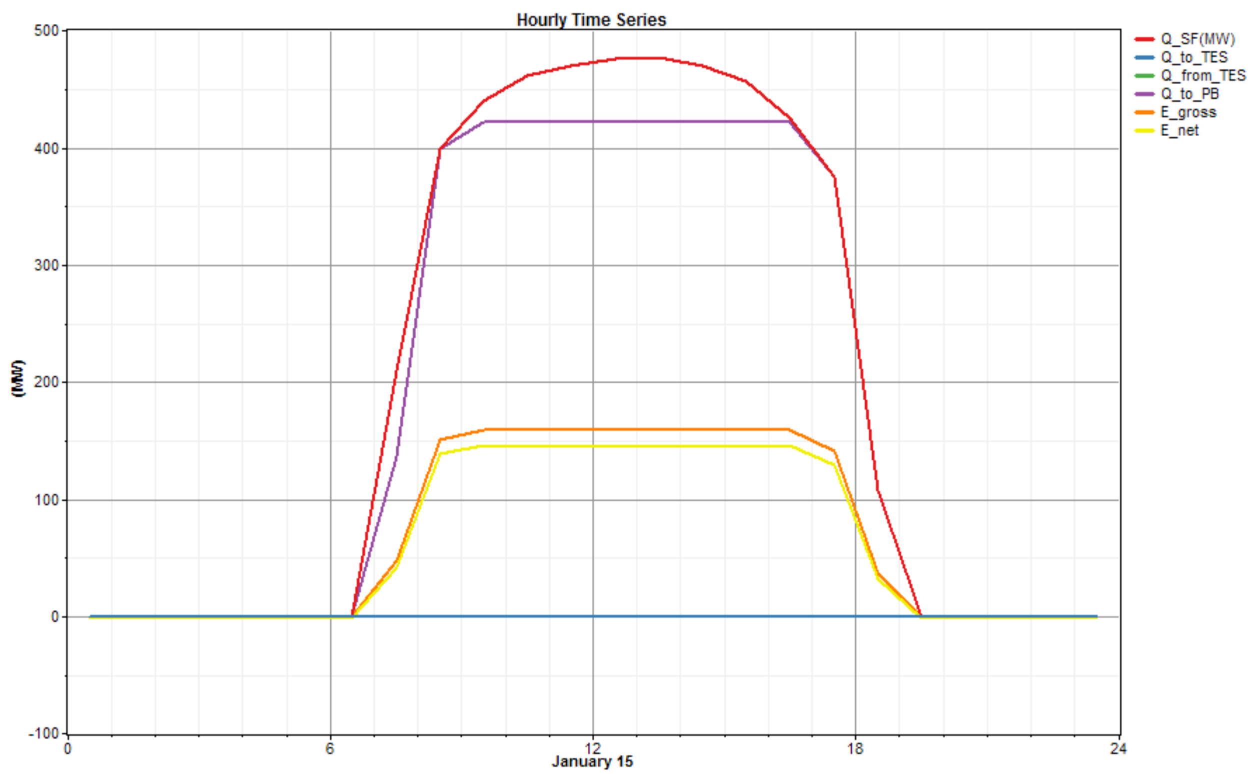
TPC – total plant cost

USD – U.S. Dollar

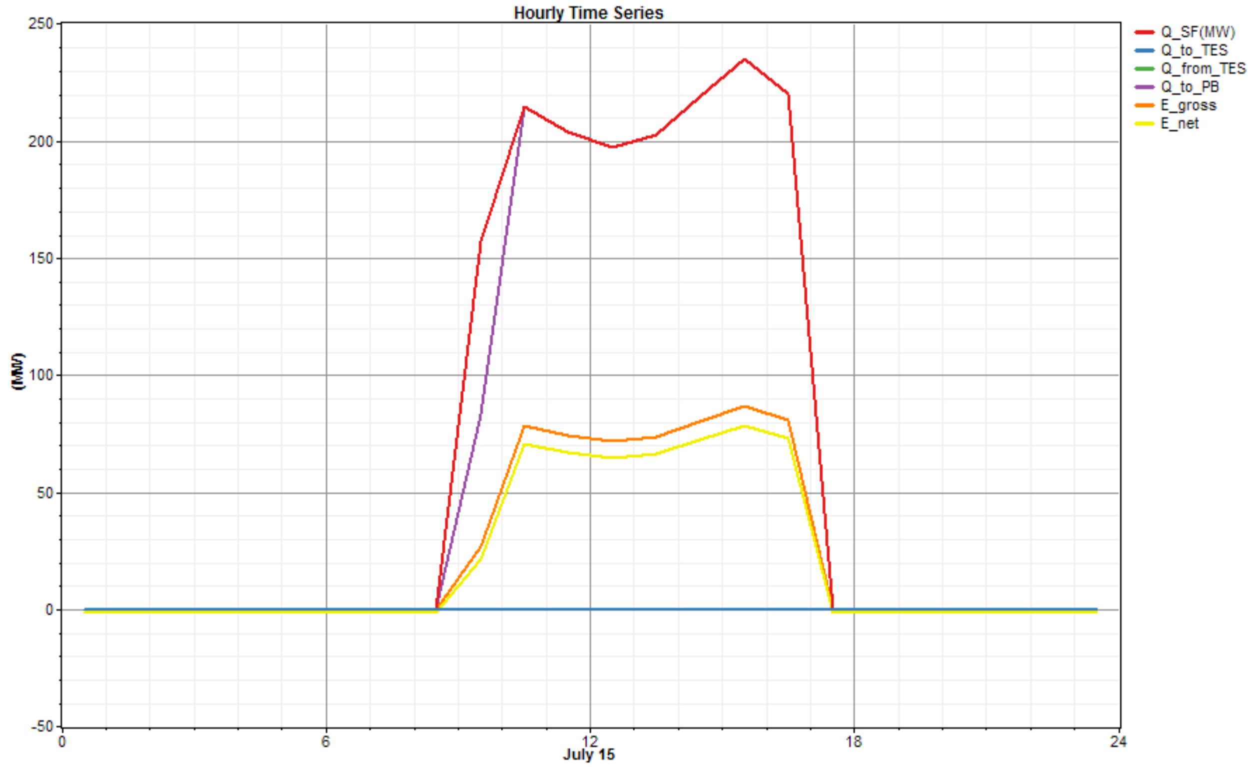
ZAR – South African Rand

B
SOLAR GENERATION PROFILES

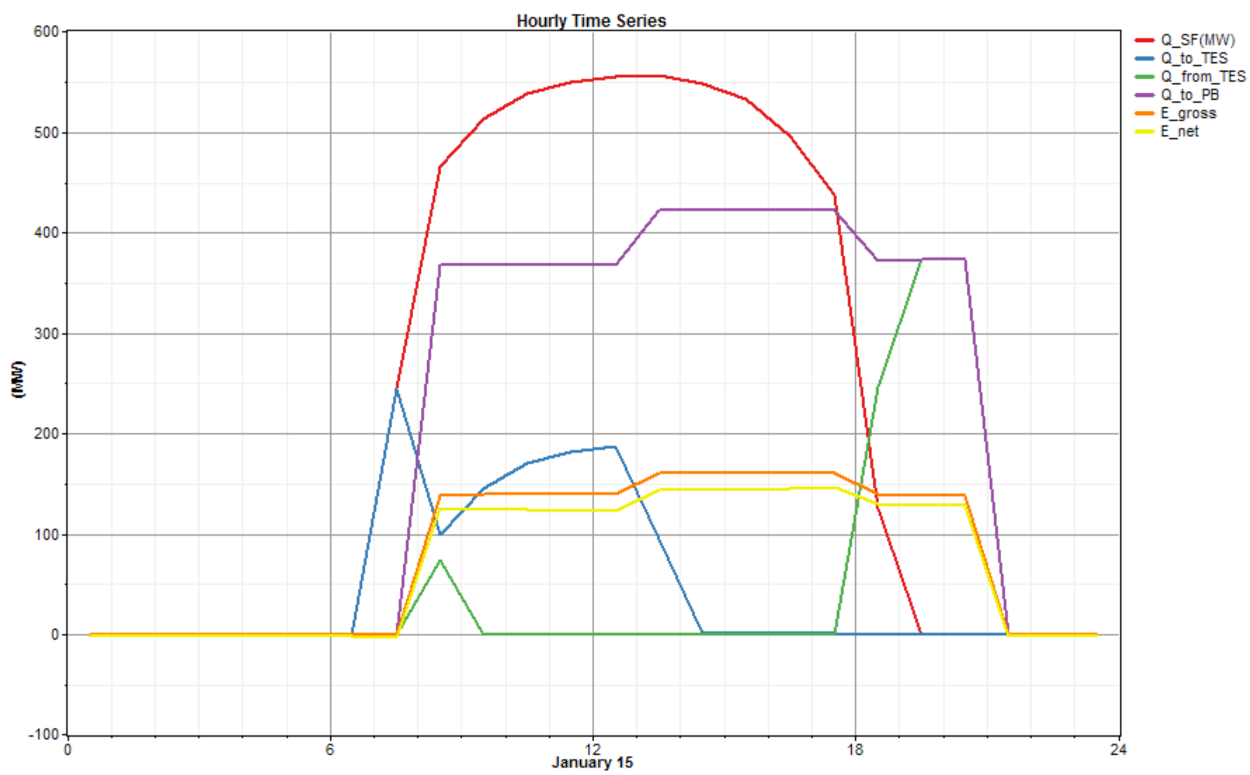
The figures below show the generation profiles for the four parabolic trough cases evaluated: no storage, 3 hours storage, 6 hours storage, and 9 hours storage for two time periods, a summer day (January 15) and a winter day (July 15). The charts show the thermal energy exiting the solar field (Q_SF(MW) in red), the thermal energy to the thermal energy storage (Q_to_TES in blue), the thermal energy from the thermal energy storage (Q_from_TES in green), the thermal energy to the power block (Q_to_PB in purple), the gross power output of the plant (E_gross in orange) and the net power output of the plant (E_net in yellow). It can be seen that as the amount of storage increases, the thermal energy available to the power block from the storage increases, which extends the operating period of the plant or allows the plant to reach maximum output more of the time. These are shown for illustrative purposes only.



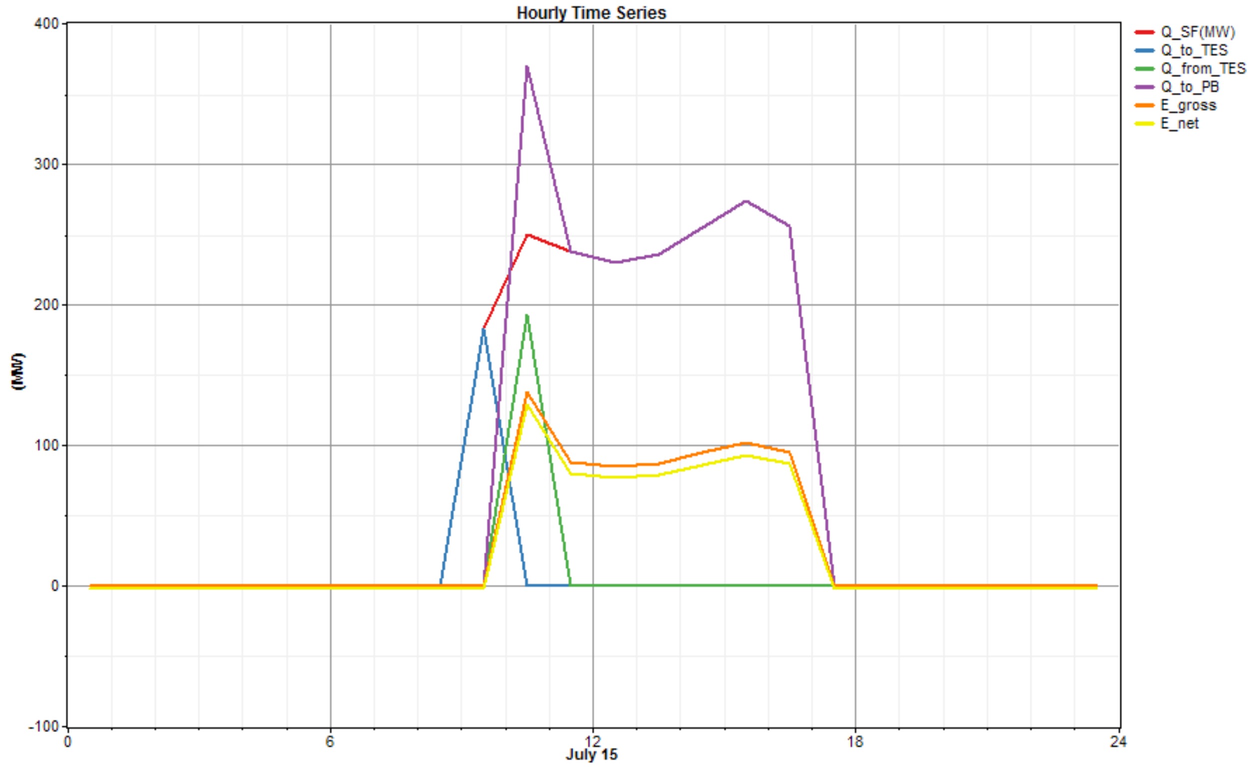
No Storage – January 15



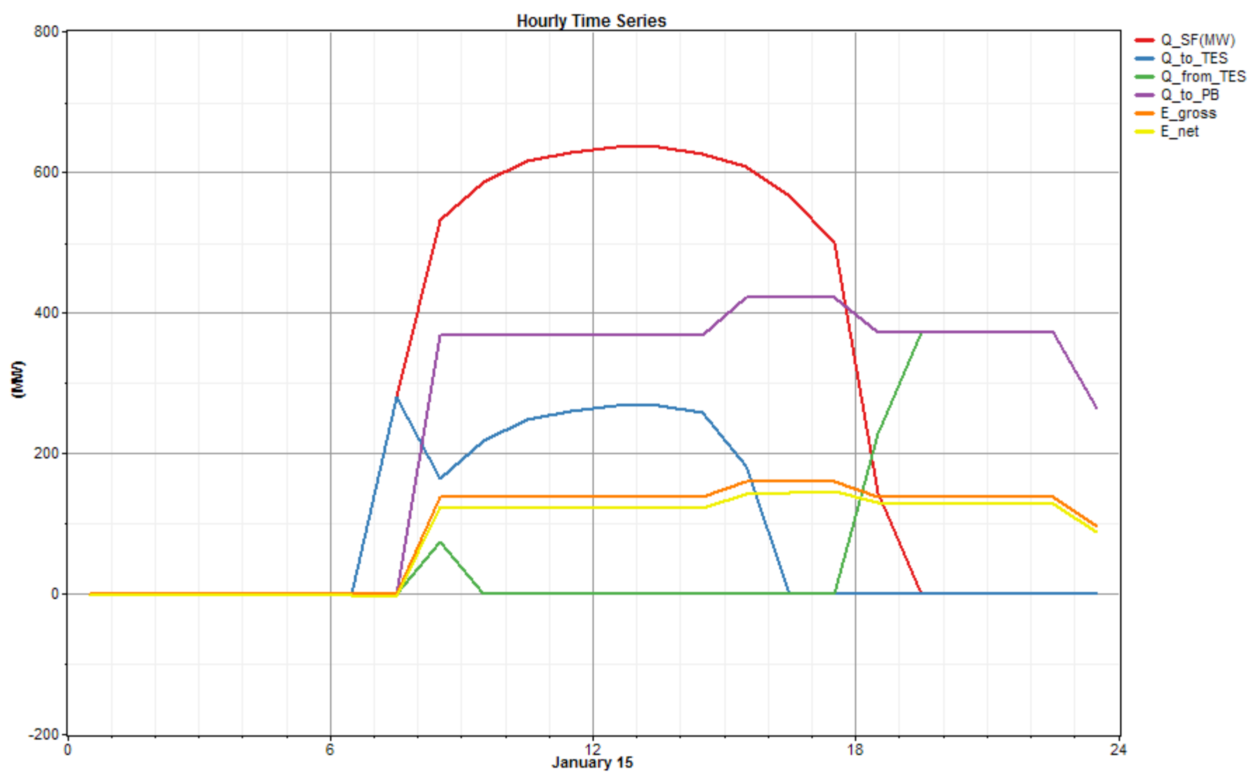
No Storage – July 15



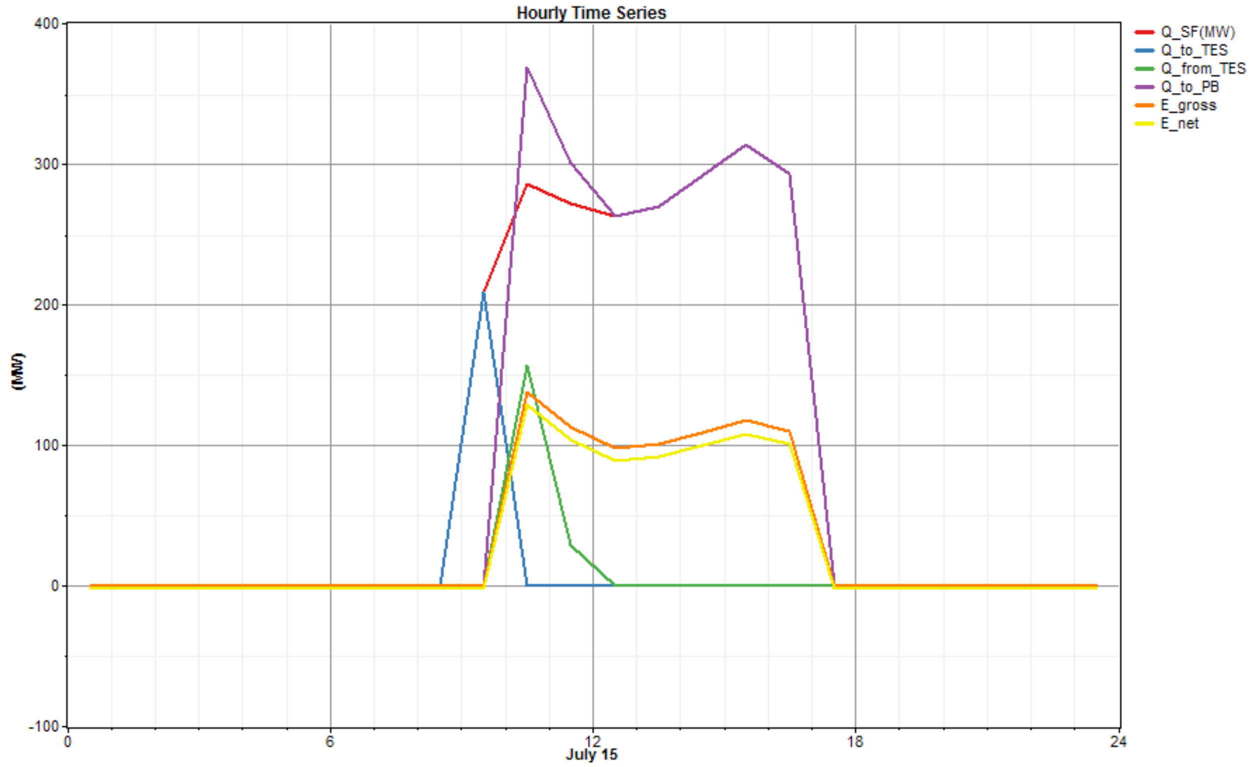
3 Hours Storage – January 15



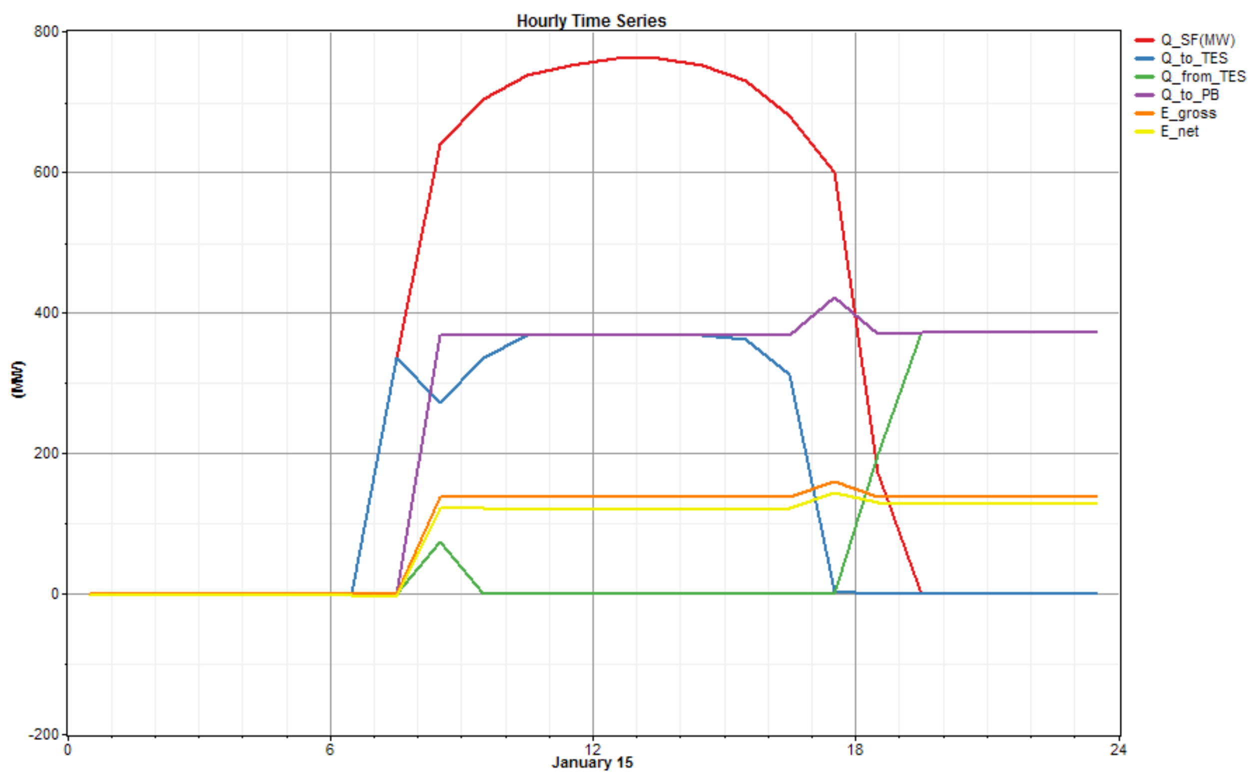
3 Hours Storage – July 15



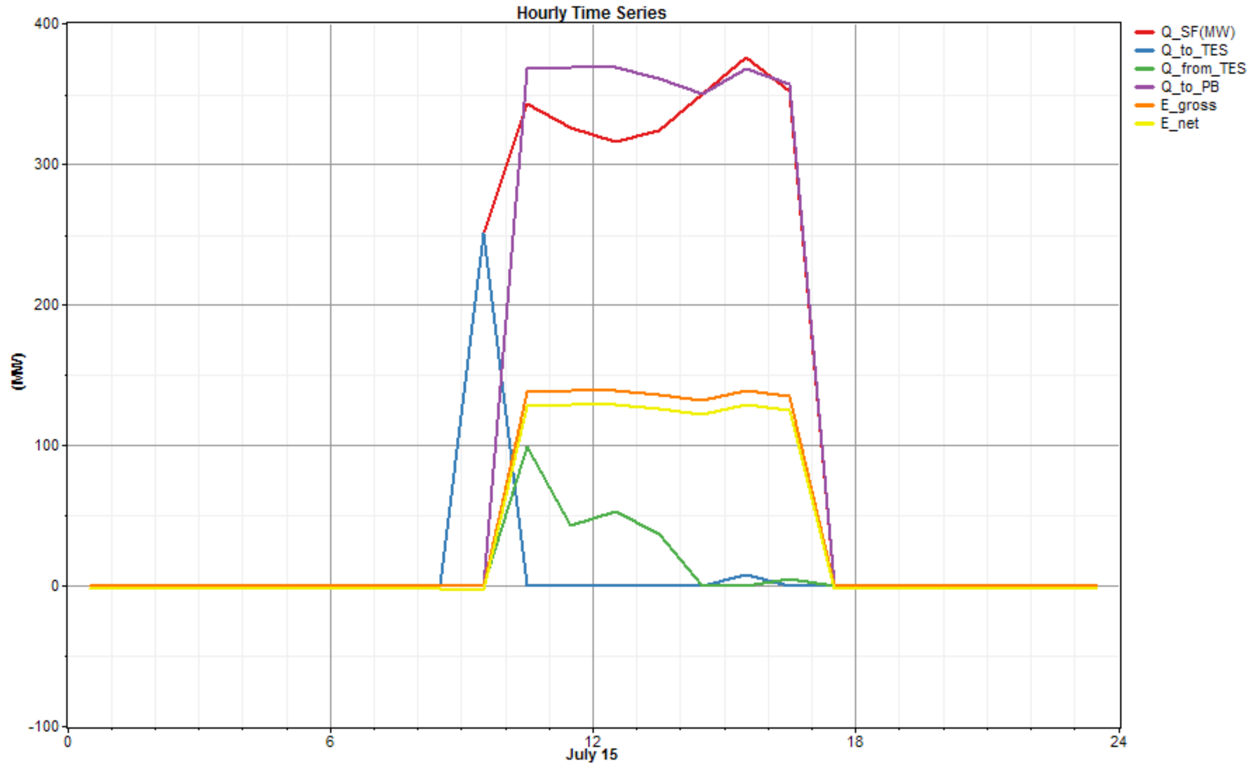
6 Hours Storage – January 15



6 Hours Storage – July 15



9 Hours Storage – January 15



9 Hours Storage – July 15