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Supply-Side Cost and Performance Data for Eskom Integrated Resource Planning

2020–2021 Update

2021 TECHNICAL REPORT

Supply-Side Cost and Performance Data for Eskom Integrated Resource Planning

2020–2021 Update

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Final Report, April 2021

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NOTE

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ABSTRACT

This report provides up-to-date cost and performance data on renewable electric power generation technologies such as wind, solar thermal, solar photovoltaic, and biomass; fossil fuel-based technologies such as pulverized coal, fluidized bed combustion, integrated coal gasification combined-cycle, open-cycle gas turbine, and combined-cycle gas turbine; nuclear technologies; and energy storage technologies. This study updates results from a 2017 project, incorporating technology enhancements, better highlighting the potential influence of market factors, enhancements to design, and revisions to cost and performance data. The South African government's Department of Mineral Resources and Energy is in the process of evaluating these technologies for future capacity additions, and the independent data and expertise presented in this report will facilitate the Integrated Resource Plan process of South Africa.

Keywords

Battery storage technologies
Coal technologies
Natural gas technologies
Nuclear technologies
Power generation
Renewable technologies

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Product Title: Supply-Side Cost and Performance Data for Eskom Integrated Resource Planning: 2020–2021 Update

PRIMARY AUDIENCE: Resource planning and project management staff at Eskom

SECONDARY AUDIENCE: Eskom stakeholders interested in supply-side cost and performance

KEY RESEARCH QUESTION

The Department of Mineral Resources and Energy (DMRE) South Africa is responsible for determining new generation capacity needed to ensure the continued uninterrupted supply of electricity, as well as determining the types of energy sources from which electricity must be generated, and developing and publishing the Integrated Resource Plan (IRP). DMRE South Africa has stipulated that the data included in the IRP must be obtained from an independent source. To obtain these independently sourced data, Eskom engaged the Electric Power Research Institute (EPRI) in 2010, 2012, and 2015 to provide technology data for new power plants that would be included in the IRPs. These reports have been extensively reviewed with public comments and acceptance. This effort is a technical update of the technologies' cost and performance with technology enhancements, market factor influences, and additional technology cases for inclusion in future resource plans.

This report 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.

RESEARCH OVERVIEW

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 the research methodology is included.

The costs of bulk materials in South Africa have escalated significantly. Although raw material pricing tends to be less expensive in South Africa than in 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 2021) represent composite material and labor cost estimates from fourth quarter 2020 for an in-service commercial year of 2021.
- The material, productivity, and labor rate factors reflect the exchange rate of 18.13 ZAR to 1 U.S. dollar provided to EPRI by Eskom[a]. All costs are reported in January 2021 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 that 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 presented in this report are based on a generic representation of generating units at specified South African locations. The estimates have been normalized, where possible, to produce a consistent database. However, site- and company-specific conditions dictate design and cost variations that require additional analysis and are 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 more than 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 on labor cost, equipment, and material costs. The uncertainties in the South African cost estimates include 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

EXECUTIVE SUMMARY

KEY FINDINGS

- There has been a significant strengthening of the U.S. dollar relative to the South African rand since the 2017 study. The effect of the exchange rate and the escalation in costs resulted in a pronounced increase in the capital cost estimates for 2021 versus 2017.
- Total plant costs of fossil generation plants increased from the previous study driven by exchange rates.
- This study includes advanced-class natural gas generation technologies, which are substantially lower in total plant cost compared to models that were previously included, primarily due to increased output.
- Costs of solar photovoltaics and wind technologies have decreased significantly since the last study was completed, even after accounting for exchange rate differences.

WHY THIS MATTERS

This report provides independent cost and performance data spanning a large portfolio of technology options for Eskom.

HOW TO APPLY RESULTS

Results from this study can be incorporated as inputs to further analyses and modeling to be undertaken as part of Eskom's integrated resource planning process.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- TAGWeb[b] software (3002002230) offers the ability to customize the data to reflect varying conditions. In addition to customization of labor, productivity, and commodities, users can change default capital and O&M costs. TAGWeb software calculates busbar costs and allows for some financial analysis, such as sensitivity analysis. TAGWeb software access is available to funders of EPRI Program 178, Project Set 178A, and the TAGWeb supplemental project.

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PROGRAM: Cost and Performance of Power Generation and Storage Technologies, Program 178A

[a] Eskom source: Eskom Treasury Market Analysis, Mandela Maleka.

[b] *TAGWeb* is a registered brand of EPRI.

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INTRODUCTION

The Electric Power Research Institute (EPRI) developed power generation and storage technology data for Eskom in 2010, 2012, and 2015 to be used in the company's Integrated Resource Plans. This report provides updates of technology data based on the current state of power generation and storage options.[1] This report 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 description of each technology is also presented. Costs are reported in January 2021 South African rand.

In this report, technology data are customized to South African conditions and environment. The estimates were developed based on a compilation of existing U.S. and international databases, and adjustments were based on international construction indices and EPRI in-house expertise. Adjustments were 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

The preceding areas were taken into consideration and were compiled to develop total plant cost (TPC) 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 change in costs driven by technology improvements. Meanwhile, the costs of some renewable and storage technologies continue to decline as developers expand production and utilities install more capacity.

The cost and performance estimates that are presented in this report are based on a generic representation of generating units at specified South African locations. The estimates have been normalized, where possible, to produce a consistent database. However, site- and company-specific conditions dictate design and cost variations that require additional analysis and are 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

[1] Previous version of this report used as the basis for this report's updates: *Power Generation Technology Data for Integrated Resource Plan of South Africa*. EPRI, Palo Alto, CA: 2015.

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:

- Pulverized coal (PC)
- Integrated coal gasification combined cycle (IGCC)
- Fluidized bed combustion (FBC)
- Nuclear
- Combined-cycle gas turbine (CCGT)
- Open-cycle gas turbine (OCGT)
- Internal combustion engine (ICE)
- Wind
- Parabolic trough with and without storage
- Central receiver with direct storage
- Thin-film solar photovoltaic (PV)
- Crystalline silicon (c-Si) PV
- Bifacial PV
- Biomass combustion
- Municipal solid waste (MSW) combustion
- Landfill gas (LFG) and biogas combustion
- Lithium-ion (Li-ion)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 several U.S. and international locations. Using adjustment factors and indices 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 previously, EPRI developed cost estimates of plant construction and O&M. 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 covering the issues surrounding the integration of renewable technologies into 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 used the 2020 Richardson International Construction Factor Manual to calculate cost adjustment factors to adjust existing EPRI data from U.S. 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. Cost boundaries were 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. 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 construction indices developed for South African market conditions, the capital and O&M cost estimates were normalized to South African costs and summarized.

Develop Performance Parameters

Performance parameters were developed for the technologies included in this evaluation based on EPRI 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[2] software. Financial parameters for the cost of electricity evaluation were chosen for illustrative purposes. The cost of electricity evaluation is broken down into capital, O&M, and fuel cost components.

Estimate Result Uncertainties

Uncertainties exist in the baseline U.S. estimates as well as in the adjustment factors used to develop South African cost and performance estimates, such as fluctuations in exchange rates. Further, the costs of some technologies, such as solar and energy storage, continue to decline rapidly and are challenging to forecast. Therefore, the estimates presented in this report attempt to capture a wide range of potential costs.

[2] *TAGWeb* is a registered brand of EPRI.

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 through 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. Due to water shortages throughout South Africa, each of these technologies, except for nuclear, was configured with air cooling of the condensers and auxiliary equipment to minimize water consumption. The nuclear plant was assumed to use once-through cooling by seawater. Coal plants were evaluated with flue gas desulfurization (FGD) units for control of sulfur emissions and with and without consideration of CO_2 capture.

Estimates were initially developed based on U.S. cost data. These estimates were then adjusted to South African conditions with the use of adjustment factors developed by EPRI using the 2020 Richardson International Construction Factor Manual. Performance data were developed using South African ambient condition assumptions.

Table 2-1
Coal technologies

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

CCS = carbon capture and storage

Table 2-2
Nuclear technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Nuclear (with seawater cooling)		
AP1000	1 and 2 units x 1115 MW	Coastal, near Port Elizabeth or north of Cape Town
Areva evolutionary pressurized reactor (EPR)	1 and 2 units x 1600 MW	Coastal, near Port Elizabeth or north of Cape Town
Small modular reactor (SMR)	12 units x 60 MW	Coastal, near Port Elizabeth or north of Cape Town

Table 2-3
Gas technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
CCGT		
1x1 F-class NGCC without CCS		Coastal, liquefied natural gas (LNG) based
1x1 F-class NGCC with CCS		Coastal, LNG based
2x1 F-class NGCC without CCS		Coastal, LNG based
2x1 F-class NGCC with CCS		Coastal, LNG based
1x1 H-class NGCC without CCS		Coastal, LNG based
1x1 H-class NGCC with CCS		Coastal, LNG based
2x1 H-class NGCC without CCS		Coastal, LNG based
2x1 H-class NGCC with CCS		Coastal, LNG based
12x1 ICE-CC without CCS		Coastal, LNG based
OCGT		
LM6000		Coastal, LNG based
LMS100		Coastal, LNG based
F-class combustion turbine (CT)		Coastal, LNG based
H-class CT		Coastal, LNG based
ICE		
9-MW ICE		Coastal, LNG based
18-MW ICE		Coastal, LNG based

NGCC = natural-gas combined-cycle

CCS = carbon capture and storage

Table 2-4
Renewable technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Wind	50, 100, 200 MW	Coastal
Parabolic trough		
Without storage	125 MW	Upington
With indirect storage	125 MW	Upington
Central receiver		
Without storage	125 MW	Upington
With direct storage	125 MW	Upington
PVs		
C-Si –SAT	20, 100 MW	Johannesburg
Thin film—SAT	20 MW	Johannesburg
Bifacial—SAT	20 MW	Johannesburg
C-Si—roof mounted	5 kW, 100 kW	Johannesburg
Biomass		
Forestry residue	25 MW	Eastern coast
MSW	25 MW	Major cities
LFG engines	5 MW	Major cities

SAT = single-axis tracking

Table 2-5 shows the storage technologies.

Table 2-5
Storage technologies

Technology Type	Rated Capacity, MWe	Assumed Location
Li-ion	1 MW, 20 MW, 100 MW 1 h and 4 h	Major cities
Solar PV plus Li-ion battery	100 MW PV, 100 MW/4 h 100 MW PV, 25 MW/4 h 20 MW PV, 20 MW/4 h	Johannesburg
Compressed air storage	180 MW	Based on suitable geologic resource availability

3
DESIGN BASIS

Introduction

This section provides an overview of the assumptions made when assessing the various power generation technologies that were 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 that are 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 and transmission lines, because these are specific and the design requirements can vary from one location to another.

Coal Technologies

Location

The site location that was 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 minemouth, 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 as follows:

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 baseload units. Baseload 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, thereby minimizing their use as load-following units. A capacity factor of 85% is assumed for all of the baseload coal units. The technical parameters for the coal plants are shown in Table 3-1.

Table 3-1
Coal plant technical parameters

	Turndown	Cycling Capability Startup to Full Load	Ramp Rates
Ultra-supercritical PC	Minimum boiler load: 25–30%	Very hot startup: <1h Hot startup: 1.5–2.5 h Warm startup: 3–5 h Cold startup: 6–7 h	30–50% load: 2–3%/min 50–90% load: 4–8%/min 90–100% load: 3–5%/min
IGCC	40–50% of maximum continuous rating	Ambient startup: 36 h Hot startup: 4 h	50–100% load: 3%/min
FBC	40% of maximum continuous rating	See below	

With regard to the FBC plants, the water/steam cycles of the FBC units are typically like 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 FBCs' fuel feed and combustion systems are different from a PC unit's design and, therefore, would require supplementary fuel to maintain minimum load below 40% maximum continuous rating.

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

Additional design features can be incorporated to accommodate more flexible operation regimes. For example, Foster Wheeler offers an optimized reheat steam bypass system for temperature control during startup and shutdown. That design also includes in-duct and over-grid startup 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.
- The air-separation unit (ASU) for a plant designed for ramping duty has liquid manufacturing capability, so that stored liquid can be available to achieve an accelerated cooldown (one to two days).
- The plant incorporates a rapid response turbine that can be started on natural gas and switched to syngas when that becomes available.
- The timing for the gasifier preheat as shown is for a membrane wall gasifier.
- A refractory lined gasifier requires a 24- to 36-hour preheat duration, similar to the ASU. 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 advanced gas-cooled reactor depends on the type of advanced gas-cooled reactor selected. An ambient system such as MethylDiethanolamine would not need any cooling down at all. Rectisol requiring cool down to -30°C would require longest.
- The sulfur recovery unit (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.

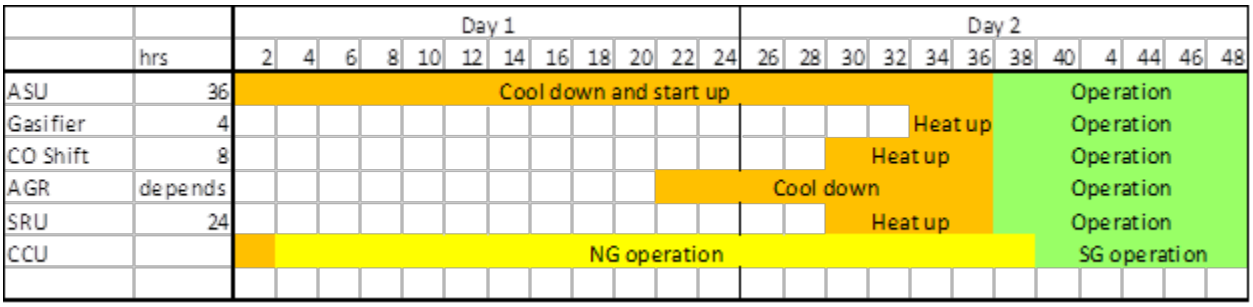

Figure 3-1
Typical ambient start schedule for IGCC

Figure 3-2 shows a hot start schedule. There can be several definitions of a *hot start*. For the purposes of this report, 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 overnight. 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 2 hours.
- On the assumption of a membrane wall gasifier, the gasifier itself can have been allowed to cool down. (Note that although a refractory lined gasifier is capable of being maintained hot and ready to start, it will in some cases be necessary on shutdown to replace the operating burner/feed injector with a preheat burner to maintain the ready-to-start status. On decision to start, the preheat burner would need to be replaced by the operation burner. This is expected to take about 2 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 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 CT is a rapid response machine that can start up on natural gas at short notice. The switch to syngas operation can be made in less than 4 hours.

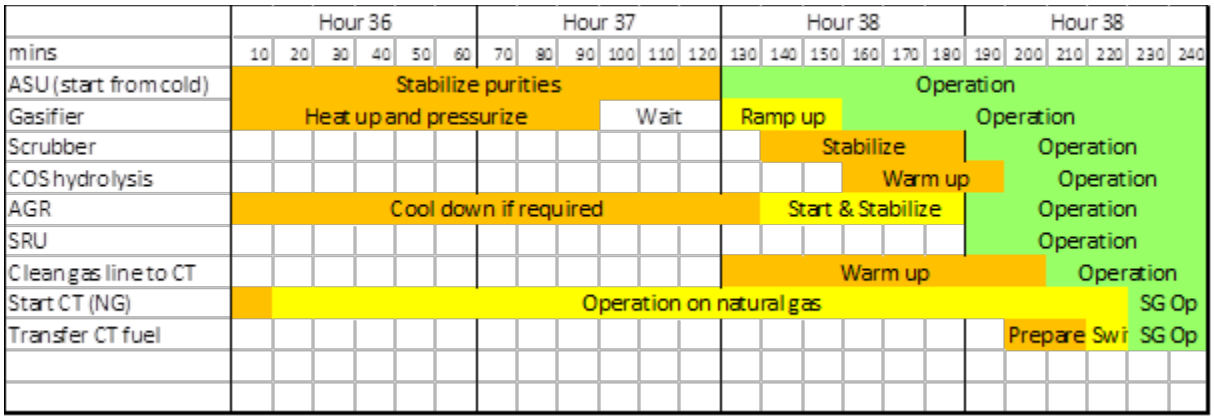

Figure 3-2
Typical hot start schedule for IGCC

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 is dictated by the size and type of gas turbine (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, two, four, and six 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 the 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, therefore, are 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 because these plants are minemouth, thereby negating the need for rail connections.

The capital costs presented throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies that were 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 that was considered for the coal plants in this study is high-ash bituminous coal. The characteristics and analysis of this coal are presented in Table 3-2. The plant sites were assumed to be minemouth 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 (7673)
Lower MJ/kg (Btu/lb)	17.12 (7363)

Resource Potential

According to BP's Statistical Review of World Energy 2020, South Africa had nearly 11 billion tons of total proven coal reserves at the end of 2019. Uncertainty in reserve estimates stem from disparate views on which resources are economical to mine. As of 2018, about 73% of South Africa's total energy supply was provided by coal.[3]

In 2019, South African coal production amounted to 285.9 million tons.[4] Coal from South African mines is consumed locally and exported. Historically, South Africa has exported about 30% of total domestic coal production, with much of it destined for India and other countries in the Asia-Pacific region.[5] 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.[6]

If the business-as-usual approach to coal mining/utilization is maintained into the future, the highest quality coal could either be exported for sale on the world market or sold at a premium in South Africa to cover the opportunity cost of not selling to the overseas market. However, global demand for coal has weakened in recent years and is expected to gradually decrease. Weakened demand has coincided with growing domestic environmental requirements and lower investment in the coal sector. Further, although demand for export coal will remain in the short term, degradation of coal quality at existing mines could constrain the available supply of the highest quality coal, because 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 a project.

A potential source of solid fuel is the large stores of discard coal that have been produced by coal beneficiation processes over several 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, so 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, the discard coal may become a more cost-effective fuel source.

[3] IEA, 2020, South Africa Country profile.

[4] Minerals Council South Africa, 2021, Key Facts and Figures.

[5] Chamber of Mines South Africa, 2018, Coal Strategy 2018.

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

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.

Other Factors

Emissions Criteria

The PC units in this study were evaluated both with and without a 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 (LSFO) 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 through 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[7] completed by Andover Technology Partners and JLM Environmental Consulting indicates that based on a thorough review of operating data from U.S. power plants, the addition of a scrubber minimally increases the heat rate. When assessing the full population of scrubbed and unscrubbed units, the study did not indicate a significant difference.

CO_2 Capture and Storage

Coal technologies were 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 an 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.

[7] "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.

Nuclear Technologies

Location

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

Duty Cycle

The nuclear plants in this study are baseload units. *Baseload 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, thereby minimizing their use as load-following units. A capacity factor of 90% is assumed for all of the baseload nuclear units. This assumption is very consistent with the U.S. market.

However, in some foreign markets with large shares of nuclear capacity (France and Germany), operational flexibility is a key ingredient to successful grid operations that now include 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 gray 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 that a nuclear plant is designed to load-follow, experience in European countries indicates 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 aging. For plants that are designed with cycling in mind, precautions can be included in planning to minimize O&M costs but translate 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%.[8]

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 1200 MW to 1600 MW. Estimates within this report cover the range of these plants with stations consisting of one-unit and two-unit construction. Additionally, the SMR plant consisting of 12 reactors with a total rated capacity of 720 MW was evaluated.

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 that are needed to operate the plant, such as wastewater-treatment facilities, shops, offices, and

[8] "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.

cafeteria. The cost boundary also includes the interconnection substation but not the switchyard and associated transmission lines. The nuclear units that were 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 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

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 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 South African government has completed studies indicating the country's ability to support the nuclear fuel requirements of a 10-GW 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 could be feasible by 2030.[9]

Nuclear Fuel and Waste Transport/Storage/Disposal

The nuclear fuel cycle, as illustrated in Figure 3-3, includes uranium recovery, conversion, enrichment, and fabrication to produce fuel for nuclear power stations. Nuclear fuel costs consist of 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.[10] The uranium price in the table has been modified to reflect current global uranium prices, whereas the other costs were escalated by annual inflation.[11] 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.

[9] "South Africa Could Resume Uranium Enrichment." www.nti.org/gsn/artilce. April 2012.

[10] "The Economics of Nuclear Power." World Nuclear Association. November 2008.

[11] http://www.indexmundi.com/commodities/

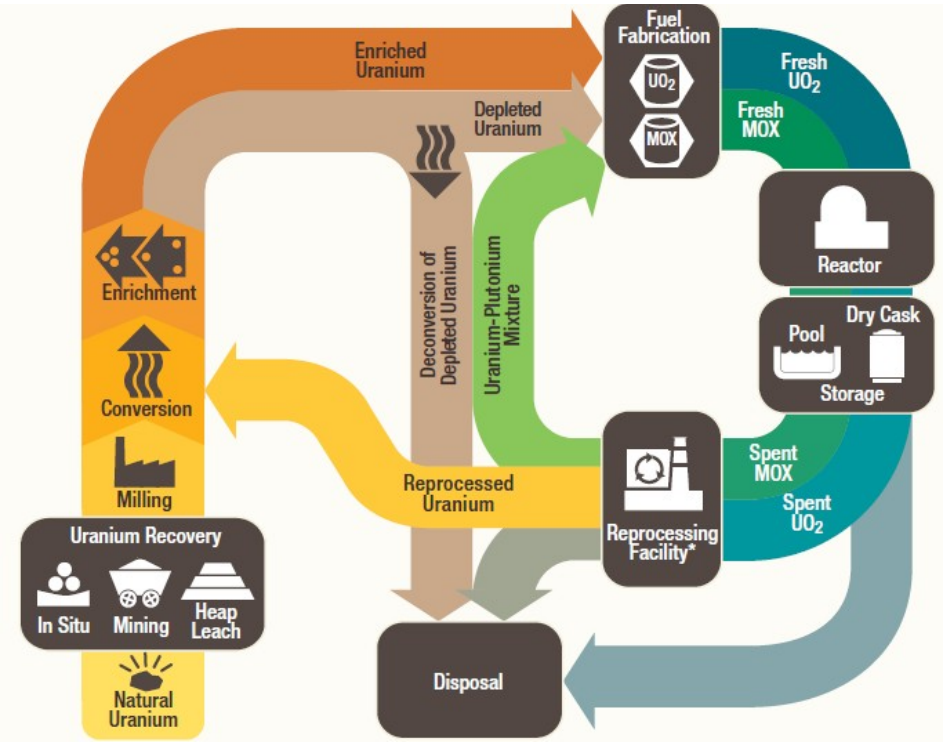

Figure 3-3
Nuclear fuel cycle[12]

Table 3-3
Front-end nuclear fuel costs, 2021$

Process Step	Cost ($/kg U)
Uranium: 8.9 kg U_3O_8 × $30	267
Conversion: 7.5 kg U × $5	40
Enrichment: 7.3 SWU × $59	433
Fabrication: per kg	107
Total ($/kg U)	848

SWU = separative work unit

[12] "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 [13]

Process Step	Cost (2021$/MWh)
Temporary on-site storage ($/MWh)	$0.11
Permanent disposal ($/MWh)	$1.30
Total ($/MWh)	$1.41

Other Factors

Once-Through Cooling

Unlike the other technologies that were evaluated in this study, the AP1000 and the AREVA nuclear units are coastally located and employ once-through seawater cooling. The SMR plant is air-cooled.

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 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 that were used for the gas plants in this study are as follows:

- 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 that was evaluated in this study is an intermediate unit, whereas the OCGT is a peaking unit. Intermediate units have costs and operating flexibility that is a cross between a baseload unit and a peaking unit. They generally have increased output flexibility compared to baseload units but have longer construction time and higher capital costs than peaking units. Peaking units, such as the OCGT, typically have lower capital costs, shorter construction time, quicker startup, and higher flexibility in their plant output compared to baseload units. However, they generally have higher fuel costs and can be less efficient and, therefore, run less frequently

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

than baseload 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	Ramp Rate	Ramping Range	Minimum Load
LM6000	5 min	10 MW/min	0–100% in 5 min	50%
LMS100	10 min	25 MW/min	0–100% in 10 min	50%
9F.05 OCGT	10 min	50 MW/min	0–100% in 10 min	40%
9HA.02 OCGT	10 min	90 MW/min	0–100% in 10 min	30%
9F.05 CCGT	Cold start: 180 min	50 MW/min	Cold start: 0–100% in 180 min	46%
9HA.02 CCGT	Cold start: 180 min	80 MW/min	Cold start: 0–100% in 180 min	40%
9-MW ICE	5 min	10 MW/min	0–100% in 5 min	30%
18-MW ICE	10 min	10 MW/min	0–100% in 10 min	30%

In addition to the CCGT and OCGT generation systems, this study also evaluates a distributed generation technology—the ICE, also known as the *reciprocating engine*. The ICE unit is a stand-alone configuration at an unoccupied (new) site and is assumed to be within or near town or metropolitan areas. The ICE that was evaluated in this study is an intermediate unit to support load-following needs on the grid. 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 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- to 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 dollars per unit of power output). A capacity factor of 10% is assumed for the simple cycle ICE units and 50% for the combined-cycle ICE unit.

Generating Unit Size

The CCGT plants consist of 1x1 units and 2x1 units with rated capacity ranging from 470 MW to 1630 MW. The OCGT outputs range from 46 MW to 545 MW. The ICE units are 9 MW and 18 MW and 216 MW for the combined-cycle plant. There is interest in combining the operational flexibility of ICEs 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 (HRSGs) feeding a single steam turbine would provide about 200 MW.

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, HRSG, and the turbine generators, and all support facilities that are needed to operate the plant. These support facilities include emissions control equipment; wastewater-treatment facilities; and shops, offices, and a 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 that were 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 that were 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 uses natural gas from existing offshore 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 offshore supplies. South Africa's closest source of LNG is the central African Atlantic coast—for example, Equatorial Guinea. South Africa is far closer to the global supplier Qatar than all of the countries in the North Atlantic, and it is relatively close to the up-and-coming suppliers off the Northwest Shelf of Australia (for example, Pluto) and northern tier offshore region of Australia (for example, Browse).

In addition to power production, a primary consumer of natural gas in South Africa is PetroSA's gas-to-liquid 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 was 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 was 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

Interior or coastal locations with a sustained minimum wind speeds of 4–8 m/s are suitable sites for wind farms. Wind data at 100-m hub height were used for this study.

Generating Unit Size

The wind farms that were investigated in this study all consist of 2.8-MW turbines. The three farm sizes are 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 4–8 m/s (annual average) are evaluated. Table 3-7 shows the wind class range for each wind speed. The wind speeds were monitored and collected at 100 m.

Table 3-7
Wind speed classes

Wind speed, m/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. The best wind resource areas in South Africa are generally in the northwestern coastal area near Namibia and the southeastern coastal area. The U.S. average wind tower hub height in 2019 was 88 m.[14] For this report, it is assumed the hub height was 100 m. Based on EPRI research conducted in 2014, on average, 100-m 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 100-m hub height provided a 15–20% increase in capacity factor over an 80-m hub height. The increased capacity factor yielded a 5–10% reduction in the levelized cost of energy.

[14] U.S. Department of Energy, Wind Energy Grows Up, May 2019.

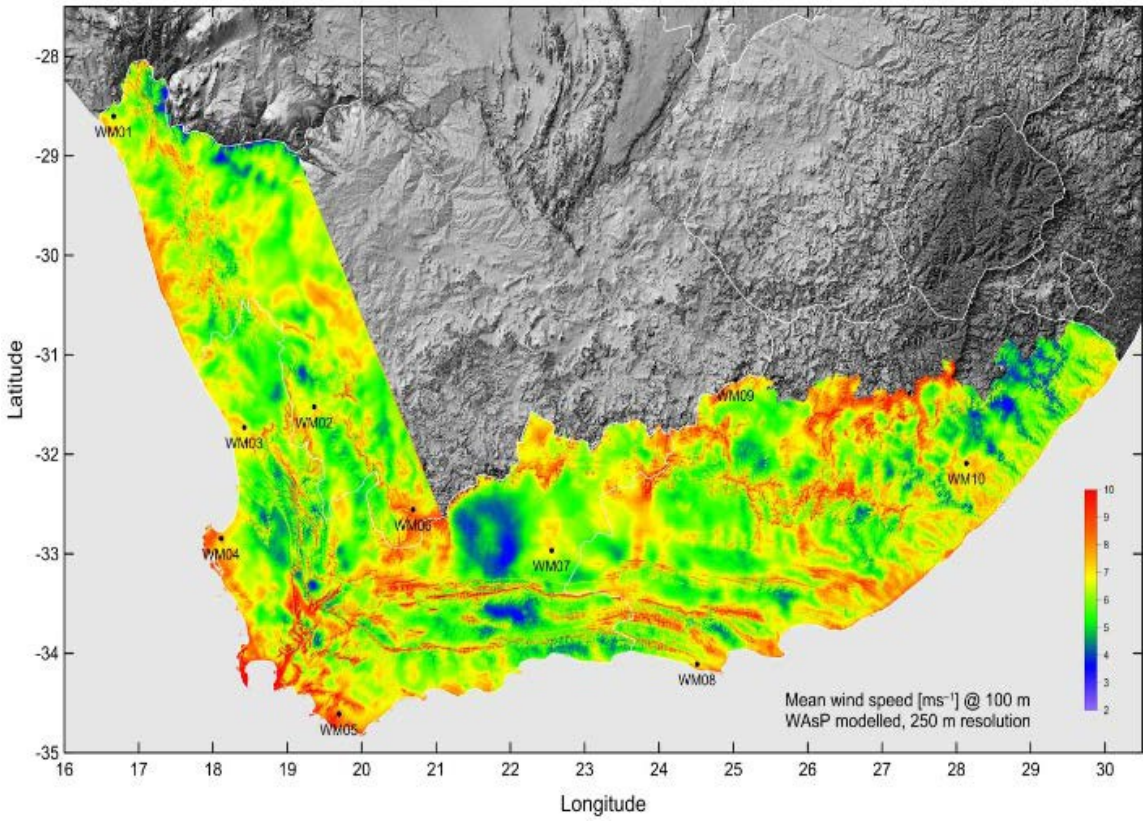

Figure 3-4
South African wind resource (measured at 100 m)

Table 3-8 shows a sample of the wind atlas mast information collected by Eskom. Although the data presented by Eskom are quite exhaustive, they require 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 2.8-MW 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.

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 (15-m 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		- 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

SAWS = above mean sea level

A.M.S.I. = South African Weather Service

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 1 being a low wind speed at less than 5.6 m/s (18.4 ft/s) and 7 being wind with a speed greater than 8.8 m/s (28.9 ft/s), as shown in Table 3-9 (source: National Renewable Energy Laboratory). 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 using 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; when 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 1.5–3 MW in size, with larger ones in limited production and under development.

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 the information in Tables 3-9 and 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: central receiver with 3, 6, 9, and 12 hours of direct molten salt storage and parabolic trough with no storage, and with 3, 6, 9, and 12 hours of indirect molten salt storage.

Location

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

Ambient Conditions

The annual average ambient air conditions for the region near Upington, South Africa, are as follows:

- 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 3, 6, 9, and 12 hours of indirect molten salt storage. The central receiver plant was evaluated with 3, 6, 9, and 12 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 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° in order for the sunlight to be focused onto the receivers. Figure 3-5 shows worldwide solar DNI data. The DLR-International Spaceborne Imaging Spectroscopy images were obtained from the Institute of Atmospheric Physics, German Aerospace Center (DLR).[15] The long-term variability of direct irradiance was derived from International Satellite Cloud Climatology data and compared with reanalysis data.[16] South Africa clearly has one of the best solar resources in the world.

[15] Institute of Atmospheric Physics, German Aerospace Center (DLR). Lohmann, S., C. Schillings, B. Mayer, and R. Meyer (2006a).

[16] "Long-term variability of solar direct and global radiation derived from International Satellite Cloud Climatology 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.

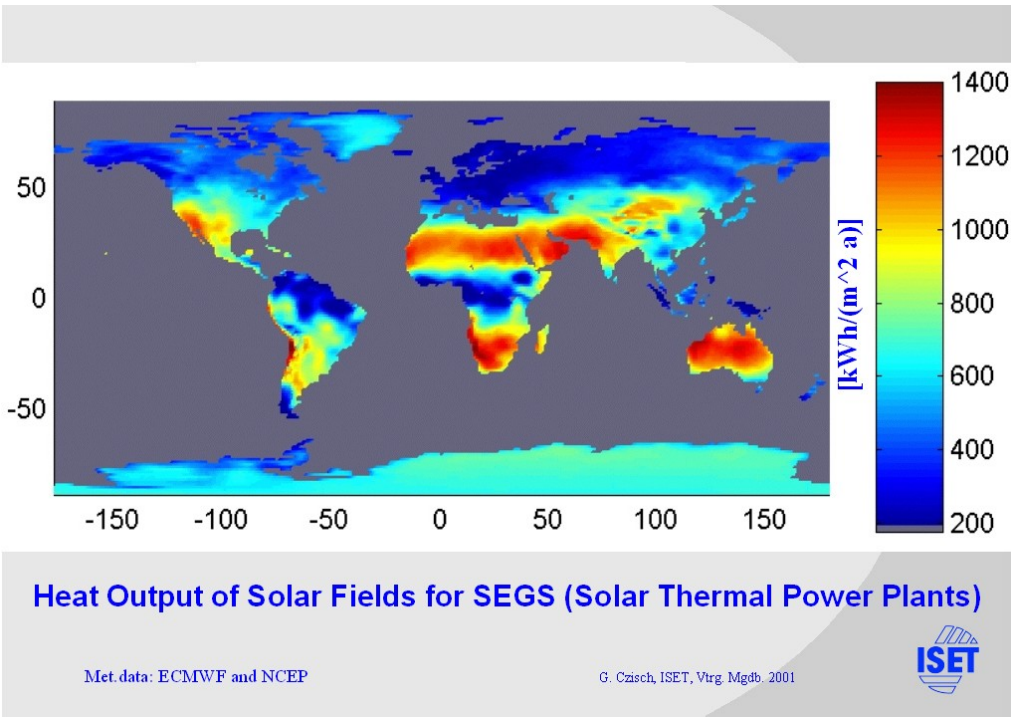

Figure 3-5
Worldwide DNI data

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

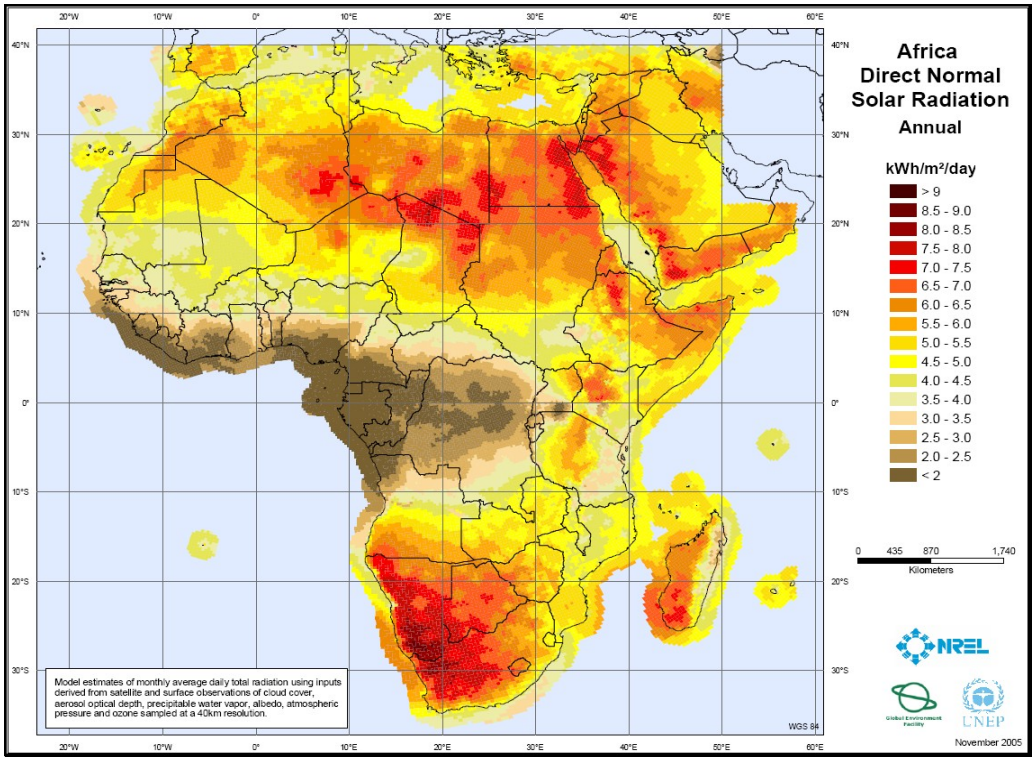

Figure 3-6
African annual direct normal radiation

Solar PVs

The solar PV technologies evaluated in this study include single-axis tracking c-Si PV, bifacial module, cadmium telluride (CdTe) thin-film PV, and rooftop c-Si PV.

Location

Thin-film and c-Si PV technologies were modeled for Johannesburg.

Ambient Conditions

The annual average ambient air conditions for Johannesburg that were used in this study are as follows:

- 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 c-Si PV systems evaluated in this study were evaluated both as commercial/industrial rooftop units (5 kWe and 100 kWe) and ground-mounted utility-scale systems (20 MWe and 100 MWe). The ground-mounted bifacial module and thin-film systems were evaluated at 20 MWe. The National Energy Regulator of South Africa 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 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 use diffuse radiation as well as normal radiation. Ground-mounted PV panels are usually installed at a latitudinal tilt, which optimizes annual energy production, whereas 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, and Figure 3-8 shows the annual horizontal solar resource in Africa.

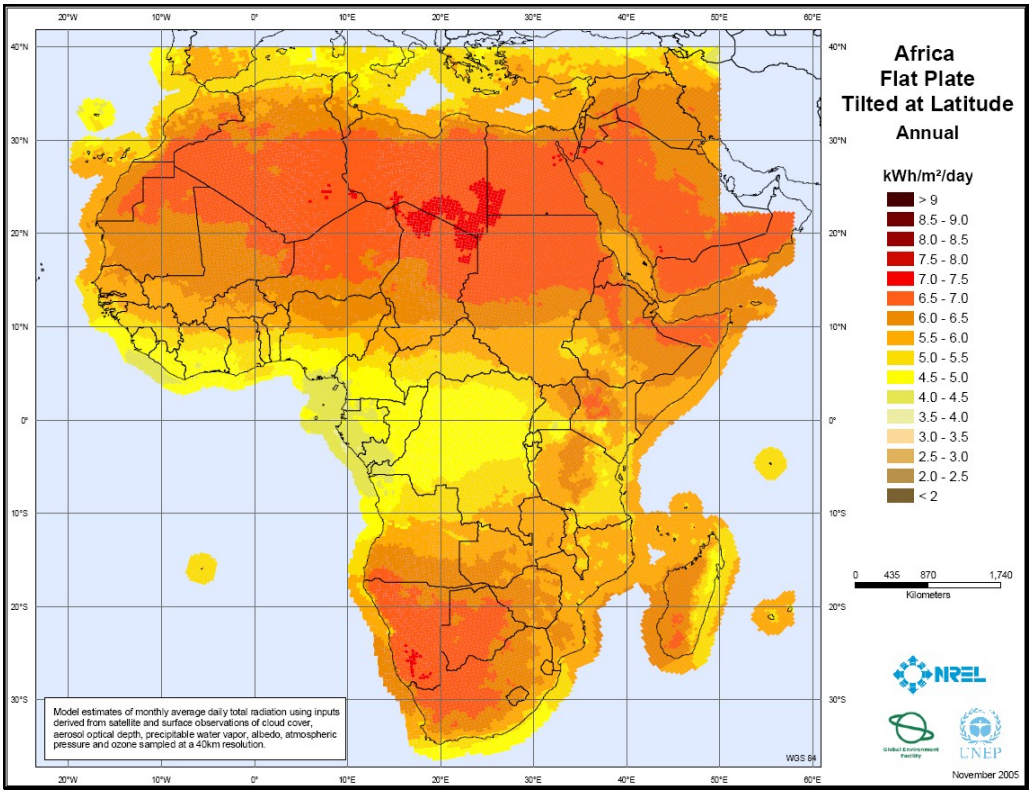

Figure 3-7
African annual latitudinal solar radiation

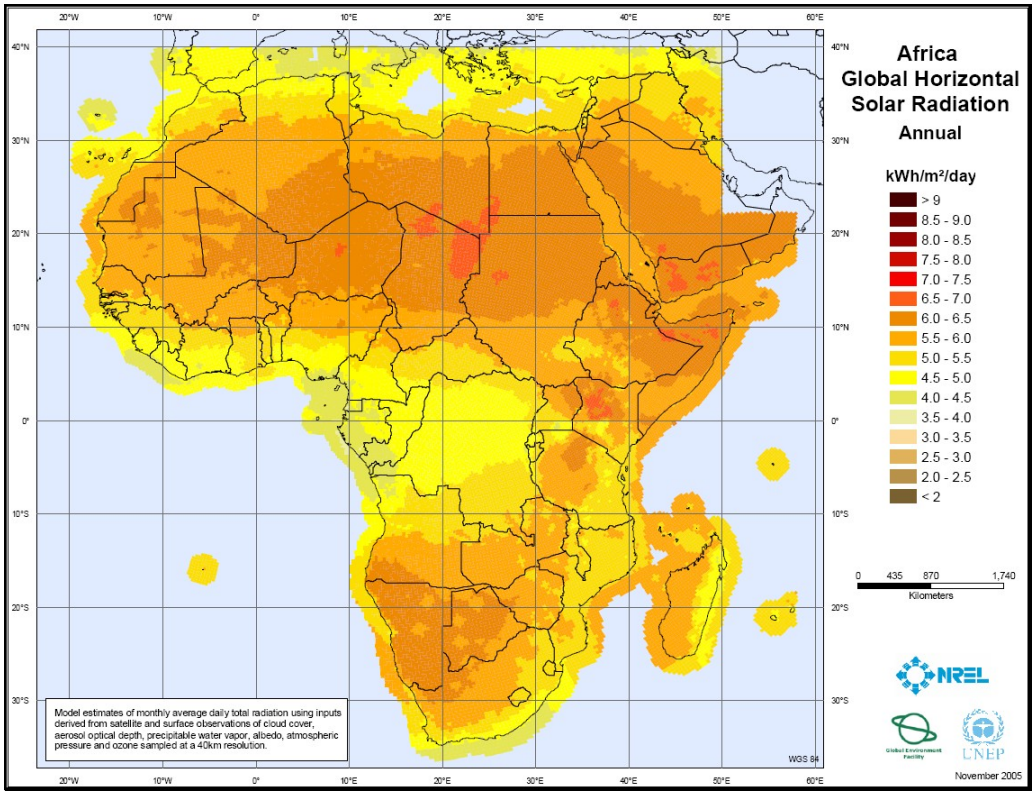

Figure 3-8
African annual horizontal solar radiation

Like the concentrating solar thermal technologies, concentrating PV requires direct normal radiation. The solar resource component used by this technology corresponds with Figure 3-6 shown in the Solar Thermal section.

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 LFG and biogas were evaluated.

Location

The biomass plants that were 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. Although 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, the LFG, and the biogas reciprocating engines are assumed to be located near population centers where waste would 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 LFG and biogas reciprocating engine plants were 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 LFG engines, the cost boundary includes the spark ignition reciprocating engines and exhaust stacks, as well as all engine auxiliaries, buildings, and the LFG 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, therefore, are 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 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 wood chips, representing forestry residue, unprocessed MSW, and LFG. Table 3-11 summarizes the characteristics of the solid fuels, and Table 3-12 summarizes the characteristics of the LFG. Biogas was assumed to have similar characteristics to LFG. Solid biomass storage is sized for five-day storage.

Table 3-11
Biomass characteristics

Composition (% wt)	Wood Chips	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 (8480)	
Wet MJ/kg (Btu/lb)	11.8 (5057)	11.4 (4896)

Table 3-12
LFG characteristics

Composition (wt %, Dry Basis)	LFG
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. LFG 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

Figure 3-9 shows the terms, definitions, and supporting variables for availability calculations, as defined by the National Electric Reliability Corporation (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.

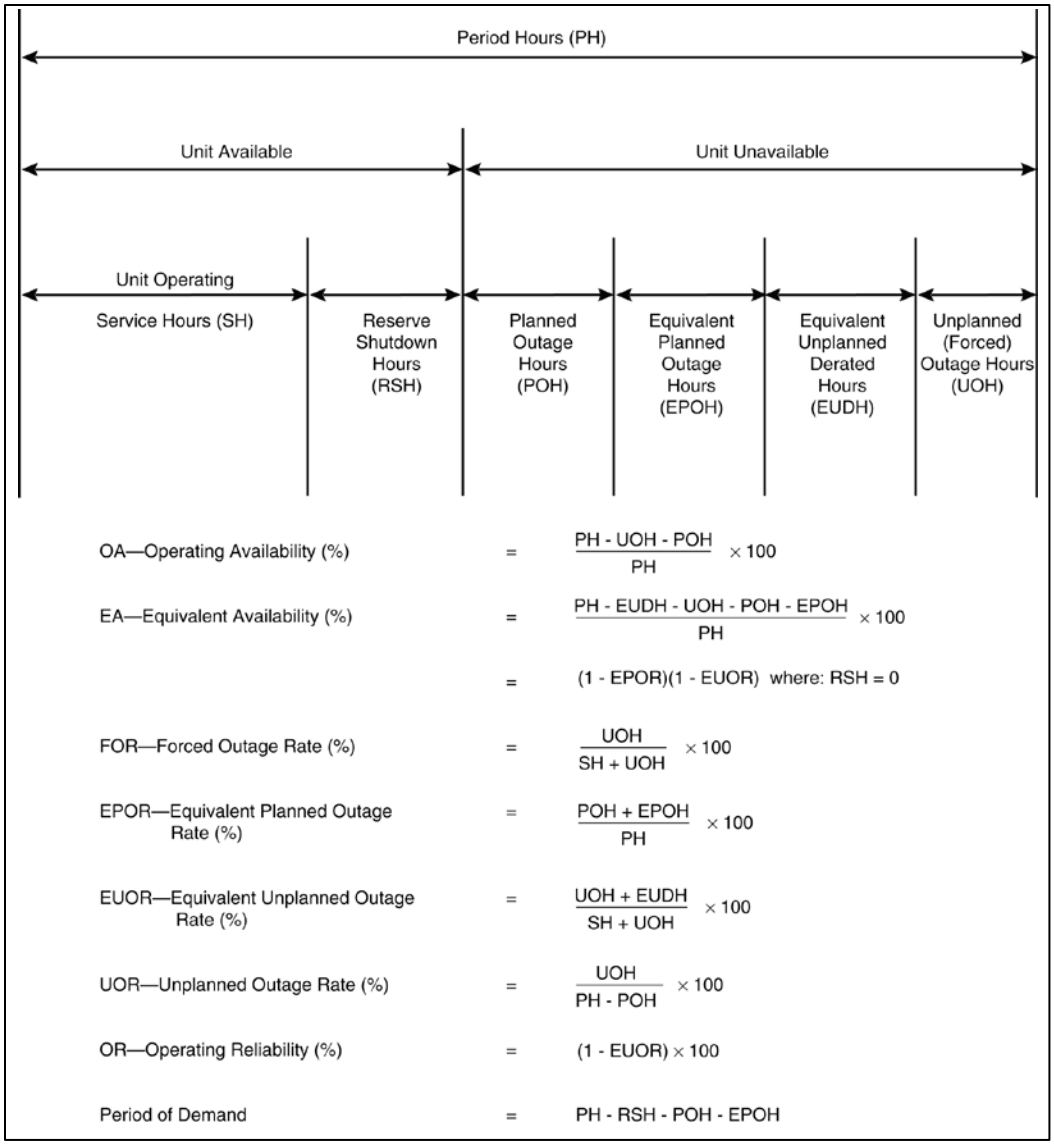

Figure 3-9
Availability definitions and calculations

Storage Technologies

Li-ion battery and underground CAES are evaluated in this section of the report.

Location

The battery storage plants that were evaluated in this study are generic greenfield plants. The CAES plant is assumed to be located at a site with suitable geology for underground air storage. The compressed air can be stored in several types of underground media, including porous rock formations, salt or rock cavern formations, and depleted oil/gas fields.

Generating Unit Size

The Li-ion battery systems evaluated in this study were 1 MW with 1 hour storage, 20 MW with 1 hour and 4 hours storage, and 100 MW with 1 hour and 4 hours storage. The CAES plant evaluated was 180 MW with 8 hours of storage capacity.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For Li-ion battery plants, this area includes the battery system rack, power conversion system, and controls system. For the CAES plant, this area includes the underground storage system, and the above-ground systems such as the CT and air compressor. 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.

4
CAPITAL COST ESTIMATING BASIS

Cost estimates were developed for each technology that was evaluated in this report. TPC and O&M costs are presented as overnight costs, which assume that the plant is built overnight and, therefore, do not include interest and financing costs. All costs are expressed in January 2021 South African rand (ZAR). These TPC estimates include the following:

- Equipment
- Materials
- Labor (direct and indirect)
- Engineering and construction management
- 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 South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for all technologies that were 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 that were included in this study, minimal site clearance and preparation was assumed, and no provision was made for new infrastructure or improvements to existing infrastructure, such as roads and transmission lines, because these are 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 that was used for developing overnight TPC and O&M estimates and the TAGWeb assumptions that were used for calculating TCR. It also covers 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. 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, using 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 20210 U.S. dollars (USD).

After capital and O&M costs were established for a U.S.-based plant with the same design as the previous study, 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 using the 2020 Richardson International Construction Factor Manual. For this update, these costs, reported in January 2021 USD, were then converted to ZAR based on an exchange rate between USD and the South African rand of 18.13.

All costs 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

The developed set of factors for conversion of construction costs developed in the U.S. Gulf Coast to the cost of construction in South Africa are shown in Table 4-1. From this table, the material costs for South African projects are approximately 11% higher for locally produced materials and 32% higher for imported materials when compared to the U.S. Gulf Coast base case. These increased material costs are largely offset by labor costs resulting in an average location factor of approximately 6%. This will vary among technologies based on the material versus labor allocation when looking at TPC.

Table 4-1
U.S. to South Africa construction factors

Data from Cost Data Online, Inc *2020 Richardson International Construction Factor Manual* **Location Factors**	**Base: Houston, Texas, USA**	**Johannesburg, South Africa**
Labor index	1.00	0.60
Imported material index	1.05	1.32
Local material index	1.00	1.11
Labor location factor	0.21	0.12
Engineered equipment location factor	0.60	0.72
Field material location factor	0.19	0.22
Location factor (not incl. currency)	1.00	1.06

EPRI assumed that a portion of the equipment used for these plants would be imported from outside South Africa and the remainder of the plants' materials and construction labor would be supplied from within South Africa. Based on 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 versus local equipment, materials, and labor, as well as the assumed material versus labor breakdown for the local portion of the cost.

Table 4-2
Assumptions of imported versus local, material versus labor percentages

Technology	Imported	Local	Materials (Local)	Labor (Local)
PC	35%	65%	50%	50%
IGCC	35%	65%	60%	40%
FBC	35%	65%	50%	50%
Nuclear	35%	65%	60%	40%
CCGT	35%	65%	60%	40%
OCGT and ICE	35%	65%	85%	15%
Wind	70%	30%	75%	25%
Solar thermal	50%	50%	45%	55%
Solar PV and storage	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 United States (in USD), based on the assumption that the same transportation costs applied for shipping to the United States and South Africa.
- The local portion of the costs was broken down into materials and labor and adjusted according to the factors that are provided in Table 4-1.
- The imported and local costs were then combined in USD and converted to ZAR based on the currency exchange rate of 18.13 ZAR/USD that was provided to EPRI by Eskom.

Figure 4-1 shows this cost estimating approach graphically.

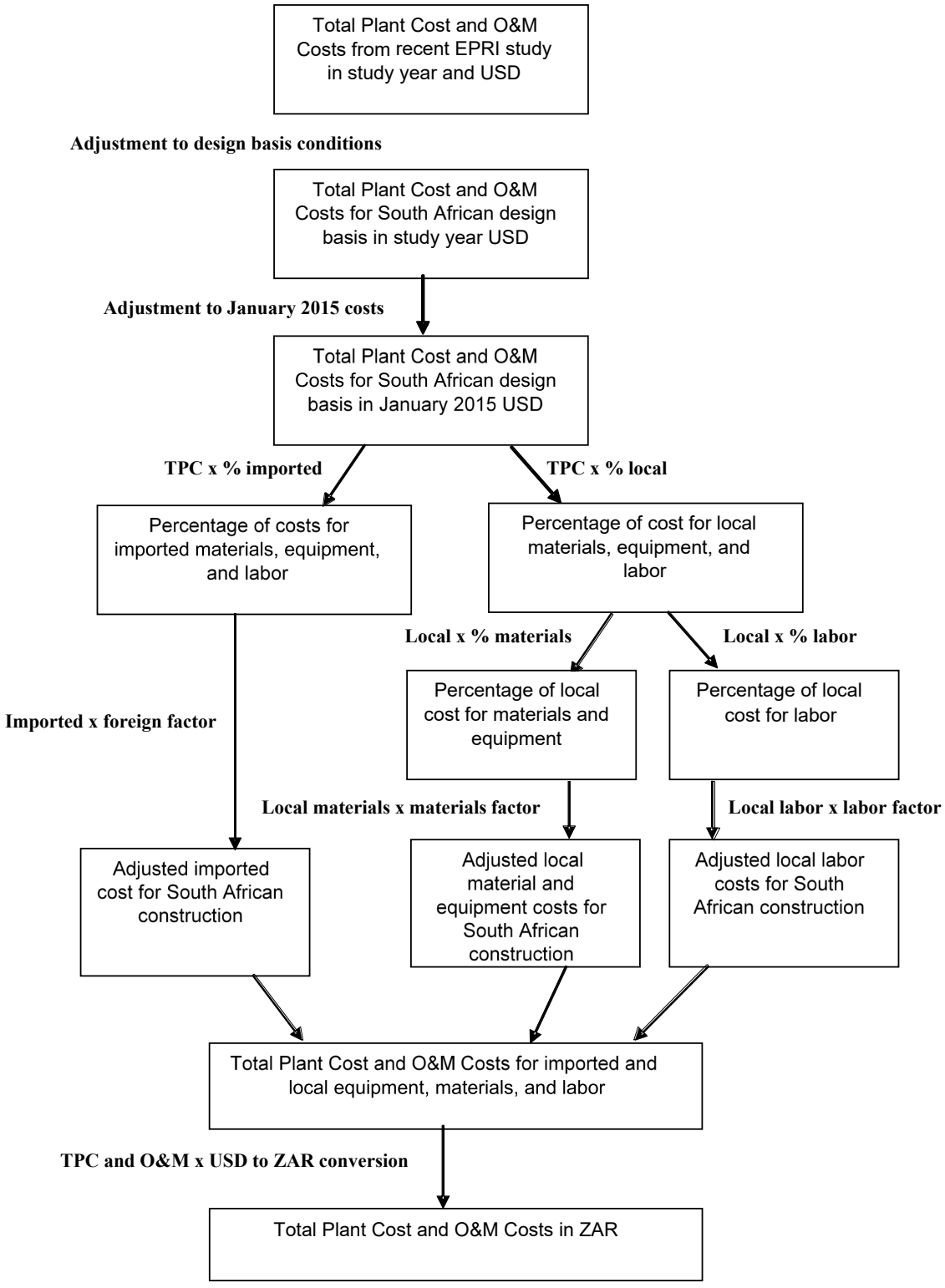

Figure 4-1
Cost-estimating approach

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 applied to the fixed O&M estimates. Variable O&M costs were adjusted using the currency exchange rate but did not consider 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 the following:
  - Prepaid royalties
  - Preproduction (or startup) costs
  - Inventory capital (fuel storage, consumables, and so forth)
  - 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 of fixed operating costs (O&M 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 byproducts during startup.

Inventory Capital

The value of inventories of fuels, consumables, and byproducts 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

Whereas a single-unit project schedule and startup is quite common, multiple-unit projects are favored in some cases where the demand for power is substantial and/or expected to grow and economy of scale lends itself to favorable contracting terms, thereby lowering overall project costs. In such a scenario, a sequential and staggered approach to project schedule with a second- and third-unit project startup one or two years after the first unit and operation following a similar order is normal. The sequential approach serves two purposes, as follows:

- The borrowing costs are staggered, thereby 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 of 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 and two units. It was assumed that the coal units would be built with sequential project initiation and startup at one-year intervals between units. Nuclear units were assumed to be built with sequential project initiation and startup 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.

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.

Tables 4-4 through 4-6 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 following 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)

5
COST OF ELECTRICITY METHODOLOGY

Introduction

This section covers 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 recover from their customers 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	70	11.0	7.7	6.2	4.4
Preferred stock	N/A	N/A	0.0	N/A	0.0
Common stock	30	13.8	4.1	8.9	2.7
Total annual return			11.8		7.0
Inflation rate	4.5				
Federal and state income tax rate	28				
Property taxes, insurance, and other taxes	2.0				
Discount rate					
After tax			9.7		5.8
Before tax			11.8		7.0

The Components of Revenue Requirements

An Overview

The components of revenue requirements can be divided into two parts: 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 the operating expenses, which include fuel and nonfuel O&M costs (see Figure 5-1).

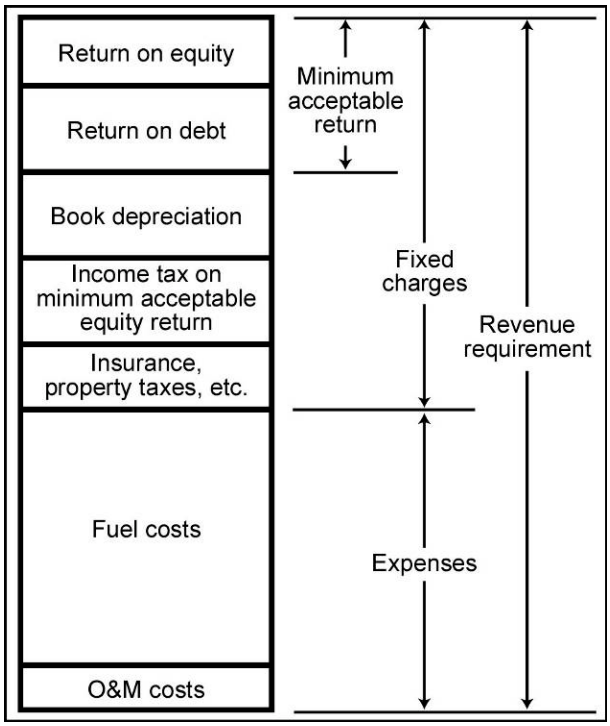

Figure 5-1
Revenue categories for the revenue requirement method of economic comparison

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*. Therefore, the booked costs for utility plants are recovered over roughly the period of time that 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, in 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. Therefore, 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.

Although 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 it is 25 years, and for wind plants it 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. Therefore, 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	25	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 sufficient for a utility to maintain its financial credit, capable of attracting whatever capital may be required in the future, and 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. 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 that was 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 covered previously 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 Table 5-4 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	1000
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 $1214/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 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:

$$P/F = 1/(1 + i)n \qquad \textbf{Eq. 5-1}$$

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, $n = 20$.

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
22	$100.47	0.083	0.162	$16.31

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
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:

$$A/P = [i(1+i)n] / [(1+i)n - 1] \quad \text{Eq. 5-2}$$

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 preceding example, the total present value (P) is $1580.4/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

The 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 Versus Current Dollars

Cost of electricity is often presented on a levelized basis. Like the annual revenue requirement presented previously, 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 considered when looking at future costs, whereas in current dollar analysis, the effects of inflation are considered. Although 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 ZAR per kilowatt (ZAR/kW). Using the annual revenue requirement calculations described previously, 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 considered; 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, whereas 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. Again, for current-dollar analysis, the year-by-year costs are calculated using general inflation, whereas 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, once the leader in share of global power generation, now produces about 37% of the world's electric supply [1]. 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 (1000°F) and pressures around 16.5 MPa (2400 psig). Present-day supercritical units generate steam at pressures of at least 24.8 MPa (3600 psig) with steam temperatures of 565–593°C (1050–1100°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 1–2% lower than that of supercritical units. Supercritical units operate at about 2 percentage points higher efficiency than subcritical units (that is, increasing from 36.5 to 38.5% efficiency on a higher heating value [HHV] 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, and 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 (that is, an air-cooled condenser) was 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 (that is, 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 preheated feedwater enters the economizer section of the steam generator and 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 is collected and pumped forward to start the circuit again.

The PC plant that was evaluated in this study is a supercritical plant operating at 24.8 MPa (3600 psig) with main steam and reheat steam temperatures of 565°C (1050°F). A schematic diagram of a PC supercritical generating unit is shown in Figure 6-1.

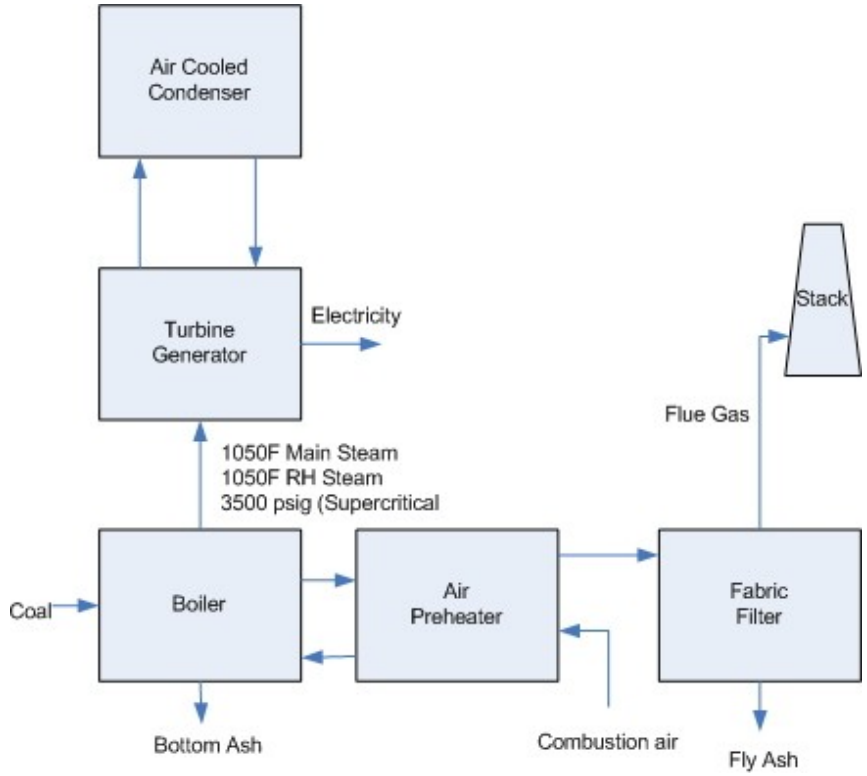

Figure 6-1
Simple schematic of PC (supercritical) generating unit

The first supercritical coal power plant was built in the late 1950s. Since then, hundreds of units have been built around the world. Research and development (R&D) continue to advance the supercritical technology and resulted in improved reliability, fuel flexibility, and wider load range operation.

Because of regulations in the United States, 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. In this study, PC plants are considered both with and without FGD units for environmental controls on top of pulse jet fabric filters (FFs) for particulate control. In cases that include CO_2 capture, a selective catalytic reduction (SCR) system is also included for NO_x removal.

A LSFO wet scrubber is the most widely used FGD system and is the system used 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 can be marketed in the United States, 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 FF 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) reacts with the amine solvent, forming heat stable salts. Although SCR is not necessarily required for a PC plant with capture, if it is not included, the plant would most likely 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 so that when passing over the catalytic 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. 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.

As shown in Figure 6-2, 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

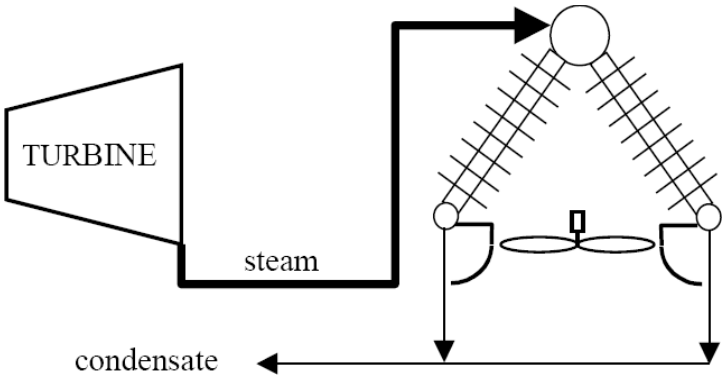

Figure 6-2
Conceptual diagram of a 100% dry cooling system

Integrated Gasification Combined-Cycle

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 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 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 6-3. It is the integration of the system components that brings the most important advantage of IGCC plants.

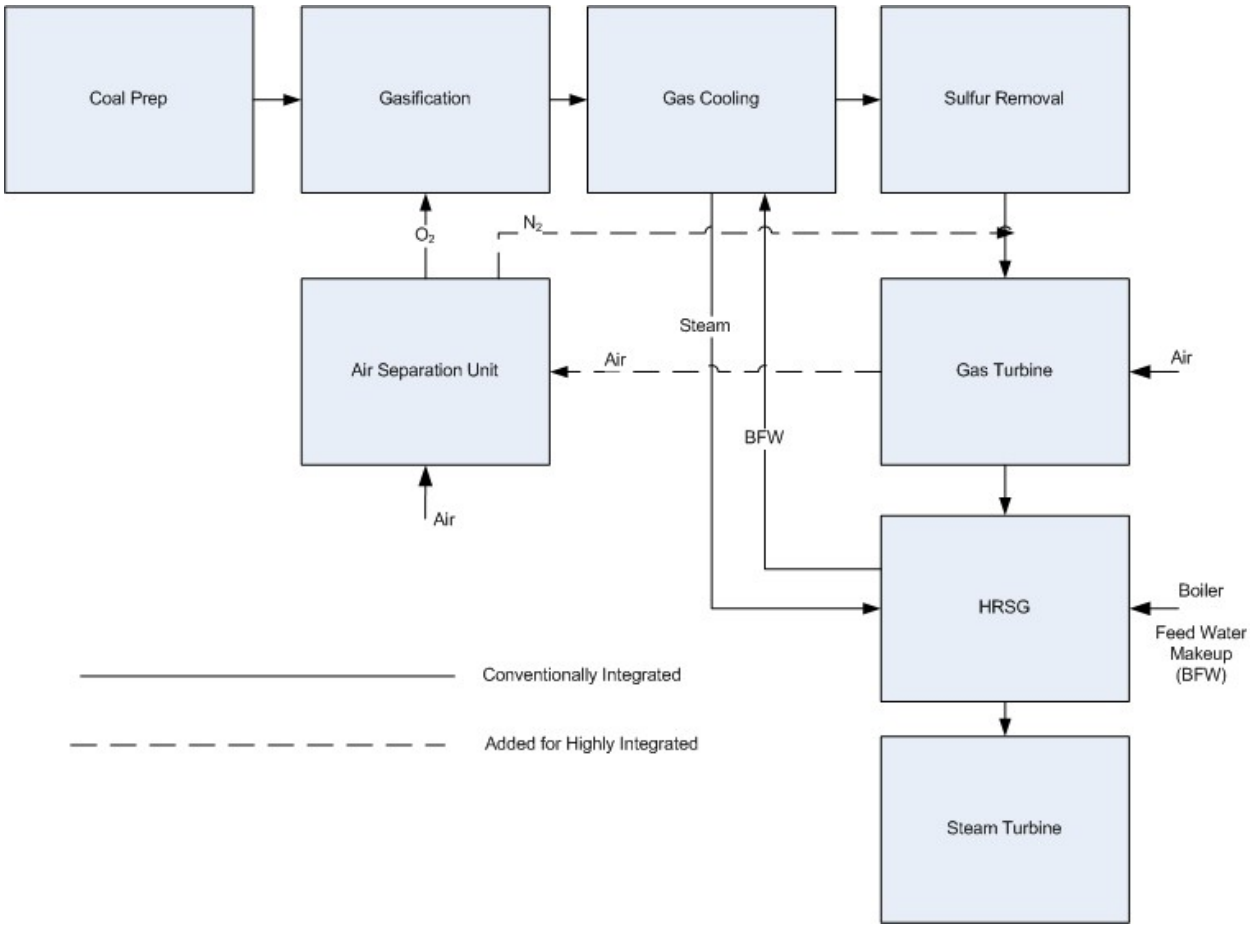

Figure 6-3
Schematic of an IGCC power plant

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 several 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 cleanup, 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 consisting 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 byproduct of the ASU is fed back to the combustor for dilution to reduce NO_x 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 cleanup equipment. Gas cleanup 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 ASU (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 produces 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 CT 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 is designed to match characteristics of the CT, HRSG, and condenser. The different heat, steam, and water requirements of the gasification system would 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 (General Electric [GE], ConocoPhillips [COP], and Shell) that operate in the high-temperature slagging region. Although 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 because achievable energy content of the slurry would probably be even lower than for the U.S Powder River Basin 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 lignite. 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 minemouth power plant sites. The power output of a GT is markedly affected by elevation because 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.

Fluidized Bed Combustion

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 (1520 and 1610°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 like that of a conventional PC boiler. Figure 6-4 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 that was evaluated in this study is a subcritical plant with main steam at 16.5 MPa (2400 psig) and both main steam and reheat steam at 565°C (1050°F).

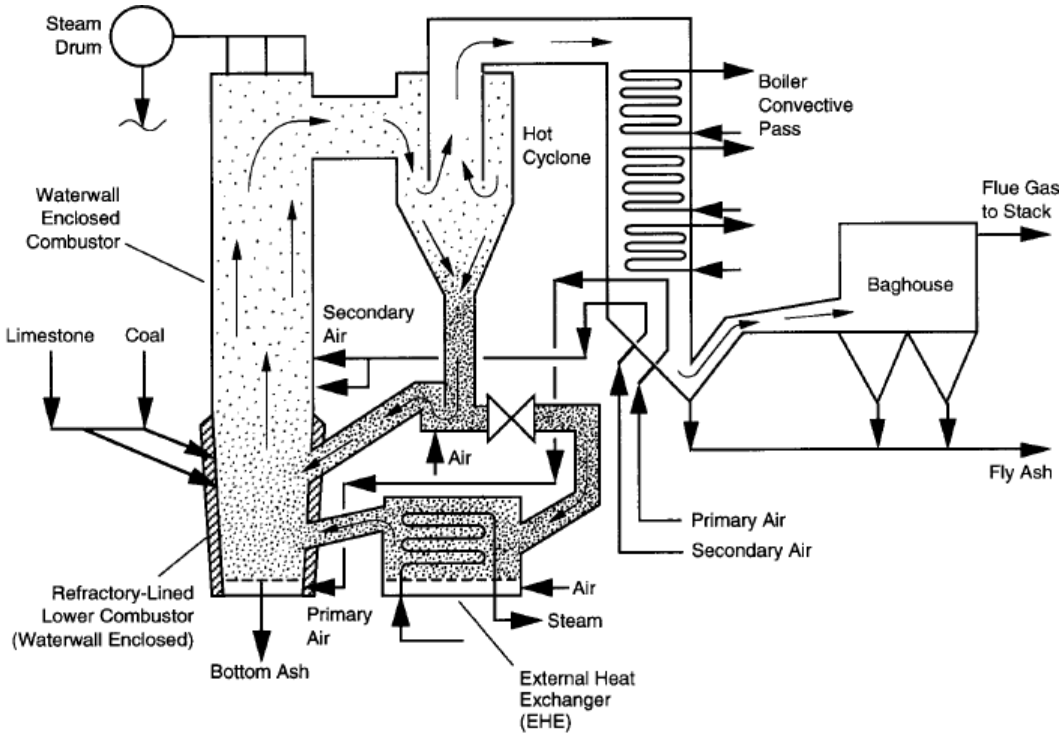

Figure 6-4
Schematic of an FBC boiler system
Used with permission from SFA Pacific, Inc.

FBC boilers operate at gas velocities high enough to entrain much of the bed material between 3.7 and 9.1 m/s (12 and 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, and so forth) 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, 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 external heat exchanger are then recycled to the foot of the furnace.

Because there are no tubes in the bed, air staging is possible in an FBC, which results in lower NO_x 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 NO_x formation. The remaining air is added approximately one-fifth of the way up the reactor, just above where the refractory lining ends. Although NO_x 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, thereby greatly reducing the fouling of heat transfer surfaces. Therefore, 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.

Nuclear Technologies

The current fleet of nuclear power plants is mature and supplied approximately 20% of the electricity generated in the United States and 10% of the electricity generated in the world in 2020 [2]. 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 reduced interest in nuclear power, at least in some areas of the world.

Compared to other large-scale central stations, nuclear plants typically have higher construction costs but lower operating costs. High construction costs are mostly due to the safety and security requirements, including 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 well managed and when the plant is expected to operate at a high-capacity factor throughout the plant life. Due to the relatively lower 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, which requires prudent management.

Nuclear power is generated through a fission chain reaction. The heat produced during fission is transferred through gas or liquid to produce steam. Light water reactors (LWRs) 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 use 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 fuel consisting of plutonium and enriched uranium oxides, thorium, and actinides are also used as nuclear fuel.

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. The last Generation I reactor—located in the United Kingdom—was shut down at the end of 2015 [3].

Generation II nuclear reactors include LWR of two primary types—PWRs and boiling water reactors (BWRs). PWRs use 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 constitute the vast majority of reactors in operation today. They generally use enriched uranium fuel. The AGR uses graphite as the moderator and natural uranium for fuel. The Canadian deuterium/uranium reactor also uses 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 like 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 burnup. 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 time frame. In addition to higher thermal efficiency, the major feature for these reactors is their expected 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 that the fuel associated with these reactors is more resistant to nuclear proliferation. It is also expected that these reactors could 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 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 1700 MW. Installations are in Russia, China, India, Ukraine, Finland, Germany, and Iran. Installations are planned or being constructed in Belarus, China, Czech Republic, Finland, Hungary, India, Russia, and Turkey [4]. Toward the end of 2014, Russia 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. Because the VVR plan design has not received certification by the U.S. nuclear regulatory agencies, the data to support this study were not as readily accessible. 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 $2121/kW (2015$). The study goes on to suggest that the difference could be due to certain costs not being included in the final report installation costs (that is, providers of the data not including design costs in the estimate).[17] A recent report from Columbia University's Center on Global Energy Policy lists an estimate of $4200/kWe for a Belarusian project using two VVE-1200 reactors.[18]

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

[18] A Comparison of Advanced Nuclear Technologies, Columbia | SIPA Center on Global Energy Policy, 2017.

Without further data to support the most probable cost estimate for the VVR design, it is not included in the analysis portion of this report. This report focuses on Areva's EPR, Westinghouse's AP1000, and a representative small modular nuclear plant.

Areva EPR

The Areva EPR is based on the PWR design. Unit 1 of the Taishan plant in China's Guangdong province became the first EPR to enter commercial operation in December 2018. Taishan 2 began commercial operation in September 2019. Reactors of this type continue to be constructed in Finland, France, and the United Kingdom [5–7]. Additionally, a U.S. version of this design known as the *U.S. EPR* was under review by the Nuclear Regulatory Commission (NRC) for licensure but was canceled in 2015 [8]. 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 during the past 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 (that is, up to 5%) or MOX fuel. The U.S. EPR design also allows for a flexible operating cycle (that is, 12–24 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) consists 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 prestressed concrete; the outer, of reinforced concrete; and both walls are 1.3 m thick, designed to withstand postulated external hazards (for example, an 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, and 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 alternating current (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, 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.

Westinghouse AP1000

The Westinghouse AP1000 is a 1200-MWe (1115-MWe net) advanced PWR 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 startup. The schedule and cost for two units constructed in parallel have an estimated seven-year project duration.

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.

The AP1000 power plant fuel design is based on a design used successfully at plants in the United States 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). Except for 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 baseload operation but also has load-follow capability.

A typical site plan for a single unit AP1000 has a power block complex that 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 like those currently used in Westinghouse reactors. The reactor is water cooled and moderated and uses 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, 1800-rpm machine (1500 rpm for 50-HZ applications). The turbine generator is intended for baseload operation but also has load-follow capability.

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 heating, ventilation, and air conditioning). The AP1000 passive safety systems are significantly simpler than typical PWR safety systems because 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 safeguard's actuation signal. They are supported by multiple, reliable power sources to avoid unnecessary actuations.

The AP1000 passive safety-related systems include the following:

- 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.

Small Modular Reactors

SMRs are another technology garnering interest for their potential to provide safe, scalable, dispatchable, and carbon-free energy. The U.S. NRC defines an *SMR* as any LWR producing under 300 MWe. This report focuses on the SMR design developed by NuScale Power, LLC, which has developed the first and only SMR technology to gain design certification approval by the NRC. The detailed study presented in *Program on Technology Innovation: Small Modular Reactor Technology: 2020 Cost and Performance Update* (EPRI report number is forthcoming) [9] is the basis of the following overview.

The technology of an SMR plant is like that of an advanced nuclear power plant but is more simplified while making use of natural phenomena to ensure passive safety responses. Although the reactors are made of the same components, the mechanical systems of an SMR are much smaller. SMR plants typically consist of multiple small-scale reactors operating in the same location, whereas most traditional nuclear plants use only one or few reactors on a much larger scale.

A NuScale SMR plant houses twelve 60-MWe (gross) reactor modules. Although the base plant configuration generates 720 MWe (gross), the modules can be uprated to produce approximately 25% more power than originally expected. Each reactor module, as shown in Figure 6-5, is vertically oriented and consists of a nuclear core, housed in a reactor vessel, and steam generator all within a containment reactor vessel. These containment vessels are partially immersed in a cooling pool, which acts as the ultimate heat sink in the event of an emergency. The pressurizer inside the reactor vessel provides reactor pressure control. The integral design limits external components or piping which greatly increases the simplicity and safety of the module.

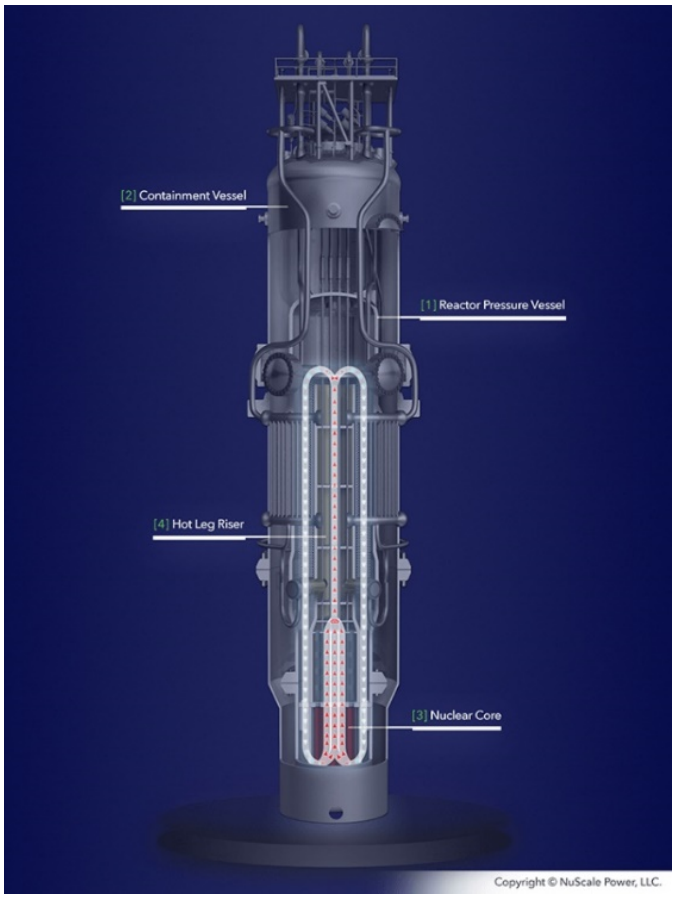

Figure 6-5
SMR individual unit
Used with permission from NuScale Power, LLC

The reactor vessel of the NuScale Power module is approximately 20.0 m (65 ft) tall and 2.7 m (9 ft) in diameter. The integral vessel contains the nuclear core consisting of fuel assemblies and control rod clusters. The fuel assemblies contain a 17-by-17 array of zircalloy-clad, low-enriched UO_2 fuel similar to traditional pressurized LWRs [10]. A central hot riser, helical coil steam generator surrounding the hot riser tube, and pressurizer are located above the core. The helical coil steam generator consists of two independent sets of tube bundles with separate feedwater inlet and steam outlet lines. Pressurized water—like in a conventional PWR—is heated as it passes over the reactor core. The water rises within the interior of the vessel by natural convection and buoyancy as it heats up. After the heated water reaches the top of the riser, it turns downward and cascades over coiled steam generator tubes, which contain cooler nonpressurized water—again, like a conventional PWR. When the hotter (primary) water contacts the steam generator tubes, it transfers energy to heat the cooler (secondary) water inside the tubes by conduction, causing it to flash to steam. This steam is then directed outside the containment vessel to drive individual steam turbines (one per module) that are attached by a single shaft to an electrical generator. After passing through the turbine, the steam is condensed back into liquid form in the condenser and then pumped by the feedwater pump back to the steam generator [11].

To summarize, SMR technologies offer several potential benefits. They are as follows:

- **Independent BOP**. As alluded to previously, each BOP system is independent, containing a steam turbine and all necessary pumps, tanks, heat exchangers, electrical equipment, and controls for operation. This enables independent operation of each reactor module, which, in turn, allows for greater efficiencies at lower operating loads when dispatched capacity is reduced.
- **Reliability**. The SMR is expected to provide exceptional reliability, with an anticipated capacity factor in excess of 95% and a grid reliability factor of 99.98% over the 60-year life of a plant.
- **Versatility**. SMRs are adaptable to nonelectrical applications such as alternative revenue streams such as desalination and hydrogen fuel production. SMRs can also respond relatively quickly to varying electrical generation demands by shutting down or varying power for any number of SMR modules (like that of a multi-unit combined-cycle power plant).
- **Modularity**. The modular design of the reactors allows for components to be fabricated and shipped to a project site, contributing to lower capital costs, shorter construction times, greater security, and other efficiencies. The modularity also allows facilities to deploy additional reactor modules as capacity demands increase or as other generation sources are retired.
- **Economies of scale**. SMR technologies capture economies of scale around plant architecture (for example, footprint), simplified design (including fewer systems and components), labor efficiencies, enhanced learning with respect to manufacture and operations, multiplicity of generating units, and standardized design.

The potential disadvantages of SMR include the following:

- **Nuclear waste**. Like any other nuclear reactor unit, the SMR will generate nuclear waste that will need to be dealt with accordingly. Although automation and controls help to reduce risks associated with refueling, the waste requires containment, as well as maintenance to monitor decay and keep personnel and the environment safe.
- **First of a kind**. SMR technology is new and yet to be commercially demonstrated at scale as an integrated system. This carries inherent risks relating to costs, performance, and construction time. Risks will be reduced as SMR technology is deployed.
- **Public perception**. SMR technology shares inherent concerns regarding nuclear generation, particularly considering events such as the 2011 Fukushima nuclear accident. Although the use of passive cooling systems could improve public acceptance of nuclear technologies, it is likely that the success of an SMR facility will still depend greatly on swaying public perception.
- **Cost**. The overnight capital costs of SMRs are expected to be more expensive than conventional and renewable generation technologies. There are many factors that affect the cost and market of SMR generation, including electricity prices, financial capabilities of vendors, and supply chain readiness.

SMRs are offer the possibility to combine nuclear with alternative energy sources, including renewables. Due to their small physical size and modularity, SMRs present a viable power generation option for remote regions with less developed infrastructure. SMRs are also being explored for their suitability for nonelectric applications and cogeneration. NuScale Power, LLC, is working with Utah Associated Municipal Power Systems (UAMPS) to build the first-ever NuScale SMR plant in Idaho, which is expected to be fully operational by 2030. Figure 6-6 shows an artistic rendering of the UAMPS facility, which is planned to supply wholesale electricity to UAMPS' 48 member utilities across six Western states.

Figure 6-6
Artistic rendering of SMR facility plant design for UAMPS
Used with permission from NuScale Power, LLC

Hualong One

China has an aggressive nuclear deployment schedule, with 48 nuclear reactors in operation, 12 under construction, and nine planned [12]. Figure 6-7 shows the projected growth of China's nuclear fleet. Seven of the 12 plants under construction use the Hualong One reactor model, three use the ACPR1000, and three use the HTR-PM. The first CPR-1000 unit was commissioned in 2010. The last two CPR-1000 installations, Hongyanhe 3 and Nindge 3, were commissioned in March 2015.

Figure 6-7
Nuclear power plants in China
Used with permission from World Nuclear Association, 2020 [13]

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, whereas 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 two EPR units in China, both taking 84–96 months for construction. In both examples, the construction schedule of the CPR-1000 units is quite favorable.

The 44 nuclear power plants that are being planned are based on one of several designs: ACPR50S, ACP100S, CAP1400, CAP1000, VVER-1200/V-491m, CFR600, 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 and the China General Nuclear Power Group. The gross capacity is 1150 MWe. 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 governed by the International Atomic Energy Agency in December 2014. The international use of the design will still depend on meeting country-specific standards and requirements, but passing the International Atomic Energy Agency safety review should make this process easier.

The pilot Hualong nuclear power design was used at the Fuqing Power station—Units 5 and 6. Construction on Unit 5 began in May 2015, and it was commissioned in September 2020. Currently, five other Hualong One units are under construction in China—Taipingling in Guangdong, Zhangzhou in Fujian province, and Fangchenggang in Guangxi province. In addition, two Hualong One units are under construction at Karachi in Pakistan, with China's support, as well as a proposed UK version of the Hualong One at the planned Bradwell nuclear power plant. 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 and has already started actively marketing its design in Northern Africa, Saudi Arabia, Egypt, Sudan, and South America [14, 15].

The target cost of the ACPR1000 in China is $2500/kW, according to 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 2300-MW project in Pakistan is $9.6B, or approximately $4200/kW, and it is expected to be commercially operational in 2021 [16].

The Areva EPR is based on the PWR design. The first reactor of this type is expected to be operational in Finland by 2022, with another in France expected to be operational by 2023 [17]. 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 1600 MW, which is under review by the NRC 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 recently constructed an APR1400 reactor—Shin-Ulchin 1—and is currently constructing multiple additional APR1400 reactors that are expected to become commercially operable before 2025 using South Korea's advanced PWR design. The reactor design was jointly developed by the Korea Electric Power Corporation (KEPCO) and the Korea Hydro and Nuclear Power (KHNP) [18]. The APR1400 is a Gen III design with a 60-year life. The gross electrical capacity is 1400 MWe. 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.

Shin Kori 3 and Shin Kori 4 entered commercial operation in December 2016 and August 2019, respectively. South Korea is currently constructing four APR1400 units. Shin Hanul 1, Ulchin and Shin Hanul 2, Ulchin are expected to be commercial in July 2021 and May 2022, respectively. Similarly, Shin Kori 5 and 6 have been under construction since 2016 and are expected to be commercial in March 2023 and June 2024, respectively [18]. Outside of South Korea, there is one operational unit in the United Arab Emirates and three additional units under construction [19]. The three units are scheduled to be in operation by 2021. The current estimate for the United Arab Emirates project is approximately $3571/kW ($20 billion/5600 MW).

As with China, South Korea has its sights on achieving big gains in the export market. The NRC accepted the application from KEPCO and KHNP to complete the U.S. 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 1550-MW evolution of the AP1400. Its modular construction is expected to reduce the construction time from 52 months to 36 months.

Pebble Bed Modular Reactor

A pebble bed modular reactor (PBMR) is a high-temperature helium gas-cooled nuclear reactor, which builds and advances on worldwide nuclear operators' experience with older reactor designs. PBMRs are designed to produce 110 MW. Multiple PBMRs can be located in a facility to create energy parks. A PBMR energy park can consist of up to 10 modules sharing a common control center. This system allows sequential construction of modules to match users' growth requirements, so that more modules can be added to meet localized load growth.

A single PBMR reactor would typically consist of a single main building, covering an area of 1300 m^2 and reaching a height of roughly 42 m. Some of the main structure would be below ground level, depending on the bed rock formations because the building would sit on bedrock. The above-ground portion of the structure would be equivalent to a six-story building. In addition to a unit control room and a high-voltage switch yard, a cooling tower for inland facilities and a sea pump house for coastal facilities would be present.

Safety is arguably the most attractive feature of the PBMR, because some researchers cite that that the fundamental design, materials used, fuel characteristics, and natural physics involved reduce the risk of nuclear accidents, including meltdowns. Short construction lead times, the ability to site reactors near points of demand, ease of storing spent fuel, low operating costs, and load-following capability have also sparked interest in PBMR.

X-energy, an American-based nuclear reactor and fuel design engineering company, is developing a pebble bed, high-temperature gas-cooled reactor capable of producing approximately 76 MW of electric power. X-energy is developing its Xe-100 reactor and specialized uranium-based pebble fuel that could be commercially available as early as the late 2020s. All components of the Xe-100 are designed to be road-transportable and will be installed, rather than constructed, at project sites.

The expected benefits of the Xe-100 include the ability to do the following:

- Operate at high temperatures to produce electricity more efficiently
- Use high-temperature helium gas in other energy-intensive processes that currently rely on fossil fuels, such as hydrogen production and petroleum refining
- Load-follow (from 100 to 40% power within 20 minutes), making the plant complementary to maintaining a stable load on a grid that includes renewables
- Continuously fuel and store fuel on-site, delivering high availability (93–95%) and promoting plant resiliency
- Reduce construction time (2.5–4 years for a 300-MWe plant)
- Use factory-produced components, enabling improved quality control and reducing per unit costs

Flexible Nuclear Generation

Nuclear reactors are known for their ability to provide constant power, and older models have been preferentially used for baseload generation for technical and economic reasons in most applications to date. However, there continues to be interest in better understanding whether nuclear power can play a flexible role within an electricity system, so that their output can be modified to meet certain grid demands.

Modern Generation III and III+ are technically capable of flexible operation. Generation III+ PBMR designs are expected to have excellent load-following capabilities, despite having highly enriched fuel, which typically makes it more difficult to control the reactor. Load-invariant high reactor temperature levels, relatively homogenous flux distribution, very low power density, and continuous reactivity control are the other key technical features of Generation III+ PBMR that would allow for operational flexibility. Heavy water reactors also provide inherently high levels of flexibility and can load-follow between 60 and 100% of their full power, whereas most PWR plants are capable of load-following between 30 and 100% at rates from 1 to 3% per minute. Generally, significant planning, forecasting, and time are required to flexibly operate nuclear power plants, and the ability of operators to modify power output decreases toward the end of the fuel cycle. As covered previously, smaller reactors, such as SMRs and microreactors, are emerging as one of the biggest trends in nuclear power generation. Some SMR plants being constructed will use multiple units within a single plant to rapidly provide power when and where it is needed, where each power module could also work independently to ramp down power simultaneously.

Table 6-1 summarizes key technical features (and assumed parameters) of the Westinghouse AP1000 advanced PWR, Areva EPR, and SMR technologies that enable flexible operations.

Table 6-1
Summary of nuclear technologies capable of flexible operations

Category	Parameter	AP 1000		Areva EPR		SMR
Cooling technology	-	Once-Through Seawater				
Number of units	-	1	2	1	2	12
Unit size (net MW)	-	1117	1117	1600	1,600	60
Plant size (MW)	-	1117	2234	1600	3,200	720
Gross capacity	-	3,400 MWt (1,217 Mwe)	6,800 MWt (2,434 MWe)	4,590 MWt 1,720 MWe)	9,180 MWt (3,440 MWe)	2,400 MWt (720 MWe)
Net capacity	-	1,117 MWe	2,234 MWe	1,600 MWe	3,200 MWe	683 MWe
Performance estimates	Economic life, years	60	60	60	60	60
	Efficiency and/or heat rate	-	-	-	-	-
	Efficiency	32%	32%	36%	36%	30%
	100% load (Btu/kwh)	10,663	10,663	9,478	9,478	11,373
	Plant load factor (% of full load)		-	-	-	-
	Typical	85	85	85	85	95
	Maximum	100	100	100	100	100
	Minimum	60	60	60	60	30%
	Ramp rate %/h	-	-	-	-	-
	Up	3–15%	3–15%	3–15%	3–15%	50%
	Down	3–15%	3–15%	3–15%	3–15%	50%
	Startup time (h)	48	48	48	48	23

International Nuclear Costs

Some researchers have worked to analyze nuclear power project cost trends across the globe to inform policy and resource planning discussions, particularly as the challenges and prospects of using nuclear power as a flexible low-carbon supply option continue to be studied.

Overnight construction costs (OCC) of nuclear power projects are the dominant component of lifetime costs for nuclear power and the component that varies most over time and between countries. OCC includes the costs of the direct engineering, procurement, and construction services that the vendors and the architect-engineer team are contracted to provide, as well as the owner's cost, which includes land, site preparation, project management, training, contingencies, and commissioning costs. Many studies of historical costs document increased costs for nuclear power projects over time, even as more nuclear projects were deployed. Most data have been from the United States and France, because these two countries have historically had the first and second largest fleets of nuclear reactors and were early leaders in the commercial nuclear power industry. A more recent study of national-level costs by Lovering et al. [20] shows a decreasing cost trend in South Korea, which entered the nuclear market much later than the United States, France, Canada, Germany, or Japan—in 1972. Unlike the cost behavior observed in the early nuclear pioneer countries, the cost of nuclear power in South Korea declined by 2% annually between 1971 and 2008, which suggests that there is not a universal cost trend for nuclear technology but a plurality of different country-specific experiences. Table 6-2 summarizes observed cost trends for the United States, France, Canada, West Germany, Japan, India, and South Korea [20].

Table 6-2
Summary of observed international nuclear technology cost trends

Country	Era	Annualized Rate of Change in OCC (%/year)	Total Change in OCC by Era (%)
United States	1954–1968, 18 demonstration reactors	-14%	-81%
	1964–1967, 14 turnkey reactors	-13%	-33%
	1967–1972, 48 reactors completed prior to Three Mile Island incident	+23%	+190%
	1968-1978, 51 reactors completed after Three Mile Island incident	+5 to +10%	+50 to +200%
France	1957–1966, 7 gas-cooled reactors	-17%	-82%
	1971–1999, 59 light-water reactors	+2 to +4%	+50 to +100%
Canada	1957–1974, 6 reactors	-8%	-77%
	1971–1986, 18 reactors	+4%	+60%
West Germany	1958-1973, 11 imported reactors	-6%	-63%
	1973–1983, 18 reactors	+12%	+200%

Table 6-2 (continued)
Summary of observed international nuclear technology cost trends

Country	Era	Annualized Rate of Change in OCC (%/year)	Total Change in OCC by Era (%)
Japan	1960–1971, 11 imported reactors	-15%	-82%
	1970–1980, 13 foreign designs	+8%	+100%
	1980–2007, 30 domestic reactors	-1 to +1%	-17 to +33%
India	1964–1972, 5 imported reactors	-7%	-38%
	1971–1980, 8 domestic reactors	+5%	+150%
	1990–2003, 6 domestic reactors plus 2 imported	-1%	-10%
South Korea	1972–1993, 9 foreign design	-2%	-25%
	1989–2008, 19 domestic reactors	-1%	-13%

Gas Technologies

Combined-Cycle Gas Turbine

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 6-8.

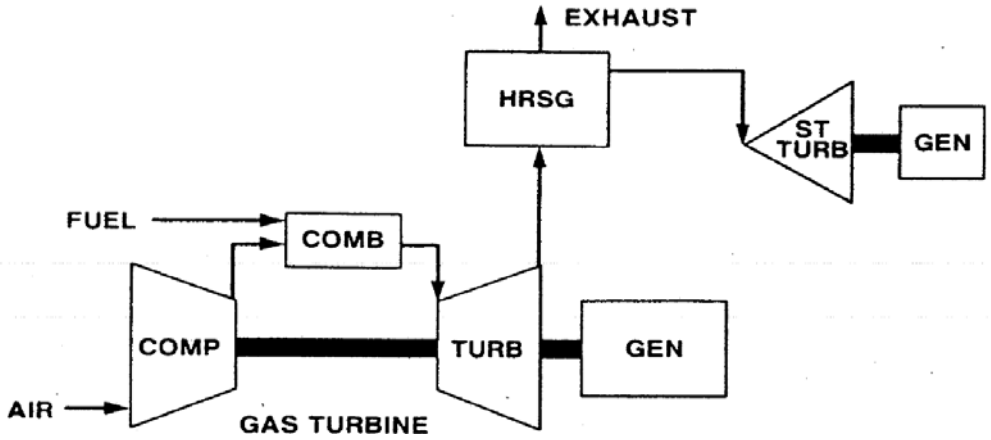

Figure 6-8
Simple schematic of CCGT

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 that is driven by the mechanical energy produced by the GT.

The hot exhaust gas exits the GT at temperatures between 538°C and 670°C (1000°F and 1240°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 and 17.23 MPa(g) (700 and 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-, F-, or lower-class turbine models, the state-of-the-art heavy-duty G-, H-, and J 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 and1093°C (1500 and 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 downflowed into the earlier models for efficiency and power output improvements. Table 6-3 provides typical correction factors that can be applied to combined-cycle output and heat rate with varying compressor inlet temperatures. Table 6-3 assumes a configuration that includes a mechanical draft cooling tower.

Table 6-3
Typical CCGT performance correction factors

Item	Output/Capacity	Heat Rate
Ambient temperature	2.5% drop for every 10°F rise	0.5% rise for every 10°F rise
Elevation	3.5% drop for every 1000-ft increase	0.2% drop for every 1000-ft increase
Inlet loss	0.3% reduction for every 1-in. water gauge (WG)	0.1% increase for every 1-in. WG
Outlet loss	0.1% reduction for every 1-in. WG	0.1% increase for every 1-in. WG

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 (that is, reheat or nonreheat), HRSG pressure levels (that is, 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 configurations for the purposes of this report are based on the Wartsila 18V50DF engine, GE 9F.05 GT, and GE 9HA.02 GT. The GT cases will consist of one and two GT configurations, with GT each exhausting into a dedicated HRSG, and sharing a common steam turbine-generator. The Wartsila engine combined cycle consists of 12 engines sharing a common steam cycle. All cases include dual fuel capability.

Open-Cycle Gas Turbine

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 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 so 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, so 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, because the work developed by the high-pressure turbine supplies all of the necessary energy to drive the compressor.

The main advantages of OCGTs 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 several 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, whereas 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.

Table 6-4 again illustrates the sensitivity of the power output of a GT 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 15°C ambient temperature at sea level drops to about 140 MW at 32°C ambient. The reference site conditions (according to International Organization for Standardization standards) for data presented are 15°C, 60% relative humidity, and sea level elevation.

Table 6-4
Typical OCGT performance correction factors

Item	Output/Capacity	Heat Rate
Ambient temperature	0.3–0.5% drop for every 1°F rise	0.1% rise for every 1°F rise
Elevation	3.5% drop for every 1000-ft increase	Elevation has minimal impact on heat rate
Inlet loss	0.4% reduction for every 1-in. WG	0.1% increase for every 1-in. WG
Outlet loss	0.1% reduction for every 1-in. WG	0.1% increase for every 1-in. WG

The GTs evaluated in this study are the GE LM6000 PF+, GE LMS100 PA+, GE 9F.05, and the GE 9HA.02 GT operated in peaking service with an annual capacity factor of 10%. The aeroderivative GTs (GE LM6000 PF+ and GE LMS100 PA+) and ICEs (Wartsila 20V34DF and Wartsila 18V50DF) were included due to their inherent flexible operating and modular deployment attributes. The engine technologies are described later in this report.

As Table 6-5 shows, there is currently over 3.9 MW of installed OCGT capacity in South Africa, most of which is fuel oil-based rather than natural gas-based. Although the units shown in Table 6-5 were mostly supplied by Siemens, GE remains the dominant original equipment manufacturer for OCGT and CCGT turbines in the broader Mediterranean and African market. Figure 6-9 further highlights that the F Class turbine is becoming more prominent in this region, despite several recent orders of advanced (G, H, and J) class turbines in Egypt.

Table 6-5
Existing South African GT fleet (data source: McCoy Reports)

Owner	Unit Name/Location	Unit Capacity (MW)	Qty.	Total Capacity (MW)	Oper. Date	Owner	Turbine Class	Model (Family)	Fuel
Eskom	Koeberg 1, Lesedi	33	3	99	9/1/2019	GE	Aero	LM2500	Oil/distillate
GDF Suez	Avon 1–4, Durban	170	4	680	8/1/2016	Ansaldo Energia	E Class	AE94.2	Oil/diesel
GDF Suez	Dedisa 1, Port Elizabeth	170	2	340	9/1/2015	Ansaldo Energia	E Class	AE94.2	Oil/diesel
AES Khanya-PE	Port Elizabeth 2	166	1	166	11/1/2009	Ansaldo Energia	E Class	AE94.2	Oil/distillate
AES Khanya-PE	Port Elizabeth 1	166	1	166	10/1/2009	Ansaldo Energia	E Class	AE94.2	Oil/distillate
Eskom	Atlantis 2, Ankerlig	173	5	865	3/1/2008	Siemens Power Gen	E Class	SGT5-2000E	Oil/distillate
Eskom	Mossel Bay 2, Gourikwa	173	2	346	3/1/2008	Siemens Power Gen	E Class	SGT5-2000E	Oil/distillate
Eskom	Atlantis 1, Ankerlig	167	4	668	4/1/2007	Siemens Power Gen	E Class	SGT5-2000E	Kerosene
Eskom	Mossel Bay 1, Gourikwa	167	3	501	4/1/2007	Siemens Power Gen	E Class	SGT5-2000E	Kerosene
City of Port Elizabeth	Mount Road	52	1	52	11/1/1981	Siemens Power Gen	Other Frame	POD 50	Gas/Natural
City of Cape Town	Roggebaai	52	1	52	3/1/1981	Siemens Power Gen	Other Frame	POD 50	Gas/Natural

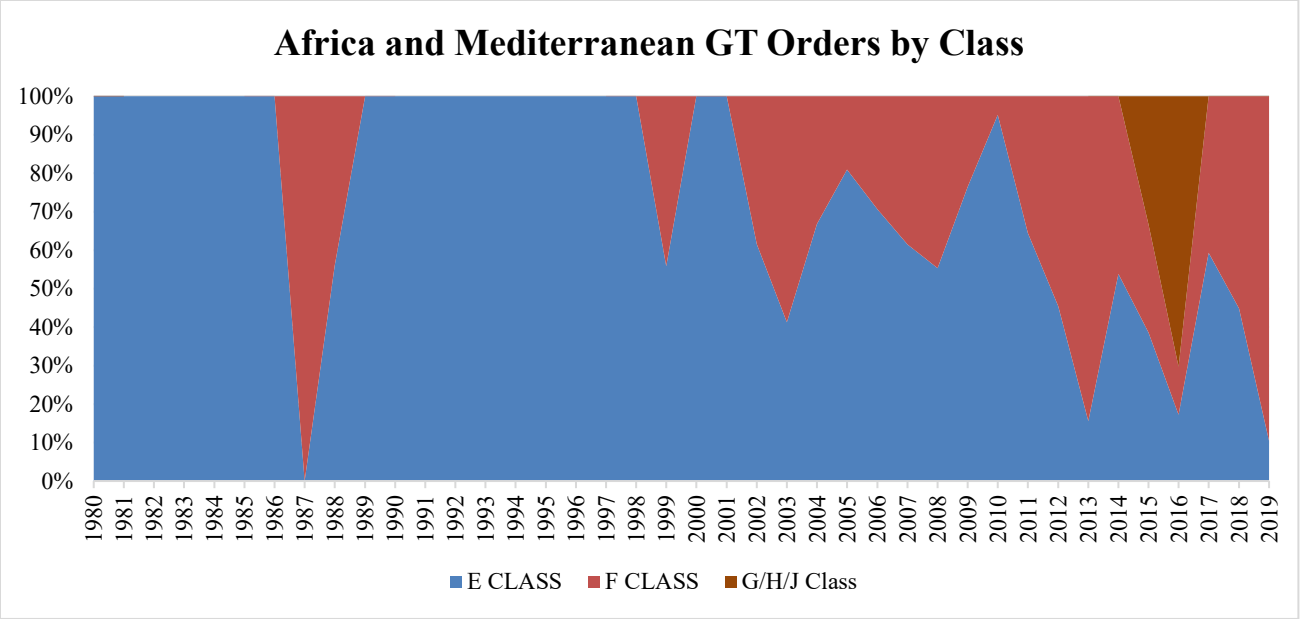

Figure 6-9
GT market share in Africa and Mediterranean region (data source: McCoy Reports)

Internal Combustion Engine

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.

Reciprocating ICEs

Background

Reciprocating ICEs (RICE) are a mature technology that can be used for power generation, but RICE play a minor role in power production in today's market. This is largely due to the historical preference to build larger-sized power plants fueled by energy sources that were cheap and relatively easy to store on site (such as coal) or that have higher efficiency (such as combustion-turbine combined-cycle [CTCC]). This made engines less desirable; therefore, stationary RICE typically have been used for remote or smaller-scale power needs such as pumping stations and emergency backup generation. Even in smaller-scale applications for power generation, utilities have relied on simple-cycle CTs over engines. However, recent changes in the power market have increased interest in RICE for wider and potentially larger-scale power generation, due to the following traits:

- **Operational flexibility.** Increasing variable renewable energy (VRE) on the grid requires dynamic, dispatchable power sources for voltage support and grid security. RICE can start up in minutes and readily vary load quickly, making them a good fit for grid stabilization and in general superior to CTs in this regard.

- **Modularity**. RICE power plants are modular in nature. Units ranging in sizes up to ~20 MW can be combined to make a larger, central station plant. Unlike CTCC or coal power plants that have only a few units to ramp up and down, engine plants can scale their output by taking individual units off-line while the remaining units can continue running at peak efficiency, similarly to simple-cycle CTs. Easy additions to capacity with small investment costs are key in today's market in which financing is becoming more difficult to obtain for larger-scale, multibillion dollar plants.
- **Fuel flexibility**. RICE are capable of running on a wide variety of fuels, increasing their flexibility and making them a fit in some regions that do not have access to a wide range of fuels, including, in particular, isolated/island areas and regions where local, poorer-quality fuels are abundant and much cheaper than imported fuels.
- **Less impact due to ambient conditions**. RICE run more efficiently in locations with more extreme ambient conditions (high-temperature, high-altitude, and low-water environments).
- **Improved efficiency**. RICE net plant efficiencies are as much as 42% HHV when operating on natural gas—which is significantly higher than simple-cycle CTs—and when adding cogeneration through heat recovery, they can compare with CTCC efficiency. Engine efficiency also does not change significantly when used in peaking and load-following modes, unlike simple-cycle CTs.

Large RICE have a long history in marine and locomotive propulsion. Small- and medium-sized engines have a similarly long history in emergency and standby power generation, power for remote locations, and industrial and commercial CHP. In the last decade, medium-speed engines, natural gas or dual-fuel, have been adapted for the utility power generation market, leading to an array of options (up to 20 MW each) for peaking, load balancing, ancillary services, and other flexible power needs. Cooperatives and municipalities have been the most likely segments of the power market to select engine plants, but there is growing interest by investor-owned utilities and independent power producers. In emerging economies, large RICE plants are being used for baseload power as well as peaking. The engine models that were studied for this report are the Wartsila 20V34DF and Wartsila 18V50DF.

RICE Market Overview

The market for RICE for power production is global, with manufacturers offering 50- and 60-Hz models and fuel combustion and emissions control systems that can be tailored to local needs. Engine manufacturing occurs most notably in Europe and Japan. The engines typically used for utility power applications are characterized as *medium speed* machines, meaning that they operate at less than 1000 revolutions per minute (rpm). In contrast, the small- and medium-sized engines used by utility customers for CHP and other applications typically run at high speed, meaning more than 1000 rpm. Larger engines used for marine applications or baseload power in locations with access to cheap liquid fuels are typically low-speed, two-stroke, diesel-based engines, which although efficient, are typically not chosen for power generation in areas with tougher environmental regulations and/or access to cheap natural gas.

Increasingly, companies are deploying engines to balance dynamic loads created by growing levels of VRE on the electric grid. The fast start and load-change capability of engines, as well as their good efficiency at part load, make them well suited for this application. Large RICE can be

designed to run on liquid fuel and/or natural gas. Generally, in areas where low-cost natural gas is available, they are designed to primarily run on the lower-cost natural gas, which puts them in direct competition with OCGT, particularly for power generation needs of less than 250 MW total. Operation on natural gas (as opposed to liquid fuels) also tends to ease air emissions permitting, especially for nitrogen oxides (NO_x) and fine particulate matter. In Hawaii and other markets that lack natural gas or are prone to gas curtailments, the ability to operate on diesel (which is widely available and easily stored) or indigenous fuel oils helps ensure grid reliability. Engines designed to run on diesel or with dual-fuel capabilities can usually also run reliably on biodiesel or other biofuels, helping satisfy renewable generation requirements. This fuel flexibility can be a differentiator from simple-cycle CTs, which do not have as wide a range of usable fuels.

To date, investor-owned utilities, independent power producers, and large cooperatives and municipalities are typically interesting in RICE plants totaling 40–250 MW and consisting of multiple, similar-model engines. Deployments are often at relatively isolated nodes of the grid where local, reliable, and flexible generation is needed or in areas with large amounts of VRE capacity. In addition, engine plants can be dispatched to take advantage of other grid-related revenue opportunities where available, including the following:

- Bidding into day-ahead markets
- Responding to real-time hourly markets
- Provide spinning (or nonspinning) reserve in ancillary service markets

There are instances in which engine-based power plants are being used or are under consideration for more baseload operation. In this scenario, RICE plants would be competing with combined-cycle or even boiler-based power plants. Typically, these plants are still expected to have dynamic operating characteristics, for which engines would be superior. Fuel flexibility is often the driver in these cases, particularly for fuel oils, for which engine-based plants would be more efficient than boiler-based ones.

Integrated resource planning studies by utilities and their regulators have shown how engine plants can help improve the overall efficiency of a portfolio of power plants. Because an engine plant can satisfy the highly variable portion of system load, it allows for scheduled operation of combined-cycle and steam-cycle plants at more efficient load points.

Engine Process

ICEs in large, stationary power generation applications are four-stroke, spark-ignited engines. The four strokes in a power cycle are intake, compression, expansion, and exhaust.

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 uses 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 turbocharging, also impacts NO_x formation—at higher pressure, the timing accuracy for air in-flow is improved, thereby achieving optimal low-NO_x 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 because a higher compression ratio could lead to autoignition 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 NO_x 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 NO_x is produced. These lean air-fuel mixtures, typical for ICE in large stationary power applications, require a precombustion 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 NO_x control is comparable to lean burners in CTs.

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 section comes strictly from the closed 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 2019 reached over 594,000 MW. Nearly 95% of all wind power capacity installed to date is onshore wind [21]. However, the superior wind resources available offshore along coastlines has led to considerable R&D of larger offshore wind turbines and the construction of a few offshore wind farms.

Onshore 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 onshore 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 in this section. Figure 6-10 shows a typical wind turbine.

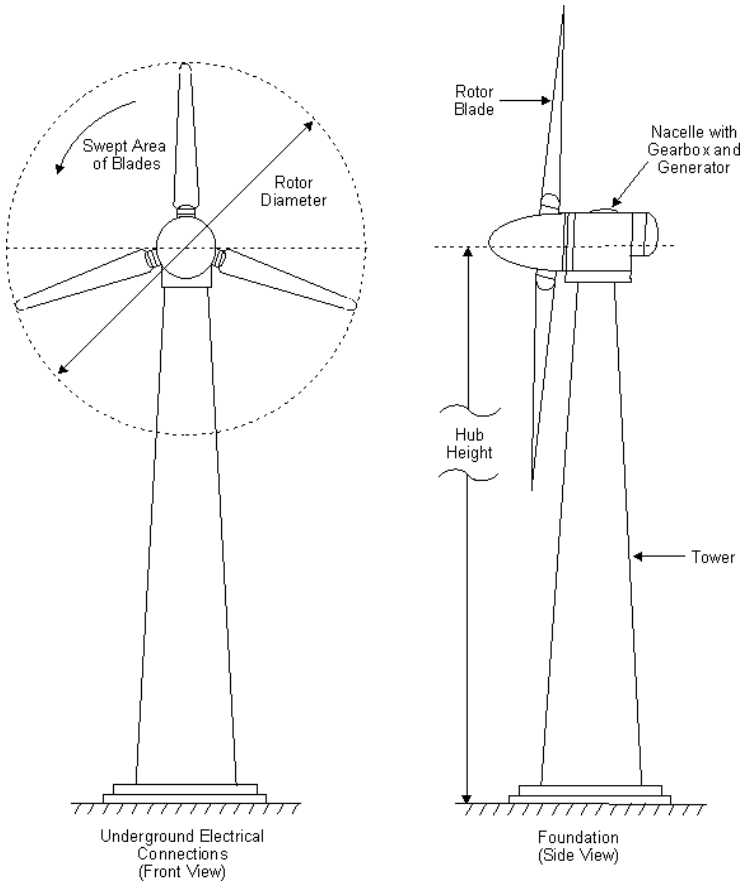

Figure 6-10
Wind turbine front and side view
Used with permission from U.S. Department of Energy. Energy Information Administration [22]

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 5–15 rotor diameters downwind and 3–5 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 may move toward 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 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 use. 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 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 would be notified.

Offshore Wind

Some countries have begun to install wind farms offshore. However, growth in offshore wind installations has remained relatively low since the development of the world's first grid-connected offshore wind farm in 1991 [23]. The primary difference between offshore and onshore wind turbines is the size and foundation requirements. Due to the high cost of offshore wind turbine foundations and undersea electric cables, offshore wind turbines are typically larger than their onshore counterparts in order to take advantage of economies of scale. In addition to the difference in size, offshore 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.

Commercial offshore wind farms have typically been 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 25–30 m into the seabed and is now believed to be able to be used in water depths of up to 60 m. 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. Monopile foundation still led in market share for announced future offshore wind projects, as of 2018, representing 59% of installations that have identified foundation technology. Jacket foundations appear to be capturing greater market share in future projects growing to 22% of projects with identified foundation technology. Floating foundations also are increasing market share among announced future projects, totaling 7% of the market [23].

Currently, offshore wind farms can be installed at distances over 100 m from shore [24]. Undersea cables connect the wind turbines within a project to an offshore substation and from the substation to the mainland. Most offshore wind farms use high-voltage ac transmission lines to transmit power from the offshore substation to the mainland. High-voltage direct current (dc) transmission is a newer 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 offshore substation and from dc back to ac at the onshore 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 onshore 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 1000 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 in the following sections are based on the concept of concentrating 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 through a series of solar steam generator heat exchangers, thereby indirectly producing steam. The direct method eliminates the HTF step by circulating water directly through the concentrated solar radiation path, thereby directly producing steam. Both solar thermal technologies that were 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 CSP 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 dispatchability. 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 covered in the following respective sections. Figure 6-11 shows a generic load profile and the impact of TES. 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 (that is, the loss of direct normal irradiation.)

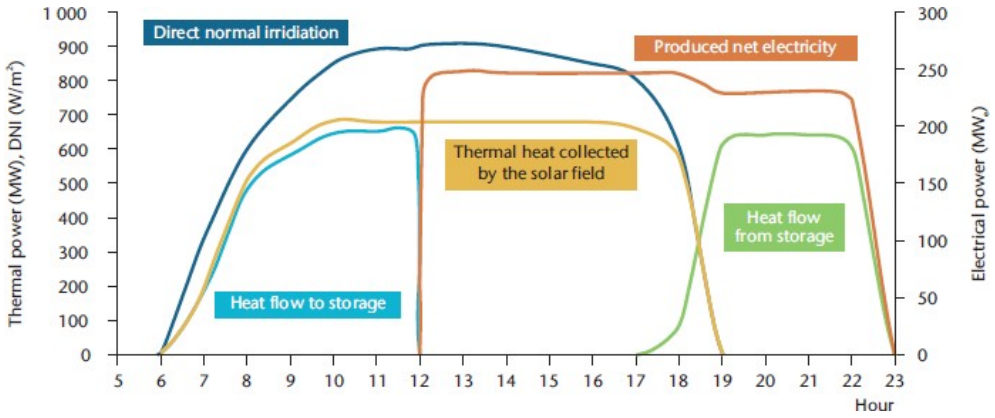

Figure 6-11
Use of storage for shifting production to cover evening peaks

The use of TES has been demonstrated to significantly improve the energy production. 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 20-MW facility set a record of operating 24/7 for 36 consecutive days in 2013. Figure 6-12 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.

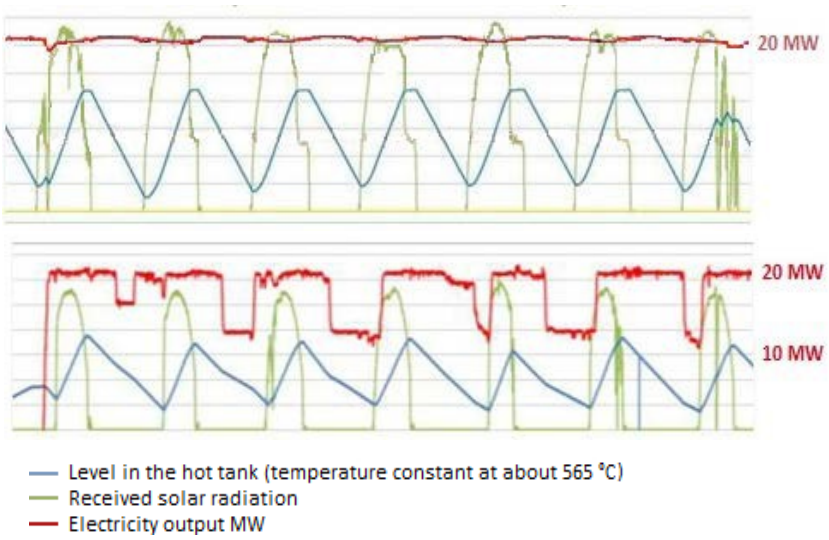

Figure 6-12
Weekly energy production for Gemasolar CSP plant

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. 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. A high-temperature HTF such as synthetic oil absorbs the thermal energy as it flows through the heat collection element. Heat collected in the solar field is transported to a series of shell-and-tube heat exchangers—collectively termed a *solar steam generator*. The superheated steam generated in the solar steam generator then expands through a conventional steam turbine to generate electricity. Steam temperatures are generally limited to ~370°C due to degradation temperature limitations of the synthetic oil.

Parabolic trough systems can be coupled with TES 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 solar steam generator 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 3 hours. This specification sizes the storage tanks, piping, pumps, and so forth. The actual performance of the storage system is based on many parameters, including the solar multiple used for sizing the field, the operating scheme, the available solar energy, and ambient temperatures. 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 tradeoff 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 6-13.

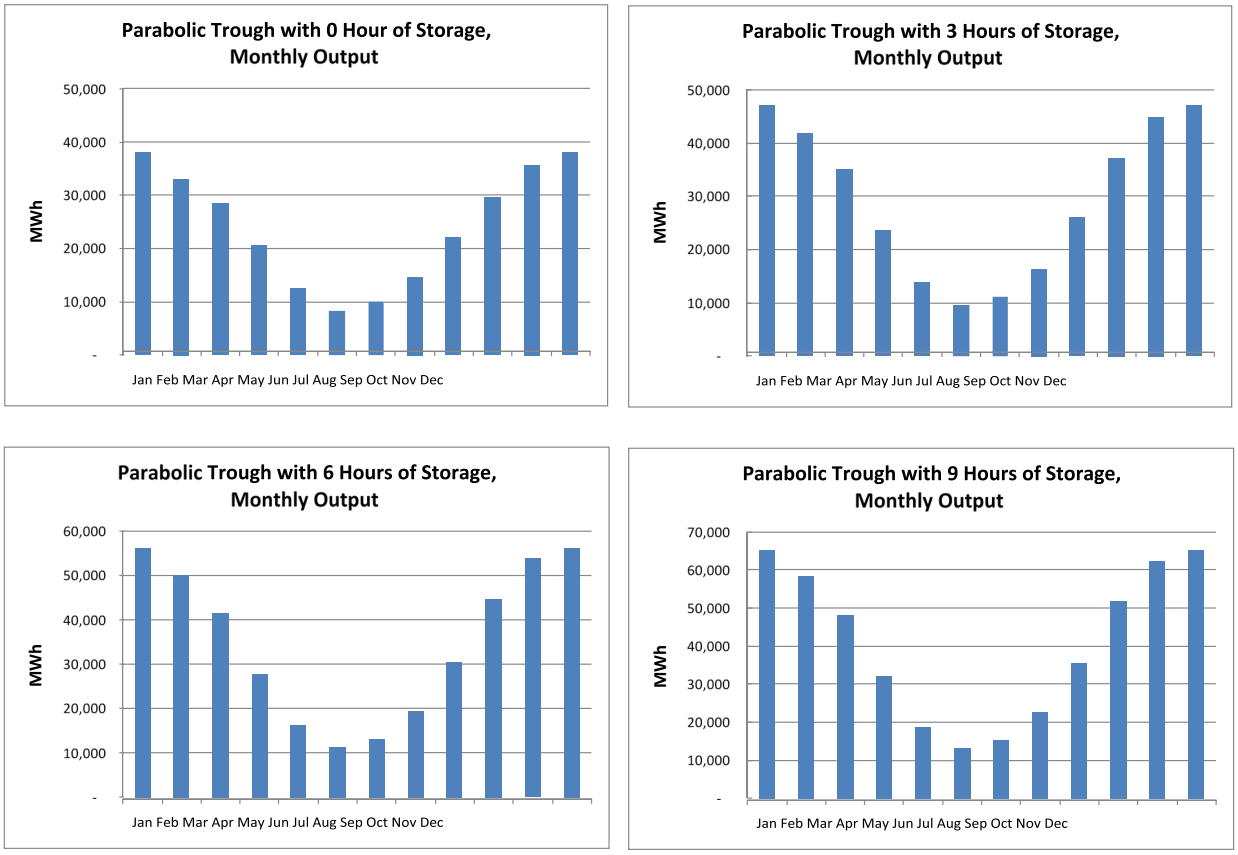

Figure 6-13
Parabolic trough generation profiles

Note: Generation profiles shown are based on interpretation of similar units located in Las Vegas, Nevada, 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. Molten nitrate salt HTF at 287°C is pumped out of the cold tank, through the receiver, and into the hot tank at 565°C. The hot tank delivers the molten salt to the solar steam generator 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.

The ability of molten salt HTF to be heated to 565°C and generate steam at 538°C 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 221°C. 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.

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 therefore 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 6-14.

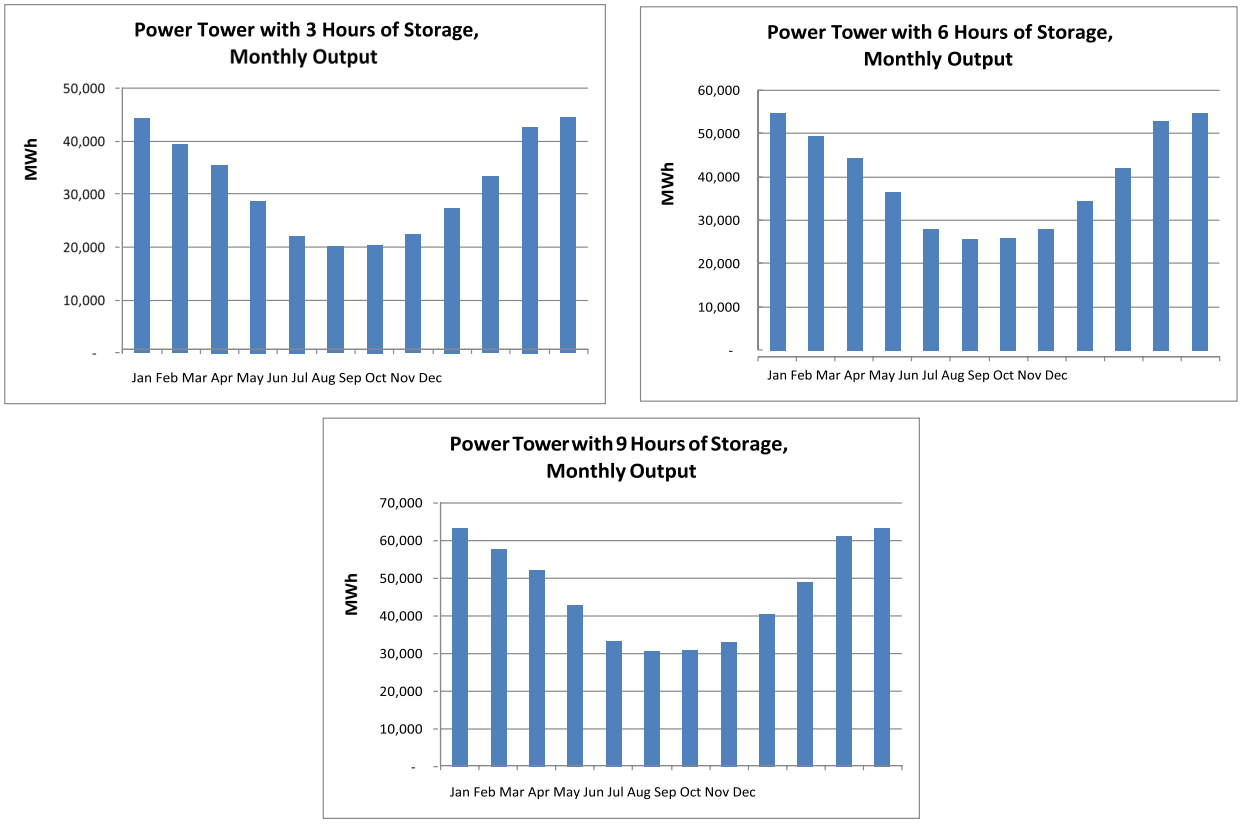

Figure 6-14
Power tower generation profiles

Note: Generation profiles shown are based on interpretation of similar units located in Las Vegas, Nevada, 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 586 GW at the end of 2019. Asia was the leading solar PV region in the world in 2019, with China reaching over 205 GW of cumulative installed capacity and Japan reaching 6.1 GW. In North America, the United States added over 13 GW of capacity, and Canada, Mexico, and Chile also grew. South Africa became the first African country to install over 1 GW in 2014 and has since reached over 3 GW of cumulative capacity; many more countries across the continent have several projects in various stages of planning and construction. Germany has established itself as the leading European market, reaching over 48 GW of cumulative capacity [25].

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, 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, 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. The solar module consists of multiple solar cells connected in series, and it generates the electrical energy in the form of dc 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.

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 1000 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, 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 toward 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. This study focused on fixed-tilt thin-film PV, fixed-tilt c-Si PV, and two-axis tracking concentrated PV 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. The c-Si cells technology is the most widely used technology to date and is what one traditionally pictures when envisioning a solar panel. Although c-Si is expected to continue to dominate the PV market, thin-film modules have continued to see advances in technology development. To date, c-Si cells have achieved the greatest efficiency of nonconcentrating technologies, but the manufacturing process remains relatively slow and energy intensive [26, 27]. 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 antireflective 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—therefore, 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, nontoxic element, which gives c-Si PV technology a relatively stable feedstock. C-Si can be grown in two main forms: monocrystalline silicon and polycrystalline silicon. Monocrystalline 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 versus temperature increase) than polycrystalline silicon. However, monocrystalline silicon is more expensive than polycrystalline silicon because of the high processing control required and high energy consumption during manufacture. The manufacturing process requirements for polycrystalline 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 polycrystalline technology. Polycrystalline 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.

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 a rare stable solid element 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 that was recently introduced to the solar PV market [28]. 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 CdTe thin-film, c-Si, and bifacial PV technologies.

It is worth noting that within the United States, single-axis tracking technologies are estimated to now account for nearly 75% of new U.S. utility-scale PV installations. Globally, there is also a trend toward increasing market share for single-axis tracking, though only 29% of ground-mount installations were estimated to be single-axis as of 2019. This is in contrast to trends seen in the last decade, where including tracking in utility-scale solar PV installations was often uneconomic for most project owners.

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, thereby, in effect, modifying PV resource availability.

Two-axis tracking results in the highest annual energy production but at a higher capital cost. 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 through motors, actuating mechanisms, and control systems.

According to Figure 6-15, 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 (for example, desert locations) and can, in turn, have a greater impact in reducing a PV plant's levelized cost of electricity.

				
	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 6-15
Effects of tracking on annual energy production and capital expenditures

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—for example, 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, LFG, 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 using biomass were developed in the 1920s and ’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 stoke (feed) 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 (for example, 113,400 kg/h (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 (1250 psig/950°F) and 10 MPa/540°C (1450 psig/1000°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 6.7–10.2 kPa (2–3 in HgA) if power is the exclusive product.

Air pollution equipment for solid biomass-fired systems includes either FFs or electrostatic precipitators for particulate control. To meet NO_x 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 systems to reduce NO_x up to a maximum reduction of 50%. Acid gas scrubbers are not required due to the compositions of typical solid biomass fuels.

Municipal Solid Waste

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 the following:

- 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 HHV 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 noncombustible components. PEF exists as a fluff, whereas densified PEF 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 prerequisite 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 of the applicable elements of the combustion system cannot be overemphasized. 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 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. LFG composition is typically 50% methane, 50% carbon dioxide, and small amounts of other organic compounds. LFG 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 LFG in ICEs, small CTs, boilers coupled with steam turbines, and microturbines. Other developing technologies that can use LFG are Stirling engines, organic Rankine cycle engines, and fuel cells. Thermal applications include packaged boilers, dryers, kilns, greenhouses, water heating for aquaculture, and so forth. In limited instances, LFG 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 LFG and using it for power generation and thermal uses reduces the contribution of methane to greenhouse gas (GHG) 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 LFG was combusted in spark ignition reciprocating engines, which is currently the most common technology used for generating electricity from LFG.

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. Although 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 (for example, 5-MW LFG engine project) can vary substantially, due to project-specific issues such as the following:

- Amount of LFG collection piping included (that is, 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, such as the following:
  - 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 the following:

- Whether a service agreement is purchased from the equipment manufacturer (or whether 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 would 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 6-6 summarizes indicative costs of the various power generation technologies, based on the Environmental Protection Administration's (EPA's) Landfill Methane Outreach Program 2020 handbook [29].

Table 6-6
Typical costs of LFG power generation technologies

	Microturbines	Reciprocating Engines	GTs	Combined Cycle	Boiler/Steam Turbine	Stirling Engines
Quantity of projects	12	360	31	9	11	2
% of electricity generation projects	2.8	84.7	7.3	2.1	2.6	0.5
Average MW per project	0.4	3	5.6	11.2	9	<500 kW
Typical project capacity range	<500 kW	500 kW to 6.0 MW	4.5–10 MW	10–30 MW	8–50 MW	<500 kW
Typical capital costs, 2020$/kW	3334	2000–2556	1556	N/A	N/A	N/A
O&M costs, 2020$/kwh	177	277–300	177	N/A	N/A	N/A

Notes:

Data are from "LFG Energy Project Development Handbook," 2020; 2013 costs were adjusted to 2020 costs.

Typical capital cost data for boiler/steam turbine, combined-cycle, and Stirling engine arrangements are not indicated in Landfill Methane Outreach Program handbook.

Technical Issues for LFG Power Production

The heating value of LFG can range from 350 to 600 Btu per cubic foot, whereas 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 using LFG for energy projects could 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, CTs, 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 CT, reciprocating engine or boiler is relatively straightforward after 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 offline, the LFG stream must be flared to comply with environmental regulations. Nonproductive flaring can be minimized or avoided using multiple LFG power generating units, with efficient turndown 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. After it is 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 using 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 previously, 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 consists 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 CTs. 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 6-7, today's LFG engines can easily meet the federal (NSPS) for spark-ignition engines; but the emission limits included in state-issued permits can be more stringent.

Table 6-7
Federal NSPS and state-permitted emissions limits for spark ignition engines (g/BHP-h)

	NO_x	CO	VOC
Federal NSPS limits for LFG engines	3.0 [2]	5.0	1.0
Recent state-permitted LFG engine projects (without catalysts) [3]	0.5–0.6	2.5–3.0	0.16–0.80

Notes:

1. Recently permitted project information was sourced from the EPA's RBL clearinghouse 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 has been reduced to 2.0 g/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 seven years, as indicated in the EPA database.

As indicated in Table 6-7, individual state permitting requirements are often more stringent than the federal NSPS levels especially in non-attainment zones. Non-attainment zones in the United States 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, 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 (GT, reciprocating engine, and so forth), 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 CTs, 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 HRSG. A second contaminant of concern is the presence of hydrogen sulfide in the LFG. This compound gives the LFG a noxious odor and 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 cleanup or pretreatment is also required prior to burning in reciprocating engines. Reciprocating engines can suffer from buildup of materials like CTs. This may result in cylinder wear. However, the costs of repairs are less than for CT piston rings, which can be replaced at least once with oversized rings at a modest cost. These new oversized rings would 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 removes 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, CTs, or boilers.

Because the replacement of the adsorption media is expensive, suppliers now offer carbon beds that can be regenerated on site. Although the initial cost of this arrangement is more than the nonregenerating 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 section, 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 LFG has been covered separately because 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 and China and 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 slaughterhouse waste and dairy farm waste. In the United States, medium- to large-scale dairy farms and slaughterhouses 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 is 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 slaughterhouse). The restaurant waste biogas discussion is based on a California Energy Commission-funded project with University of California, Davis, California (UC Davis). 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 anaerobic phased solids-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 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 digester system is housed in the recently developed UC Davis Biogas Energy Plant and has a capacity of treating 50 tons of organic waste per day, which produces 5.6 GWh of electricity per year [30]. 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. The electrical energy delivered to the grid is measured by the instrumentation and metering equipment installed on the Cummins generator system. The generator system would 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 capital cost of the project was estimated to be about $1.8 million (30 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 such as animal dung, human sewage, or food waste. This produces biogas, which is a mixture of methane and carbon dioxide, and a semisolid 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 GHG 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 that is produced pushes some of the slurry into a separate reservoir. When the biogas is taken off, the slurry flows back (see Figure 6-16).

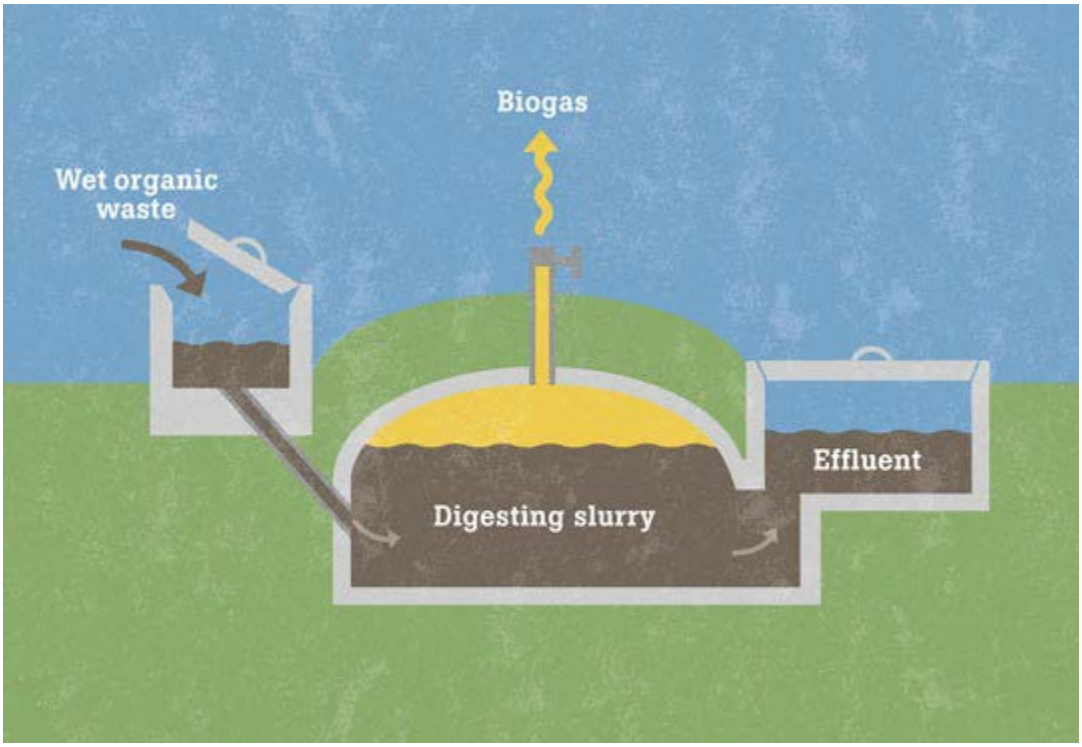

Figure 6-16
Biogas process

In floating dome plants, the gas container floats in the slurry. The gas container gradually rises 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 CT. 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 consisting 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 1 kilowatt of electricity production requires five to eight dairy cows.

A biogas plant needs some methane-producing bacteria to get it started. After 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.

Energy Storage Technologies

Energy storage technologies are positioned to play a substantial role in future power systems. As covered further in Section 11 of this report, 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 6-8 summarizes 10 key applications. This list is not comprehensive. Additional energy storage applications exist now, and others could emerge in the future and will be the subject of future research. However, these 10 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 6-8
Definition of major energy storage applications [31]

Value Chain	Application		Description
Generation and 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
↓	4	Transportable storage for T&D support	Transportable storage systems for T&D system support and T&D deferral at multiple sites as needed
Transmission and distribution (T&D) system applications	5	Distributed energy storage systems	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
	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
End-user applications	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

C&I = commercial and industrial; ESCO = energy services company; TOU = time of use

Each of these 10 applications centers on 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*.

Energy storage technologies have unique attributes compared to other generation resources. Understanding these parameters can assist in making comparisons among different options, particularly in determining which storage technology best meets a particular grid service. Table 6-9 provides definitions for key performance characteristics and their potential impact on life-cycle project costs [32] that are covered further in this section.

Table 6-9
Energy storage definitions of performance characteristics and impacts on their use [31]

Performance Characteristics	Definition	Potential Impact
Auxiliary power	Also known as *housekeeping power*, the load that is required to maintain the system during normal operations; can include thermal management, communications, and monitoring system.	Auxiliary power requirements result in energy losses and decreased system efficiency.
Calendar life (for Li-ion)	The number of years until the energy storage system reaches its end of life (EOL), independent of cycling degradation.	Storage systems with longer calendar life can serve long-term needs. Like cycle life (below), systems requiring more frequent replacement increases maintenance costs.
Charge power	The maximum steady state active power at which the energy storage system can continuously absorb at the ac terminals of the power conversion system.	Limitations in charge power or rate may impact the storage system's ability to perform dynamic responses, such as frequency regulation, and its ability to perform multiple cycles per day.
Cycle life (for Li-ion)	The number of cycles (typically given at specified depths of discharge) that the energy storage system can perform until EOL and is independent of calendar life degradation.	Storage systems with longer cycle life can undergo more charge/discharge cycles and be more suitable for use cases with daily cycling such as energy time shift. Systems with shorter cycle life may require more frequent augmentation or component replacement, increasing maintenance expenses. Depending on duty cycle, cycle life may not be a concern because the system may reach the end of its calendar life ahead of end of cycle life.

Table 6-9 (continued)
Energy storage definitions of performance characteristics and impacts on their use [31]

Performance Characteristics	Definition	Potential Impact
Energy density	The amount of energy stored per unit mass occupied by the system, (kWh/kg); can be expressed for per volume basis for other energy sources, (kWh/L).	If space is a concern, such as in urban areas, substation fences, or commercial facilities, systems that have higher energy density may be more desirable because they could have a reduced footprint. However, based on the packaging, two systems of the same technology may have different system footprints (for example, ISO containers versus dedicated building).
Power density	The amount of power delivered on demand per unit mass (kW/kg).	High power density chemistries are lighter for high power usage; can be important for transportation, less for stationary applications.
Round-trip efficiency (RTE)	Total ac roundtrip efficiency of the facility is defined as the ratio of the delivered discharge energy to the delivered charge energy, including facility parasitic loads. Note: RTE varies at different charge/discharge rates.	More energy can be extracted per charge/discharge cycle for systems with higher RTE. RTE has a larger impact on applications that are more frequently cycled and have higher energy throughput as RTE will impact cost of charging. RTE assumptions are also important in calculating the emissions implications of energy storage.
Self-discharge rate	Rate at which the energy storage system will lose state of charge (SOC) while being held at a given SOC, not including auxiliary load energy (%/hour).	Systems with high self-discharge rate are less effective when idling for long duration, making them less suitable for infrequent operations and seasonal storage than systems with a lower self-discharge rate.

Li-ion Battery Energy Storage

Battery energy storage is sometimes viewed as the most favored energy storage technology for future power systems. Li-ion batteries have emerged as the top battery energy storage technology, whose emergence can be attributed to lower costs associated with economies of scale, as well as the rapid growth and high demand of Li-ion in the consumer electronics and electric vehicle (EV) markets. This rise in demand stems from Li-ion's strong combination of performance characteristics, including energy and volumetric density, efficiency, and cycle life.

Technical/Process Description

A Li-ion battery is a type of electrochemical energy storage that stores energy during charge transfer reactions in the electrode structure. A Li-ion battery consists of a cathode, the positive end, and an anode, the negative end, separated by a liquid organic electrolyte. There are also a polymer separator, copper and aluminum current collectors, and packaging materials to enclose the material [33]. The anode is typically a graphitic carbon electrode that holds lithium in its layers; the cathode is a lithium-intercalation compound, such as an oxide, that forms a layered

structured with Li-ions. During charging, Li-ions move across the electrolyte from layered oxide to intercalate into the graphite layers, creating a voltage potential between the two ends. The process is reversed during discharge, releasing storage energy [34].

The most common types of liquid Li-ion cells are cylindrical and prismatic 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 EVs.

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. Therefore, 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. Therefore, there is a current and voltage (that is, power) applied to the load.

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 (LFP). Although NCM remains the dominant chemistry, original equipment manufacturers are continuing to increase production capacity of LFP. Research is also ongoing to develop lithium-based anode materials. Altair Nanotechnologies, for example, has developed a lithium titanate material, which it is using in cells designed for use in a stationary energy storage system. It is expected that over the next few years, energy storage batteries could begin to diverge from those used in EVs, enabling different Li-ion subchemistries to gain market share.

Li-ion batteries are the predominant and most mature battery technology being deployed for stationary power applications, particularly in the United States, where they make up more than 97% of the capacity of stationary energy storage systems [31]. However, companies developing flow battery technologies are securing sufficient capital to begin deploying demonstration projects and move toward commercialization. The four primary flow battery technologies starting to enter market applications are all-vanadium, zinc-bromine, zinc-iron, and all-iron. Nevertheless, given current and projected costs, Li-ion is likely to remain in the leading position for most stationary applications for at least the next 3–10 years and possibly beyond. Flow battery demonstration

projects and commercial deployments, meanwhile, are starting to come online or be announced. If flow battery technology costs decrease, they have potential to be competitive with Li-ion batteries for longer duration applications. Flow battery systems have an advantage over Li-ion given that their power and energy ratings can be decoupled. Additionally, flow batteries do not experience the degradation issues related to cycling that affects Li-ion batteries.

Summary of Li-ion Battery Energy Storage Performance Characteristics

Table 6-10 summarizes select key technology performance parameters of Li-ion batteries, most of which were defined in Table 6-9. These parameters may also be used in a lifecycle cost-benefit analysis tools such as EPRI's Storage Value Estimation Tool (StorageVET[19]) [36].

Table 6-10
Performance characteristics of Li-ion batteries for cost-benefit modeling

Parameter	EPRI Modeling Default
Calendar life* [%/year] and [years]	2.7%/year or 15 years
Cycle life [# cycles at % depth of discharge]	5000 @ 80% depth of discharge
Housekeeping power [kW]	Negligible for screening analysis
RTE [%]	80–90%
Self-discharge rate [%/h]	Negligible for screening analysis

*Assumes EOL is at 60% of initial energy capacity

Li-ion systems sustain some form of erosion during every charge and discharge cycle. Different use cases have various effects on the degree of cycle life degradation. For example, performing frequency regulation may require thousands of shallow cycles per year, whereas resource adequacy capacity may require hundreds or less deep cycles. Charging and discharging at shallow depth of discharge will have less impact on the cycle life degradation, compared to deeper depth of discharge cycles. It can be difficult to assess cycle life because data are often provided at the cell level and extrapolated for shallow depths of discharge. Additionally, the battery management system will impact the cycle life at the system level.

Calendar degradation occurs independent of cycling. For Li-ion systems, calendar degradation occurs more quickly with higher average SOC and higher operating temperature, and particularly if those occur concurrently.

RTE varies based on charge and discharge power, ambient conditions, rest periods, and other factors. For Li-ion batteries, RTE is generally in the range of 80–90%.

Self-discharge rate and housekeeping power are often ignored for screen analyses. However, if the system is not being dispatched for extended periods of time, these factors may become more prominent and should be considered. Housekeeping power is low when ambient conditions are near 25°C, and spikes when ambient temperatures are colder or warmer than the normal operating range for the technology used, for example, near -20°C or greater than 60°C for a lithium nickel manganese cobalt oxide chemistry.

[19] *StorageVET* is a registered brand of EPRI.

Table 6-11 summarizes some of the main advantages and disadvantages of Li-ion battery technologies.

Table 6-11
Advantages and disadvantages of Li-ion battery technologies [31]

Advantages	Disadvantages
• High power and energy density • Low self-discharge rate • Higher RTE	• Potential for thermal runaway • Energy capacity degradation due to cycling and time • Calendar degradation • Sensitivity to overcharging and temperature extremes (therefore, requires well-designed control systems) • Some raw material costs are expensive

Applications

The huge manufacturing scale of Li-ion batteries (estimated to reach approximately 646 GWh by 2021) [37] 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 can range from 80 to 90% (when the system is run for 2 or more hours), Li-ion batteries are also being considered for several utility grid-support applications such as distributed energy storage systems (for community energy storage), transportable systems for grid-support, commercial end-user energy management, home backup energy management systems, frequency regulation, and wind and PV smoothing. 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 EV 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

Li-ion systems have been commercially demonstrated at a wide range of capacity and duration scales and from residential and commercial customer-sited installations, to utility-scale systems providing grid services.

Frequency regulation applications for energy storage continue to gain traction in the United States. New analyses and operating methods are being developed to 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.

Key drivers for future cost decreases for Li-ion battery packs include the following:

- Further upscaling of battery manufacturing capacity
- Diversification of stationary energy storage subchemistries
- Innovation in raw battery materials (for example, cathode, anode, and electrolyte materials)
- Improved rack-level electronics
- Battery recycling to enable second life

Most forecasts of battery Li-ion battery packs envision considerable declines over the next 10 years on a $/kW basis, as shown by Figure 6-17 [31].

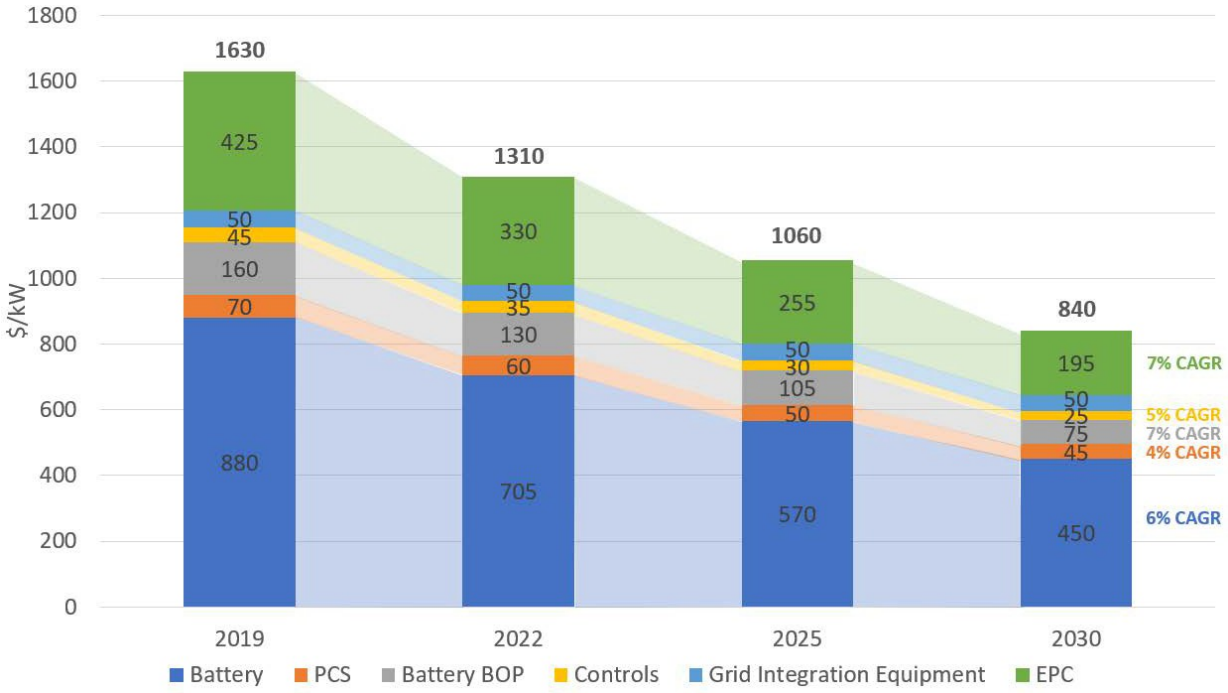

Figure 6-17
Installed cost projections for a 20-MW, 4-hour Li-ion system, 2019–2030

Compressed-Air Energy Storage

Technical/Process Description

Today, CAES and pumped hydro systems are the largest commercially deployed bulk-energy storage technologies (that is, on the scale of hundreds or thousands of MWh) at relatively low capital and operational cost. However, the deployment of these technologies is often limited to available natural formations that provide suitable infrastructure. 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 through combustion with fuel, and passed through an expansion turbine to drive an electric generator (see Figure 6-18). These first-generation CAES plants burn about one-third the premium fuel of a conventional CT and produce about one-third the pollutants per kWh generated.

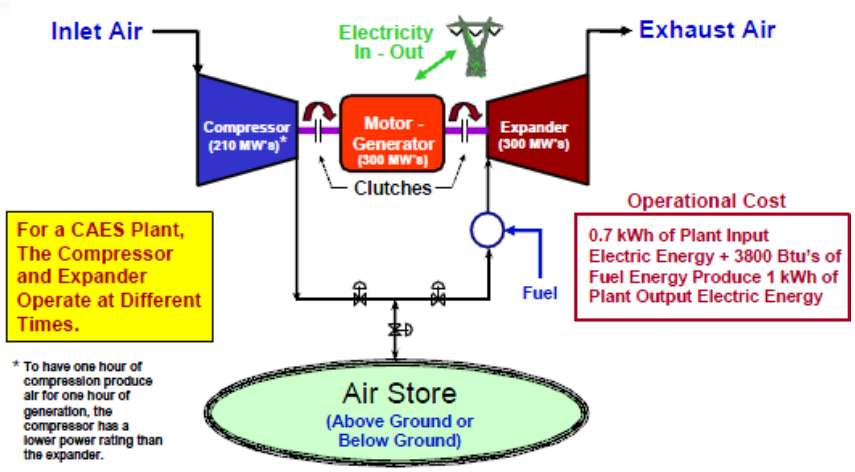

Figure 6-18
CAES system

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 8–26 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 would typically be smaller than plants with underground storage because of the limited capacity of the storage reservoir, with capacities on the order of 3–15 MW and discharge times of 2–4 hours. Above-ground CAES plants are easier to site but more expensive to build (on a $/kW basis) than CAES plants using underground air storage systems, primarily due to the incremental additional cost associated with above-ground storage.

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 nonsynchronous spinning reserve
- Capacity credits that can be valued at either the market price for firm capacity in an ISO/regional transmission organization environment, or the cost of alternative 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.)

CAES plants could also provide services and benefits for large solar PV systems, which present some of the same intermittent output challenges as wind. In California and other places with large installed solar PV capacity, CAES could help shift power from peak solar production in the midafternoon to peak demand hours in the evening.

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 turbomachinery and customized high-pressure combustor. The 110-MW CAES plant at PowerSouth Energy Cooperative (formerly Alabama Electric Cooperative) has operated reliably for 29 years and has successfully demonstrated the technical viability of this early design. This plant requires additional auxiliary equipment to meet NO_x emission standards. A 290-MW Huntorft plant in Germany, in operation since December 1978, has demonstrated strong performance with 90% availability and 99% starting reliability. This plant uses two man-made, solution-mined salt caverns to store the air and was recently upgraded to a 321-MW discharge rate [38].

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 6-19), no fuel is used to heat the air before it is passed through the expansion turbine, because the air is heated with exhaust of a CT, which is part of the CAES plant. New compressor designs and advanced turbomachinery are also leading to improved non-CT-based CAES systems.

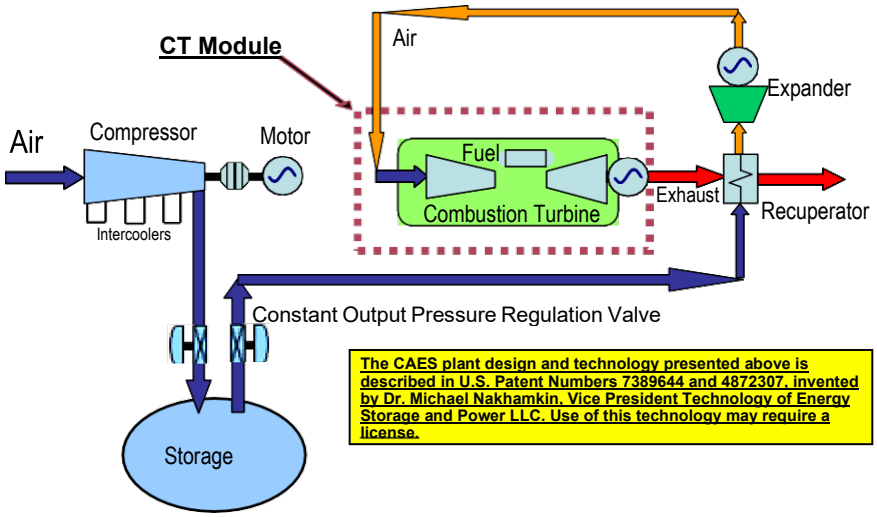

Figure 6-19
CAES second-generation chiller arrangement

The preceding fuel-based CAES designs have a low heat rate compared to CTs, 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 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, also known as *adiabatic CAES*, would provide carbon-free operation through different methods, such as capturing and storing higher grade compression heat from high-temperature compressors (see Figure 6-20). However, No-fuel CAES requires technology development and greater capital investment than low-fuel CAES. Both CAES cycles could look increasingly attractive as wind penetration levels increase, fuel prices rise, and/or CO_2 emission charges are implemented.

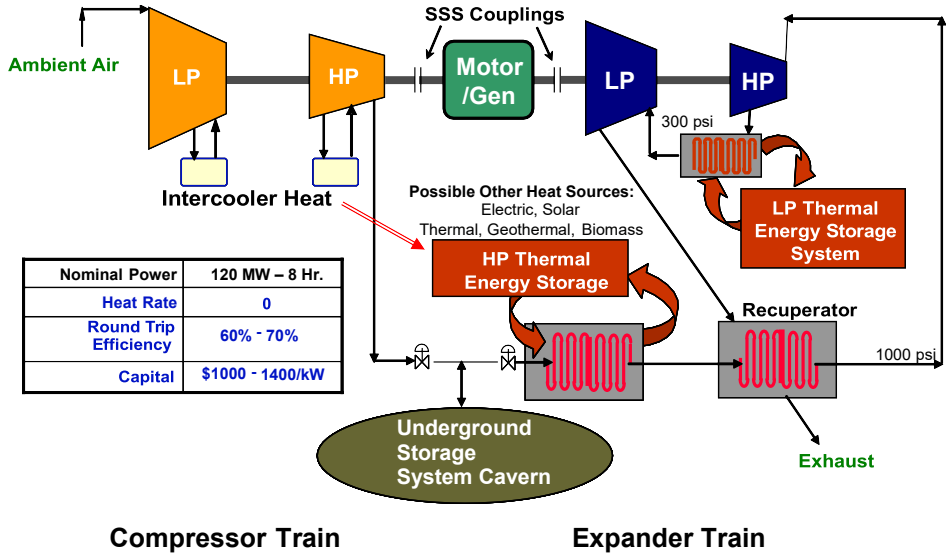

Figure 6-20
Adiabatic or no-fuel CAES

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 relatively 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, because 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 can be associated with securing the necessary environmental permits on time to ensure that the plant will be commissioned on schedule. To minimize the risk of exceeding project time frames, a dedicated project team that specializes in securing permits can be assigned. Scheduling risk can be relatively minimal; the McIntosh Alabama CAES plant was designed and constructed in three years. CAES systems should be able to earn revenues in the ancillary services markets in addition to energy arbitrage. Therefore, 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 should be specified to accommodate this capability.

Underground Pumped Hydro Storage

Pumped hydroelectric storage (PHS) projects generally involve an upper and lower reservoir. During times of low electricity demand, such as at night or on weekends, excess energy is used to pump water to an upper reservoir. During periods of high electricity demand, the stored water is released through the penstock. The force of the water drives the turbines. The spinning turbines are connected to large generators, which produce the electricity. The water then flows through a discharge tunnel into a lower reservoir. When demand for electricity is low, the turbines spin backward and pump the water back up into the upper reservoir to make it available to generate electricity when it is needed.

Underground PHS (UPHS) is an extension of PHS, where one or both reservoirs are located below ground. In a conventional PHS or UPHS system the energy is stored as potential energy by lifting a mass of water into an upper reservoir. The amount of stored energy is roughly proportional to the lift height between the lower and upper reservoir, the density of water and the volume of water stored.

The size of a UPHS can range from 100 to 1000 MW and energy capacity from 1 to 15 GWh, depending on the size of the reservoirs. UPHS has been viewed as having the potential to provide cost-effective large-scale energy storage technology. The underground reservoir can be either newly built for the purpose of the UPHS or reused from abandoned mines. Although several UPHS projects have been studied over the past 50 years, there are currently no large-size UPHS projects in operation. UPHS has potential to help integrate intermittent renewable generation into the electric power grid by allowing storage of electricity at the time of high production and low demand and releasing it at the demand of higher demand and low production. Like traditional pumped hydro storage, the main advantages of UPHS are high cycle efficiency, capacity to deliver large power over long periods, long lifetime, low landscape impacts, and use of proven technology for site preparation, such as tunnel boring machines. Table 6-12 summarizes the general performance of UPHS as described by European Energy Research Alliance [39].

Table 6-12
UPHS performance summary
Source: European Energy Research Alliance

Typical power (MW)	100–1000 MW
Head range	750 m in one-stage configuration; 1500 m in two-stage configuration
Cycle efficiency	75%
Energy capacity	1–15 GWh
Discharge time	8–16 h
Response time	Seconds to minutes
Technical lifetime	40–80 yr
Energy to power ratio	8–16 MWh/MW

Emerging Low-Carbon Technologies

The energy resource landscape is a quickly evolving landscape. Recently, there has been an emergence of interest in developing low-carbon energy carriers to support decarbonization within the electric sector and other sectors of the economy. In the near term, substantial GHG emissions reductions for much of the economy are projected to be driven by cleaner sources of electricity generation, advances in energy efficiency, the electrification of transportation, and where possible, other sectors. However, additional solutions are needed for the estimated 40% or more of end uses that cannot be easily or cost-effectively decarbonized through electrification [40]. Low-carbon fuels and energy carriers, such as hydrogen, ammonia, synthetic hydrocarbon fuels, and biofuels, along with the technologies that enable their application, could provide solutions for these difficult-to-decarbonize sectors. When produced with zero or low GHG emissions—from clean electricity, renewable feedstocks, or fossil resources with carbon capture, utilization, and storage—these low-carbon resources could provide pathways to decarbonization for end-use applications including the following:

- Maritime shipping and aviation
- Long haul and heavy-duty transport
- Provision of high-temperature heat for industry
- Provision of heat for certain segments of the building heating market

In some cases, low-carbon fuels can be delivered, stored, and used in a similar fashion as fossil fuels. This may present opportunities to repurpose existing power generation assets and fossil fuel infrastructure for the transition to a deeply decarbonized energy system [41].

Many low-carbon fuels can be produced from electricity, making them a promising source of large-scale energy storage for the electric grid. These fuels (hydrogen, ammonia, and so forth) can be transported and stored in bulk for subsequent use in electric power generation. This, in turn, provides an option for temporally and geographically balancing electricity supply and demand.

In order to include these resources within the energy mix, significant research is underway to better understand production, transportation, storage, and use of these resources. EPRI and the Gas Technology Institute have recently launched the Low-Carbon Resources Initiative to advance technologies and understanding across the value chain.

Within this effort EPRI will develop an integrated cost and performance assessment that will include production, transportation, storage, and delivery of low-carbon energy carriers. The development of credible and independently developed cost and performance estimates is a vital step in understanding the baseline of today's technology and moving beyond the current market technologies. Foundational cost and performance data will enable the identification of potential cost reductions in the future as well as the magnitude of those reductions relative to delivering low-carbon energy. Upon completion, these data could be included in further iterations of this report. Figure 6-21 is an example of the low-carbon energy carrier supply-side and infrastructure technologies being evaluated.

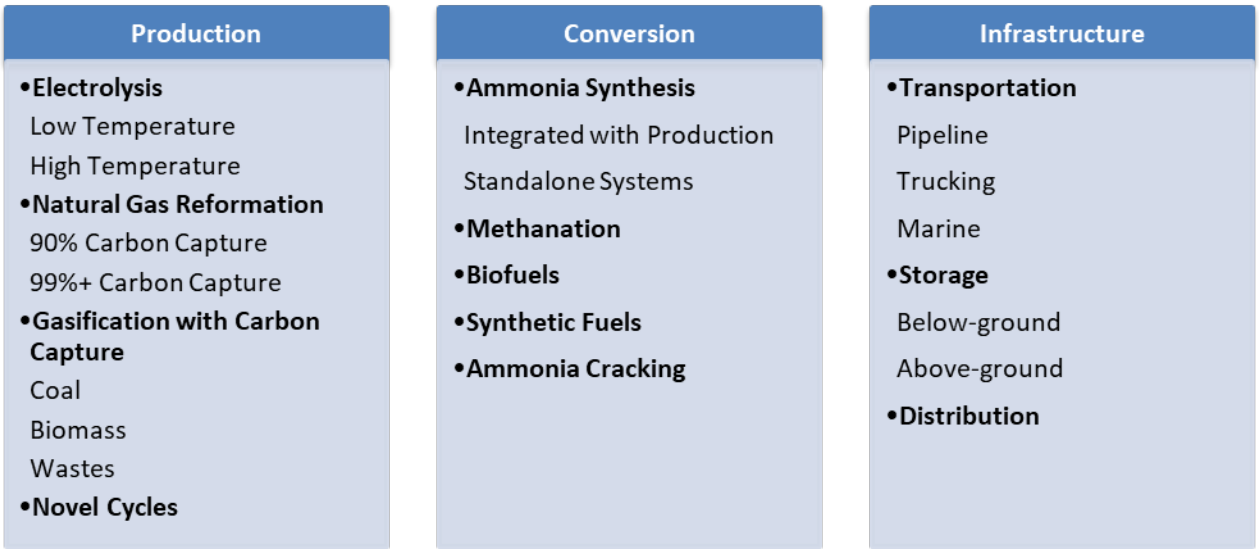

Figure 6-21
Example of low-carbon carrier pathways

The global energy system is transforming rapidly, and the emerging consensus surrounding the urgency of decarbonization has driven unprecedented momentum in low-carbon fuels. No single technology or fuel is capable of providing substantial, widespread emissions reductions and energy services. Economy-wide, deep decarbonization requires a robust portfolio of low-carbon fuels in combination with other measures, including electrification and energy efficiency. When produced by low-carbon means, fuels such as hydrogen, ammonia, methanol, and synthetic drop-in fuels can provide pathways to decarbonization for a wide variety of end uses that currently rely on fossil fuels. In some cases, these fuels can be delivered, stored, and used similarly to fossil fuels, enabling existing assets and infrastructure to be leveraged in the transition to a low-carbon energy system. Where existing infrastructure cannot be used, new infrastructure development can play a critical role in the timing and feasibility of low-carbon fuel adoption [41].

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7
COAL TECHNOLOGIES PERFORMANCE AND COST

Pulverized Coal

Tables 7-1 through 7-5 summarize cost and performance for the PC plants.

Table 7-1
PC with dry cooling—cost and performance summary

Technology	1x750 MW, Dry Cooling	2x750 MW, Dry Cooling	4x750 MW, Dry Cooling	6x750 MW, Dry Cooling
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 2021)				
Total overnight cost, ZAR/kW	59,445	56,290	53,135	51,558
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	1,398	1,323	1,236	1,193
Variable O&M, ZAR/MWh	33.4	33.4	33.4	33.4
Availability estimates				
Equivalent availability	91.7	91.7	91.7	91.7
Maintenance planned outages, %	4.8	4.8	4.8	4.8
Unplanned outages, %	3.7	3.7	3.7	3.7

Table 7-1 (continued)
PC with dry cooling—cost and performance summary

Technology	1x750 MW, Dry Cooling	2x750 MW, Dry Cooling	4x750 MW, Dry Cooling	6x750 MW, Dry Cooling
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	9,776	9,776	9,776	9,776
75% load	9,967	9,967	9,967	9,967
50% load	10,529	10,529	10,529	10,529
25% load	12,866	12,866	12,866	12,866
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	197.6	197.6	197.6	197.6
For wet and dry cooling (where applicable)	0	0	0	0
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	15.8	15.8	15.8	15.8
Air emissions, kg/MWh				
CO_2	942.9	942.9	942.9	942.9
SO_x	0.46	0.46	0.46	0.46
NO_x	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 7-2
PC with wet cooling—cost and performance summary

Technology	1x750 MW, Wet Cooling	2x750 MW, Wet Cooling	4x750 MW, Wet Cooling	6x750 MW, Wet Cooling
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 2021)				
Total overnight cost, ZAR/kW	55,209	52,283	49,357	47,894
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	1,362	1,289	1,202	1,162
Variable O&M, ZAR/MWh	55.3	55.3	55.3	55.3
Availability estimates				
Equivalent availability	91.7	91.7	91.7	91.7
Maintenance planned outages, %	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 wet cooling—cost and performance summary

Technology	1x750 MW, Wet Cooling	2x750 MW, Wet Cooling	4x750 MW, Wet Cooling	6x750 MW, Wet Cooling
Heat rate, kJ/kWh				
100% load	9,453	9,453	9,453	9,453
75% load	9,622	9,622	9,622	9,622
50% load	10,139	10,139	10,139	10,139
25% load	12,228	12,228	12,228	12,228
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	2,707	2,707	2,707	2,707
For wet and dry cooling (where applicable)	2,396	2,396	2,396	2,396
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	15.3	15.3	15.3	15.3
Air emissions, kg/MWh				
CO_2	911.2	911.2	911.2	911.2
SO_x	0.44	0.44	0.44	0.44
NO_x	1.87	1.87	1.87	1.87
Particulates	0.12	0.12	0.12	0.12
Solid wastes, kg/MWh				
FGD solids	24.3	24.3	24.3	24.3
Fly ash	162.4	162.4	162.4	162.4
Bottom ash	3.2	3.2	3.2	3.2

Table 7-3
PC with dry cooling and carbon capture—cost and performance summary

Technology	1x750 MW, Dry Cooling with CO_2 Removal	2x750 MW, Dry Cooling with CO_2 Removal	4x750 MW, Dry Cooling with CO_2 Removal	6x750 MW, Dry Cooling with CO_2 Removal
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 2021)				
Total overnight cost, ZAR/kW	114,234	109,931	105,629	103,479
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	2,435	2,332	2,208	2,150
Variable O&M, ZAR/MWh	59.3	59.3	59.3	59.3
Availability estimates				
Equivalent availability	91.7	91.7	91.7	91.7
Maintenance planned outages, %	4.8	4.8	4.8	4.8
Unplanned outages, %	3.7	3.7	3.7	3.7

Table 7-3 (continued)
PC with dry cooling and carbon capture—cost and performance summary

Technology	1x750 MW, Dry Cooling with CO_2 Removal	2x750 MW, Dry Cooling with CO_2 Removal	4x750 MW, Dry Cooling with CO_2 Removal	6x750 MW, Dry Cooling with CO_2 Removal
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
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	23,686	23,686	23,686	23,686
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	281.6	281.6	281.6	281.6
For wet and dry cooling (where applicable)	0	0	0	0
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	22.8	22.8	22.8	22.8
Air emissions, kg/MWh				
CO_2	135.5	135.5	135.5	135.5
SO_x	0.66	0.66	0.66	0.66
NO_x	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

Table 7-4
PC with wet cooling and carbon capture—cost and performance summary

Technology	1x750 MW, Wet Cooling with CO_2 Removal	2x750 MW, Wet Cooling with CO_2 Removal	4x750 MW, Wet Cooling with CO_2 Removal	6x750 MW, Wet Cooling with CO_2 Removal
Rated capacity, MW gross	919	1,838	3,676	5,514
Rated capacity, MW net	750	1,500	3,000	4,500
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	105,277	101,403	97,529	95,590
Lead-times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	2,274	2,179	2,065	2,011
Variable O&M, ZAR/MWh	94.6	94.6	94.6	94.6
Availability estimates				
Equivalent availability	91.7	91.7	91.7	91.7
Maintenance planned outages, %	4.8	4.8	4.8	4.8
Unplanned outages, %	3.7	3.7	3.7	3.7

Table 7-4 (continued)
PC with wet cooling and carbon capture—cost and performance summary

Technology	1x750 MW, Wet Cooling with CO_2 Removal	2x750 MW, Wet Cooling with CO_2 Removal	4x750 MW, Wet Cooling with CO_2 Removal	6x750 MW, Wet Cooling with CO_2 Removal
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	13,352	13,352	13,352	13,352
75% load	13,790	13,790	13,790	13,790
50% load	14,971	14,971	14,971	14,971
25% load	21,486	21,486	21,486	21,486
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	4,413	4,413	4,413	4,413
For wet and dry cooling (where applicable)	3,947	3,947	3,947	3,947
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	21.7	21.7	21.7	21.7
Air emissions, kg/MWh				
CO_2	129.1	129.1	129.1	129.1
SO_x	0.63	0.63	0.63	0.63
NO_x	0.40	0.40	0.40	0.40
Particulates	0.17	0.17	0.17	0.17
Solid wastes, kg/MWh				
FGD solids	34.5	34.5	34.5	34.5
Fly ash	230.1	230.1	230.1	230.1
Bottom ash	4.5	4.5	4.5	4.5

Table 7-5
Coal-to-gas plant cost and performance summary

Technology	580-MW Subcritical PC Plant Conversion to Gas Firing
Rated capacity, MW gross	582
Rated capacity, MW net	569
Plant cost estimates (January 2021)	
Total overnight cost, ZAR/kW	952
Lead times and project schedule (months)	24
Expense schedule, % of TPC per year	95%, 5%
Fuel cost estimates	
First year (ZAR/GJ)	127.2
Expected escalation (beyond inflation)	0%
Fuel energy content, MJ/SCM	39.3
O&M cost estimates	
Fixed O&M, ZAR/kW/year	285
Variable O&M, ZAR/MWh	64.9
Availability estimates	
Equivalent availability	91.7
Maintenance planned outages, %	4.8
Unplanned outages, %	3.7
Performance estimates	
Economic life, years	30
Heat rate, kJ/kWh	10,762
Plant load factor	
Typical capacity factor	65%
Maximum of rated capacity	100%
Minimum of rated capacity	25%
Water usage	
Per unit of energy, L/MWh	3,078
Air emissions, kg/MWh	
CO_2	541.1
SO_x	0
NO_x	0.46
CO	0.69
Particulates	0

Plant Cost Estimates

The total overnight cost for a PC plant with dry cooling ranges from 51,600 ZAR/kW to 59,400 ZAR/kW and, for a plant with wet cooling, from 47,900 ZAR/kW to 55,200 ZAR/kW, depending on the number of units. With addition of carbon capture, the overnight cost ranges from 103,500 ZAR/kW to 114,200 ZAR/kW for a dry-cooled plant and 95,600 ZAR/kW to 105,300 ZAR/kW for a wet-cooled plant, 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 cost of the plant by 90% 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.

The estimated cost to modify a subcritical 580-MW coal plant to add natural gas firing capability is about 952 ZAR/kW. Major cost components of the plant modification include the natural gas firing system, natural gas piping, and the flue gas recirculation system for NO_x control. Coal and ash handling equipment are kept in place for dual-firing capabilities. The coal-to-gas conversion project would have a two-year expense and construction period, with the expected expense schedule of 95% in year 1 and 5% in year 2.

A PC unit would have about a four-year expense and construction period. Early in the project, costs would include preliminary design, project siting, and permitting. Later in the project, equipment would be procured, delivered, and installed. This would be when the majority of the expenditures take place. The final stage of the project would be the commissioning of the plant. Based on this schedule, the expected expense schedule would be 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 startup of each unit would be staggered by a year, so 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 37.8 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 a PC plant with dry cooling is between 1190 and 1400 ZAR/kW/year and, for a plant with wet cooling, between 1160 and 1360 ZAR/kW/year, depending on the number of units. For a plant with dry cooling and carbon capture, the fixed O&M costs are between 2150 and 2435 ZAR/kW/year, and for a plant with wet cooling plus carbon capture, between 2010 and 2270 ZAR/kW/year, 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 33 ZAR/MWh for a dry-cooled plant and 55 ZAR/MWh for a wet-cooled plant. The variable O&M increases to 59 ZAR/MWh for a dry-cooled plant with carbon capture and 95 ZAR/MWh for a wet-cooled plant with carbon capture. The increased O&M from carbon capture is due to the additional labor needs and amine cost.

For the coal-to-gas plant, the fixed O&M is 285 ZAR/kW, and the variable O&M is 40 ZAR/MWh. The O&M costs of an existing coal plant would be lower when firing natural gas due to savings in coal handling and ash disposal costs, as well as reduction in labor costs.

Availability and Performance Estimates

The PC plants have an expected equivalent availability of 91.7% and a capacity factor of 85%. The full-load heat rate is about 9780 kJ/kWh for a plant with dry cooling and 9450 kJ/kWh for a plant with wet cooling. With carbon capture, the full-load heat rate increases to 13,990 kJ/kWh for a dry-cooled plant and 13,350 kJ/kWh for a wet-cooled plant.

For a plant with carbon capture and dry cooling, the full-load heat rate is about 13,990 kJ/kWh, and, for a plant with carbon capture and wet cooling, it is about 13,350 kJ/kWh. The increased heat rate of the plants with carbon capture is 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.

The coal-to-gas plant has a heat rate of about 10,760 kJ/kWh with natural gas firing.

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

Tables 7-6 through 7-10 show a representative levelized cost of electricity for the PC plants. These assume sequential startup so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single startup 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 7-6
PC with dry cooling—levelized cost of electricity

Technology	1x750 MW, Dry Cooling	2x750 MW, Dry Cooling	4x750 MW, Dry Cooling	6x750 MW, Dry Cooling
Rated capacity, MW net	750	1,500	3,000	4500
Fuel cost (ZAR/MWh)	374.4	374.4	374.4	374.4
O&M (ZAR/MWh)	221.2	211.0	199.2	193.6
Capital (ZAR/MWh)	1020.5	966.7	912.8	885.8
LCOE (ZAR/MWh)	**1616.1**	**1552.1**	**1486.5**	**1453.8**

Table 7-7
PC with wet cooling—levelized cost of electricity

Technology	1x750 MW, Wet Cooling	2x750 MW, Wet Cooling	4x750 MW, Wet Cooling	6x750 MW, Wet Cooling
Rated capacity, MW net	750	1,500	3,000	4,500
Fuel cost (ZAR/MWh)	361.9	361.9	361.9	361.9
O&M (ZAR/MWh)	238.4	228.4	216.8	211.4
Capital (ZAR/MWh)	948.2	898.3	848.3	823.5
LCOE (ZAR/MWh)	**1,548.5**	**1,488.7**	**1,427.0**	**1,396.7**

Table 7-8
PC with dry cooling and carbon capture—levelized cost of electricity

Technology	1x750 MW, Dry Cooling with CO_2 Removal	2x750 MW, Dry Cooling with CO_2 Removal	4x750 MW, Dry Cooling with CO_2 Removal	6x750 MW, Dry Cooling with CO_2 Removal
Rated capacity, MW net	750	1,500	3,000	4,500
Fuel cost (ZAR/MWh)	538.1	538.1	538.1	538.1
O&M (ZAR/MWh)	386.2	372.2	355.9	348.1
Capital (ZAR/MWh)	1,958.0	1,884.6	1,811.0	1,774.4
LCOE (ZAR/MWh)	**2,882.3**	**2,794.9**	**2,705.0**	**2,660.6**

Table 7-9
PC with wet cooling and carbon capture—levelized cost of electricity

Technology	1x750 MW, Wet Cooling with CO_2 Removal	2x750 MW, Wet Cooling with CO_2 Removal	4x750 MW, Wet Cooling with CO_2 Removal	6x750 MW, Wet Cooling with CO_2 Removal
Rated capacity, MW net	750	1,500	3,000	4,500
Fuel cost (ZAR/MWh)	512.7	512.7	512.7	512.7
O&M (ZAR/MWh)	399.9	387.3	371.8	364.6
Capital (ZAR/MWh)	1,805.0	1,739.0	1,672.9	1,639.7
LCOE (ZAR/MWh)	**2,717.7**	**2,639.0**	**2,557.4**	**2,517.0**

Table 7-10
Coal-to-gas plant levelized cost of electricity

Technology	580-MW Subcritical PC Plant Conversion to Gas Firing
Rated capacity, MW net	569
Fuel cost (ZAR/MWh)	1408.7
O&M (ZAR/MWh)	111.7
Capital (ZAR/MWh)	25.2
LCOE (ZAR/MWh)	**1,545.6**

Water Usage

The water consumption is about 2710 L/MWh for PC plants with wet cooling and about 198 L/MWh for plants with dry cooling because the only water usage is makeup water to the boiler. The addition of carbon capture increases the water consumption to 4410 L/MWh for wet cooling plants and 282 L/MWh for dry cooling plants. The coal-to-gas plant consumes about 3080 L/MWh of water.

Emissions

Both the air and solid emissions of the PC plants that were evaluated in this study are listed in the preceding summary tables. 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

Tables 7-11 and 7-12 summarize cost and performance for the IGCC plants.

Table 7-11
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 2021)				
Total overnight cost, ZAR/kW	79,388	74,623	69,860	67,480
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	1,938	1,806	1,664	1,599
Variable O&M, ZAR/MWh	38.4	38.4	38.4	38.4
Availability estimates				
Equivalent availability	85.7	85.7	85.7	85.7
Maintenance planned outages, %	4.7	4.7	4.7	4.7
Unplanned outages, %	10.1	10.1	10.1	10.1

Table 7-11 (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				
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
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
For wet and dry cooling (where applicable)	0	0	0	0
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	0	0	0	0
Air emissions, kg/MWh				
CO_2	930	930	930	930
SO_x	0.18	0.18	0.18	0.18
NO_x	0.23	0.23	0.23	0.23
Particulates	0.04	0.04	0.04	0.04
Solid wastes, kg/MWh				
Ash as slag	182.3	182.3	182.3	182.3

Table 7-12
IGCC with carbon capture—cost and performance summary

Technology	One 2x2x1 Shell IGCC with CO_2 Removal	Two 2x2x1 Shell IGCC with CO_2 Removal	Four 2x2x1 Shell IGCC with CO_2 Removal	Six 2x2x1 Shell IGCC with CO_2 Removal
Rated capacity, MW gross	894	1,788	3,576	5,364
Rated capacity, MW net	644	1,288	2,576	3,864
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	125,333	117,812	110,292	106,532
Lead-times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	2,754	2,584	2,388	2,199
Variable O&M, ZAR/MWh	108.1	108.1	108.1	108.1
Availability estimates				
Equivalent availability	85.7	85.7	85.7	85.7
Maintenance planned outages, %	4.7	4.7	4.7	4.7
Unplanned outages, %	10.1	10.1	10.1	10.1

Table 7-12 (continued)
IGCC with carbon capture—cost and performance summary

Technology	One 2x2x1 Shell IGCC with CO_2 Removal	Two 2x2x1 Shell IGCC with CO_2 Removal	Four 2x2x1 Shell IGCC with CO_2 Removal	Six 2x2x1 Shell IGCC with CO_2 Removal
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
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
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
For wet and dry cooling (where applicable)	0	0	0	0
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	0	0	0	0
Air emissions, kg/MWh				
CO_2	120	120	120	120
SO_x	0.23	0.23	0.23	0.23
NO_x	0.29	0.29	0.29	0.29
Particulates	0.05	0.05	0.05	0.05
Solid wastes, kg/MWh				
Ash as slag	234.3	234.3	234.3	234.3

Plant Cost Estimates

The total overnight cost for the IGCC plants evaluated in this study ranges from 67,500 ZAR/kW to 79,400 ZAR/kW for a plant without carbon capture and from 106,500 ZAR/kW to 125,300 ZAR/kW for a 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 58% 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 would include preliminary design, project siting, and permitting. Later in the project, equipment would be procured, delivered, and installed. This would be when the majority of the expenditures take place. The final stage of the project would be the commissioning of the plant.

Based on this schedule, the expected expense schedule would be 10% in year 1, 25% in year 2, 45% in year 3, and 20% in year 4. For a multi-unit plant, it would be expected that the construction and startup of each unit would be staggered by a year, so that the first unit would start after four years and a new unit would startup each subsequent year.

Fuel Cost Estimates

The cost of the South African coal used in this study is estimated to be 37.8 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 1600 to 1940 ZAR/kW/year for a plant without carbon capture and 2200 to 2750 ZAR/kW for a plant with carbon capture, depending on unit configuration. 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 38 ZAR/MWh for a plant without carbon capture and 108 ZAR/MWh for a plant with carbon capture. No credit was assumed for sulfur byproduct or for the ash, which is recovered as a glassy, nonleachable slag that can be sold for various building material or roadbed uses.

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 minemouth 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 full-load heat rate of the IGCC plant is expected to be about 9650 kJ/kWh, which is roughly similar to the air-cooled PC units that were 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 full-load heat rate of an IGCC with carbon capture is expected to be about 12,400 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

Tables 7-13 and 7-14 show representative levelized cost of electricity for the IGCC plants that were evaluated in this study. These assume sequential startup so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single startup 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 7-13
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)	372.2	372.2	372.2	372.2
O&M (ZAR/MWh)	298.8	280.8	261.8	253.1
Capital (ZAR/MWh)	1,367.0	1,285.8	1,204.4	1,163.8
LCOE (ZAR/MWh)	**2,038.0**	**1,938.8**	**1,838.4**	**1,789.1**

Table 7-14
IGCC with carbon capture—levelized cost of electricity

Technology	One 2x2x1 Shell IGCC with CO_2 Removal	Two 2x2x1 Shell IGCC with CO_2 Removal	Four 2x2x1 Shell IGCC with CO_2 Removal	Six 2x2x1 Shell IGCC with CO_2 Removal
Rated capacity, MW net	644	1,288	2,576	3,864
Fuel cost (ZAR/MWh)	478.5	478.5	478.5	478.5
O&M (ZAR/MWh)	478.1	455.1	428.8	403.4
Capital (ZAR/MWh)	2,152.9	2,024.8	1,896.4	1,832.0
LCOE (ZAR/MWh)	**3,109.5**	**2,958.3**	**2,803.6**	**2,713.9**

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 about 1027 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 preceding summary table. The gas cleanup process required before sending the syngas to the GT results in very low SO_x and NO_x 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.

Fluidized Bed Combustion

Tables 7-15 through 7-18 summarize cost and performance for the FBC plants.

Table 7-15
Fluidized bed with dry cooing—cost and performance summary

Technology	1x250 MW, Dry Cooling	2x250 MW, Dry Cooling	4x250 MW, Dry Cooling	6x250 MW, Dry Cooling
Rated capacity, MW gross	274	547	1,094	1,641
Rated capacity, MW net	250	500	1,000	1,500
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	61,071	57,407	53,743	51,910
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	816	765	693	662
Variable O&M, ZAR/MWh	156.3	152.7	150.8	150.3

Table 7-15 (continued)
Fluidized bed with dry cooing—cost and performance summary

Technology	1x250 MW, Dry Cooling	2x250 MW, Dry Cooling	4x250 MW, Dry Cooling	6x250 MW, Dry Cooling
Availability estimates				
Equivalent availability	90.4	90.4	90.4	90.4
Maintenance planned outages, %	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				
100% load	10,740	10,740	10,740	10,740
75% load	10,941	10,941	10,941	10,941
50% load	11,526	11,526	11,526	11,526
25% load	13,916	13,916	13,916	13,916
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
For wet and dry cooling (where applicable)	0	0	0	0
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	21	21	21	21
Air emissions, kg/MWh				
CO_2	1003	1003	1003	1003
SO_x	0.50	0.50	0.50	0.50
NO_x	1.28	1.28	1.28	1.28
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

Table 7-16
Fluidized bed with wet cooing—cost and performance summary

Technology	1x250 MW, Wet Cooling	2x250 MW, Wet Cooling	4x250 MW, Wet Cooling	6x250 MW, Wet Cooling
Rated capacity, MW gross	270	540	1,080	1,620
Rated capacity, MW net	250	500	1,000	1,500
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	54,240	50,985	47,731	46,105
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	763	716	647	618
Variable O&M, ZAR/MWh	169.5	166.1	164.3	163.5
Availability estimates				
Equivalent availability	90.4	90.4	90.4	90.4
Maintenance planned outages, %	5.7	5.7	5.7	5.7
Unplanned outages, %	4.1	4.1	4.1	4.1

Table 7-16 (continued)
Fluidized bed with wet cooing—cost and performance summary

Technology	1x250 MW, Wet Cooling	2x250 MW, Wet Cooling	4x250 MW, Wet Cooling	6x250 MW, Wet Cooling
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	10,382	10,382	10,382	10,382
75% load	10,561	10,561	10,561	10,561
50% load	11,099	11,099	11,099	11,099
25% load	13,220	13,220	13,220	13,220
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	1,941	1,941	1,941	1,941
For wet and dry cooling (where applicable)	1,908	1,908	1,908	1,908
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	20	20	20	20
Air emissions, kg/MWh				
CO_2	1003	1003	1003	1003
SO_x	0.49	0.49	0.49	0.49
NO_x	1.23	1.23	1.23	1.23
Particulates	0.14	0.14	0.14	0.14
Solid wastes, kg/MWh				
FGD solids	35.0	35.0	35.0	35.0
Fly ash	140.1	140.1	140.1	140.1
Bottom ash	41.9	41.9	41.9	41.9

Table 7-17
Fluidized bed with dry cooling and carbon capture—cost and performance summary

Technology	1x250 MW, Dry Cooling with CO_2 Removal	2x250 MW, Dry Cooling with CO_2 Removal	4x250 MW, Dry Cooling with CO_2 Removal	6x250 MW, Dry Cooling with CO_2 Removal
Rated capacity, MW gross	397	794	1,588	2,382
Rated capacity, MW net	250	500	1,000	1,500
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	108,122	103,254	98,386	95,951
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	1,242	1,168	1,088	1,044
Variable O&M, ZAR/MWh	191.8	186.6	184.0	183.1
Availability estimates				
Equivalent availability	90.4	90.4	90.4	90.4
Maintenance planned outages, %	5.7	5.7	5.7	5.7
Unplanned outages, %	4.1	4.1	4.1	4.1

Table 7-17 (continued)
Fluidized bed with dry cooling and carbon capture—cost and performance summary

Technology	1x250 MW, Dry Cooling with CO_2 Removal	2x250 MW, Dry Cooling with CO_2 Removal	4x250 MW, Dry Cooling with CO_2 Removal	6x250 MW, Dry Cooling with CO_2 Removal
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	15,451	15,451	15,451	15,451
75% load	15,741	15,741	15,741	15,741
50% load	16,585	16,585	16,585	16,585
25% load	20,025	20,025	20,025	20,025
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
For wet and dry cooling (where applicable)	0	0	0	0
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	30	30	30	30
Air emissions, kg/MWh				
CO_2	148	148	148	148
SO_x	0.72	0.72	0.72	0.72
NO_x	1.84	1.84	1.84	1.84
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

Table 7-18
Fluidized bed with wet cooling and carbon capture—cost and performance summary

Technology	1x250 MW, Wet Cooling with CO_2 Removal	2x250 MW, Wet Cooling with CO_2 Removal	4x250 MW, Wet Cooling with CO_2 Removal	6x250 MW, Wet Cooling with CO_2 Removal
Rated capacity, MW gross	381	762	1,524	2,286
Rated capacity, MW net	250	500	1,000	1,500
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	98,604	94,307	90,010	87,862
Lead times and project schedule (months)	48	60	84	108
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)	37.8	37.8	37.8	37.8
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/year	1,171	1,102	1,026	984
Variable O&M, ZAR/MWh	214.5	209.2	206.7	205.8
Availability estimates				
Equivalent availability	90.4	90.4	90.4	90.4
Maintenance planned outages, %	5.7	5.7	5.7	5.7
Unplanned outages, %	4.1	4.1	4.1	4.1

Table 7-18 (continued)
Fluidized bed with wet cooling and carbon capture—cost and performance summary

Technology	1x250 MW, Wet Cooling with CO_2 Removal	2x250 MW, Wet Cooling with CO_2 Removal	4x250 MW, Wet Cooling with CO_2 Removal	6x250 MW, Wet Cooling with CO_2 Removal
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	14,760	14,760	14,760	14,760
75% load	14,992	14,992	14,992	14,992
50% load	15,710	15,710	15,710	15,710
25% load	18,263	18,263	18,263	18,263
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	3,371	3,371	3,371	3,371
For wet and dry cooling (where applicable)	3,321	3,321	3,321	3,321
Sorbent (limestone) usage				
Per unit of energy, kg/MWh	28	28	28	28
Air emissions, kg/MWh				
CO_2	141	141	141	141
SO_x	0.69	0.69	0.69	0.69
NO_x	1.76	1.76	1.76	1.76
Particulates	0.19	0.19	0.19	0.19
Solid wastes, kg/MWh				
FGD solids	49.7	49.7	49.7	49.7
Fly ash	199.1	199.1	199.1	199.1
Bottom ash	59.5	59.5	59.5	59.5

Plant Cost Estimates

The total overnight cost for the FBC plants evaluated in this study ranges from about 51,900 ZAR/kW to 61,100 ZAR/kW for a plant with dry cooling and from 46,100 ZAR/kW to 54,200 ZAR/kW for a plant with wet cooling, depending on the number of units. For FBC plants with 90% CO_2 capture, the total overnight cost ranges from 96,000 ZAR/kW to 108,100 ZAR/kW for a plant with dry cooling and from 87,900 ZAR/kW to 98600 ZAR/kW for a plant with wet cooling, depending on unit configuration. Adding carbon capture increases the plant cost by about 85–90% on a per kilowatt basis. All FBC plants that were evaluated in this study include an FGD unit to reduce SO_x emissions.

The expected expense and construction period for a single FBC unit is about four years. Early in the project, costs would include preliminary design, project siting, and permitting. Later in the project, equipment would be procured, delivered, and installed. This is when the majority of the expenditures would take place. The final stage of the project would 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 startup of each unit would be staggered by a year, so 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 37.8 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 662–816 ZAR/kW/year for a plant with dry cooling and 618–763 ZAR/kW/year for a plant with wet cooling. For FBC plants with carbon capture, the fixed O&M costs are about 1044–1242 ZAR/kW/year for an air-cooled plant, and 984 –1171 ZAR/kW/year for a wet-cooled plant. For this study, both maintenance labor and material costs are considered to be fixed O&M costs. The variable O&M cost ranges from 156 ZAR/MWh for an air-cooled plant to 170 ZAR/MWh for a wet-cooled plant. The addition of carbon capture increases the variable O&M to 192 ZAR/MWh for an air-cooled plant and 215 ZAR/MWh for a wet-cooled plant.

Availability and Performance Estimates

The equivalent availability of the FBC plants evaluated in this study is expected to be about 90.4% and a capacity factor of 85%. The full-load heat rate is 10,740 kJ/kWh for a plant with dry cooling and 10,380 kJ/kWh for a plant with wet cooling. The inclusion of carbon capture increases the heat rate to 15,450 kJ/kWh for an air-cooled plant and 14,760 kJ/kWh for a wet-cooled plant.

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

Tables 7-19 through 7-22 show representative levelized costs of electricity for the FBC plants that were evaluated in this study. These assume sequential startup so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single startup 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 7-19
Fluidized bed with dry cooling—levelized cost of electricity

Technology	1x250 MW, Dry Cooling	2x250 MW, Dry Cooling	4x250 MW, Dry Cooling	6x250 MW, Dry Cooling
Rated capacity, MW net	250	500	1,000	1,500
Fuel cost (ZAR/MWh)	411.6	411.6	411.6	411.6
O&M (ZAR/MWh)	265.8	255.5	244.0	239.1
Capital (ZAR/MWh)	1,049.5	987.0	924.4	893.3
LCOE (ZAR/MWh)	**1,726.9**	**1,654.0**	**1,580.0**	**1,544.0**

Table 7-20
Fluidized bed with wet cooling—levelized cost of electricity

Technology	1x250 MW, Wet Cooling	2x250 MW, Wet Cooling	4x250 MW, Wet Cooling	6x250 MW, Wet Cooling
Rated capacity, MW net	250	500	1,000	1,500
Fuel cost (ZAR/MWh)	397.6	397.6	397.6	397.6
O&M (ZAR/MWh)	272.1	262.2	251.1	246.6
Capital (ZAR/MWh)	933.0	877.5	821.8	794.1
LCOE (ZAR/MWh)	**1,602.7**	**1,537.2**	**1,470.5**	**1,438.3**

Table 7-21
Fluidized bed with dry cooling and carbon capture—levelized cost of electricity

Technology	1x250 MW, Dry Cooling with CO_2 Removal	2x250 MW, Dry Cooling with CO_2 Removal	4x250 MW, Dry Cooling with CO_2 Removal	6x250 MW, Dry Cooling with CO_2 Removal
Rated capacity, MW net	250	500	1,000	1,500
Fuel cost (ZAR/MWh)	592.1	592.1	592.1	592.1
O&M (ZAR/MWh)	358.4	343.4	330.0	323.4
Capital (ZAR/MWh)	1,854.9	1,771.8	1,688.8	1,647.3
LCOE (ZAR/MWh)	**2,805.4**	**2,707.4**	**2,610.9**	**2,562.9**

Table 7-22
Fluidized bed with wet cooling and carbon capture—levelized cost of electricity

Technology	1x250 MW, Wet Cooling with CO_2 Removal	2x250 MW, Wet Cooling with CO_2 Removal	4x250 MW, Wet Cooling with CO_2 Removal	6x250 MW, Wet Cooling with CO_2 Removal
Rated capacity, MW net	250	500	1,000	1,500
Fuel cost (ZAR/MWh)	565.1	565.1	565.1	565.1
O&M (ZAR/MWh)	371.7	357.3	344.5	338.1
Capital (ZAR/MWh)	1,692.4	1,619.2	1,545.8	1,509.1
LCOE (ZAR/MWh)	**2,629.2**	**2,541.6**	**2,455.3**	**2,412.4**

Water Usage

The water consumption is about 1940 L/MWh for FBC plants with wet cooling and about 33 L/MWh for plants with dry cooling because the only water usage is makeup water to the boiler. The addition of carbon capture increases the water consumption to 3370 L/MWh for wet cooling plants and to 50 L/MWh for dry-cooling plants. 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 that were evaluated in this study are shown in the preceding summary table. 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. 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

Tables 8-1 through 8-3 summarize cost and performance for nuclear plants.

Table 8-1
Nuclear AREVA EPR technology performance and cost summary

Technology	1x1600 MW, AREVA	2x1600 MW, AREVA
Rated capacity, MW net	1,600	3,200
Plant cost estimates (January 2021)		
Total overnight cost, ZAR/kW	122,976	121,440
Lead times and project schedule (months)	72	84
Expense schedule, % of TPC per year	15%, 15%, 25%, 25%, 10%, 10%	10%, 10%, 25%, 25%, 10%, 10%, 10%
Fuel cost estimates		
First year, ZAR/GJ	11.9	11.9
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, GJ/kg	1,299	1,299
O&M cost estimates		
Fixed O&M, ZAR/kW/year	979	809
Variable O&M, ZAR/MWh	66.5	66.5
Availability estimates		
Equivalent availability	92	92
Maintenance	6.7	6.7
Unplanned outages	1.4	1.4
Performance estimates		
Economic life, years	60	60
Heat rate, kJ/kWh	10,002	10,002
Water usage		
Cooling (once-through seawater), L/MWh	1,514	1,514
Boiler makeup, L/MWh	Negligible	Negligible

Table 8-2
Nuclear AP1000 technology performance and cost summary

Technology	1x1117 MW, AP1000	2x1117 MW, AP1000
Rated capacity, MW net	1,117	2,234
Plant cost estimates (January 2021)		
Total overnight cost, ZAR/kW	117,524	116,077
Lead times and project schedule (months)	72	84
Expense schedule, % of TPC per year	15%, 15%, 25%, 25%, 10%, 10%	10%, 10%, 25%, 25%, 10%, 10%, 10%
Fuel cost estimates		
First year, ZAR/GJ	11.9	11.9
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, GJ/kg	1,299	1,299
O&M cost estimates		
Fixed O&M, ZAR/kW/year	1,606	1,327
Variable O&M, ZAR/MWh	43.0	43.0
Availability estimates		
Equivalent availability	93	93
Maintenance	5.7	5.7
Unplanned outages	1.4	1.4
Performance estimates		
Economic life, years	60	60
Heat rate, kJ/kWh	11,250	11,250
Water usage		
Cooling (once-through seawater), L/MWh	1,514	1,514
Boiler makeup, L/MWh	Negligible	Negligible

Table 8-3
Nuclear SMR technology performance and cost summary

Technology	12x57 MW, SMR
Rated capacity, MW net	684
Plant cost estimates (January 2021)	
Total overnight cost, ZAR/kW	116,357
Lead times and project schedule (months)	48
Expense schedule, % of TPC per year	15%, 35%, 35%, 15%
Fuel cost estimates	
First year, ZAR/GJ	11.9
Expected escalation (beyond inflation)	0%
Fuel energy content, GJ/kg	1,299
O&M cost estimates	
Fixed O&M, ZAR/kW/year	1,849
Variable O&M, ZAR/MWh	11.1
Availability estimates	
Equivalent availability	92
Maintenance	6.7
Unplanned outages	1.4
Performance estimates	
Economic life, years	60
Heat rate, kJ/kWh	11,996
Water usage, L/MWh	250

Plant Cost Estimates

The total overnight cost is estimated to be between 121,400 ZAR/kW and 123,000 ZAR/kW for the Areva EPR and 116,100 ZAR/kW to 117,500 ZAR/kW for the AP1000, depending on the number of units. The total overnight cost for the SMR is about 116,400 ZAR/kW. The overnight costs include project contingency and process contingency. Total contingencies were assumed to be 10% of total process capital and engineering, procurement, and construction services.

Due to long lead times for procurement of equipment for the Areva and AP1000 nuclear plants, 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. The expected expense and construction period for a SMR plant is about four years, with 15% in year 1, 35% in year 2, 35% in year 3, and 15% in year 4.

Nuclear Cost Uncertainty Risks

As mentioned in the Section 4 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. Although 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 United States. Examples are upgrades such as 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 (for example, welders, electrical) will likely be limited due to other nuclear projects and nonnuclear projects that compete for resources; though, as the demand becomes more certain, supply could expand to meet the increase in demand.

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 after it is 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. 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 of the risks cannot be wrapped into the project engineering, procurement, and construction contracts because 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 cost of uranium is estimated to be 11.9 ZAR/GJ. 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. For the SMR, refueling can be done on a two-year cycle, with each unit requiring a 10-day outage. Provided there is no overlap in any of the units fueling cycles, a 12-unit SMR facility will have 120 days per two years with one module not operating. During this time, all other modules can remain operational at full capacity. The refueling modules are maintained by a dedicated refueling crew that includes a senior reactor operator.

O&M Cost Estimates

It is expected that manpower requirements for modern nuclear plants will be reduced due to the reduction in equipment and focus on passive safety features. Furthermore, advances in online diagnostic equipment and control room interfaces will reduce maintenance time. The Areva EPR has lower fixed O&M cost than the AP1000, with cost ranging from 809 to 979 ZAR/kW/year compared to 1327 to 1606 ZAR/kW/year for the AP1000. Lower staffing requirements and materials costs result in lower fixed O&M cost for the Areva plant compared to the AP1000. The SMR plant has the highest fixed O&M, estimated at 1850 ZAR/kW/year. Variable O&M costs are about 67 ZAR/MWh for the Areva EPR, 43 ZAR/MWh for the AP1000, and 11 ZAR/MWh for the SMR. The lower variable O&M cost for the SMR plant is attributed to the use of an air-cooling system for heat rejection.

Availability and Performance Estimates

Availability of nuclear plants has continued to improve over the years as maintenance practices have been refined and online diagnostic equipment has developed. Availability of the nuclear plants is expected to be about 92–93%.

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 10,000 kJ/kWh for the Areva EPR, 11,250 kJ/kWh for the AP1000, and 11,996 kJ/kWh for the SMR. These plants are expected to operate primarily at full load but are designed to allow for some load-follow capability.

Cost of Electricity

Tables 8-4 through 8-6 show the levelized cost of electricity of the Areva EPR, the AP1000, and the SMR plants. These assume sequential startup so that AFUDC accumulates only for a single unit and not for the full schedule of the project. A single startup 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 8-4
Nuclear Areva EPR levelized cost of electricity

Technology	1x1600 MW, Areva	2x1600 MW, Areva
Rated capacity, MW net	1,600	3,200
Fuel cost (ZAR/MWh)	118.6	118.6
O&M (ZAR/MWh)	190.5	169.0
Capital (ZAR/MWh)	2,138.6	2,164.5
LCOE (ZAR/MWh)	**2,447.7**	**2,452.1**

Table 8-5
Nuclear AP1000 levelized cost of electricity

Technology	1x1117 MW, AP1000	2x1117 MW, AP1000
Rated capacity, MW net	1,117	2,234
Fuel cost (ZAR/MWh)	133.4	133.4
O&M (ZAR/MWh)	246.6	211.4
Capital (ZAR/MWh)	2,044.5	2,069.5
LCOE (ZAR/MWh)	**2,424.5**	**2,414.4**

Table 8-6
Nuclear SMR levelized cost of electricity

Technology	12x57 MW, SMR
Rated capacity, MW net	684
Fuel cost (ZAR/MWh)	142.3
O&M (ZAR/MWh)	245.7
Capital (ZAR/MWh)	1,899.1
LCOE (ZAR/MWh)	**2,287.1**

Water Usage

It was assumed that the Areva and AP1000 nuclear plants are cooled using a once-through cooling seawater condenser and that the SMR plant is air-cooled. The once-through condenser has a water requirement of about 1500 L/MWh, but the water is returned to the ocean after it has cooled the condenser; therefore, 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

Tables 9-1 through 9-4 summarize cost and performance for the GT and ICE plants.

Table 9-1
OCGT cost and performance summary

Technology	1xLM6000	1xLMS100	1x9F.05	1x9HA.02
Rated capacity, MW gross	46	108	300	545
Rated capacity, MW net	45	106	297	540
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	28,694	19,617	10,961	9,409
Lead times and project schedule (months)	36	36	36	36
Expense schedule, % of TPC per year	15%, 44%, 41%	15%, 44%, 41%	15%, 44%, 41%	15%, 44%, 41%
Fuel cost estimates				
First year (ZAR/GJ)	127.2	127.2	127.2	127.2
Expected escalation (beyond inflation)	0%	0%	0%	0%
Fuel energy content, MJ/SCM	39.3	39.3	39.3	39.3
O&M cost estimates				
Fixed O&M, ZAR/kW/year	453	194	89	51
Variable O&M, ZAR/MWh	92.3	131.4	67.4	64.9
Availability estimates				
Equivalent availability	93.6	93.6	93.6	93.6
Maintenance planned outages, %	4.5	4.5	4.5	4.5
Unplanned outages, %	2.0	2.0	2.0	2.0

Table 9-1 (continued)
OCGT cost and performance summary

Technology	1xLM6000	1xLMS100	1x9F.05	1x9HA.02
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	10,340	9,612	10,624	9,453
75% load	11,553	10,086	11,078	9,970
50% load	13,842	11,141	12,840	11,289
25% load	13,842	11,141	14,349	13,399
Plant load factor				
Typical capacity factor	10%	10%	10%	10%
Maximum of rated capacity	100%	100%	100%	100%
Minimum of rated capacity	50%	50%	50%	50%
Water usage				
Per unit of energy, L/MWh	0	772	0	0
For wet and dry cooling (where applicable)	0	0	0	0
Air emissions, kg/MWh				
CO_2	540	497	547	487
SO_x	0.00	0.00	0.00	0.00
NO_x	0.47	0.43	0.25	0.38
CO	0.23	0.66	0.23	0.16

Table 9-2
CCGT cost and performance summary

Technology	1x1 9F.05 Dry Cool	2x1 9F.05 Dry Cool	1x1 9HA.02 Dry Cool	2x1 9HA.02 Dry Cool
Rated capacity, MW gross	470	945	810	1,627
Rated capacity, MW net	460	281	792	1,028
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	18,246	13,685	13,340	10,503
Lead times and project schedule (months)	48	48	48	48
Expense schedule, % of TPC per year	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%
Fuel cost estimates				
First year (ZAR/GJ)	127.2	127.2	127.2	127.2
Expected escalation (beyond inflation)	0%	0%	0%	0%
Fuel energy content, MJ/SCM	39.3	39.3	39.3	39.3
O&M cost estimates				
Fixed O&M, ZAR/kW/year	140	80	82	47
Variable O&M, ZAR/MWh	63.1	52.9	60.4	50.0
Availability estimates				
Equivalent availability	97.5	97.5	97.5	97.5
Maintenance planned outages, %	1.5	1.5	1.5	1.5
Unplanned outages, %	1.0	1.0	1.0	1.0
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	6,942	6,900	6,499	6,541
75% load	7,069	7,016	6,668	6,700
50% load	7,565	6,984	7,079	6,594
25% load	7,881	8,092	7,596	7,839

Table 9-2 (continued)
CCGT cost and performance summary

Technology	1x1 9F.05 Dry Cool	2x1 9F.05 Dry Cool	1x1 9HA.02 Dry Cool	2x1 9HA.02 Dry Cool
Plant load factor				
Typical capacity factor	50%	50%	50%	50%
Maximum of rated capacity	100%	100%	100%	100%
Minimum of rated capacity	1%	1%	1%	1%
Water usage				
Per unit of energy, L/MWh	9.1	9.1	7.5	7.5
For wet and dry cooling (where applicable)	0	0	0	0
Air emissions, kg/MWh				
CO_2	358	356	335	337
SO_x	0.00	0.00	0.00	0.00
NO_x	0.02	0.02	0.02	0.02
CO	0.01	0.01	0.01	0.01

Table 9-3
CCGT with carbon capture—cost and performance summary

Technology	1x1 9F.05 Dry Cool with CO_2 Removal	2x1 9F.05 Dry Cool with CO_2 Removal	1x1 9HA.02 Dry Cool with CO_2 Removal	2x1 9HA.02 Dry Cool with CO_2 Removal
Rated capacity, MW gross	430	865	741	1,488
Rated capacity, MW net	398	498	685	828
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	56,236	45,428	45,834	35,537
Lead times and project schedule (months)	48	48	48	48
Expense schedule, % of TPC per year	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%
Fuel cost estimates				
First year (ZAR/GJ)	127.2	127.2	127.2	127.2
Expected escalation (beyond inflation)	0%	0%	0%	0%

Table 9-3 (continued)
CCGT with carbon capture—cost and performance summary

Technology	1x1 9F.05 Dry Cool with CO_2 Removal	2x1 9F.05 Dry Cool with CO_2 Removal	1x1 9HA.02 Dry Cool with CO_2 Removal	2x1 9HA.02 Dry Cool with CO_2 Removal
Fuel energy content, MJ/SCM	39.3	39.3	39.3	39.3
O&M cost estimates				
Fixed O&M, ZAR/kW/year	257	141	183	91
Variable O&M, ZAR/MWh	140.9	129.3	138.0	126.5
Availability estimates				
Equivalent availability	97.5	97.5	97.5	97.5
Maintenance planned outages, %	1.5	1.5	1.5	1.5
Unplanned outages, %	1.0	1.0	1.0	1.0
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh				
100% load	8,018	7,976	7,512	7,554
75% load	8,145	8,092	7,681	7,712
50% load	8,641	8,061	8,092	7,607
25% load	8,957	9,168	8,609	8,852
Plant load factor				
Typical capacity factor	50%	50%	50%	50%
Maximum of rated capacity	100%	100%	100%	100%
Minimum of rated capacity	1%	1%	1%	1%
Water usage				
Per unit of energy, L/MWh	13.6	13.6	11.4	11.4
For wet and dry cooling (where applicable)	0	0	0	0
Air emissions, kg/MWh				
CO_2	41	41	39	39
SO_x	0.00	0.00	0.00	0.00
NO_x	0.03	0.03	0.02	0.02
CO	0.01	0.02	0.02	0.02

Table 9-4
ICE cost and performance summary

Technology	1x9 MW ICE	1x18 MW ICE	18 MW ICE 12x1 Combined Cycle, Dry Cooling
Rated capacity, MW gross	9.7	16.6	216
Rated capacity, MW net	9.5	16.2	211
Plant cost estimates (January 2021)			
Total overnight cost, ZAR/kW	51,540	42,234	27,278
Lead times and project schedule (months)	12	12	36
Expense schedule, % of TPC per year	100%	100%	15%, 44%, 41%
Fuel cost estimates			
First year (ZAR/GJ)	127.2	127.2	127.2
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/year	1,091	763	238
Variable O&M, ZAR/MWh	111.1	117.8	62.9
Availability estimates			
Equivalent availability	95.1	95.1	95.1
Maintenance planned outages, %	3.0	3.0	3.0
Unplanned outages, %	2.0	2.0	2.0
Performance estimates			
Economic life, years	30	30	30
Heat rate, kJ/kWh			
100% load	9,042	9,042	8,419
75% load	9,527	9,506	11,226
50% load	10,477	10,266	16,828
25% load	12,007	12,049	N/A

Table 9-4 (continued)
ICE cost and performance summary

Technology	1x9 MW ICE	1x18 MW ICE	18 MW ICE 12x1 Combined Cycle, Dry Cooling
Plant load factor			
Typical capacity factor	10%	10%	50%
Maximum of rated capacity	100%	100%	100%
Minimum of rated capacity	10%	10%	10%
Water usage			
Per unit of energy, L/MWh	0.0	0.0	2.5
For wet and dry cooling (where applicable)	0	0	0
Air emissions, kg/MWh			
CO_2	458	470	434
SO_x	0.00	0.00	0.00
NO_x	0.00	0.00	0.00
CO	0.11	0.12	0.11

Plant Cost Estimates

All costs reported for gas technologies include dual fuel capability. However, all performance data reported are based on the firing of natural gas.

The total overnight cost for an open-cycle plant with aeroderivatives ranges from 19,600 ZAR/kW for the LMS100 to 28,700 ZAR/kW for the LM6000, and the range for an open-cycle plant with heavy-duty turbines is 9400 ZAR/kW for the 9HA.02 and 11,000 ZAR/kW for the 9F.05. For a combined-cycle plant, the total overnight cost, which ranges from 10,500 ZAR/kW to 13,300 ZAR/kW for the 9HA.02 CCGT plant, is slightly lower compared to that of the 9F.05 CCGT plant, which is estimated at 13,700 ZAR/kW to 18,200 ZAR/kW, depending on the number of units. The addition of carbon capture to a CCGT plant increases the total overnight cost to a range of 45,400 ZAR/kW to 56,200 ZAR/kW for the 9F.05 plant and to 35,500 ZAR/kW to 45,800 ZAR/kW for the 9HA.02 plant.

The total overnight cost for the 9-MW ICE unit is 51,500 ZAR/kW and 42,200 ZAR/kW for the 18-MW ICE unit. The combined-cycle ICE plant is estimated at 27,300 ZAR/kW. These costs are presented for a single unit. Typically, RICE plants are deployed in blocks where multiple units are constructed within the same project. This approach would decrease the TOC of deploying RICE through taking advantage of economies of scope and project scale.

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 the OCGT plants is about three years. The first two years would include the majority of design, equipment procurement, and construction, and the third year would involve the commissioning of the plant, leading to an expected expense schedule of 15% in the first year, 44% in the second year, and 41% in the last year. The CCGT plants have an expected expense and construction period of about four years. The first year would involve permitting at the beginning followed by equipment procurement, delivery, and installation in the latter part of the year and into the second year, and the final year of the project would involve commissioning of the plant, leading to an expected expense schedule of 4% in year 1, 17% in year 2, 51% in year 3, and 29% in year 4. Lastly, the ICE unit has an expected expense and construction period of about one year, whereas the combined-cycle ICE unit has an expense and construction period similar to that of the OCGT plant.

Fuel Cost Estimates

The cost of the LNG is estimated to be 127.2 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 for an OCGT plant ranges from 194 to 453 ZAR/kW/year for plants with aeroderivative turbines and 51–89 ZAR/kW/year for plants with the heavy-duty turbines. For a CCGT plant, the fixed O&M cost is about 80–140 ZAR/kW/year for the 9F.05 plant and 47–82 ZAR/kW/year for the 9HA.02 plant. With the addition of a carbon capture unit, the fixed O&M cost is 141-257 ZAR/kW/year for the 9F.05 CCGT plant and 91–183 ZAR/kW/year for the 9HA.02 plant.

For the ICE unit, the fixed O&M is about 1091 ZAR/kW/year for the 9-MW unit, 763 ZAR/kW/year for the 18-MW unit, and 238 ZAR/kW/year for the combined-cycle ICE 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 noncoastal location.

The variable O&M for the gas plants include consumables and major maintenance costs. The variable O&M ranges from 92 to 131 ZAR/MWh for the OCGT aeroderivative plants and is about 65 ZAR/MWh for the OCGT heavy-duty turbine plants. The variable O&M for the combined-cycle plants is between 50 and 63 ZAR/MWh. With carbon capture, the variable O&M cost increases to 127–141 ZAR/MWh. 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 is 111 ZAR/MWh for the 9-MW ICE unit, 118 ZAR/MWh for the 18-MW unit, and 63 ZAR/MWh for the combined-cycle ICE unit.

Availability and Performance Estimates

The equivalent availability of the plants evaluated in this study is expected to be about 93.6% for the OCGT plants and 97.5% for the CCGT plants. Both plants are expected to have an economic life of at least 30 years. The full-load heat rate of the OCGT plants ranges from about 9450 to 10,600 kJ/kWh, depending on turbine type. At part-load an OCGT plant becomes less efficient.

The combined-cycle plants without carbon capture have heat rates ranging from about 6500 to 6900 kJ/kWh. The CCGT plant 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 heat rates of the CCGT plants increase to 7500–8000 kJ/kWh with carbon capture. The ICE unit has a heat rate of 9040 kJ/kWh for the open-cycle plant, and 8400 kJ/kWh for the combined-cycle ICE plant. As a peaking plant, the OCGT has an expected capacity factor of 10%, and the combined-cycle plant has a capacity factor of 50%.

Cost of Electricity

Tables 9-5 through 9-8 show 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 9-5
OCGT levelized cost of electricity

Technology	1xLM6000	1xLMS100	1x9F.05	1x9HA.02
Rated capacity, MW net	45	106	297	540
Fuel cost (ZAR/MWh)	1,355.0	1,258.4	1,391.3	1,238.3
O&M (ZAR/MWh)	609.7	353.0	168.8	122.9
Capital (ZAR/MWh)	3,878.7	2,657.7	1,498.1	1,286.7
LCOE (ZAR/MWh)	**5,843.5**	**4,269.1**	**3,058.2**	**2,647.9**

Table 9-6
CCGT levelized cost of electricity

Technology	1x1 9F.05 Dry Cool	2x1 9F.05 Dry Cool	1x1 9HA.02 Dry Cool	2x1 9HA.02 Dry Cool
Rated capacity, MW net	460	281	792	1,028
Fuel cost (ZAR/MWh)	909.6	904.3	850.7	857.4
O&M (ZAR/MWh)	95.0	71.1	79.0	60.9
Capital (ZAR/MWh)	506.9	381.1	371.3	293.0
LCOE (ZAR/MWh)	**1,511.5**	**1,356.5**	**1,301.0**	**1,211.3**

Table 9-7
CCGT with carbon capture—levelized cost of electricity

Technology	1x1 9F.05 Dry Cool with CO_2 Removal	2x1 9F.05 Dry Cool with CO_2 Removal	1x1 9HA.02 Dry Cool with CO_2 Removal	2x1 9HA.02 Dry Cool with CO_2 Removal
Rated capacity, MW net	398	498	685	828
Fuel cost (ZAR/MWh)	1,050.5	1,045.2	983.4	988.8
O&M (ZAR/MWh)	199.6	161.5	179.8	147.2
Capital (ZAR/MWh)	1,555.2	1,257.0	1,268.0	983.9
LCOE (ZAR/MWh)	**2,805.3**	**2,463.7**	**2,431.2**	**2,119.9**

Table 9-8
ICE levelized cost of electricity

Technology	1x9 MW ICE	1x18 MW ICE	18 MW ICE 12x1 Combined-Cycle Dry Cooling
Rated capacity, MW net	10	16	211
Fuel cost (ZAR/MWh)	1,184.6	1,184.6	1,102.8
O&M (ZAR/MWh)	1,357.0	989.2	117.1
Capital (ZAR/MWh)	6,688.3	5,483.8	736.4
LCOE (ZAR/MWh)	**9,230.0**	**7,657.6**	**1,956.4**

Water Usage

The water requirement for all OCGT plants in this study, except for the LMS100, is zero due to the use of the dry low emission combustion technology, which requires no water or steam injection for NO_x control. The LMS100 unit uses single annular combustor, which requires about 772 L/MWh of water or steam injection to operate with low NO_x emissions.

A small amount of makeup water is needed for the steam cycle of the combined-cycle plant. Air cooling of a CCGT plant greatly reduces water consumption compared to a wet-cooled plant. The water use is about 7.5–9 L/MWh in the combined-cycle plants without carbon capture and 11.4–13.6 L/MWh in the plants with carbon capture. The water consumption of the open cycle ICE plants is zero and for the combined-cycle ICE plant is 2.5 L/MWh.

Emissions

The air emissions of the GT and ICE plants that were evaluated in this study are shown in the preceding summary tables. 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 summarizes cost and performance for wind technology.

Table 10-1
Wind technology performance and cost summary

Technology	2.8 MW x18	2.8 MW x36	2.8 MW x72
Rated capacity, MW gross	50	100	200
Rated capacity, MW net	43	86	169
Plant cost estimates (January 2021)			
Total overnight cost, ZAR/kW	26,328	26,020	25,061
Lead times and project schedule (months)	24	24	24
Expense schedule, % of TPC per year	96%, 4%	96%, 4%	96%, 4%
O&M cost estimates			
Fixed O&M, ZAR/kW/year	801	792	727
Availability estimates	94–97%	94–97%	94–97%
Performance estimates			
Economic life, years	25	25	25
Capacity factor	36.3%	36.3%	36.3%

Plant Cost Estimates

The total overnight cost for the wind technology ranges from 25,000 ZAR/kW for a 200-MW plant to 26,300 ZAR/kW for a 50-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 years. It is expected that most of the costs in the earlier months of the project would be equipment procurement and installation, leading to a heavier weighting of expenses in the first year of the project.

O&M Cost Estimates

First year O&M costs for wind turbines range from 727 ZAR/kW/year for a 200-MW plant to 800 ZAR/kW/year for a 50-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 25 years.

The performance of a wind turbine depends primarily on the wind resource available. The average capacity factor of the wind turbine in this study is 36.3%.

Cost of Electricity

Table 10-2 shows 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 10-2
Wind levelized cost of electricity

Technology	2.8 MW x18	2.8 MW x36	2.8 MW x72
Rated capacity, MW net	43	86	169
Fuel cost (ZAR/MWh)	0.0	0.0	0.0
O&M (ZAR/MWh)	252.2	249.3	229.0
Capital (ZAR/MWh)	999.9	988.1	951.6
LCOE (ZAR/MWh)	**1,252.1**	**1,237.4**	**1,180.6**

Solar Thermal

Tables 10-3 and 10-4 summarize cost and performance for solar thermal technology.

Table 10-3
Parabolic trough cost and performance summary

Technology	0 h Storage	3 h Storage	6 h Storage	9 h Storage	12 h Storage
Rated capacity, MW net	125	125	125	125	125
Plant cost estimates (January 2021)					
Total overnight cost, ZAR/kW	73,084	98,993	121,154	147,522	73,084
Lead times and project schedule (months)	48	48	48	48	48
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/year	789	810	832	852	789
Variable O&M, ZAR/MWh	0.7	0.7	0.5	0.5	0.7
Availability estimates	95%	95%	95%	95%	95%
Performance estimates					
Economic life, years	30	30	30	30	30
Capacity factor (in Upington, SA)	25.7%	32.5%	38.0%	45.6%	53.9%
Water usage					
Per unit of energy, L/MWh	84.3	80.9	78.6	78.1	78.1

Table 10-4
Central receiver cost and performance summary

Technology	3 h Storage	6 h Storage	9 h Storage	12h Storage
Rated capacity, MW net	125	125	125	125
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	95,320	115,546	130,492	145,769
Lead times and project schedule (months)	48	48	48	48
Expense schedule, % of TPC per year	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/year	745	778	800	821
Variable O&M, ZAR/MWh	0.7	0.7	0.7	0.7
Availability estimates	92%	92%	92%	92%
Performance estimates				
Economic life, years	30	30	30	30
Capacity factor (in Upington, SA)	39.5%	51.0%	60.3%	69.7%
Water usage				
Per unit of energy, L/MWh	82.0	87.0	86.3	84.5

Plant Cost Estimates

The total overnight cost for the parabolic trough ranges from 73,100 ZAR/kW for a plant without storage to 175,600 ZAR/kW for a plant with 12 hours of storage. For the central receiver, costs range from 95,300 ZAR/kW for a plant with 3 hours of storage to 145,800 ZAR/kW for a plant with 12 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 would include preliminary design, project siting, and permitting. Later in the project, equipment would be procured, delivered, and installed. This is when the majority of the expenditures would take place. The final stage of the project would 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.

O&M Cost Estimates

First year O&M costs for parabolic troughs range from 790 ZAR/kW/year for a plant without storage to 890 ZAR/kW/year for a plant with 12 hours of storage. For the central receiver, O&M costs range from 745 ZAR/kW/year for a plant with 3 hours of storage to 820 ZAR/kW/year for a plant with 12 hours of storage. These costs include both maintenance labor and materials. Variable O&M cost for the solar thermal plants is negligible because the plants require only a small amount of water for mirror cleaning. 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 25.7% whereas a plant with 12 hours of storage has a capacity factor of 53.9%. A central receiver with 3 hours of storage has a capacity factor of 39.5%, and a plant with 12 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

Tables 10-5 and 10-6 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 precommercial 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 10-5
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)	351.5	285.4	250.6	213.8	188.2
Capital (ZAR/MWh)	4,305.9	4,607.6	4,819.7	4,886.9	4,924.7
LCOE (ZAR/MWh)	**4,657.4**	**4,892.9**	**5,070.2**	**5,100.7**	**5,112.8**

Table 10-6
Central receiver levelized cost of electricity

Technology	Central Receiver			
Rated capacity, MW net	**125**			
Hours of storage	3	6	9	12
Fuel cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	216.1	175.0	152.1	135.2
Capital (ZAR/MWh)	3,650.5	3,428.0	3,275.0	3,163.0
LCOE (ZAR/MWh)	**3,866.6**	**3,603.0**	**3,427.1**	**3,298.2**

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 makeup.

PVs

Tables 10-7 and 10-8 summarize the cost and performance of the PV plants.

Table 10-7
PV cost and performance summary

Technology	Monocrystalline Silicon				C-Si Bifacial Module	Thin-Film CdTe
Mounting	Rooftop fixed tilt	Rooftop fixed tilt	Ground mount SAT	Ground mount SAT	Ground mount SAT	Ground mount SAT
Rated capacity, MW net	0.005	0.100	20	99.5	20	20
Plant cost estimates (January 2021)						
Total overnight cost, ZAR/kW	49,993	34,686	21,448	18,661	23,081	20,295
Lead times and project schedule (months)	12	12	12	12	12	12
Expense schedule, % of TPC per year	100%	100%	100%	100%	100%	100%
O&M cost estimates						
Fixed O&M, ZAR/kW/year	343	270	248	214	254	245
Availability estimates	99%	99%	99%	99%	99%	99%
Performance estimates						
Economic life, years	25	25	25	25	25	25
Capacity factor	22.5%	22.5%	26.9%	27.8%	29.8%	26.5%

SAT = single-axis tracking

Table 10-8
Solar PV plus storage—cost and performance summary

Technology	Solar PV plus Battery Storage		
PV system size, MW	20	100	100
Battery system size, MW	20	25	100
Storage capacity, h	4	4	4
Energy storage, MWh	80	100	400
Plant cost estimates (January 2021)			
Total overnight cost, ZAR/kW	45,392	46,032	41,443
Lead times and project schedule, months	12	12	12
Expense schedule, % of TPC per year	100%	100%	100%
O&M cost estimates			
Fixed O&M, ZAR/kW/year	760	297	738
Variable O&M, ZAR/MWh	0	0	0
Availability estimates	99%	99%	99%
Performance estimates	99%	99%	99%
Economic life, years	25	25	25
Capacity factor (based on solar)	26.9%	27.8%	27.8%

Plant Cost Estimates

The total overnight cost for the monocrystalline silicon PV systems ranges from 18,700 ZAR/kW for a 100-MW ground-mounted, single-axis tracking plant to 50,000 ZAR/kW for a 5-kW roof-mounted system. The overnight cost of the 20-MW c-Si system with bifacial modules, estimated at 23,100 ZAR/kW, is slightly more expensive compared to the system with monocrystalline modules at the same capacity rating, which costs about 21,500 ZAR/kW. The 20-MW CdTd system is the least expensive, at 20,300 ZAR/kW, compared to either the monocrystalline or the bifacial module c-Si systems at the same capacity rating.

The overnight cost increases to 45,400 ZAR/kW when the 20-MW PV unit is coupled with an 80-MWh storage system. For the 100-MW PV unit, the overnight cost increases to 46,000 ZAR/kW with a 100-MWh storage system, and 41,400 ZAR/kW with a 400-MWh storage system.

O&M Cost Estimates

First year O&M costs for the monocrystalline silicon plants are expected to be 270–343 ZAR/kW/year for the rooftop systems and 214–248 ZAR/kW/year for the ground-mounted, single-axis tracking plants. The O&M for the bifacial c-Si plant is 254 ZAR/kW/year and 245 ZAR/kW/year for the CdTe plant. For PV plants with battery storage, the O&M is 297 ZAR/kW/year for the 100-MW PV/100-MWh storage system, 738 ZAR/kW/year for the 100-

MW PV/400-MWh storage system, and 760 ZAR/kW/year for the 20-MW PV/100-MWh storage system. The annual O&M costs for both the PV and battery systems were estimated, and then the O&M in terms of ZAR/kW/year was calculated for each system based on the PV capacity. This resulted in the 100-MW PV plant with a smaller battery storage capacity having the lowest O&M.

Although 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. The 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 and single-axis tracking PV systems are expected to have an availability of 99%. 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 rooftop mounted panels were assumed to be installed without any tilt, whereas 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 for 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.

Cost of Electricity

Tables 10-9 and 10-10 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. The economy of scale of the larger ground-mounted systems results in lower costs of electricity.

Table 10-9
PV levelized cost of electricity

Technology	**Monocrystalline Silicon**				**C-Si Bifacial Module**	**Thin-Film CdTe**
Mounting	Rooftop fixed tilt	Rooftop fixed tilt	Ground-mount SAT	Ground-mount SAT	Ground-mount SAT	Ground-mount SAT
Rated capacity, MW net	0.005	0.100	20	99.5	20	20
Fuel cost (ZAR/MWh)	0	0	0	0	0	0
O&M (ZAR/MWh)	173.5	137.4	105.5	87.6	97.0	105.9
Capital (ZAR/MWh)	3,219.2	2,233.6	1,046.8	879.8	1,014.4	1,005.7
LCOE (ZAR/MWh)	**3,392.7**	**2,371.0**	**1,152.3**	**967.4**	**1,111.4**	**1,111.6**

Table 10-10
Solar PV plus storage—levelized cost of electricity

Technology	Solar PV plus Battery Storage		
Rated capacity, MW net	20 MW PV, 20MW/4 h	100 MW PV, 25MW/4 h	100 MW PV, 100MW/4 h
Fuel cost (ZAR/MWh)	0	0	0
O&M (ZAR/MWh)	520.5	204.1	504.7
Capital (ZAR/MWh)	4,011.6	4,067.6	3,665.5
LCOE (ZAR/MWh)	**4,532.1**	**4,271.8**	**4,170.3**

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. A PV system would require about 1.5 liters per meter squared of panel area, assuming that the system is washed twice a year.

Biomass

Table 10-11 summarizes the cost and performance for biomass plants.

Table 10-11
Biomass cost and performance summary

Technology	Forestry Residue	MSW	LFG	Biogas
Rated capacity, MW net	25	25	5	5
Plant cost estimates (January 2021)				
Total overnight cost, ZAR/kW	103,646	199,071	43,213	107,585
Lead times and project schedule (months)	24	24	12	12
Expense schedule, % of TPC per year	50%, 50%	50%, 50%	100%	100%
Fuel cost estimates				
First year (ZAR/GJ)	43.3	0.0	0.0	0.0
Expected escalation (beyond inflation)	0%	0%		
Fuel energy content, HHV, kJ/kg	11,763	11,388	25,016	25,016
O&M cost estimates				
Fixed O&M, ZAR/kW/year	1,358	4,297	1,575	1,289
Variable O&M, ZAR/MWh	91.6	194.4	88.7	72.5

Table 10-11 (continued)
Biomass cost and performance summary

Technology	Forestry Residue	MSW	LFG	Biogas
Availability estimates				
Equivalent availability	90.2	90.2	85.5	85.5
Maintenance planned outages, %	4.0	4.0	5.0	5.0
Unplanned outages, %	6.0	6.0	10.0	10.0
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh	14,132	18,991	12,302	11,999
Plant load factor				
Typical capacity factor	85%	85%	85%	85%
Maximum of rated capacity	100%	100%	100%	100%
Minimum of rated capacity	40%	40%	13%	13%
Water usage				
Per unit of energy, L/MWh	227	227	0	0
Air emissions, kg/MWh				
CO_2	1243	1633	806	787
SO_x	0.75	0.57	0.00	0.00
NO_x	0.58	2.21	0.61	0.59
CO	1.47	1.91	3.00	2.93
Particulates	0.18	0.31	0.22	0.20
Solid wastes, kg/MWh				
Fly ash	21.0	312.0	0.0	0.0
Bottom ash	5.3	78.0	0.0	0.0

Plant Cost Estimates

The total overnight cost for a biomass plant burning forestry residue is estimated to be 103,600 ZAR/kW and 199,000 ZAR/kW for a plant 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 a MSW plant is considerably higher than that of a forestry residue biomass plant. The total overnight cost is estimated to be 43,200 ZAR/kW for a LFG reciprocating engine and 107,600 ZAR/kW for a biogas reciprocating engine.

It is expected that a wood-fired and a MSW biomass plant would have a two-year expense and construction period. Early in the project, costs would include preliminary design, project siting, and permitting. Later in the project, equipment would be procured, delivered, and installed. This would be when the majority of the expenditures take place. The final stage of the project would be the commissioning of the plant. The expected expense schedule is 50% in first year and 50% in year second year.

The construction period for the LFG 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 time frame does not include the development of the LFG 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. LFG and biogas have an energy content of 18.6 MJ/SCM. The cost of forestry residue was assumed to be 43.3 ZAR/GJ for this study. For MSW, the cost was 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.

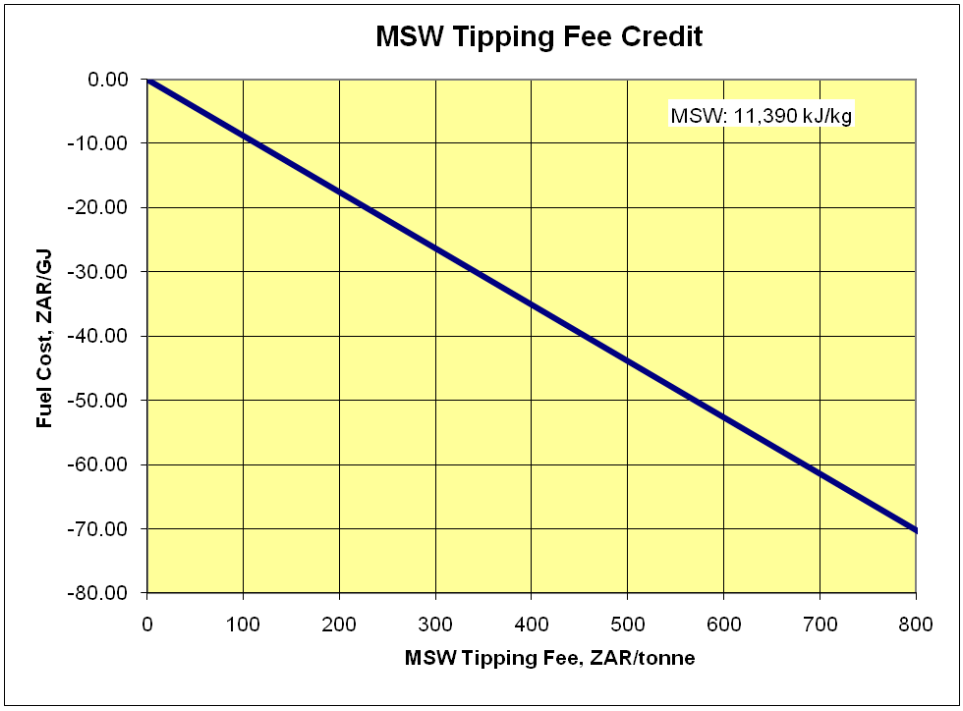

Figure 10-1
Fuel cost for MSW based on tipping fee

The LFG and biogas were also assumed to be zero for this study. The price of LFG 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, and the O&M arrangement on the gas collection and supply system. The fact that a large landfill flares the LFG to waste if it is not used will depress the price that the landfill will charge the gas user substantially below the prevailing price of natural gas. Many LFG 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.

O&M Cost Estimates

For a wood-fired biomass boiler, the fixed O&M is expected to be 1360 ZAR/kW/year and the variable O&M is expected to be 92 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 4300 ZAR/kW/year, and variable O&M is expected to be 194 ZAR/MWh for the mass burn MSW boiler. The fixed O&M for the LFG engines is 1575 ZAR/kW/year, and the variable O&M is 89 ZAR/MWh. For the biogas engines, the fixed O&M is 1290 ZAR/kW/year, and the variable O&M is 73 ZAR/MWh.

The O&M costs for the landfill and biogas plants are for the engines, gas filtering/cleanup, and the compressor/blower.

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 14,130 kJ/kWh, whereas MSW plants have a higher heat rate of 18,990 kJ/kWh. The LFG engines have an expected availability of 86%. This takes into consideration that at times the engines would not operate due to outages caused by the LFG supply company. The LFG engines have a heat rate of 12,300 kJ/kWh, and 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. The estimates in this study were informed by operating data taken from systems operating in the United States—mainly from data collected by the California Public Utility Commission.[20]

[20] *California Energy Almanac*. http://energyalmanac.ca.gov/electricity/web_qfer/Heat_Rates.php.

Cost of Electricity

Table 10-12 shows the levelized cost of electricity for the biomass plants. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 10-12
Biomass levelized cost of electricity

Technology	Forestry Residue	MSW	LFG	Biogas
Rated capacity, MW net	25	25	5	5
Fuel cost (ZAR/MWh)	616.8	3.3	2.2	2.0
O&M (ZAR/MWh)	273.9	771.4	300.2	245.5
Capital (ZAR/MWh)	1,780.2	3,402.5	719.6	1,791.2
LCOE (ZAR/MWh)	**2,670.9**	**4,177.2**	**1,022.0**	**2,038.7**

Water Usage

Because the steam cycles of these plants are air-cooled, the only water usage is for makeup water to the boiler. The water consumption for both the wood-fired and MSW plants 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, be larger to generate the same amount of steam and output the same amount of electricity. Because there is no steam cycle for the LFG and bio plants, 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 be burned to generate the same amount of electricity. The air emissions and solid wastes, where applicable, are shown in the preceding summary tables.

11
STORAGE TECHNOLOGIES PERFORMANCE AND COST

Energy Storage Cost Estimates

Tables 11-1 and 11-2 summarize cost and performance for energy storage technologies.

Table 11-1
Battery storage cost and performance summary

Technology	Li-ion				
System size, MW	1	20	20	100	100
Storage capacity, h	1	1	4	1	4
Energy storage, MWh	1	20	100	100	400
Plant cost estimates (January 2021)					
Total overnight cost, ZAR/kW	17,265	12,950	31,147	12,229	29,206
Lead times and project schedule, months	12	12	12	12	12
Expense schedule, % of TPC per year	100%	100%	100%	100%	100%
O&M cost estimates					
Fixed O&M, ZAR/kW/year	317	317	983	317	983
Variable O&M, ZAR/MWh	0	0	0	0	0
Availability estimates					
Equivalent availability	94.2	94.2	94.2	94.2	94.2
Maintenance	1.9	1.9	1.9	1.9	1.9
Unplanned outages	4.0	4.0	4.0	4.0	4.0
Energy requirements, (I/O Ratio)	1.11	1.11	1.11	1.11	1.11
Round-trip ac/ac efficiency, %	80–90%	80–90%	80–90%	80–90%	80–90%
Duty cycle					
Cycles/year	365	365	365	365	365
Hours/cycle	1	1	4	1	4
Minimum load	0%	0%	0%	0%	0%
Economic life, years	20	20	20	20	20

Table 11-2
CAES cost and performance summary

Technology	CAES (Below Ground)
System size, MW	180
Storage capacity, h	8
Energy storage, MWh	1,440
Plant cost estimates (January 2021)	
Total overnight cost, ZAR/kW	29,178
Lead times and project schedule, months	36
Expense schedule, % of TPC per year	40%, 50%, 10%
Fuel cost estimates	
First year, ZAR/GJ	127.2
Expected escalation (beyond inflation)	0%
Fuel energy content, MJ/SCM	39.3
O&M cost estimates	
Fixed O&M, ZAR/kW/year	270
Variable O&M, ZAR/MWh	38.4
Availability estimates	
Equivalent availability	97.2
Maintenance	2.3
Unplanned outages	0.5
Performance estimates	
Economic life, years	40
Heat rate, kJ/kWh	4,340
Energy charge ratio, (kWh in/kWh out)	0.68–0.75
Duty cycle	
Cycles/year	No limit
Hours/cycle	8
Minimum load	0%
Air emissions, kg/MWh	
CO_2	340
SO_x (as SO_2)	0.00
NO_x (as NO_2)	0.30
CO	0.24
Water usage	
Per unit of energy, L/MWh	0

Plant Cost Estimates

The total overnight cost for the Li-ion battery systems ranges from about 13,000 ZAR/kW to 31,100 ZAR/kW for a 20-MW system depending on storage capacity. The 100-MW system costs slightly less, ranging from 12,300 ZAR/kW to 29,200 ZAR/kW. The 1-MW system has the highest cost at 17,300 ZAR/kW. Li-ion battery costs have dropped in the last several years as mega battery supply factories have been built in the United States. The total overnight cost for the CAES system is 29,200 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 6 to 10% of the plant cost.

The expected expense and construction period are one year for the Li-ion battery system and three years for the CAES facility. Early in the project, costs would include preliminary design, project siting, and permitting. Later in the project, equipment would be procured, delivered, and installed. The final stage of the project would be the commissioning of the plant.

Fuel Cost Estimates

The cost of the LNG for the CAES plant is estimated to be 127.2 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 317 ZAR/kW/year for a Li-ion system with 1-hour storage, 983 ZAR/kW/year for a system with 4-hour storage, and 270 ZAR/kW/year 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 zero for the Li-ion battery system, and 38.4 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 4340 kJ/kWh.

Cost of Electricity

Table 11-3 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 11-3
Energy storage levelized cost of electricity

Technology	Li-ion					CAES
System size, MW	1	20	20	100	100	180
Storage capacity, h	1	1	4	1	4	8
Fuel cost (ZAR/MWh)	0	0	0	0	0	587.6
Charging cost (ZAR/MWh)	1,389.7	1,389.7	1,389.7	1,373.5	1,373.5	909.2
O&M (ZAR/MWh)	870.2	870.2	672.6	870.2	672.6	135.1
Capital (ZAR/MWh)	6,052.5	4,539.4	2,729.7	4,287.0	2,559.6	1,328.4
LCOE (ZAR/MWh)	**8,312.4**	**6,799.3**	**4,791.9**	**6,530.8**	**4,605.7**	**2,960.3**

Water Usage

The water use in both the Li-ion battery and CAES facilities is zero.

Emissions

The air emissions of the CAES plant evaluated in this study are shown in the preceding summary table. In this study, the CAES power plant was assumed to use similar equipment as that of the OCGT plant.

12
PROJECTION TECHNOLOGY COSTS

Figure 12-1 presents projected total overnight costs through 2030 for select central station fossil fuel and nuclear generation technologies, and Figures 12-2 and 12-3 show the same information for select renewables and a 100-MW/4-hour Li-ion battery energy storage system, respectively. The fossil, nuclear, and renewables projections are based on the U.S. Energy Information Administration's estimated technology learning rates. The Li-ion battery pack projections are based on EPRI base case estimates based on "electric vehicle battery pack cost projections with adjustments for stationary racks." All values shown in the three figures are based on an 18.13 ZAR/USD exchange rate, consistent with the cost-estimating approach taken for the entirety of this research.

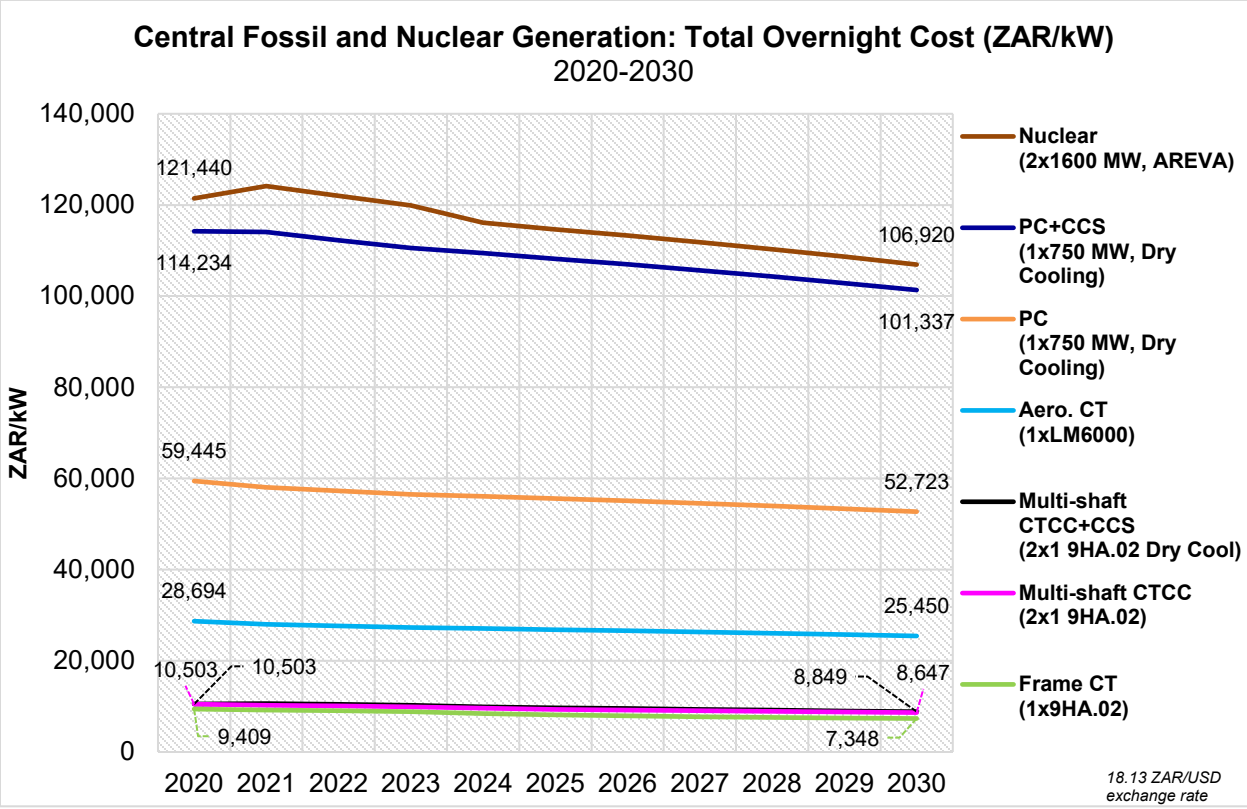

Figure 12-1
Projected capital costs for central fossil and nuclear generation

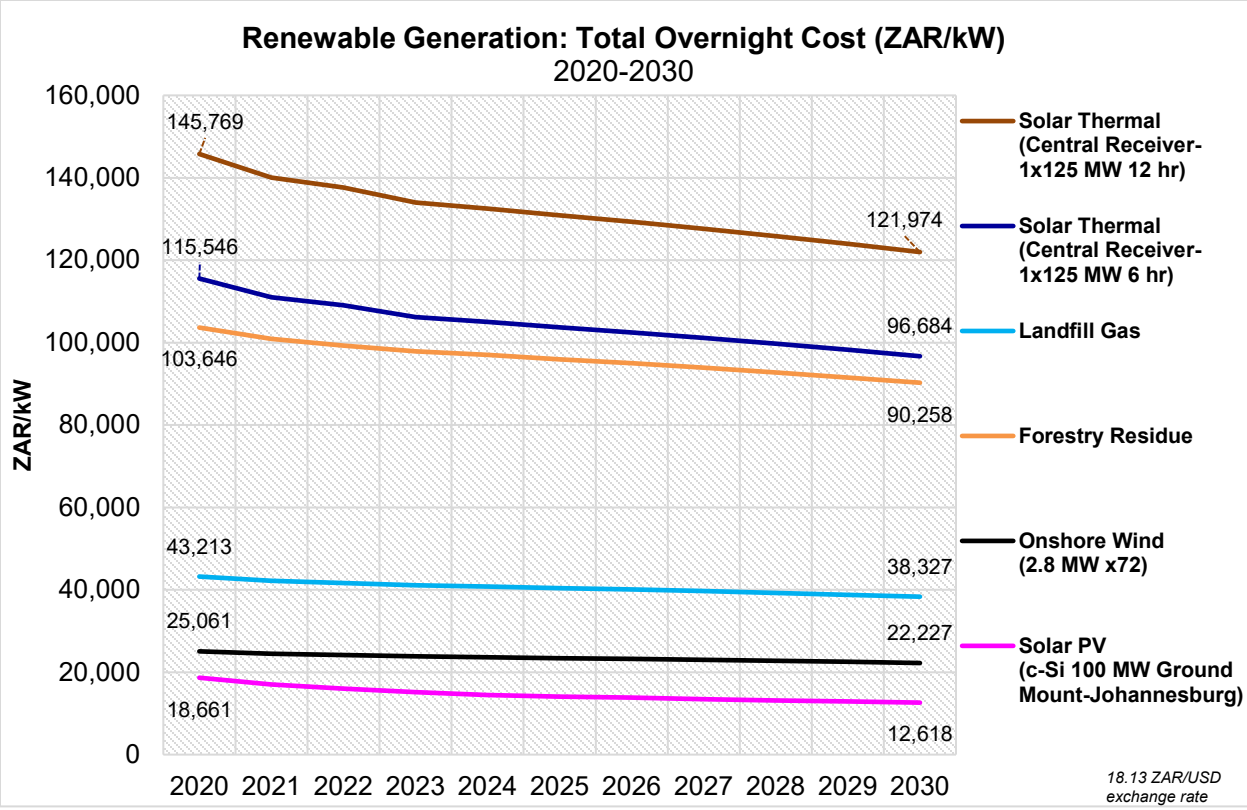

Figure 12-2
Projected capital costs for renewable generation

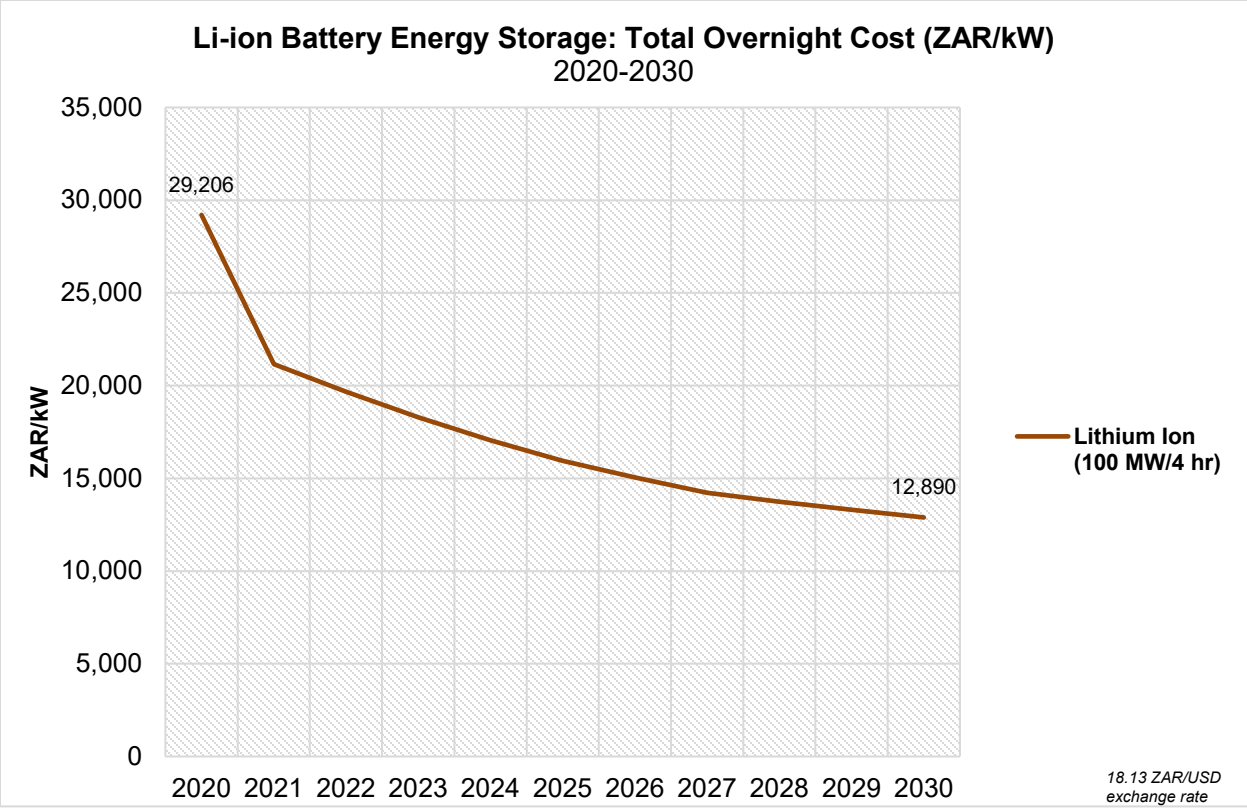

Figure 12-3
Projected capital costs for Li-ion battery energy storage (100 MW/4 hours)

13
GRID INTEGRATION AND INTERMITTENCY OVERVIEW FOR NONTHERMAL 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 may 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 increase in importance for operators to meet reliability standards.

Because renewable technologies, especially solar and wind, are not dispatchable, the practice in the United States is to provide for GTs as a backup in system reserve. In general, the regulatory agencies (public utility commissions and ISOs) in the United States assign a value of about 10–15% 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, in most regions, the evaluations have only just begun to assess 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 is expected to enable higher penetration levels without reducing safety, reliability, or utility asset utilization effectiveness.

As a point of reference, in its January 2021 Fact Sheet, the Electric Reliability Council of Texas (ERCOT, the agency responsible for managing electricity flow throughout the state of Texas) reported a peak load of 74.8 GW, average production of 43.8 GW, and 23.3% installed capacity from wind generation. This portion of capacity represents a significant impact on the power system. The maximum instantaneous penetration of wind energy was 59.3% and set on 2 May 2020 [1].

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 2020 Integrated Resource Planning report, Eskom reported peak demand, not counting demand reductions, of 32.9 GW (down slightly from 2019) [2]. Average production was about 26.4 GW out of 49.5 GW net maximum capacity. South Africa has 1980-MW wind capacity, about 4% of total capacity and 1669-MW solar PV capacity, about 3% of total capacity.

Technology Characteristics

The primary challenges for the nonthermal renewable generation technologies considered that were in this study are variability and uncertainty 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 that wind turbine generators simply cannot perform all of 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 integrating greater amounts of solar resources.

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, though more often rooftop solar, can sometimes be located more closely to load centers. One exception is the rapid rate of change in output that may occur as clouds pass over solar arrays.

By its nature, solar energy tends to be more available during the summer than winter. For most areas with summer-peaking demand, the solar 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 PV 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 typically higher than those of wind generation [3, 4]. 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.

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 subhourly 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 time frame. Also, some units are required to ramp more quickly, following an automatic generation control 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 short-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. The same geographic diversity also serves to smooth the short-term power output from solar PV resources.

Fluctuating Power Output

Rapid changes in power system loading or in generation can also cause small voltage fluctuations that manifest as light flicker. Voltage changes of 1–2% 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 producing in flicker 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 can 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 wind power systems can provide both dynamic and static reactive power control. Most newer wind turbines use power inverters and are asynchronous with grid frequency in order to vary their turbine speed with the wind speed [5].

In the case of inverter-connected solar PV, many older systems do not have reactive power control. The reactive power output varies depending online voltage and solar output. This variation can be quite different from the real power output and may require some form of utility control and penetration levels to increase. However, newer wind and solar have inverters with real/reactive control capabilities, though these controls may only be effective at lower voltage collector networks, and separate voltage controls may be needed at the substation to ensure proper integration with the transmission system.

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 distribution systems were originally designed for one-way power flow, distributed generators may 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. Considerable 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. It is important to consider the available transmission capacity to these sites and include the proper transmission-related costs of delivering to the demand center.

Integration Technologies for Distribution-Connected Renewable Generation

Today's electric distribution systems have evolved over many years in response to load growth and technology changes. One of the largest single investments 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 protective device closest 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, meshed distribution systems are common. These systems are fed by multiple transmission sources, and thereby provide high reliability. Both radial and meshed 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 Standard C84-1, which specifies that the 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 technologies such as plug-in hybrid EVs. A number of system characteristics lead to these limitations, as follows:

- Voltage control is achieved with devices (voltage regulators and capacitor banks) that have localized controls. These schemes work well for radial circuits, but they do not readily handle circuit reconfigurations and voltage impacts of local generation. This results in limits on the ways circuits can be configured and 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 a distribution system.

- There is no communication infrastructure to facilitate control and management of distributed resources that may include renewables, other distributed generation, and storage. Without communication and control, the penetration of distributed generation on most circuits is more 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 may be no communication with customer facilities allowing customers and customer loads to react to electricity price changes and/or emergency conditions. Customer-owned and distributed resources may not be able to participate in electricity markets, limiting the economic payback in many cases. Communications with customers may also provide feedback on energy use that has been shown to help customers achieve improved energy efficiency.
- The infrastructure is limited in its capacity to support new electrical demand such as home electronics and plug-in hybrid EVs. 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 must contend with finding the required investment to both maintain existing reliability and 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.

At the heart of the challenges with renewables integration is that today's power distribution system has not been designed for distribution-connected PV nor for a high penetration of distributed generation. In the past this was not an issue, but in the future, with larger amounts of PV connecting to the electric system, utilities can expect new challenges with how distributed and variable generation resources are 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. They are as follows:

- Voltage regulation practices
- Overcurrent protection practices
- Grounding practices
- 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 so that the distribution-level generation is expected to provide voltage support and eventually energy balancing.

This is anticipated to occur initially on individual feeders with high penetrations and later at the substation and subtransmission 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 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, integrating variable generation could lead to increased cost related to the impacts of intermittency, ramping, fluctuating output, lack of control, 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 is expected to interact with distributed energy resources including PV generation and battery systems. This, in turn, enables better utilization of these resources and higher penetration. The changes in the distribution grid for high-penetration PV likely include the following:

- **Interactive voltage regulation and VAR management**. Utility voltage regulator and capacitor controls are expected to become interactive with each other and with nearby PV sources, with a central controller to help manage this interactivity ensuring optimized voltage and reactive power conditions.
- **Bulk system coordination of PV generation for market and bulk system control**. Control of renewable generation from a dispatch center is becoming more prevalent. Such a control enables renewable generation to participate and to be aggregated into energy markets as well as to allow for control that maintains system stability, power quality, and reliability at the bulk level.
- **Protective relaying schemes designed for renewable generation**. The distribution and subtransmission systems are expected to include more extensive use of directional relaying, communication-based transfer trips, pilot signal relaying, and impedance-based fault-protection schemes (such as those used in transmission). These types of protection technologies work more effectively in the presence of multiple sources.

- **Advanced islanding control**. Islanding in the presences of distributed resources requires detection and control. This involves automated switchgear and renewable generation with new features for islanding detection that is expected to improve a utility's overall 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. When they are 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. The following are examples of such techniques:
  - Control or limit ground fault overvoltage through 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 are able to correct temporary load/generation mismatches, regulate frequency, mitigate flicker, and assist advanced islanding functions and service restoration, and these functions are expected to be used increasingly.

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. Such a transformation is not expected overnight and may require decades as well as considerable engineering planning and development to determine the balance of features and capabilities congruent with cost and complexity of implementation. Nonetheless, these are the approaches needed to move to high-penetration PV, and the industry needs immediate R&D programs for the technologies, tools, and approaches to be available in a timely manner.

Integration for Transmission-Connected Renewable Generation

Until the past few years, interconnection requirements worldwide for variable generation were predominantly applicable for wind generation only. An updated summary of existing interconnection requirements and recommendations for variable generation, as adopted by entities in North America and worldwide is summarized in the EPRI report, *Global Interconnection Requirements for Variable and Distributed Generation* (3002011528) [6].

The report overviews interconnection requirements and recommendations put forth by the Federal Energy Regulatory Commission (FERC), NERC, ERCOT, Bonneville Power Administration (BPA), California Independent System Operator (CAISO), Alberta Electric System Operator (AESO), Manitoba Hydro (MH), and European Network of Transmission System Operators for Electricity (ENTSO-E) for variable generation with respect to the following:

- Reactive power/voltage control
- Inertial and primary frequency control
- Disturbance performance (for example, fault ride-through requirements)
- Ramp rate limitations
- Distributed energy resources requirements addressing bulk system impacts

Interconnection requirements have changed in many systems over the past several years, some due in large part to the increased prevalence of transmission and distribution-connected solar PV. At the transmission level, this has typically resulted in updating wind interconnection requirements to include solar PV. Further, FERC and ENTSO-E have issued new, more stringent interconnection requirements that apply to all nonsynchronous resources.

With respect to reactive power/voltage control, FERC, BPA, ERCOT, CAISO, and MH generally require intermittent resource plants to operate within a power factor range of ± 0.95 (leading or lagging). MH's requirements apply only to wind technologies.

Considering inertia adequacy and primary frequency control, FERC 862, NERC, ERCOT, and Puerto Rico Electric Power Authority (PREPA) neither require nor address inertial response from nonsynchronous technologies. ENTSO-E requires that all generator types be capable of providing frequency response to a high system frequency, falling between, and including, 50.2 and 50.5 Hz, with a droop in range of 2–12%. In addition, it requires that Type C and D generators (voltage level ≥110 kV) provide active power frequency response for a frequency threshold between and including 49.8 Hz and 49.5 Hz, with a droop in a range of 2–12%. With respect to providing inertial response, Type C and D generators are required to supply additional active power to limit the change of frequency following a sudden loss of generator (or infeed). PREPA, ERCOT, and FERC 842 require a 5% droop for primary frequency control with different deadbands, and NERC has established a requirement of 5%.

With respect to voltage ride-through, FERC 661 requires wind plants to remain online for certain durations and voltage levels, when a stability study demonstrates such performance in order to ensure safety and reliability. ERCOT requires wind plants to remain interconnected during three-phase faults on transmission systems for a voltage level as low as zero volts for at least nine cycles. AESO requires wind plants, with output greater than 5 MW, to meet their standard voltage ride-through requirements, and MH requires wind turbine generators to remain online without intermittent tripping during normally clearing single, multi-phase, and three-phase faults. Ireland (EirGrid) has a voltage ride-through requirement for similar to that of the AESO. It requires that wind plants remain connected to the bulk system for voltage dips on any or all of the three phases and remain stable if the operating condition is above the low voltage ride through curve. NERC does not have direct fault-ride through requirements for the wind (or solar)

plants. However, NERC standard PRC-024-2 specifies a no-trip envelope for generator protection relays, which provides a voltage and frequency tolerance standard for all types of generators. Requirements in Germany were under revision at the time of EPRI report 3002011528.

Finally, many grid codes and interconnection requirements also include specifications for ramp control. Hawaii currently sets ramp rate requirements based on the size of the generator, where the largest generators (100–200 MW) are required to provide a performance ramp rate of 5–10 MW/min. PREPA's ramp rate control is +/-10%/minute. EirGrid's code states that it shall be possible to vary wind power ramp rates and active power controls, over a range of between 1% and 100% of registered capacity per minute. ERCOT has a ramp requirement of a 5-minute average of 20% of nameplate rating per minute with no individual minute exceeding 25%. Germany has a limit of +/-10% per minute for ramps of bulk connected variable with the additional requirement that above 50.2 Hz power should be reduced with a gradient of 40% of available power per Hz.

Grid Planning and Operating Tools

New tools to enable grid operators to better visualize their real time grid status and anticipate contingencies are needed to integrate intermittent resources. Several tools and methods are being developed in this area, as described in EPRI report 3002016924, *Review of Technologies and Operations When Considering Low Inertia Systems* [7]. They are as follows:

- Forecasting tools predict renewable energy output on a near-real time frame and up to 24–72 hours in advance, using measured and numerical weather wind and solar resource data and statistical techniques. The forecasts are increasingly accompanied by measures of uncertainty, such as confidence intervals, for grid operators to assess resource adequacy, to plan, and to schedule energy. Benefits include mitigating unscheduled power flows, real-time voltage and dynamic stability issues, and preventing blackouts. Research projects include the use of time-dependent optimal power flow techniques for creating adaptive strategies in real-time operations.
- New methods are evaluating the capacity value of aggregated resources that combine intermittent generation, energy storage, and demand response. These methods enable integrated dispatching and scheduling that help energy markets balance the economics and risks in power system operations.
- Visualization tools are being extended to represent intermittent generation in a geographical display, integrated with visualizations of load and demand response capabilities and their effect on the transmission loadings, voltages, and system frequency. This concept, developed by EPRI, provides greater wide-area situational awareness to operators. Such a control center visualization may be a key technology for increasing intermittent generation without significant cost or loss of grid reliability. R&D producing automation concepts on adaptive relay protection, and voltage instability, and load shedding to handle the integration of substantial amounts of intermittent generation.

Technology Measures to Mitigate Low Inertia Challenges

In addition to operational changes (not covered here), new or existing technologies may be deployed to combat issues associated with low system inertia. Various technologies have been discussed as potentially supporting system operations having low inertia and are presented in Table 13-1. These technologies have two broad categories: synchronous and nonsynchronous [6].

Table 13-1
Potential technologies to support system operations with low inertia

Synchronous Inertia	Nonsynchronous or Synthetic Inertia
Synchronous generators (fossil, nuclear, hydro)	Battery energy storage
Synchronous condensers	Flywheels
Rotating stabilizers: a synchronous machine designed with a high mass	Wind turbines
CAES (operates like a normal GT power plant; provides inertia and primary, secondary, and tertiary responses)	Solar PV
Reduction of unit minimum generation setpoint	Distributed power system virtual inertia
AC interconnectors: increased synchronous interconnections (to increase the synchronous area)	Virtual synchronous generators or virtual synchronous machines
Wind turbines with induction generator technology (no inverter interface)	High-voltage direct current interconnectors
	Demand-side response
	Hydraulic-pneumatic flywheel system in a wind turbine rotor for inertia control
	Supercapacitors

With respect to synchronous inertia, one technology gaining attention is the synchronous condenser (SC), which is a is a synchronous machine that is neither a motor nor a generator. The machine does not inject or withdraw active power and only produces reactive power. SCs are now being proposed as good alternatives to synchronous generators for providing inertia support. Synchronous generators that are about to retire may be retrofitted as SCs, which may have a lower cost than installing a new machine. However, there is need to consider the age of the machine and the potential for increased maintenance. ElectraNet, the transmission network service provider in South Australia, is working to install SCs as a cost-effective way to restore system strength and address an inertia shortfall.

There is also growing interest and discussion about the ability of nonsynchronous resources to provide inertia. As inverter-based resources, wind, and arguably to a lesser extent, solar PV can provide synthetic inertia. By slowing down the speed of a wind turbine, stored kinetic energy in the rotor can be extracted to emulate inertial response, like a synchronous generator. With an additional synthetic inertia control loop, Type-3 and Type-4 wind turbines can temporarily boost power output by extracting kinetic energy stored in spinning rotors. However, a synthetic inertia

response is not limited to wind turbines; solar PV and batteries also have the capability to approximate a synchronous generator-like inertial response. EPRI report 3002016924, *Review of Technologies and Operations When Considering Low Inertia Systems*, provides a detailed examination of virtual synchronous generators applications, which refers to operation of a voltage source converter as a synchronous generator. These resources are expected to be applied to wind or solar PV resources that are coupled with battery storage, and they may use both grid forming and grid following inverters to approximate the outcomes as synchronous machines.

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A
COST AND PERFORMANCE DATA

Tables A-1 through A-5 provide a summary of the technologies that were evaluated in this study.

Table A-1
Coal technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Pulverized coal (PC) [1]		
With dry cooling and wet cooling	1, 2, 4, 6 x 750 MW	Minemouth at 1800-m elevation
With carbon capture, dry cooling, and wet cooling	1, 2, 4, 6 x 750 MW	Minemouth at 1800-m elevation
Coal to gas conversion	580 MW	Existing PC plant
Integrated gasification combined cycle (IGCC), without carbon capture	1, 2, 4, 6 x 644 MW	Minemouth at 1800-m elevation
With carbon capture	1, 2, 4, 6 x 644 MW	Minemouth at 1800-m elevation
Fluidized bed combustion (FBC)		Minemouth at 1800-m elevation
With limestone for in-bed sulfur removal	1, 2, 4, 6 x 250 MW	Minemouth at 1800-m elevation
With carbon capture	1, 2, 4, 6 x 250 MW	Minemouth at 1800-m elevation

[1] Multiple units are sequentially built

Table A-2
Nuclear technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Nuclear (with seawater cooling)		
AP1000	1, 2 x 1,115 MW	Coastal, near Port Elizabeth or north of Cape Town
Areva evolutionary pressurized reactor (EPR)	1, 2 x 1,600 MW	Coastal, near Port Elizabeth or north of Cape Town
Small modular reactor (SMR)	12 x 60 MW	Coastal, near Port Elizabeth or north of Cape Town

Table A-3
Gas technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Open-cycle gas turbine (OCGT)		
1xLM6000	46 MW	Coastal, liquefied natural gas (LNG) based
1xLMS100	108 MW	Coastal, LNG based
1x9F.05	300 MW	Coastal, LNG based
1x9HA.02	545 MW	Coastal, LNG based
Combined-cycle gas turbine (CCGT)		
1x1 9F.05, 2x1 9F.05	470–945 MW	Coastal, LNG based
1x1 9HA.01, 2x1 9HA.02	810–1630 MW	Coastal, LNG based
1x1 9F.05, 2x1 9F.05 with carbon capture	430–865 MW	Coastal, LNG based
1x1 9HA.01, 2x1 9HA.02 with carbon capture	740–1490 MW	Coastal, LNG based
Internal combustion engine (ICE)	9 MW, 18 MW	Coastal, LNG based
Combined-cycle ICE	18 MW ICE 12x1	Coastal, LNG based

Table A-4
Renewable technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Wind	50, 100, 200 MW	Coastal
Parabolic trough		
Without storage	125 MW	Upington
With indirect storage (3, 6, 9, and 12 h)	125 MW	Upington
Central receiver		
With direct storage (3,6, 9, and 12 h)	125 MW	Upington
Photovoltaics (PVs)		
Thin film	20 MW	Johannesburg
Monocrystalline silicon—rooftop	5 kW, 100 kW	Johannesburg
Monocrystalline silicon—ground mount	20 kW, 100 MW	Johannesburg
Bifacial	20 MW	Johannesburg
Solar plus storage	20 MW PV, 20 MW/4 h 100 MW PV, 25 MW/4 h 100 MW PV, 100 MW/4 h	Johannesburg
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

Table A-5
Storage technologies

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Storage		
Compressed-air energy storage (CAES)	180 MW/8 h	Based on suitable geologic resource availability
Lithium-Ion	1 MW/1 h 20 MW/1 h 20 MW/4 h 100 MW/1 h 100 MW/4 h	Johannesburg

Tables A-6 through A-28 provide a summary of the levelized costs of electricity from this study.

Table A-6
PC with dry cooling levelized cost of electricity

Technology	1x750 MW, Dry Cooling	2x750 MW, Dry Cooling	4x750 MW, Dry Cooling	6x750 MW, Dry Cooling
Rated capacity, MW net	750	1,500	3,000	4,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	374.4	374.4	374.4	374.4
O&M (ZAR/MWh)	221.2	211.0	199.2	193.6
Capital (ZAR/MWh)	1,020.5	966.7	912.8	885.8
LCOE (ZAR/MWh)	**1,616.1**	**1,552.1**	**1,486.5**	**1,453.8**

Table A-7
PC with wet cooling levelized cost of electricity

Technology	1x750 MW, Wet Cooling	2x750 MW, Wet Cooling	4x750 MW, Wet Cooling	6x750 MW, Wet Cooling
Rated capacity, MW net	750	1,500	3,000	4,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	361.9	361.9	361.9	361.9
O&M (ZAR/MWh)	238.4	228.4	216.8	211.4
Capital (ZAR/MWh)	948.2	898.3	848.3	823.5
LCOE (ZAR/MWh)	**1,548.5**	**1,488.7**	**1,427.0**	**1,396.7**

Table A-8
PC with dry cooling and carbon capture levelized cost of electricity

Technology	1x750 MW, Dry Cooling with Carbon Capture	2x750 MW, Dry Cooling with Carbon Capture	4x750 MW, Dry Cooling with Carbon Capture	6x750 MW, Dry Cooling with Carbon Capture
Rated capacity, MW net	750	1,500	3,000	4,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	538.1	538.1	538.1	538.1
O&M (ZAR/MWh)	386.2	372.2	355.9	348.1
Capital (ZAR/MWh)	1,958.0	1,884.6	1,811.0	1,774.4
LCOE (ZAR/MWh)	**2,882.3**	**2,794.9**	**2,705.0**	**2,660.6**

Table A-9
PC with wet cooling and carbon capture levelized cost of electricity

Technology	1x750 MW, Wet Cooling with Carbon Capture	2x750 MW, Wet Cooling with Carbon Capture	4x750 MW, Wet Cooling with Carbon Capture	6x750 MW, Wet Cooling with Carbon Capture
Rated capacity, MW net	750	1,500	3,000	4,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	512.7	512.7	512.7	512.7
O&M (ZAR/MWh)	399.9	387.3	371.8	364.6
Capital (ZAR/MWh)	1,805.0	1,739.0	1,672.9	1,639.7
LCOE (ZAR/MWh)	**2,717.7**	**2,639.0**	**2,557.4**	**2,517.0**

Table A-10
Coal-to-gas plant levelized cost of electricity

Technology	580-MW Subcritical PC Plant Conversion to Gas Firing
Rated capacity, MW net	569
Capacity factor, %	65
Fuel cost (ZAR/MWh)	1,408.7
O&M (ZAR/MWh)	111.7
Capital (ZAR/MWh)	25.2
LCOE (ZAR/MWh)	**1,545.6**

Table A-11
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)	372.2	372.2	372.2	372.2
O&M (ZAR/MWh)	298.8	280.8	261.8	253.1
Capital (ZAR/MWh)	1,367.0	1,285.8	1,204.4	1,163.8
LCOE (ZAR/MWh)	**2,038.0**	**1,938.8**	**1,838.4**	**1,789.1**

Table A-12
IGCC with carbon capture levelized cost of electricity

Technology	One 2x2x1 Shell IGCC with Carbon Capture	Two 2x2x1 Shell IGCC with Carbon Capture	Four 2x2x1 Shell IGCC with Carbon Capture	Six 2x2x1 Shell IGCC with Carbon Capture
Rated capacity, MW net	644	1,288	2,576	3,864
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	478.5	478.5	478.5	478.5
O&M (ZAR/MWh)	478.1	455.1	428.8	403.4
Capital (ZAR/MWh)	2,152.9	2,024.8	1,896.4	1,832.0
LCOE (ZAR/MWh)	**3,109.5**	**2,958.3**	**2,803.6**	**2,713.9**

Table A-13
Fluidized bed with dry cooling levelized cost of electricity

Technology	1x250 MW, Dry Cooling	2x250 MW, Dry Cooling	4x250 MW, Dry Cooling	6x250 MW, Dry Cooling
Rated capacity, MW net	250	500	1,000	1,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	411.6	411.6	411.6	411.6
O&M (ZAR/MWh)	265.8	255.5	244.0	239.1
Capital (ZAR/MWh)	1,049.5	987.0	924.4	893.3
LCOE (ZAR/MWh)	**1,726.9**	**1,654.0**	**1,580.0**	**1,544.0**

Table A-14
Fluidized bed with wet cooling levelized cost of electricity

Technology	1x250 MW, Wet Cooling	2x250 MW, Wet Cooling	4x250 MW, Wet Cooling	6x250 MW, Wet Cooling
Rated capacity, MW net	250	500	1,000	1,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	397.6	397.6	397.6	397.6
O&M (ZAR/MWh)	272.1	262.2	251.1	246.6
Capital (ZAR/MWh)	933.0	877.5	821.8	794.1
LCOE (ZAR/MWh)	**1,602.7**	**1,537.2**	**1,470.5**	**1,438.3**

Table A-15
Fluidized bed with dry cooling and carbon capture levelized cost of electricity

Technology	1x250 MW, Dry Cooling with Carbon Capture	2x250 MW, Dry Cooling with Carbon Capture	4x250 MW, Dry Cooling with Carbon Capture	6x250 MW, Dry Cooling with Carbon Capture
Rated capacity, MW net	250	500	1,000	1,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	592.1	592.1	592.1	592.1
O&M (ZAR/MWh)	358.4	343.4	330.0	323.4
Capital (ZAR/MWh)	1,854.9	1,771.8	1,688.8	1,647.3
LCOE (ZAR/MWh)	**2,805.4**	**2,707.4**	**2,610.9**	**2,562.9**

Table A-16
Fluidized bed with wet cooling and carbon capture levelized cost of electricity

Technology	1x250 MW, Wet Cooling with Carbon Capture	2x250 MW, Wet Cooling with Carbon Capture	4x250 MW, Wet Cooling with Carbon Capture	6x250 MW, Wet Cooling with Carbon Capture
Rated capacity, MW net	250	500	1,000	1,500
Capacity factor, %	85	85	85	85
Fuel cost (ZAR/MWh)	565.1	565.1	565.1	565.1
O&M (ZAR/MWh)	371.7	357.3	344.5	338.1
Capital (ZAR/MWh)	1,692.4	1,619.2	1,545.8	1,509.1
LCOE (ZAR/MWh)	**2,629.2**	**2,541.6**	**2,455.3**	**2,412.4**

Table A-17
Nuclear levelized cost of electricity

Technology	1x1600 MW, Areva	2x1600 MW, Areva	1x1117 MW, AP1000	2x1117 MW, AP1000	12x57 MW, SMR
Rated capacity, MW net	1,600	3,200	1,117	2,234	684
Capacity factor, %	90	90	90	90	90
Fuel cost (ZAR/MWh)	118.6	118.6	133.4	133.4	142.3
O&M (ZAR/MWh)	190.5	169.0	246.6	211.4	245.7
Capital (ZAR/MWh)	2,138.6	2,164.5	2,044.5	2,069.5	1,899.1
LCOE (ZAR/MWh)	**2,447.7**	**2,452.1**	**2,424.5**	**2,414.4**	**2,287.1**

Table A-18
OCGT levelized cost of electricity

Technology	1xLM6000	1xLMS100	1x9F.05	1x9HA.02
Rated capacity, MW net	45	106	297	540
Capacity factor, %	10	10	10	10
Fuel cost (ZAR/MWh)	1,355.0	1,258.4	1,391.3	1,238.3
O&M (ZAR/MWh)	609.7	353.0	168.8	122.9
Capital (ZAR/MWh)	3,878.7	2,657.7	1,498.1	1,286.7
LCOE (ZAR/MWh)	**5,843.5**	**4,269.1**	**3,058.2**	**2,647.9**

Table A-19
CCGT levelized cost of electricity

Technology	1x1 9F.05 Dry Cool	2x1 9F.05 Dry Cool	1x1 9HA.02 Dry Cool	2x1 9HA.02 Dry Cool
Rated capacity, MW net	460	281	792	1,028
Capacity factor, %	50	50	50	50
Fuel cost (ZAR/MWh)	909.6	904.3	850.7	857.4
O&M (ZAR/MWh)	95.0	71.1	79.0	60.9
Capital (ZAR/MWh)	506.9	381.1	371.3	293.0
LCOE (ZAR/MWh)	**1,511.5**	**1,356.5**	**1,301.0**	**1,211.3**

Table A-20
CCGT with carbon capture levelized cost of electricity

Technology	1x1 9F.05 Dry Cool with Carbon Capture	2x1 9F.05 Dry Cool with Carbon Capture	1x1 9HA.02 Dry Cool with Carbon Capture	2x1 9HA.02 Dry Cool with Carbon Capture
Rated capacity, MW net	398	498	685	828
Capacity factor, %	50	50	50	50
Fuel cost (ZAR/MWh)	1,050.5	1,045.2	983.4	988.8
O&M (ZAR/MWh)	199.6	161.5	179.8	147.2
Capital (ZAR/MWh)	1,555.2	1,257.0	1,268.0	983.9
LCOE (ZAR/MWh)	**2,805.3**	**2,463.7**	**2,431.2**	**2,119.9**

Table A-21
ICE levelized cost of electricity

Technology	1x9 MW ICE	1x18 MW ICE	18 MW ICE 12x1 Combined Cycle Dry Cooling
Rated capacity, MW net	10	16	211
Capacity factor, %	10	10	50
Fuel cost (ZAR/MWh)	1,184.6	1,184.6	1,102.8
O&M (ZAR/MWh)	1,357.0	989.2	117.1
Capital (ZAR/MWh)	6,688.3	5,483.8	736.4
LCOE (ZAR/MWh)	**9,230.0**	**7,657.6**	**1,956.4**

Table A-22
Wind levelized cost of electricity

Technology	2.8 MW x18	2.8 MW x36	2.8 MW x72
Rated capacity, MW net	43	86	169
Capacity factor, %	36.3	36.3	36.3
Fuel cost (ZAR/MWh)	0.0	0.0	0.0
O&M (ZAR/MWh)	252.2	249.3	229.0
Capital (ZAR/MWh)	999.9	988.1	951.6
LCOE (ZAR/MWh)	**1,252.1**	**1,237.4**	**1,180.6**

Table A-23
Solar thermal parabolic trough levelized cost of electricity

Technology	Parabolic Trough				
Rated capacity, MW net	125				
Hours of storage	0	3	6	9	12
Capacity factor, %	25.7	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)	351.5	285.4	250.6	213.8	188.2
Capital (ZAR/MWh)	4,305.9	4,607.6	4,819.7	4,886.9	4,924.7
LCOE (ZAR/MWh)	**4,657.4**	**4,892.9**	**5,070.2**	**5,100.7**	**5,112.8**

Table A-24
Solar thermal central receiver levelized cost of electricity

Technology	Central Receiver			
Rated capacity, MW net	**125**			
Hours of storage	3	6	9	12
Capacity factor, %	39.5	51.0	60.3	69.7
Fuel cost (ZAR/MWh)	0.0	0.0	0.0	0.0
O&M (ZAR/MWh)	216.1	175.0	152.1	135.2
Capital (ZAR/MWh)	3,650.5	3,428.0	3,275.0	3,163.0
LCOE (ZAR/MWh)	**3,866.6**	**3,603.0**	**3,427.1**	**3,298.2**

Table A-25
PVs levelized cost of electricity

Technology	Monocrystalline Silicon				C-Si Bifacial Module	Thin-Film CdTe
Mounting	Rooftop fixed tilt	Rooftop fixed tilt	Ground-mount SAT	Ground-mount SAT	Ground-mount SAT	Ground-mount SAT
Rated capacity, MW net	0.005	0.100	20	99.5	20	20
Capacity factor, %	22.5	22.5	26.9	27.8	29.8	26.5
Fuel cost (ZAR/MWh)	0	0	0	0	0	0
O&M (ZAR/MWh)	173.5	137.4	105.5	87.6	97.0	105.9
Capital (ZAR/MWh)	3,219.2	2,233.6	1,046.8	879.8	1,014.4	1,005.7
LCOE (ZAR/MWh)	**3,392.7**	**2,371.0**	**1,152.3**	**967.4**	**1,111.4**	**1,111.6**

Table A-26
Solar plus storage levelized cost of electricity

Technology	Solar PV plus Battery Storage		
Rated capacity, MW net	20 MW PV, 20MW/4 h	100 MW PV, 25MW/4 h	100 MW PV, 100MW/4 h
Fuel cost (ZAR/MWh)	0	0	0
O&M (ZAR/MWh)	520.5	204.1	504.7
Capital (ZAR/MWh)	4,011.6	4,067.6	3,665.5
LCOE (ZAR/MWh)	**4,532.1**	**4,271.8**	**4,170.3**

Table A-27
Biomass levelized cost of electricity

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)	616.8	3.3	2.2	2.0
O&M (ZAR/MWh)	273.9	771.4	300.2	245.5
Capital (ZAR/MWh)	1,780.2	3,402.5	719.6	1,791.2
LCOE (ZAR/MWh)	**2,670.9**	**4,177.2**	**1,022.0**	**2,038.7**

Table A-28
Energy storage levelized cost of electricity

Technology	Lithium-Ion					CAES
System size, MW	1	20	20	100	100	180
Storage capacity, h	1	1	4	1	4	8
Fuel cost (ZAR/MWh)	0	0	0	0	0	587.6
Charging cost (ZAR/MWh)	1,389.7	1,389.7	1,389.7	1,373.5	1,373.5	909.2
O&M (ZAR/MWh)	870.2	870.2	672.6	870.2	672.6	135.1
Capital (ZAR/MWh)	6,052.5	4,539.4	2,729.7	4,287.0	2,559.6	1,328.4
LCOE (ZAR/MWh)	**8,312.4**	**6,799.3**	**4,791.9**	**6,530.8**	**4,605.7**	**2,960.3**

Figures A-1 through A-10 provide a comparison of the levelized costs of electricity from this study and comparisons of the 2017 and 2021 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 18.13 ZAR to 1 U.S. dollar. This represents a significant strengthening of the U.S. dollar relative to the South African rand since the 2017 study. The effect of the exchange rate and the escalation in costs resulted in a pronounced increase in the capital cost estimates for 2021 versus 2017.

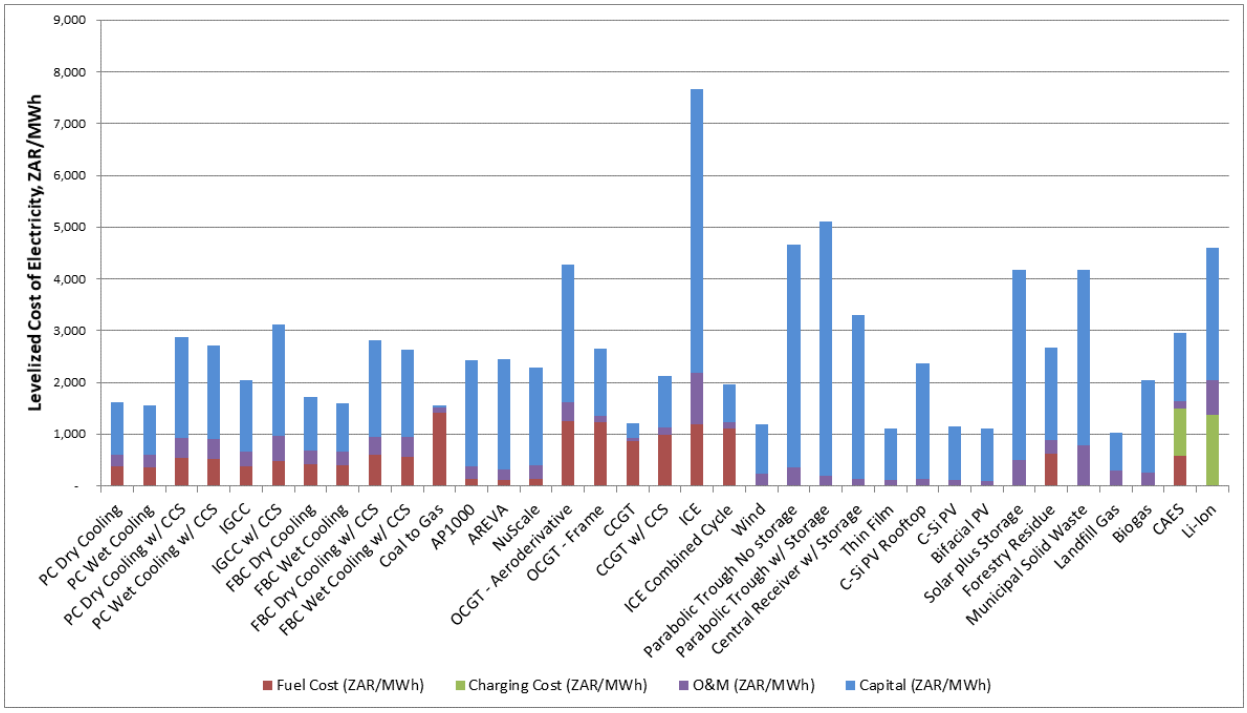

Figure A-1
Comparison of representative levelized cost of electricity results

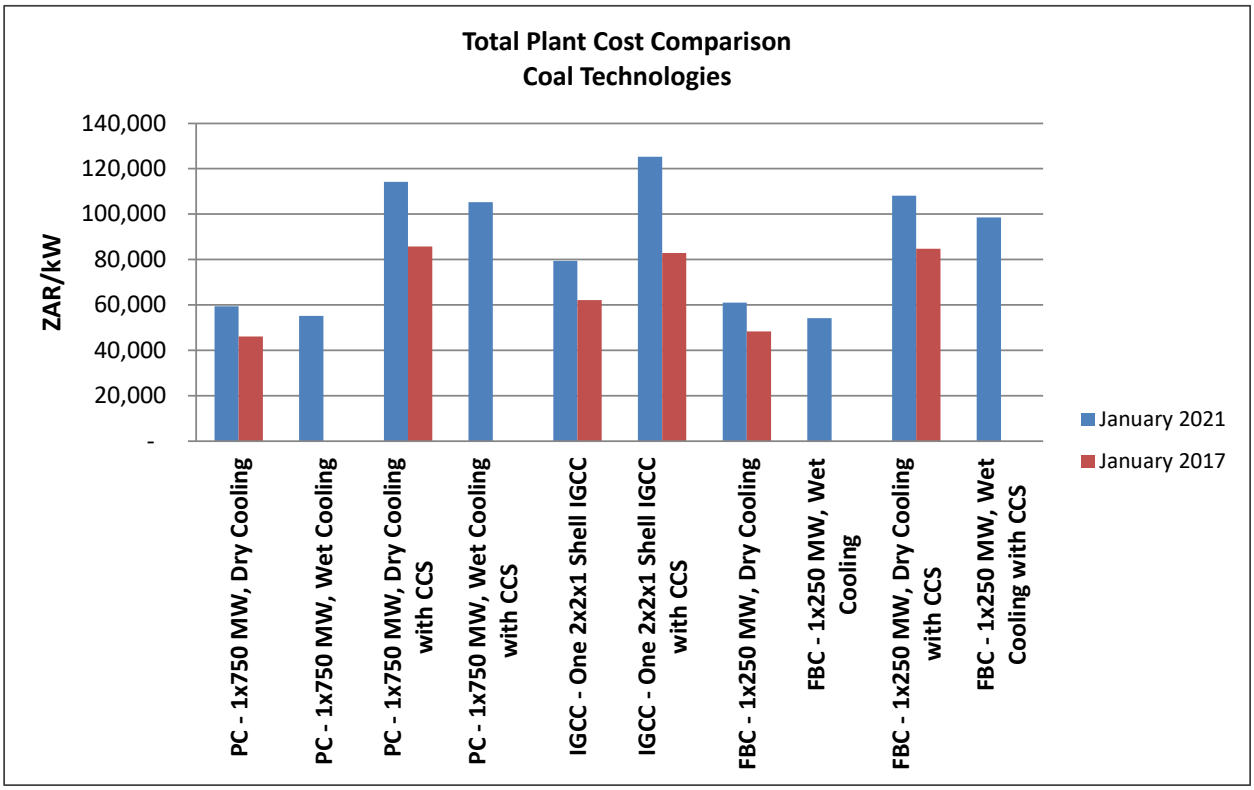

Figure A-2
TPC comparison for coal technologies

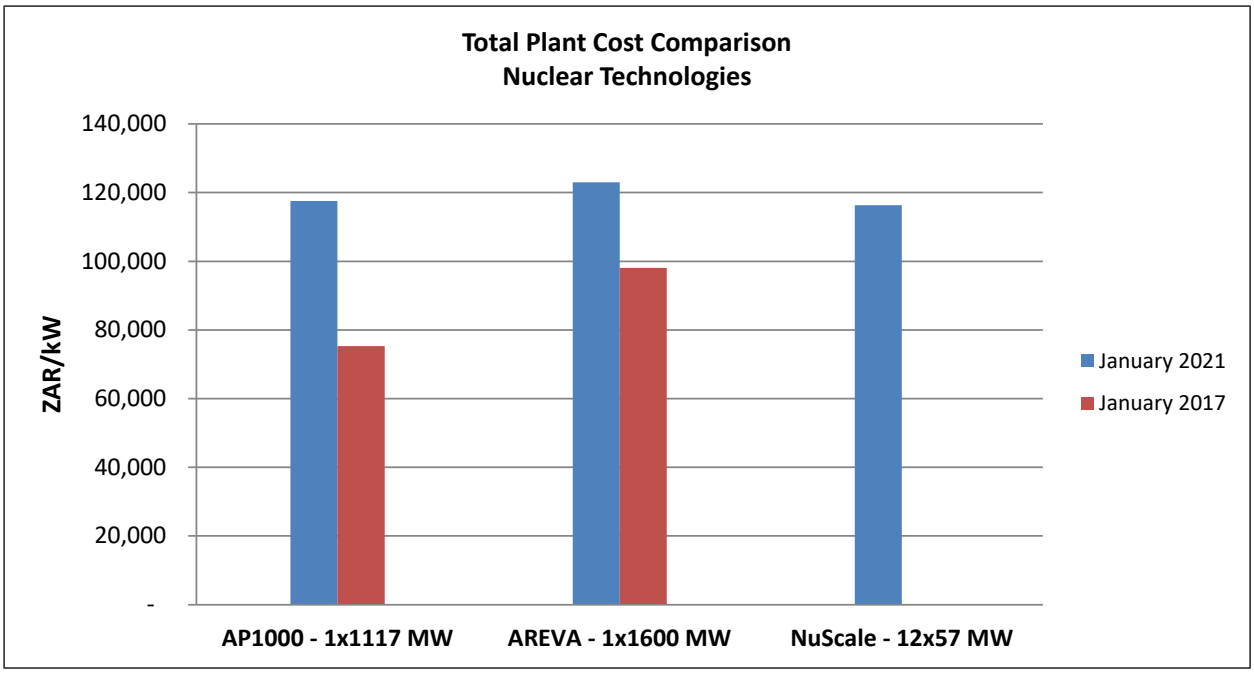

Figure A-3
TPC comparison for nuclear technology

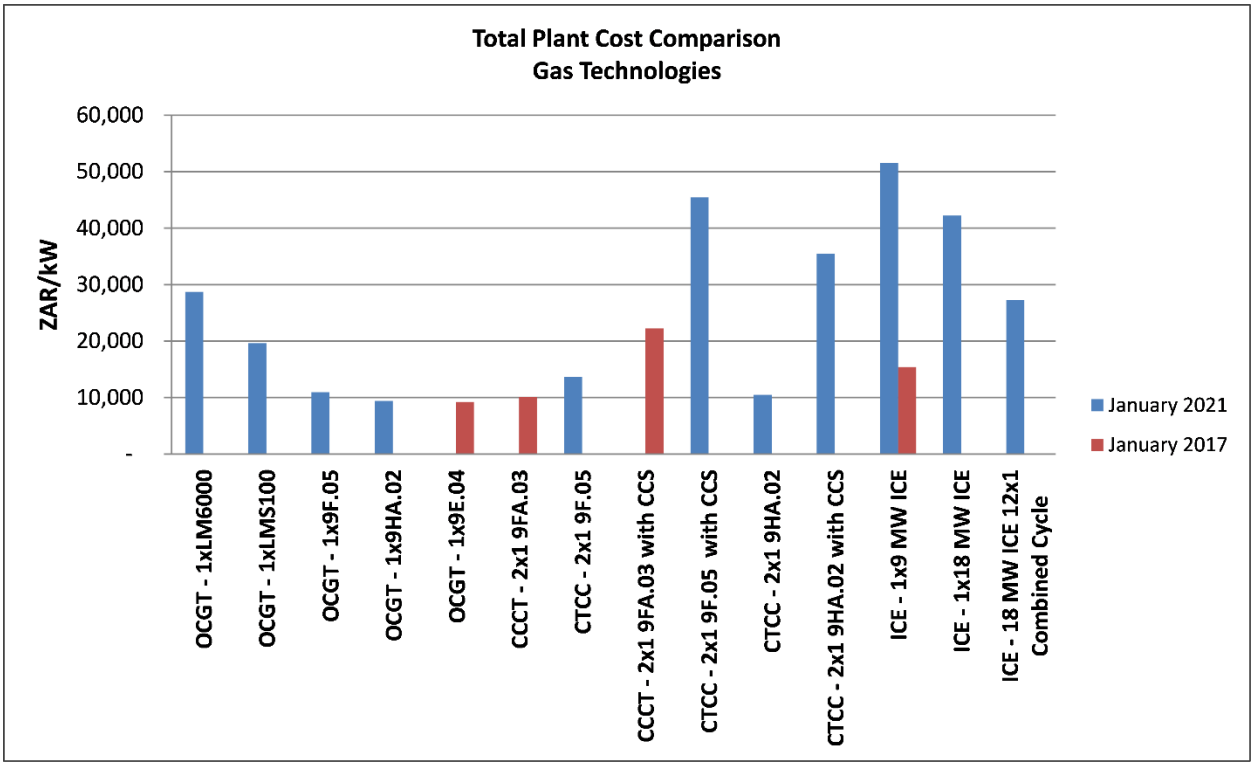

Figure A-4
TPC comparison for combustion turbine technology

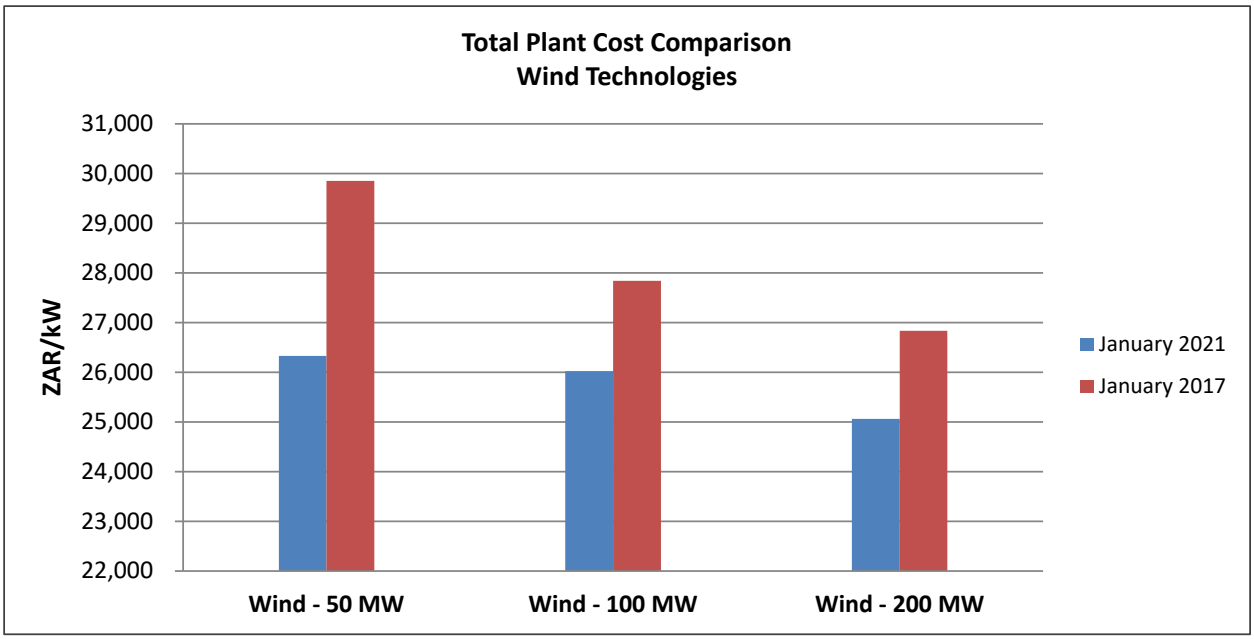

Figure A-5
TPC comparison for wind technology

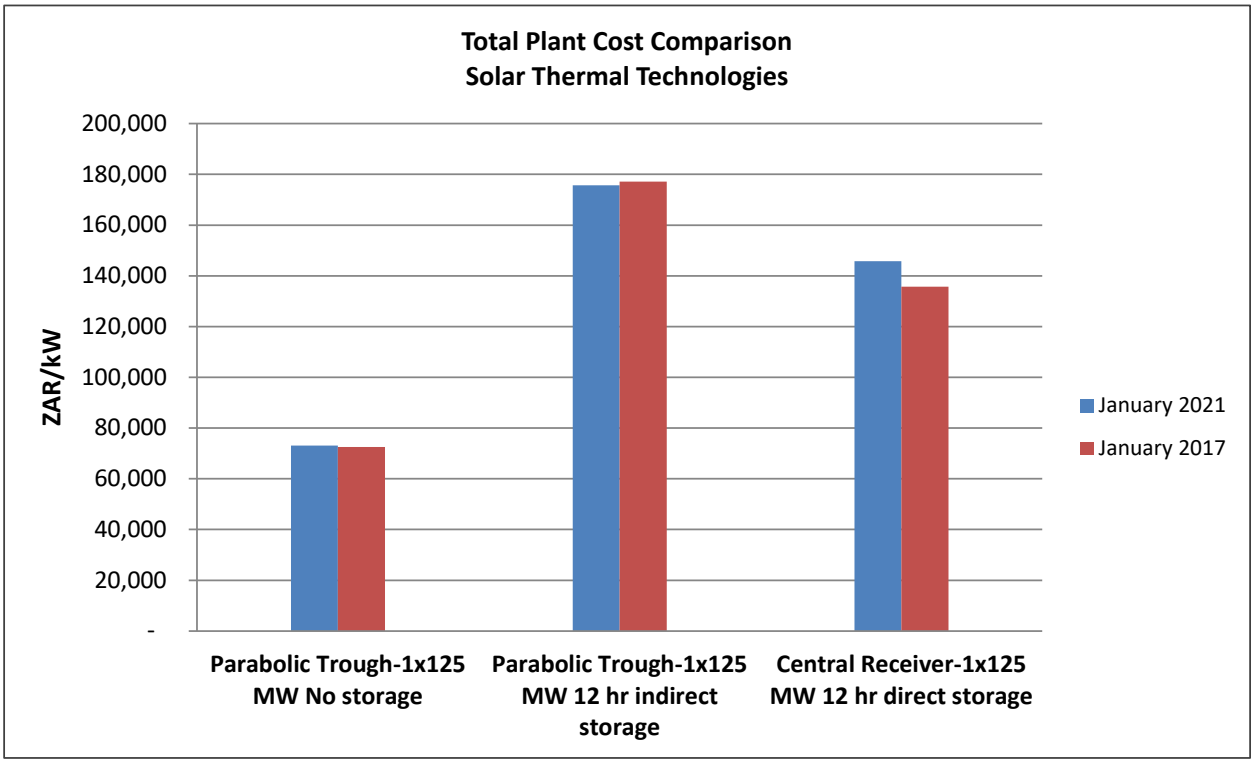

Figure A-6
TPC comparison for solar thermal technology (125 MW)

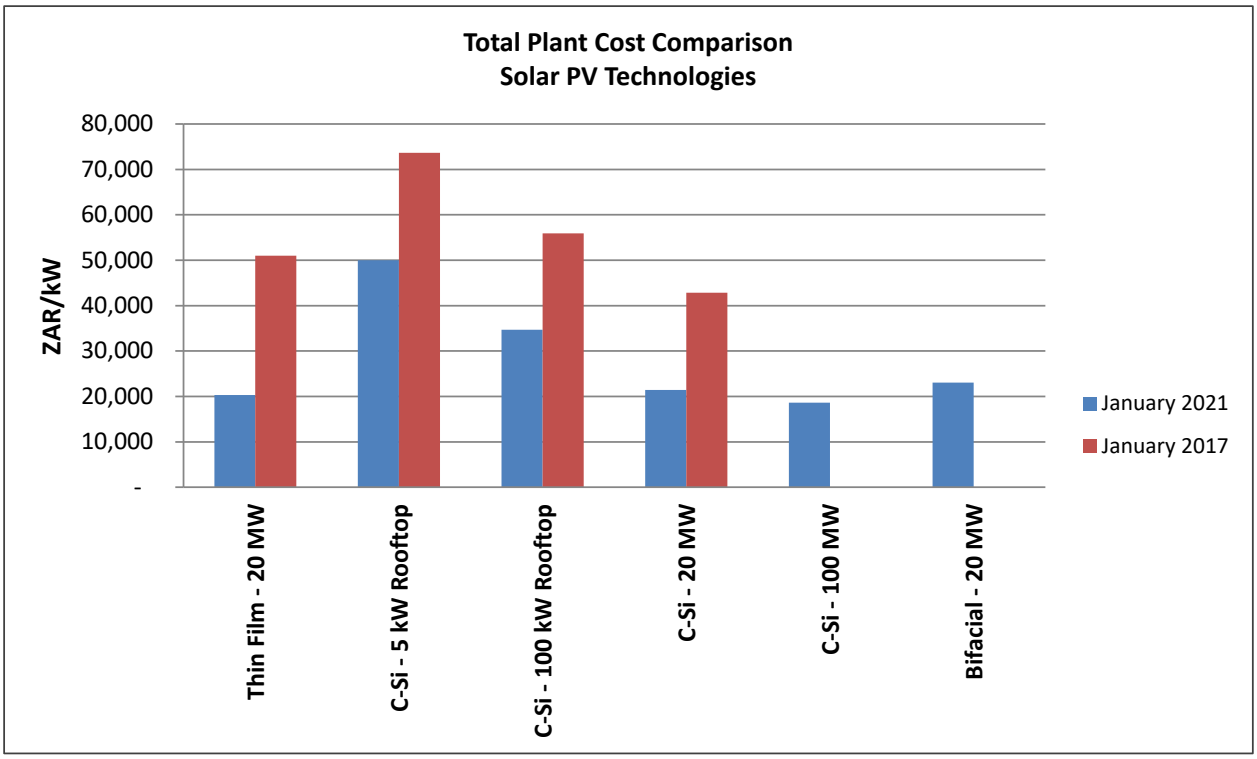

Figure A-7
TPC comparison for solar PV technology

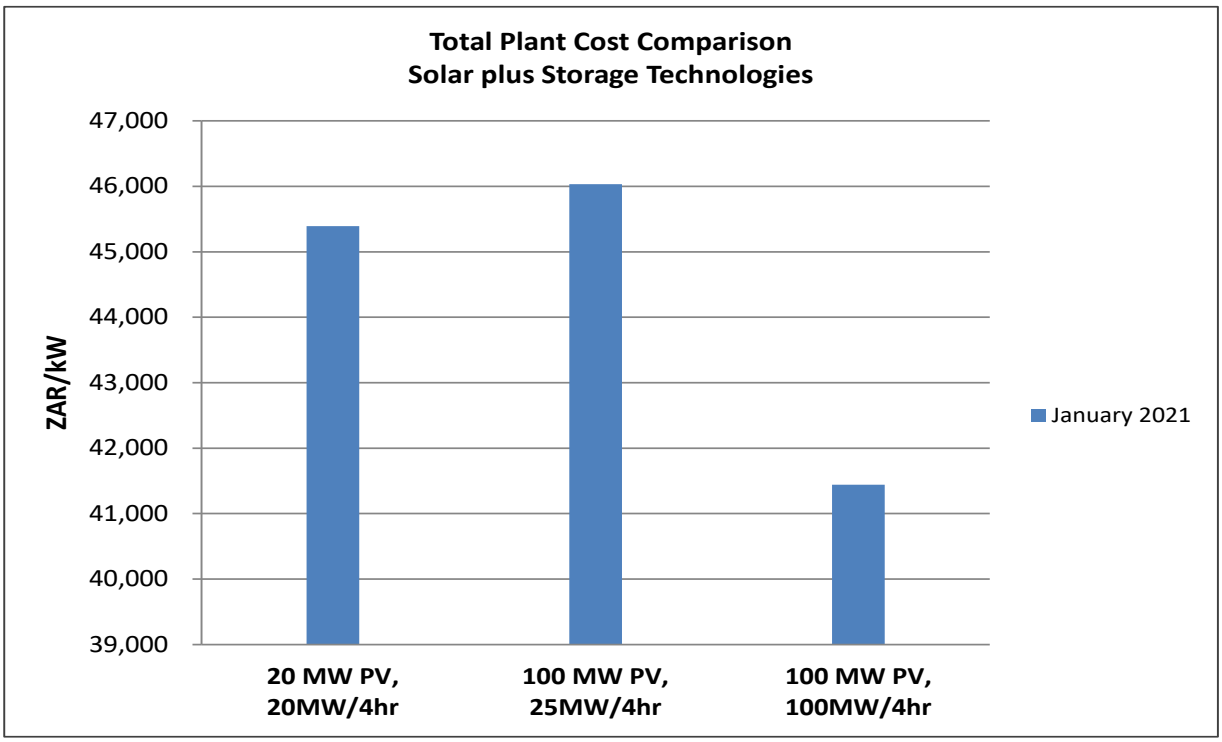

Figure A-8
TPC comparison for solar plus storage technology

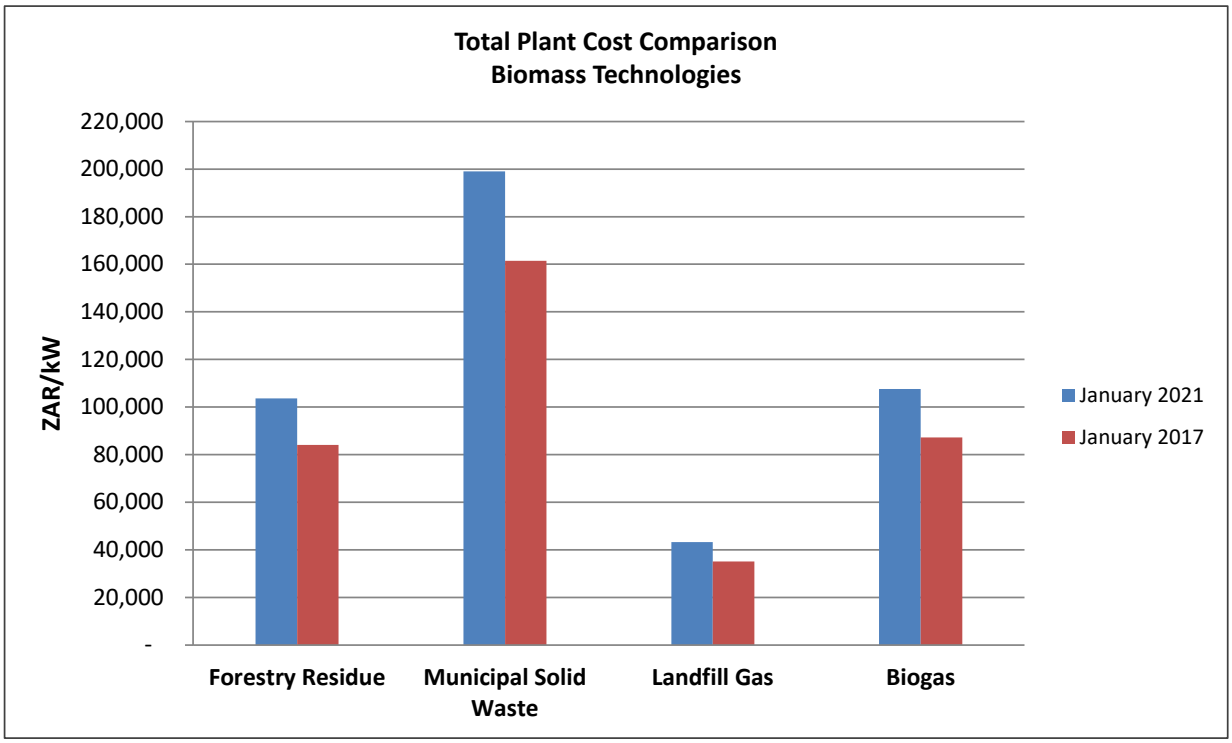

Figure A-9
TPC comparison for biomass technologies

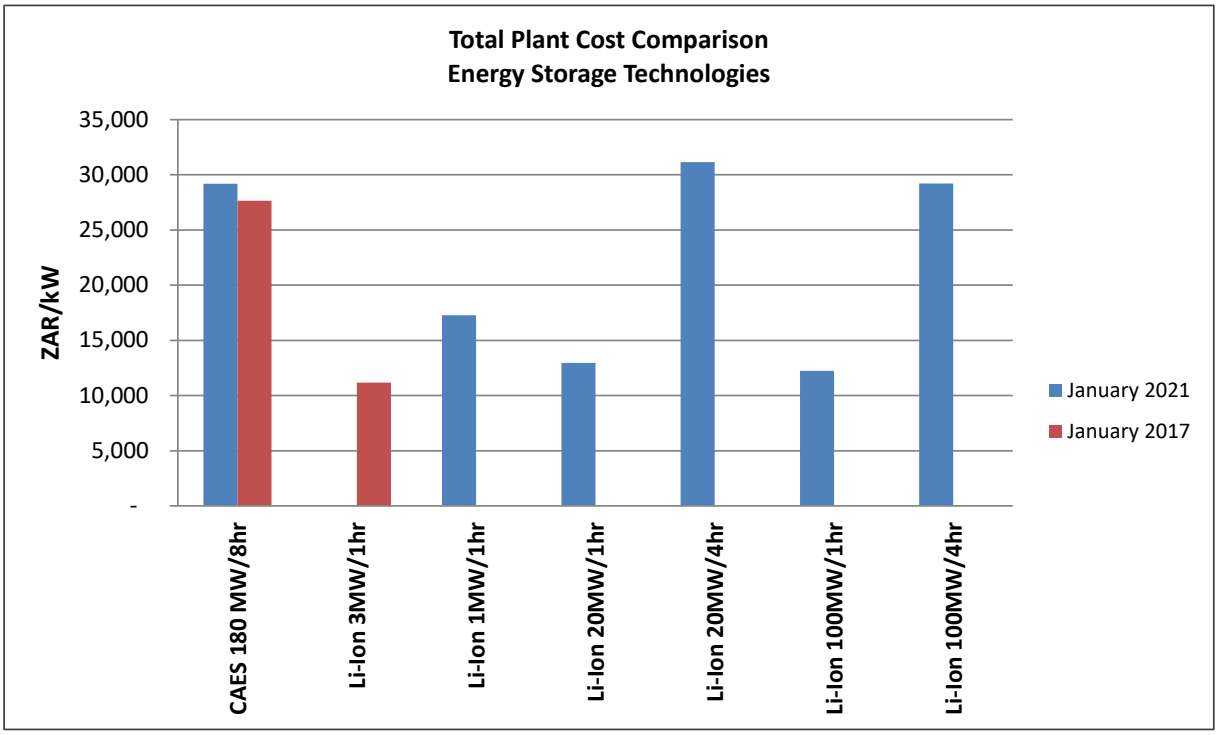

Figure A-10
TPC comparison for energy storage technologies

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