

2024 TECHNICAL REPORT

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

2023–2024 Update

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

2023–2024 Update

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ABSTRACT

The South African government's Department of Mineral Resources and Energy (DMRE) is in the process of reviewing the integrated resource plan for South Africa. This report provides up-to-date cost and performance data on renewable electric power generation technologies such as offshore wind, solar thermal, and solar photovoltaic with battery storage; fossil fuel-based technologies such as pulverized coal, open-cycle gas turbine, combined-cycle gas turbine, and internal combustion engines; large-scale nuclear and small modular reactor (SMR) technologies; and energy storage technologies. The study also provides cost estimates for conversion of a coal plant to natural gas plant and coal plant to SMR. This study updates results from a 2020–2021 project by incorporating technology enhancements and better highlighting the potential influence of market factors, enhancements to design, and revisions to cost and performance data. The independent data and expertise presented in this report will facilitate the integrated resource plan (IRP) process for the Republic of South Africa.

Keywords

Integrated resource plan (IRP)
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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 1) new generation capacity needed to ensure the continued uninterrupted supply of electricity, 2) the types of energy sources from which electricity must be generated, and 3) development and publication of an 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 EPRI in 2010, 2012, 2015, 2021 to provide technology data for new power plants that would be included in the IRPs. These IRP reports have been extensively reviewed with public comments and acceptance. This effort is a technical update of technology cost and performance with technology enhancements, market factor influences, and additional technology cases for inclusion in future IRPs.

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, which were 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 summary of the research methodology is included.

The costs of bulk materials in South Africa have escalated significantly. While raw materials are generally more affordable in South Africa compared to the United States, the potential cost savings are negated by a higher percentage of imported materials and elevated production costs. These increased production costs stem from less sophisticated production techniques and lower worker productivity in the region.

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

- Estimates (constant January 2023) represent composite material and labor cost estimates from fourth quarter 2022 for an in-service commercial year of 2023 except where explicitly noted.
- Material, productivity, and labor rate factors reflect the exchange rate of 18.35 ZAR to 1 U.S. dollar. This rate was reported by the South African Reserve Bank on January 2, 2024. 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 are 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 for 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 that 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 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 and craft rates
- Equipment and material transportation cost
- Expatriate skilled labor, supervision, and management requirements
- Design and engineering labor requirements

KEY FINDINGS

- Since the 2021 study, there has been a strengthening of the U.S. dollar against the South African rand. Furthermore, in the post-pandemic era, the global economy has faced ongoing supply chain challenges influencing delivery schedules and affecting the costs of equipment and materials. The combined impact of exchange rate fluctuations and cost escalations, driven by factors such as supply chain constraints and inflation, has led to a notable increase in the capital cost estimates for 2024 compared to those in 2021.
- Total plant costs of solar thermal and fossil generation plants including gas turbines (open cycle and combined cycle) and internal combustion engines increased from the previous study driven by the inflation and exchange rate. The reported cost of a pulverized coal plant with carbon capture has increased more significantly due to the use of a different technology configuration with a smaller unit size in addition to the inflation and exchange rate.
- Battery storage costs have decreased from the previous study due to technology cost declines as the industry gains experience and projects grow in scale.
- Nuclear technology costs have increased significantly since the last study due to inflation driving higher materials and labor.

- This study incorporates cost estimates for both coal boiler to small modular nuclear reactor (SMR) conversion and coal to natural gas conversion. It is important to note that the conversion costs from coal to SMR are considerably higher compared to the conversion from coal to natural gas.

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 IRP process.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- TAGWeb^{®1} software ([3002030823](https://www.epri.com/3002030823)) offers the ability to customize 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: Project Set 178A: Energy System Technology Cost, Performance, and Technoeconomic Analysis

¹ TAGWeb, which stands for Technical Assessment Guide Web, is a registered EPRI brand.

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INTRODUCTION

The Electric Power Research Institute (EPRI) developed power generation and storage technology data for Eskom in 2010, 2012, 2015, and 2021 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.² 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 2023 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 and craft rates
- 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 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

² 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: 2021.

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)
- Coal boiler to natural gas boiler conversion
- Coal boiler to small modular reactor conversion
- Large-scale nuclear
- Small modular reactor
- Combined-cycle gas turbine (CCGT)
- Open-cycle gas turbine (OCGT)
- Internal combustion engine (ICE)
- Offshore Wind
- Parabolic trough with and without storage
- Central receiver with direct storage
- Photovoltaic solar with battery storage
- Lithium ion battery storage
- Underground hydrogen storage
- Pumped storage hydropower (PSH)

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, as applicable. The plant's performance, water and sorbent usage, and emissions were also estimated. From these results, EPRI developed leveled cost of electricity estimates. This report also includes a section covering strategies to extend the life of existing coal plants beyond

original useful life. The section outlines the typical roadmap of life extension program and important consideration during the implementation of plant life-extension.

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 2023 Richardson International Construction Factor Manual to calculate cost adjustment factors to adjust existing EPRI data from U.S. location to South African location. Factors considered included the following:

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

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 TAGWeb³ 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 energy storage, continue to decline rapidly and are challenging to forecast. For some technology still in its infancy phase, such as floating offshore wind, scarcity of operating projects can result in lacking readily available cost data. Therefore, the estimates presented in this report attempt to capture a wide range of potential costs.

³ TAGWeb is a registered brand of EPRI.

2

BACKGROUND AND GENERAL APPROACH

Introduction

A comprehensive list of coal, nuclear, gas, renewable, and energy storage technologies was selected for the overall evaluation. These are shown in Tables 2-1 through Table 2-5. Due to water shortages throughout South Africa, each of these technologies, except for coal with CCS, large-scale nuclear, and hydrogen storage was configured with air cooling of the condensers and auxiliary equipment to minimize water consumption. The large-scale nuclear plants were 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 consideration of CO₂ 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 2023 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 with 90% CCS	1 x 591MW	Inland
Coal boiler to natural gas boiler	1 x 569 MW	Inland
Coal boiler to small modular reactor	6 x 80 MW	Inland

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 1117 MW	Coastal, near Gqeberha or north of Cape Town
Areva evolutionary pressurized reactor (EPR)	1 and 2 units x 1600 MW	Coastal, near Gqeberha or north of Cape Town
Small modular reactor (SMR)	12 units x 73 MW	Inland

**Table 2-3
Natural Gas technologies**

Technology Type	Rated Capacity, MWe (net)	Assumed Location
OCGT and CCGT		
1x1 F-class NGCC without CCS	297 MW	Coastal, liquefied natural gas (LNG) based
2x1 F-class NGCC without CCS	925 MW	Coastal, LNG based
1x1 H-class NGCC without CCS	540 MW	Coastal, LNG based
2x1 H-class NGCC without CCS	1591 MW	Coastal, LNG based
ICE		
9-MW ICE without CCS	9.5 MW	Coastal, LNG based
18-MW ICE without CCS	16.2 MW	Coastal, LNG based

NGCC = natural-gas combined-cycle
ICE = internal combustion engine

**Table 2-4
Renewable technologies**

Technology Type	Rated Capacity, MWe (net)	Assumed Location
Offshore Wind		
Fixed Bottom	800MW	Offshore
Floating	800MW	Offshore
Parabolic trough		
Without storage	125 MW	Upington
With indirect storage	125 MW	Upington
Central receiver		
With direct storage	125 MW	Upington
Solar PV		
With battery storage	250 MW	Welkom

Table 2-5
Storage technologies

Technology Type	Rated Capacity	Assumed Location
Lithium ion	100 MW, 4 h	Major cities
Underground hydrogen storage		
Cost of electrolyzer	Alkaline - 104 MW PEM - 115 MW	Based on location of water source or hydrogen storage facility
Hydrogen storage	1912 tonnes of H ₂	Based on suitable geological location
H ₂ fired power generation – aeroderivative turbine	39.1 MWe (net)	Based on location of hydrogen storage facility
Pumped Storage Hydropower	1000 MW, 10h	Based on suitable topology and resource availability

PEM = Proton exchange membrane

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 plant 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.

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 pulverized coal (PC) plant in this study is a baseload unit. 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 the baseload coal unit. The technical parameters for the coal plant is 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
Coal to NG boiler			
Coal to SMR	Minimum SMR load – 40%	Estimate: 6–8 h	Up – 5%/min Down – 5%/min

For coal to natural gas (NG) conversion, the capacity factor of 65% is considered for natural gas plant, whereas coal to SMR conversion considers capacity factor of 90% for SMR.

Generating Unit Size

The net output capacity of the PC unit is 591 MW and is evaluated for stations consisting of one unit. For coal to NG conversion, the net capacity of NG unit is 569MWe and is evaluated for station consisting of one unit. Similarly, for coal to SMR conversion, the net capacity of SMR unit is 80MWe and is evaluated for station consisting of six units. The plants are considered to 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. CO₂ compression equipment and energy penalties are included for PC plants but the capital costs for the CO₂ 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. The estimates included in this study do not include a railroad spur.

For coal to SMR conversion, all structures except the switchyard are assumed to be demolished. Such structures would include boiler buildings, substation, turbine buildings, screen house, pump house, coal handling facilities, oil tanks, machine shop, maintenance buildings, warehouses, and miscellaneous buildings. The decommissioning cost is included to account for demolishing these structures.

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 PC coal plant in this study is high-ash bituminous coal. The characteristics and analysis of this coal are presented in Table 3-2.

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 ₂ O ₃	22.00
Fe ₂ O ₃	3.80
TiO ₂	1.80
P ₂ O ₅	0.40
CaO	5.00
MgO	1.40
Na ₂ O	0.45
K ₂ O	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.⁴

In 2019, South African coal production amounted to 285.9 million tons.⁵ 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.⁶ 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.⁷

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.

⁴ IEA, 2020, South Africa Country profile.

⁵ Minerals Council South Africa, 2021, Key Facts and Figures.

⁶ Chamber of Mines South Africa, 2018, Coal Strategy 2018.

⁷ "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 unit in this study was evaluated with a FGD unit for sulfur dioxide removal. A limestone forced oxidation (LSFO) system wet scrubber achieving 95% removal of inlet SO₂ 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.

CO₂ Capture and Storage

PC coal plant was evaluated with CO₂ capture in this study with a capture rate of 85–90%. 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 CO₂ capture and storage, the CO₂ pipeline and storage area for sequestration are not included in these capital cost estimates.

No CO₂ capture is considered for NG unit in coal to NG conversion case.

Wet Cooling

Wet cooling system is considered for PC plant. Whereas dry cooling is considered for natural gas plant and SMR plant in coal to NG/SMR conversion case.

Nuclear Technologies

Location

Large-scale nuclear plants would 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 Gqeberha.

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 Evolutionary Pressurized Reactor (EPR). These units range in size from 1120 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 NuScale's SMR plant consisting of 12 reactors with a total net capacity of 876 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 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.

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.

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. The South African government has completed studies indicating the country's ability to support the nuclear fuel requirements of a multi-gigawatt nuclear fleet.

Uranium mining is only a segment of the nuclear fuel cycle, however. Given sufficient investment in fuel conversion, enrichment, and fabrication capacity⁹, South Africa could become self-reliant in the future. This shift in raw uranium sourcing from external to internal is viewed by some stakeholder as necessary for national security.

Nuclear Fuel and Waste Transport/Storage/Disposal

The nuclear fuel cycle, as illustrated in Figure 3-1, includes uranium recovery, conversion, enrichment, and fabrication to produce fuel for nuclear power stations. Uranium fuel prices fluctuate and are challenging to forecast as they are influenced by supply, demand, and geopolitical considerations. Further, uranium does not trade on an open market like other commodities. Instead, buyers and sellers enter into contracts privately, and electric companies typically negotiate long-term supply contracts. Uranium prices have increased considerably due to a reduction in inventories and the Russia-Ukraine war. Nuclear fuel costs consist of front-end and back-end costs. Front-end costs are outlined in Table 3-3, which is based on 2008¹⁰ and 2021¹¹ data from the World Nuclear Association. The uranium price in the table has been modified to reflect costs escalated by annual inflation.¹² Month-end industry average uranium prices and settlement prices were obtained from Cameco¹³ and IndexMundi.

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 <https://world-nuclear-news.org/Articles/Russia-and-South-Africa-sign-MoU-on-nuclear-fuel>.

¹⁰ “The Economics of Nuclear Power.” World Nuclear Association. November 2008.

¹¹ <https://world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx>

¹² <http://www.indexmundi.com/commodities/>

¹³ <https://www.cameco.com/invest/markets/uranium-price>.

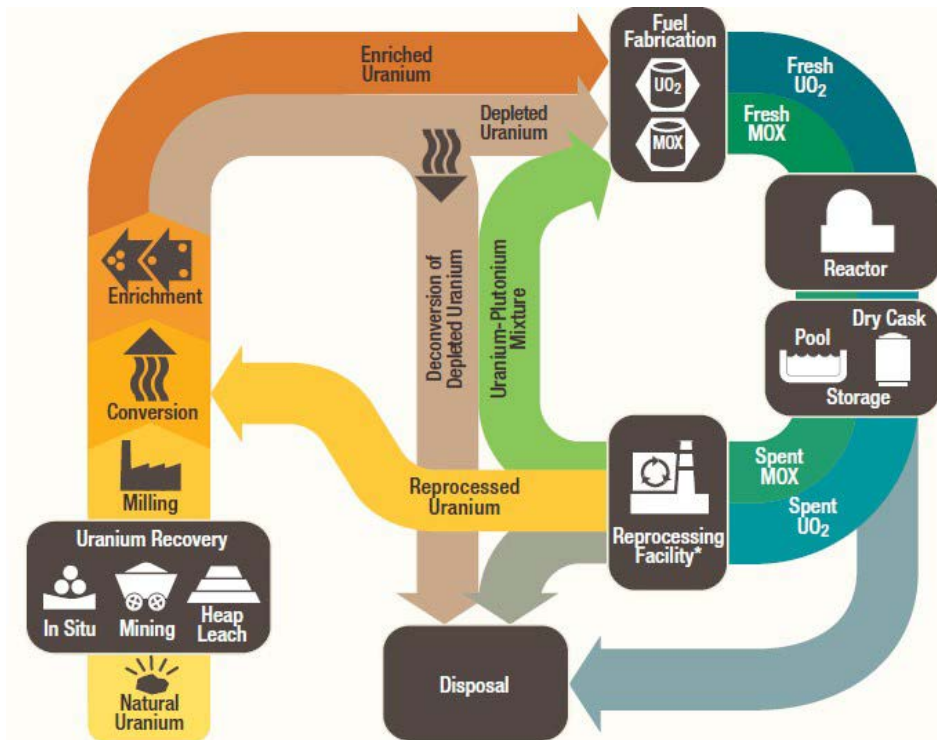


Figure 3-1
Nuclear fuel cycle¹⁴

Table 3-3
Front-end nuclear fuel costs, 2023\$

Process Step	Cost (\$/kg U)
Uranium: 8.9 kg U ₃ O ₈ × \$140	1,246
Conversion: 7.5 kg U × \$17	128
Enrichment: 7.3 SWU × \$183	1,336
Fabrication: per kg	319
Total (\$/kg U)	3,029

SWU = separative work unit

¹⁴ “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 costs¹⁵

Process Step	Cost (2023\$/MWh)
Temporary on-site storage (\$/MWh)	\$0.12
Permanent disposal (\$/MWh)	\$1.47
Total (\$/MWh)	\$1.59

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 located inland and 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,

¹⁵ "The Economic Future of Nuclear Power." The University of Chicago, 2004.

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 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
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 a peaking 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.

Generating Unit Size

The CCGT plants consist of 2x1 units with rated capacity ranging from 945 MW to 1630 MW. The OCGT outputs range from 300 MW to 545 MW. The ICE units are 9 MW and 18 MW. 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.

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

CO₂ Capture and Storage

The CCGT and OCGT plant were evaluated without CO₂ capture in this study.

Dry Cooling

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

Renewable Technologies

Offshore Wind Turbines

Location

South Africa's entire 2,500 km coastline has wind speeds over 7 m/s¹⁶. For this project, two offshore wind projects are evaluated. Fixed-bottom foundation design for water depth <50m and floating foundation design analyzed for water depth of 100m. Wind data at 100-m hub height was used for this study¹⁷.

The cost of fixed foundation structures is notably influenced by water depth, primarily affecting material quantities. Additionally, water depth plays a crucial role in floating foundation costs, leading to increased lengths of mooring lines and cables, as well as prolonged installation durations. In this evaluation, depth considerations for both fixed and floating foundation scenarios were determined based on bathymetry data sourced from the Global Wind Atlas¹⁸.

The proximity of the offshore project location to the onshore interconnection points impacts costs, with higher expenses for export cable materials and longer installation durations. In this

¹⁶ ESMAP. 2019. Going Global: Expanding Offshore Wind to Emerging Markets. Washington, DC: World Bank.

¹⁷ The wind resource data is from the Global Wind Atlas (version 3.0) (<https://globalwindatlas.info/>)

¹⁸ Global Wind Atlas bathymetry layer is based on data provided by the General Bathymetric Chart of the Oceans

study, a distance of 5km and 30km to shore is considered for fixed and floating offshore wind, respectively.

Generating Unit Size

A project capacity of 800 MW was selected for both technology cases. This is consistent with trends seen in the European offshore market and recent project announcements in the U.S. and East Asia. The turbine capacity was selected as 10 MW.

Foundation	Project Capacity (MW)	Turbine Nameplate (MW)	Distance to Shore (km)	Water Depth (m)
Fixed	800	10	5	30
Floating	800	10	30	100

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 estimated annual wind speed in meters per second at a height of 100 m above ground level is shown in Figure 3-2. The map is obtained from Global Wind Atlas, a free, web-based application developed, owned, and operated by the Technical University of Denmark (DTU) in partnership with the World Bank Group, utilizing data provided by Vortex, with funding provided by ESMAP. South Africa's coastline has wind speeds over 7 m/s suitable for offshore wind installation; however, the waters are deep (>50 m) and the currents on the southern and eastern coasts are some of the strongest in the world posing challenge for offshore wind turbines¹⁹. For this report, it is assumed the hub height was 100 m.

¹⁹ ESMAP. 2019. Going Global: Expanding Offshore Wind to Emerging Markets. Washington, DC: World Bank.

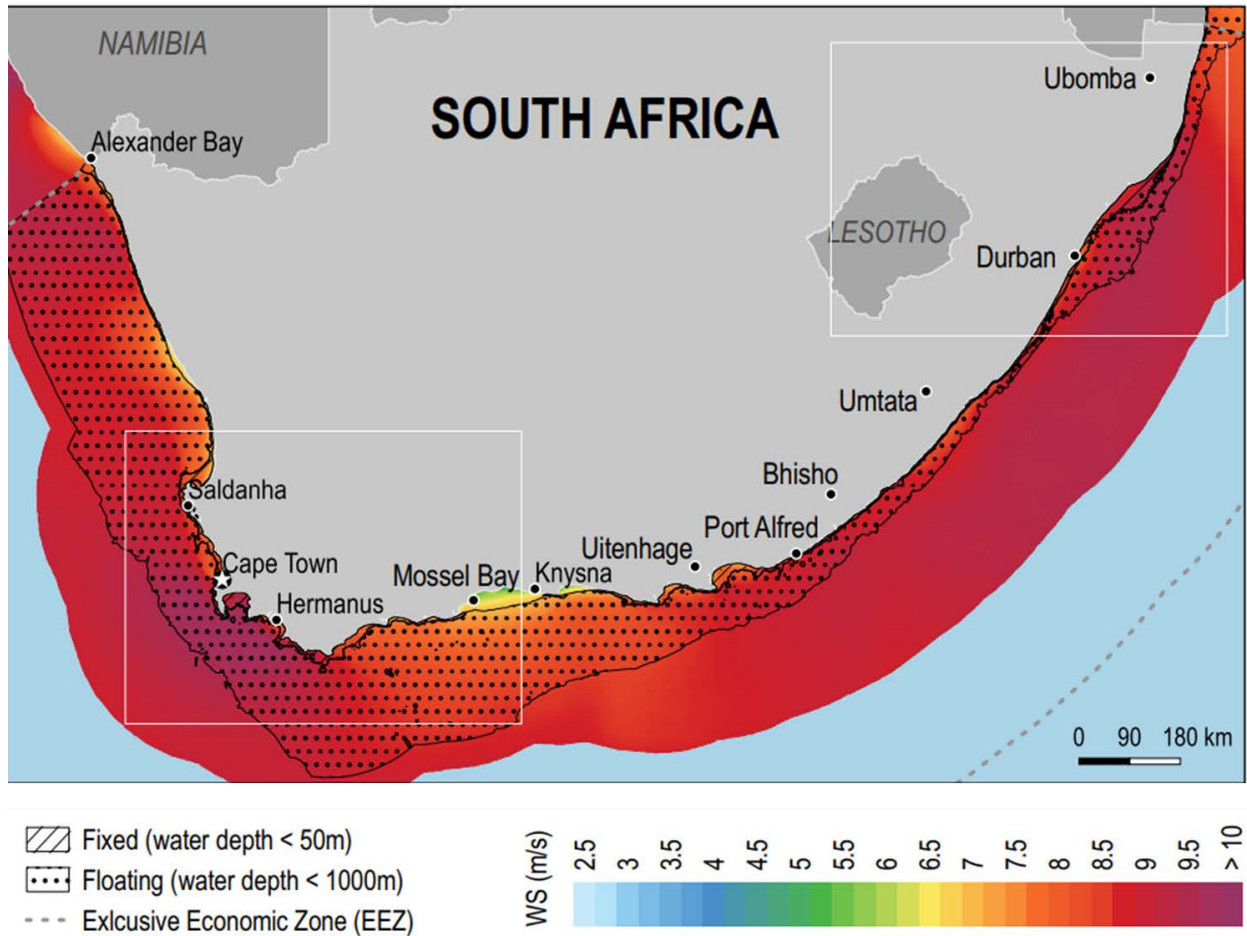


Figure 3-2
South African offshore wind resource (measured at 100 m)

Source: Global Wind Atlas (version 3.0) Available at: <https://globalwindatlas.info>

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/m²

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 no storage and 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 3-3 shows worldwide solar DNI data. The DLR-International Spaceborne Imaging Spectroscopy images were obtained from the Institute of Atmospheric Physics, German Aerospace Center (DLR).²⁰ The long-term variability of direct irradiance was derived from International Satellite Cloud Climatology data and compared with reanalysis data.²¹ South Africa clearly has one of the best solar resources in the world.

²⁰ Institute of Atmospheric Physics, German Aerospace Center (DLR). Lohmann, S., C. Schillings, B. Mayer, and R. Meyer (2006a).

²¹ “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.

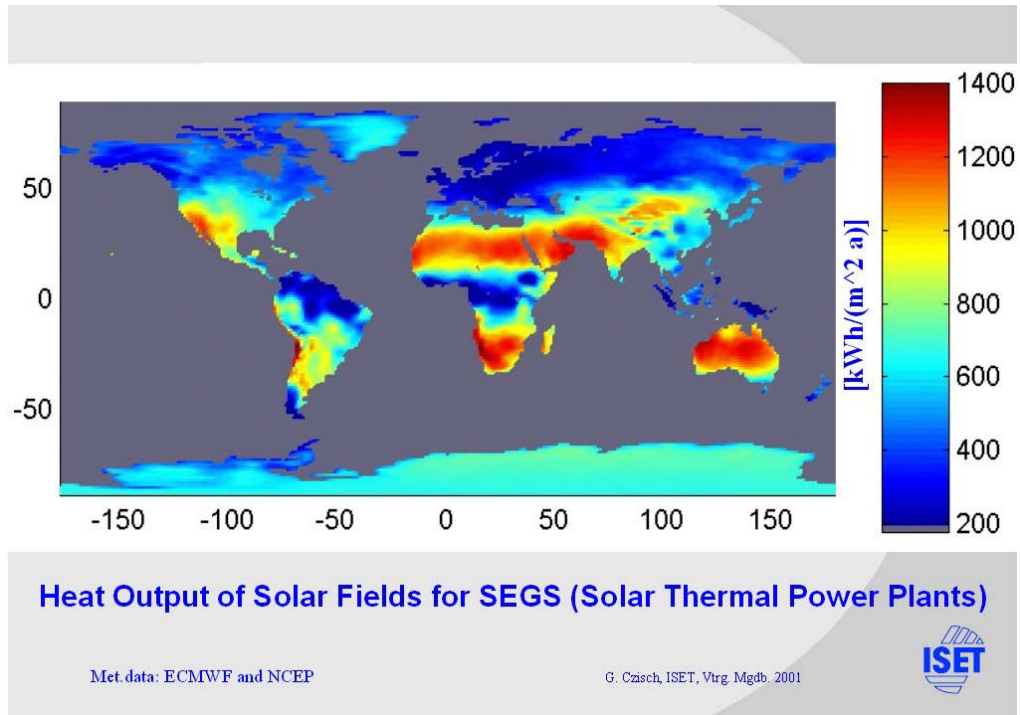


Figure 3-3
Worldwide DNI data

Figure 3-4 shows the annual direct normal solar energy in Africa in kWh/m²/day.

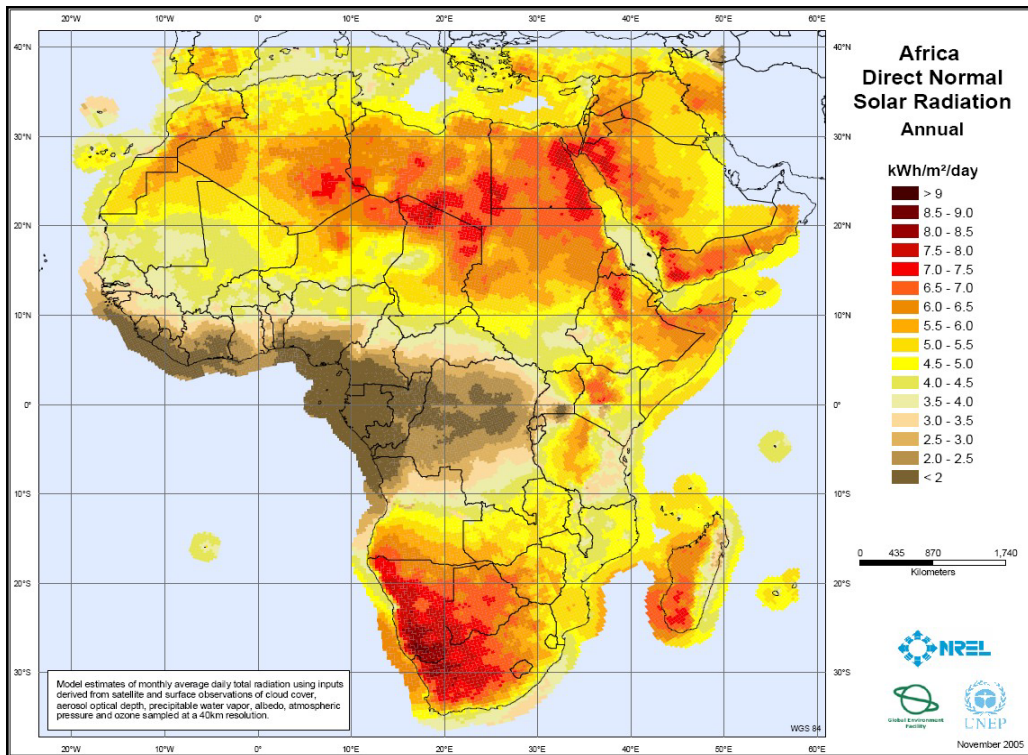


Figure 3-4
African annual direct normal radiation

Solar Photovoltaic plus lithium ion battery storage

This study evaluates single-axis tracking c-Si PV systems with bifacial modules and 1500V central inverter. The storage technology considered is a lithium ion battery energy storage system (BESS). The coupling configuration examined is a monodirectional DC-coupled system, where power flows exclusively from the system to the grid, and the BESS can only be charged by the PV, not the grid.

The study considered single axis tracking as it results in relatively higher energy yield and subsequently lower LCOE as compared to fixed tilt systems. However, trackers require more capital cost, operation and maintenance cost, and land to avoid shading between panels. Areas with higher solar insolation typically benefit more from single axis tracking solar PV systems. However, the choice between single-axis tracking and fixed-tilt solar PV systems should be made based on a detailed analysis of the specific project conditions, including location, budget, land availability, and long-term financial projections.

Location

The location for solar PV plus storage considered is near Welkom in the Free State province of South Africa for the study purposes.

Selecting a suitable site for a utility-scale solar PV plus storage installation requires assessing various factors, including solar resource potential, land availability and suitability, proximity to transmission lines, grid capacity, environmental impact, and socio-economic factors. The subsequent section includes a map showing the solar resource potential in South Africa. This study does not include an assessment for selecting the optimal location for the solar PV plus storage system.

Ambient Conditions

The annual average ambient air conditions for location used in this study are listed below:

Average dry bulb temperature	18.3°C
Relative humidity	48.6%
Equivalent altitude	1370 m
Average global horizontal irradiation	6.24 kWh/m ² /day

System Size

Solar PV plus storage system evaluated in this study is 250MWAC solar PV with 100MW/400MWh lithium ion BESS. The DC:AC ratio for solar PV system considered is 1.3 with ground coverage ratio of 35%.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. This includes the solar PV modules, mounting structures, inverters, battery system rack, power conversion system, control system, balance of plant, general facilities, and an interconnection

substation. The capital costs throughout this study do not include government tariffs that may be charged for imported labor, equipment, or materials from outside of South Africa. The costs do include shipping charges for this equipment. Contingencies have been included for BESS system cost. The amount of contingency considered are appropriate for the state of experience for BESS technology.

Resource Potential

Solar PV systems can utilize diffuse radiation as well as direct normal radiation (DNI). Global horizontal irradiation (GHI), which is sum of diffused and direct normal irradiation, is important for understanding the total available solar resource. However, tracking solar PV system are significantly impacted by DNI as it adjusts the orientation of the solar panels to follow the sun's path across the sky.

Figure 3-5 and Figure 3-6 show the global horizontal irradiation and direct normal irradiation for South Africa region.

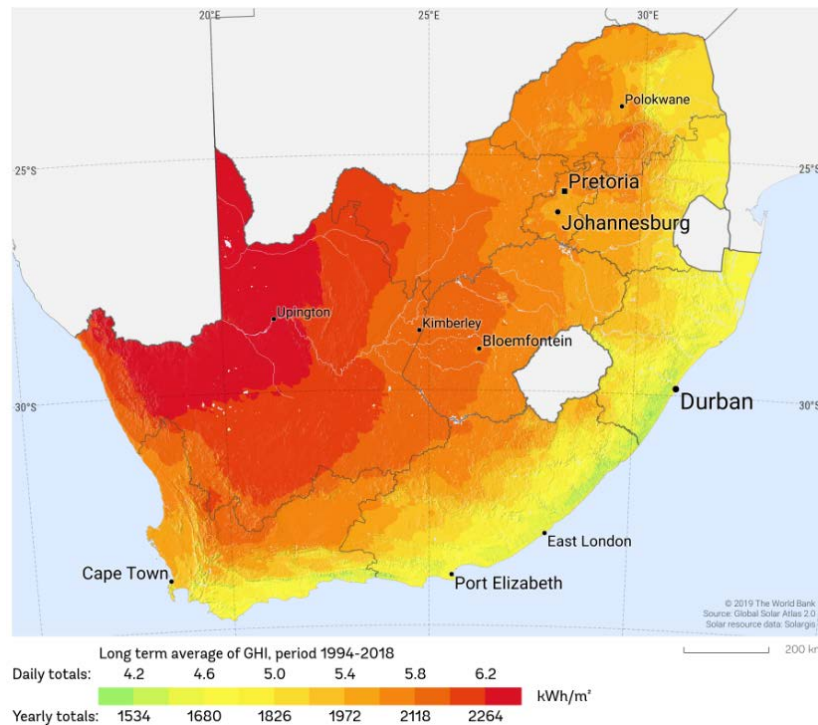


Figure 3-5
Global Horizontal Irradiation - South Africa²²

²² Energy Sector Management Assistance Program (ESMAP) Washington, D.C.: World Bank Group

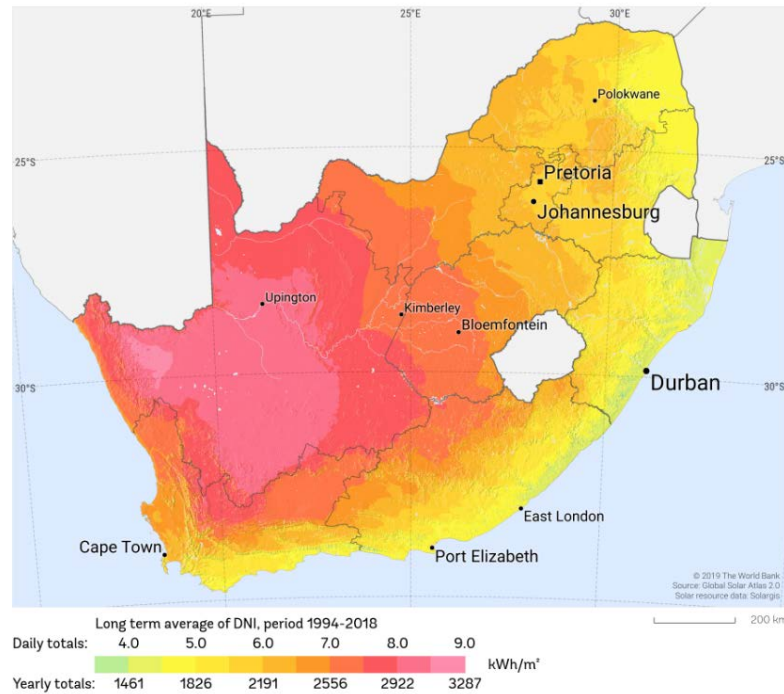


Figure 3-6
Direct Normal Irradiation South Africa

Storage Technologies

Lithium ion battery, underground hydrogen storage, and pumped storage hydropower (PSH) are evaluated in this section of the report.

Location

The battery storage plants that were evaluated in this study are generic greenfield plants. It is assumed that if can be located in any city.

The PSH technology includes pumping water from a lower reservoir to a higher reservoir where it is stored until needed. When released, water from the upper reservoir flows back down through a turbine and generates electricity. There are various configurations of PSH technology, including open loop (one or more of the reservoirs are connected to a natural body of water) and closed loop (reservoirs are separate from natural waterways). The PSH is assumed to be located at a site with suitable topology for PSH.

Siting an underground hydrogen storage facility is highly dependent on the underlying geology. This report includes assumptions for four types of storage facilities: salt caverns, depleted oil & gas reservoirs, hard rock caverns, aquifers. Careful assessment of the geological conditions, such as the permeability, porosity, stability, and integrity of the storage formations must be taken before siting an underground hydrogen storage facility. The facility must also be connected via pipeline to an electrolysis facility, or if the electrolysis facility is located nearby, there must be a source of water and power. The hydrogen storage cases studied are assumed to be located at a site where these conditions are met.

Generating Unit Size

The lithium ion battery system evaluated in this study is 100 MW with 4 hours storage. The PSH plant evaluated is 1000 MW with 10 hours of storage capacity. The underground hydrogen storage evaluated in this study has storage capacity of 1,910 tonnes of hydrogen.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For Lithium ion battery plants, this area includes the battery system rack, power conversion system, and controls system. For the PSH plant, this area includes the two water reservoirs, a waterway to connect them, powerhouse with pumps/turbines, and the electro-mechanical system. For underground hydrogen storage, this includes the electrolysis facility, the underground storage infrastructure, the compressors and associated equipment, and the hydrogen fired aeroderivative turbines. 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 2023 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 2023 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 2023 Richardson International Construction Factor Manual. For this update, these costs, reported in January 2023 USD, were then converted to ZAR based on an exchange rate between USD and the South African rand of 18.35.

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. Similar factors were developed for other U.S. locations for specific power generation technology e.g., Atlantic U.S. (fixed bottom offshore wind) and Pacific U.S. (floating offshore wind). From the table below, the material costs for South African projects are approximately 11% higher for locally produced materials and ~30% higher for imported materials when compared to the U.S. Gulf Coast base case. The increase in imported material cost is due to higher freight and duty cost. These increased material costs are partially offset by labor costs resulting in an average location factor of approximately 11%. 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

<i>Data from Cost Data Online, Inc</i> <i>2023 Richardson International Construction Factor Manual</i> Location Factors	Base: Houston, Texas, USA	Johannesburg, South Africa
Labor index	1.00	0.80
Imported material index	1.05	1.35
Local material index	1.00	1.11
Labor location factor	0.21	0.17
Engineered equipment location factor	0.60	0.72
Field material location factor	0.19	0.22
Location factor (not incl. currency)	1.00	1.11

EPRI estimated the breakdown of material/equipment and labor portion of TPC based on in-house studies and typical breakdown for each technology. Table 4-2 shows the breakdown about the percentage of TPC that is related to material versus labor. Some of the material consists of

engineered equipment, with significant portion imported, while the remaining material is field material, primarily sourced locally.

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

Technology	Materials	Labor
PC	80%	20%
Nuclear	80%	20%
CCGT	80%	20%
OCGT and ICE	80%	20%
Offshore wind	93%	7%
Solar thermal	65%	35%
Lithium ion storage	85%	15%
Underground hydrogen storage	80%	20%
Pumped storage hydropower	70%	30%

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.
- The imported portion of the cost were adjusted according to factors as shown in Table 4-1 for corresponding U.S. location.
- The local portion of the costs was broken down into materials and labor and adjusted according to the factors as shown in Table 4-2 for corresponding U.S. location.
- The imported and local costs were then combined in USD and converted to ZAR based on the currency exchange rate of 18.35 ZAR/USD.

Figure 4-1 shows this cost estimating approach graphically.

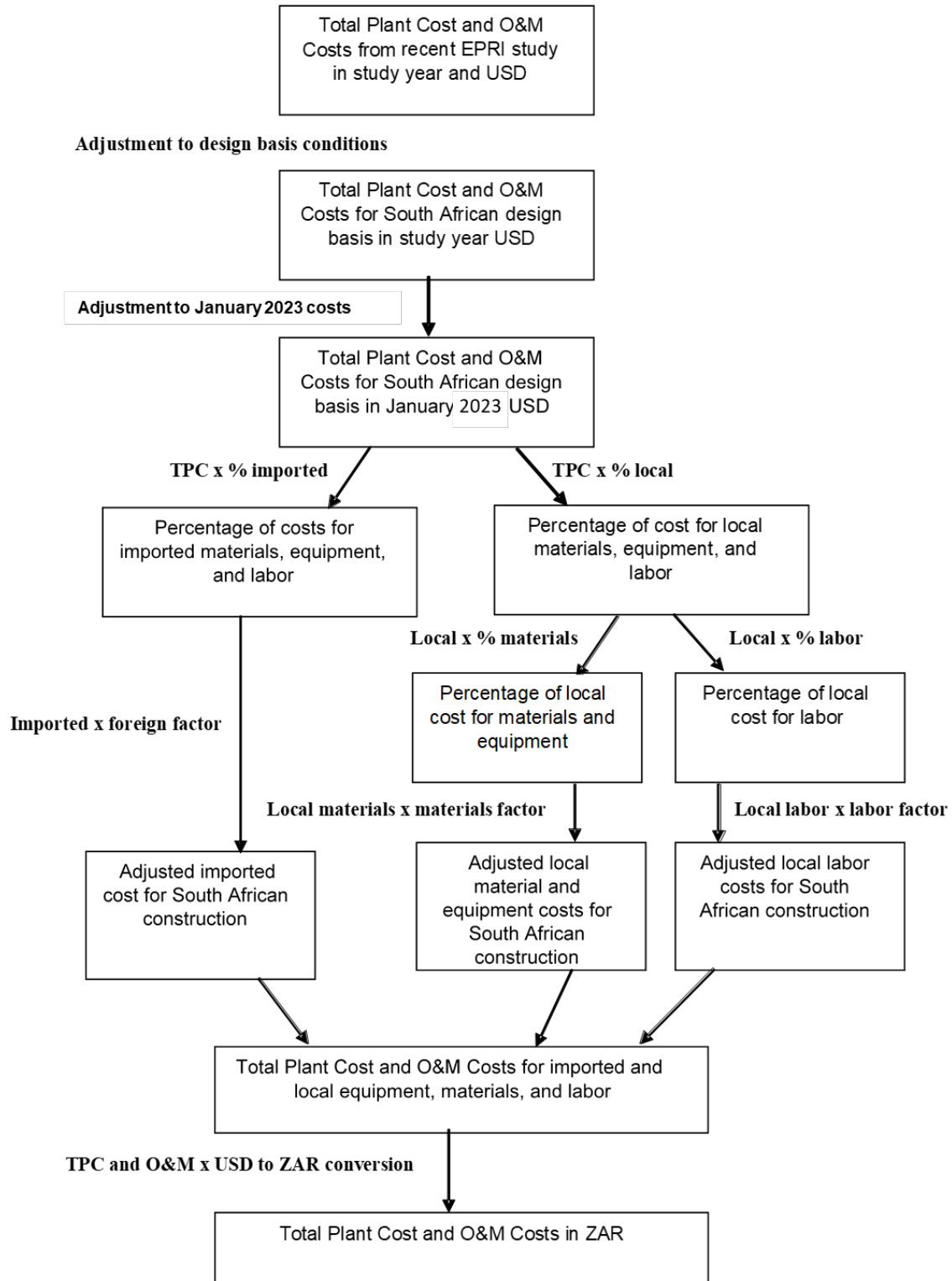


Figure 4-1
Cost-estimating approach

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. O&M costs were split into material and labor costs and adjustment factors were applied as shown in Table 4-1 for corresponding U.S. location.

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, nuclear plants were built with one and two 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 Table 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.

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)
- Supply chain constraints

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

Type of Security	% of Total	Current Dollars		Constant Dollars	
		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 non-fuel O&M costs (see Figure 5-1).

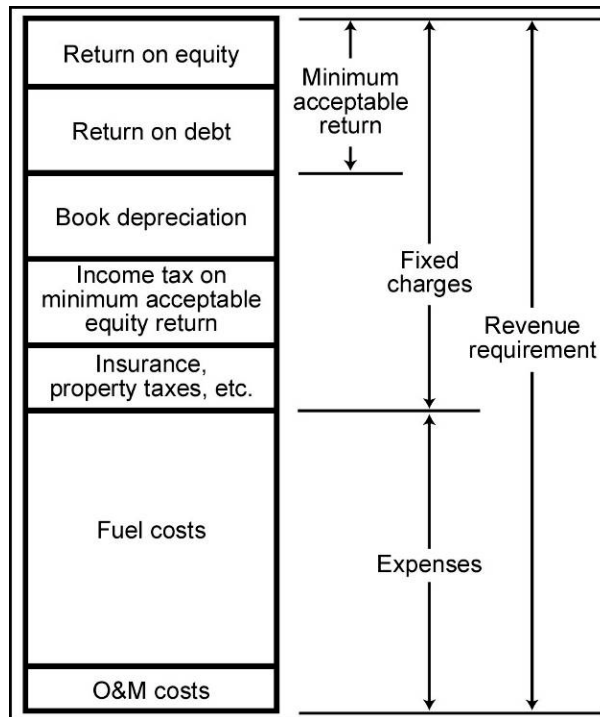


Figure 5-1
Revenue categories for the revenue requirement method of economic comparison

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 offshore in this study is 30 years. 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 offshore wind plant.

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 (SLTL) depreciation and modified accelerated cost recovery system (MACRS) tax life depreciation are commonly used tax depreciation methodology in electric utility industry. Table 5-2 provides examples of factors for the midquarter convention for MACRS depreciation methodology. These factors are provided as general reference. Any detailed tax calculations should, of course, involve the appropriate tax expert. Table 5-3 gives the details of tax depreciation methodology employed for each technology.

**Table 5-2
MACRS Depreciation Schedule**

Depreciation Period	Depreciation Schedule		
	5	15	20
1	35.00%	8.75%	6.56%
2	26.00%	9.13%	7.00%
3	15.60%	8.21%	6.48%
4	11.01%	7.39%	6.00%
5	11.01%	6.65%	5.55%
6	1.38%	5.99%	5.13%
7		5.90%	4.75%
8		5.91%	4.46%
9		5.90%	4.46%
10		5.91%	4.46%
11		5.90%	4.46%
12		5.91%	4.46%
13		5.90%	4.46%
14		5.91%	4.46%
15		5.90%	4.46%
16		0.74%	4.46%
17			4.46%
18			4.46%

Depreciation Period	Depreciation Schedule		
	5	15	20
19			4.46%
20			4.46%
21			0.57%

Table 5-3
Tax depreciation methodology

Technology	Depreciation Method	Tax life
PC	SLTL	30
Coal to NG	MACRS	20
Coal to SMR	SLTL	30
Nuclear	SLTL	30
CCGT	MACRS	20
OCGT and ICE	MACRS	15
Offshore wind	MACRS	5
Solar thermal	SLTL	30
Lithium ion storage	MACRS	15
Underground hydrogen storage	SLTL	30
Pumped storage hydropower	MACRS	20

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 5-4.

Table 5-4
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. For the purposes of this study, they are assumed to represent 2% per year of the booked cost of the plant.

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. 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. 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.

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

$$P/F = 1/(1 + i)^n \quad \text{Eq. 5-1}$$

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, $n = 20$.

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.

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.

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, produced about 37% of the world's electric supply in 2020 [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.

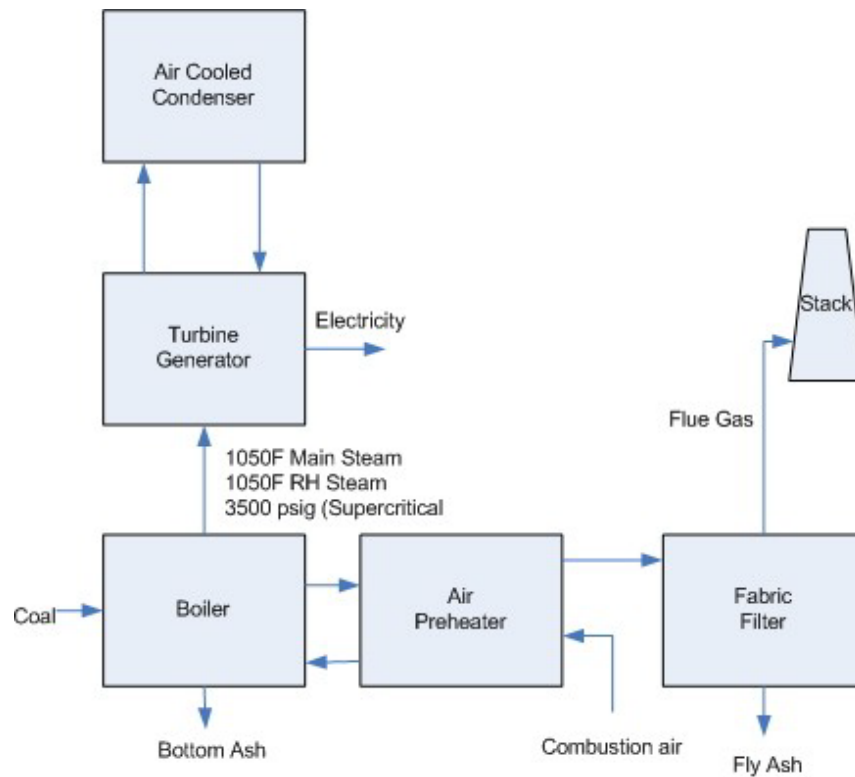


Figure 6-1
Simple schematic of PC (supercritical) generating unit

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 SO₂, NO_x, particulate (including condensables), mercury, and several other hazardous air pollutants such as lead and arsenic. In this study, PC plants are considered with FGD units for environmental controls on top of pulse jet fabric filters (FFs) for particulate control. 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 SO₂ 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 with CO₂ capture, a small portion of the NO_x present in the flue gas (NO₂, 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 CO₂ 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 SO₂, 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 CO₂, and the cleaned flue gas is emitted from the plant stack. The amine solution, which is now rich in CO₂, is pumped into a stripper in order to separate the amine and the gas, where steam provides the energy needed to desorb the CO₂ from the solution. The CO₂ is then removed from the absorber to be dried and compressed for transportation and storage.

Recirculating Wet Cooling System

In recirculating wet cooling systems, the steam is condensed in water-cooled shell-and-tube surface condensers. The heated cooling water is conveyed to a cooling component, typically a wet cooling tower (other options include cooling ponds, spray enhanced ponds or spray canals) and then recirculated to the condenser. A typical system with a cooling tower is shown schematically in Figure 6-2.

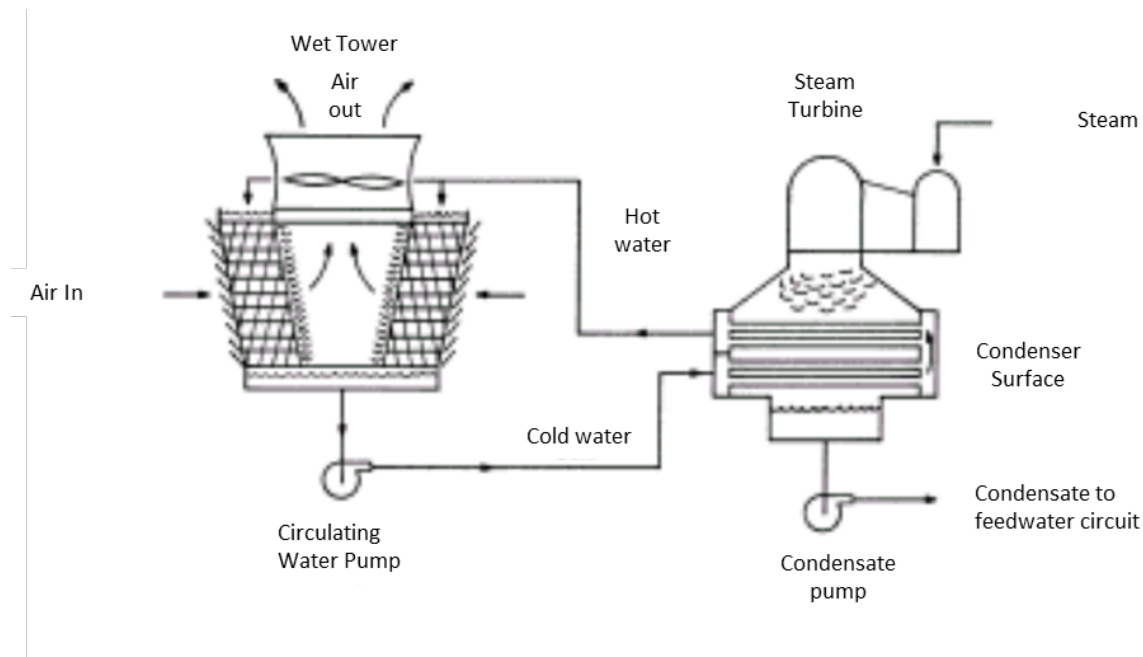


Figure 6-2
Conceptual diagram of a wet cooling system

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).²³ 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.²⁴ 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

²³ "Minatom Export Control Behavior: Economic Factors and Motivations." Maloney, Michael T. and Oana Diaconu. Clemson University, John E. Walker Department of Economics. June 2003.

²⁴ A Comparison of Advanced Nuclear Technologies, Columbia | SIPA Center on Global Energy Policy, 2017.

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 *Light Water Small Modular Reactor Technology: 2021 Cost and Performance Update* (EPRI report number 3002021039) [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 73-MWe (gross) reactor modules. Each reactor module 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.

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 UO₂ 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 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.

Hualong One

China has an aggressive nuclear deployment schedule, with 55 nuclear reactors in operation and 26 under construction [12]. Figure 6-3 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.

Nuclear Power Plants in China



Figure 6-3
Nuclear power plants in China

Copyright: World Nuclear Association, 2020 [12]

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 (CNNC) 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. After Fuqing 5&6 CNNC is building the next at Zhangzhou in Fujian province, previously an AP1000 project. This reactor design will be dedicated to the domestic market and some international markets such as Pakistan, Argentina, and possibly Eastern Europe [12].

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 2.2GW project in Pakistan is \$10B, or approximately \$4500/kW, and started commercial operation in April 2022 [16].

Areva EPR

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.

Saeul 1 and 2 (formerly Shin Kori 3 and Shin Kori 4) entered commercial operation in December 2016 and August 2019, respectively. Shin Hanul unit 1 started commercial operations in December 2022. Recently, Shin Hanul 2 became south Korea's fourth operational APR1400 - after Saeul units 1 and 2 and Shin Hanul unit 1 [18]. Two further APR1400s are under construction as Saeul units 3 and 4, with two more units planned as Shin Hanul units 3 and 4. [18]. Outside of South Korea, four APR1400 units have been built at the Barakah nuclear power plant in the UAE, three of which are now in operation, with the fourth currently in its commissioning phase [18]. 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 m² 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. 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				Dry cooling
Number of units	-	1	2	1	2	12
Unit size (net MW)	-	1117	1117	1600	1,600	73
Plant size (MW)	-	1117	2234	1600	3,200	876
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)	3000 MWt (924 MWe)
Net capacity	-	1,117 MWe	2,234 MWe	1,600 MWe	3,200 MWe	876 MWe

Category	Parameter	AP 1000		Areva EPR		SMR
Performance estimates	<u>Economic life, years</u>	60	60	60	60	60
	<u>Efficiency and/or heat rate</u>	-	-	-	-	-
	Efficiency	32%	32%	36%	36%	31%
	100% load (kJ/kWh)	11,250	11,250	10,000	10,000	11,500
	<u>Plant load factor (% of full load)</u>		-	-	-	-
	Typical	85	85	85	85	95
	Maximum	100	100	100	100	100
	Minimum	60	60	60	60	30%
	<u>Ramp rate %/h</u>	-	-	-	-	-
	Up	3–15%	3–15%	3–15%	3–15%	40%
	Down	3–15%	3–15%	3–15%	3–15%	40%
	<u>Startup time (h)</u>	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%
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 6-3.

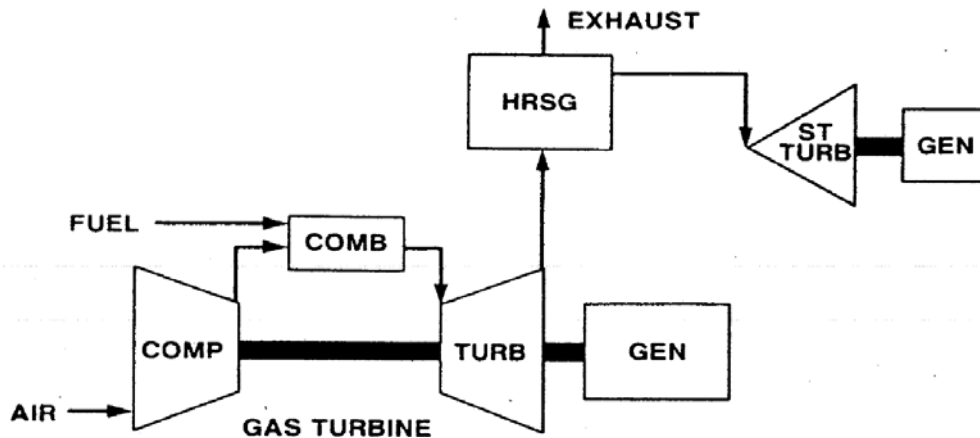


Figure 6-3
Simple schematic of CCGT

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 and 1093°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 down flowed 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.

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 9F.05, and the GE 9HA.02 GT operated in peaking service with an annual capacity factor of 10%. The 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 GW 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	Turbin e 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, Gqeberha	170	2	340	9/1/2015	Ansaldo Energia	E Class	AE94.2	Oil/diesel
AES Khanya- PE	Gqeberha 2	166	1	166	11/1/200 9	Ansaldo Energia	E Class	AE94.2	Oil/distillate
AES Khanya- PE	Gqeberha 1	166	1	166	10/1/200 9	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 Gqeberha	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

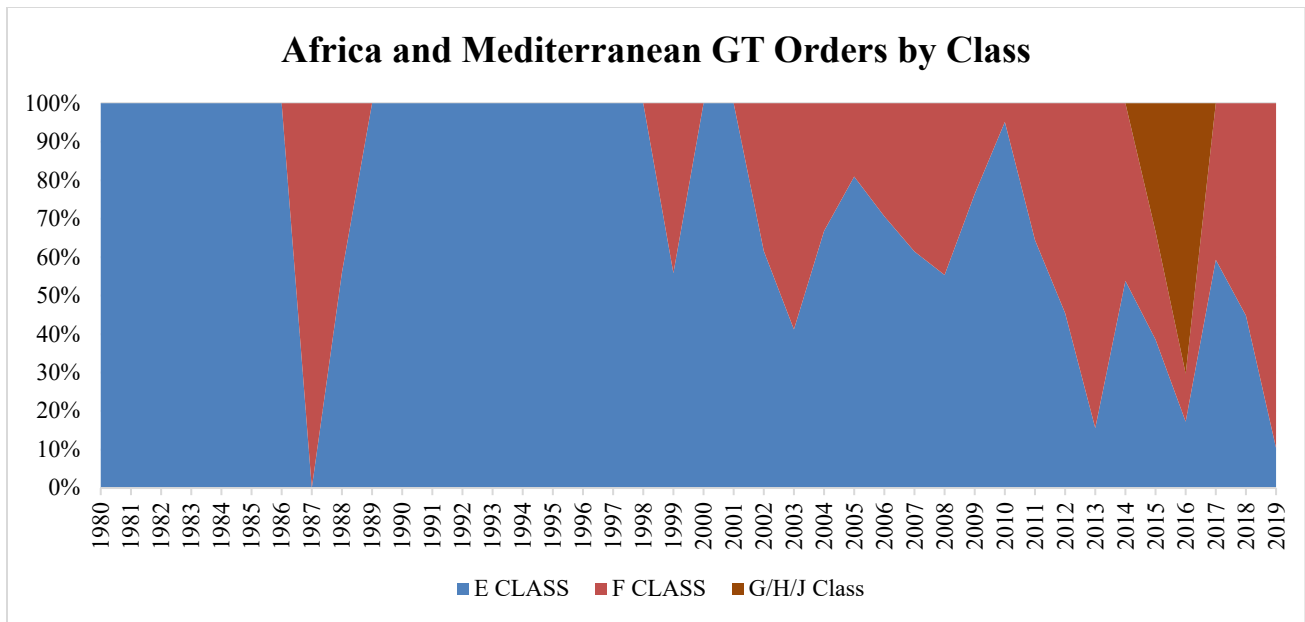


Figure 6-4
GT market share in Africa and Mediterranean region (data source: McCoy Reports)

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. In 2022, total installed wind capacity stood at 900GW with 93% of the installed wind capacity was onshore, while the remaining 7% was offshore. Onshore wind technology is well-established in 115 countries globally, whereas offshore wind is in the early stages of expansion, with a presence in 20 countries. The offshore sector is expected to grow as more countries plan to develop their first offshore wind farms. In 2022, 18% of the 74 GW total wind capacity growth came from offshore technology, indicating its increasing contribution to the overall wind energy landscape [21]. Offshore wind in the U.S. is still in its nascent stage with 42 MW of capacity installed, but state policy commitments are expected to increase this market by three orders of magnitude through 2040 to nearly 40,000 MW [22]. This study focused on cost and performance data for offshore wind.

Offshore Wind

Some countries have begun to install wind farms offshore. Initial projects incurred higher costs and experienced delays beyond the anticipated timelines. This was primarily attributed to developers' limited familiarity with the intricate logistical demands associated with planning and implementing projects in ocean environments. Over time, the offshore wind technology evolved into a specialized and distinct technology. 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. As of July 2023, the most powerful wind turbine in operation is the 16 MW Mingyang MySE 16-260. The equipment of this size is extremely difficult to install onshore. 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. Moreover, wind resource in offshore location is better than it is on onshore locations. Therefore, better resource and larger wind turbines are key drivers expected to bring the cost of offshore wind energy down and achieve parity with onshore wind.

Offshore wind foundations are categorized into fixed and floating types. Fixed foundations involve a base embedded in the sea floor, supporting the wind tower above the water line. In contrast, floating foundations have an anchor point in the sea floor connected to a floating foundation at the water line, with the wind tower secured on top. Various iterations of both types are currently in use or undergoing research. Each foundation type possesses distinct characteristics suitable for varied water depths and soil conditions. Analysis suggests that fixed foundations prove most economical in water depths up to approximately 45 meters, while deeper waters favor the economic feasibility of floating foundations [23]. The most common foundation type for fixed offshore wind 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, suction pile, tripod and jacket foundation. Figure 6-5 show typical fixed offshore wind foundation [24].

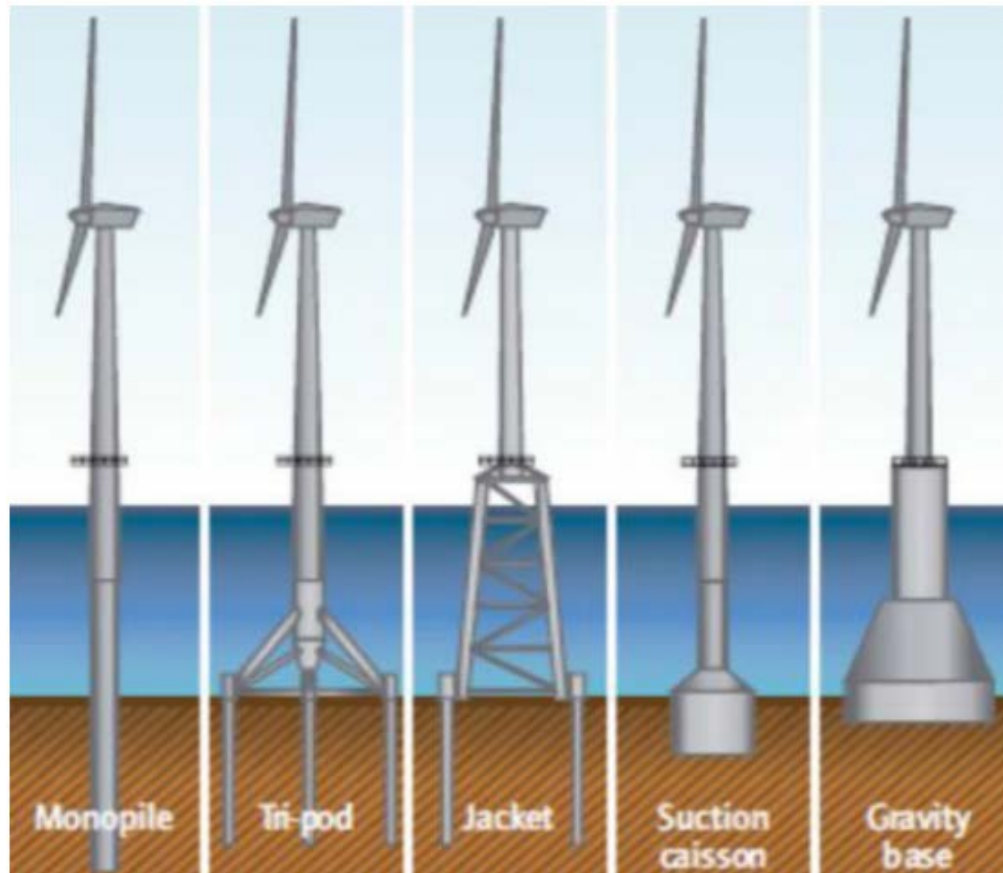


Figure 6-5
Typical Fixed Offshore Wind Foundations

As suitable shallow water locations become scarcer, attention has shifted toward the innovative frontier of floating bottom offshore wind. Unlike, fixed-bottom systems, floating platforms are not anchored to the seabed, facilitating deployment in locations featuring challenging seabed conditions or increased water depths between 50m to 1000m. This strategy extends the reach of offshore wind energy projects geographically and presents considerable opportunities for countries with extensive deep offshore regions. Offshore wind foundations (see Figure 6-6) are still in their early days in terms of commercialization, with numerous small demonstration or pilot projects built but limited commercial deployment. Despite being in the nascent stages of deployment, floating bottom offshore wind is garnering attention as a promising solution to unlock new offshore wind potential, contributing significantly to the global transition to sustainable energy.

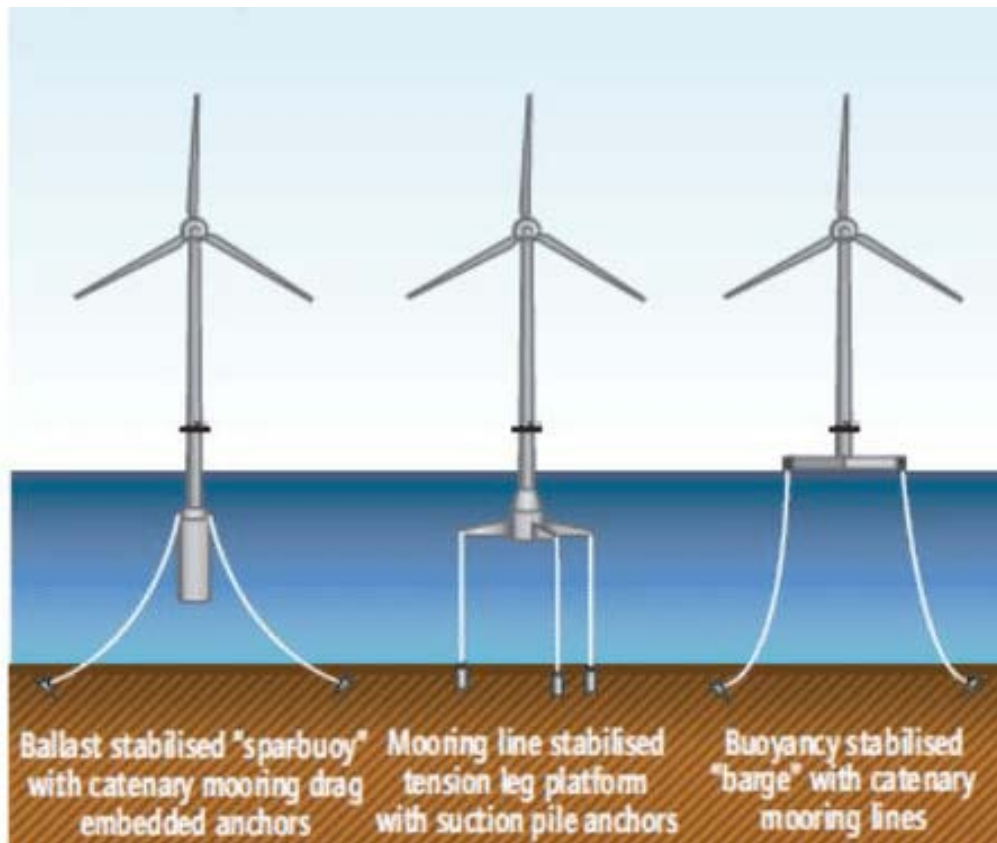


Figure 6-6
Floating offshore wind design examples

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.

Solar Thermal

Solar Thermal Power harnesses sunlight to generate electricity. This technology employs mirrors or lenses to focus sunlight onto a small area, intensifying solar radiation. The concentrated solar energy heats a working fluid, usually a liquid or gas, to generate steam for a turbine, ultimately producing alternating current (AC) electricity. This approach parallels the conventional method in thermal power plants, but instead of fossil fuels, it relies on solar energy for heat and electricity production.

Unlike solar photovoltaic (PV) technologies that use both direct normal irradiance (DNI) and diffuse horizontal irradiance (DHI), CSP systems exclusively rely on DNI. DNI represents the radiation per unit area received by a surface perpendicular to incident sun rays. Solar collectors in CSP systems harness DNI by tracking and staying perpendicular to the sun.

There are four primary CSP technologies:

1. **Parabolic Trough:** Employs parabolic mirrors to focus sunlight onto a linear receiver, heating the heat transfer fluid (HTF) that generates steam to drive a turbine for electricity. Units typically have a 10–200 MW capacity.
2. **Power Tower/Central Receiver:** Utilizes a field of mirrors (heliostats) reflecting sunlight onto a central receiver atop a tower, heating a transfer fluid to generate steam and electricity. Units typically have a 10–150 MW capacity.
3. **Linear Fresnel Reflector (LFR):** Uses flat mirrors to reflect sunlight onto a linear receiver with tubes containing HTF. The heated fluid produces steam for electricity. Units typically have a 10–200 MW capacity.
4. **Dish-Engine:** Employs a dish-shaped reflector concentrating sunlight onto a receiver with a Stirling engine, converting heat to mechanical energy for electricity. Units typically have a 0.01–0.04 MW capacity. Currently, there are no utility-scale projects, and commercial interest is limited.

Parabolic trough and Power Tower/Central Receiver CSP technologies were investigated in this study.

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 6-7 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. The 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.)

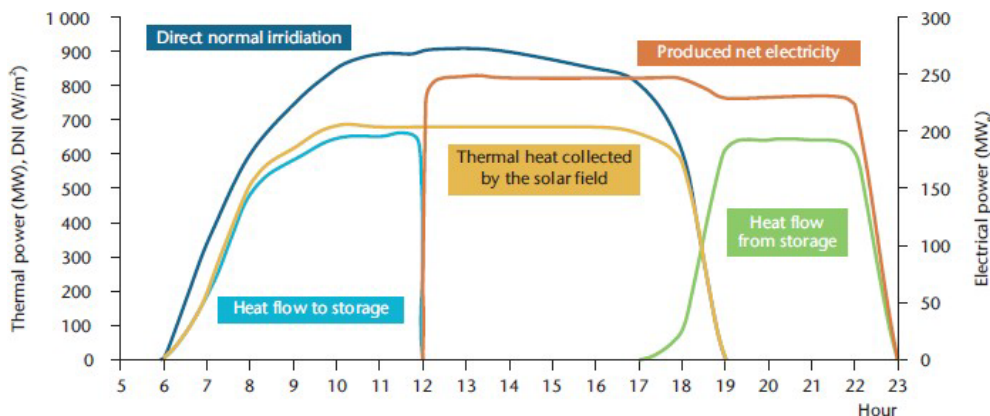
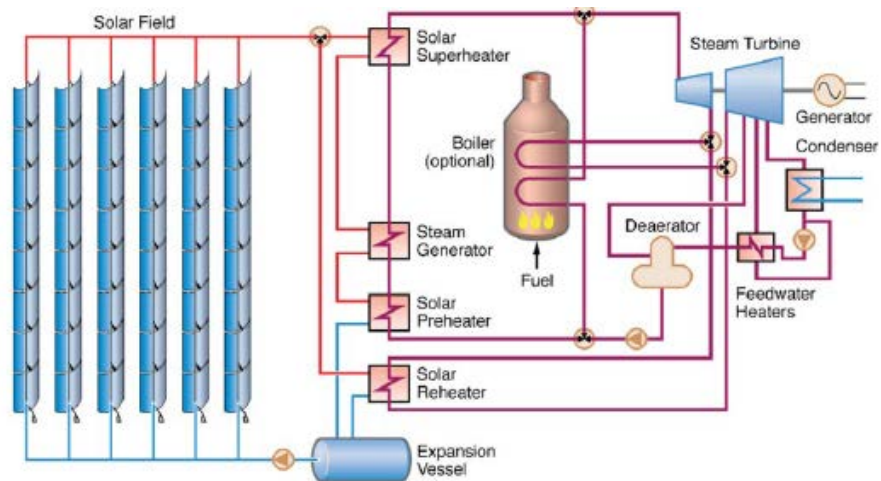


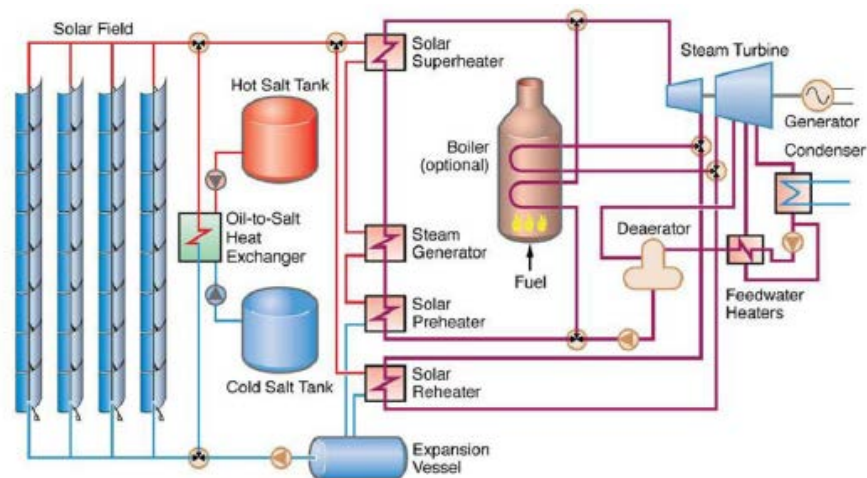
Figure 6-7
Use of storage for shifting production to cover evening peaks

Parabolic Trough

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.



(a)



(b)

Figure 6-8
Schematics of parabolic trough systems: (a) no storage; (b) with indirect molten salt thermal energy storage

Source: EPRI [25]

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.

Power Tower/Central Receiver

Central Receiver uses molten nitrate salt HTF which is pumped out of the cold tank at 287°C, 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.

Unlike the synthetic oil HTF parabolic trough system, central receiver 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 oval-shaped footprint is also a valuable feature. The footprint of tower systems is relatively larger than a trough-based plant.

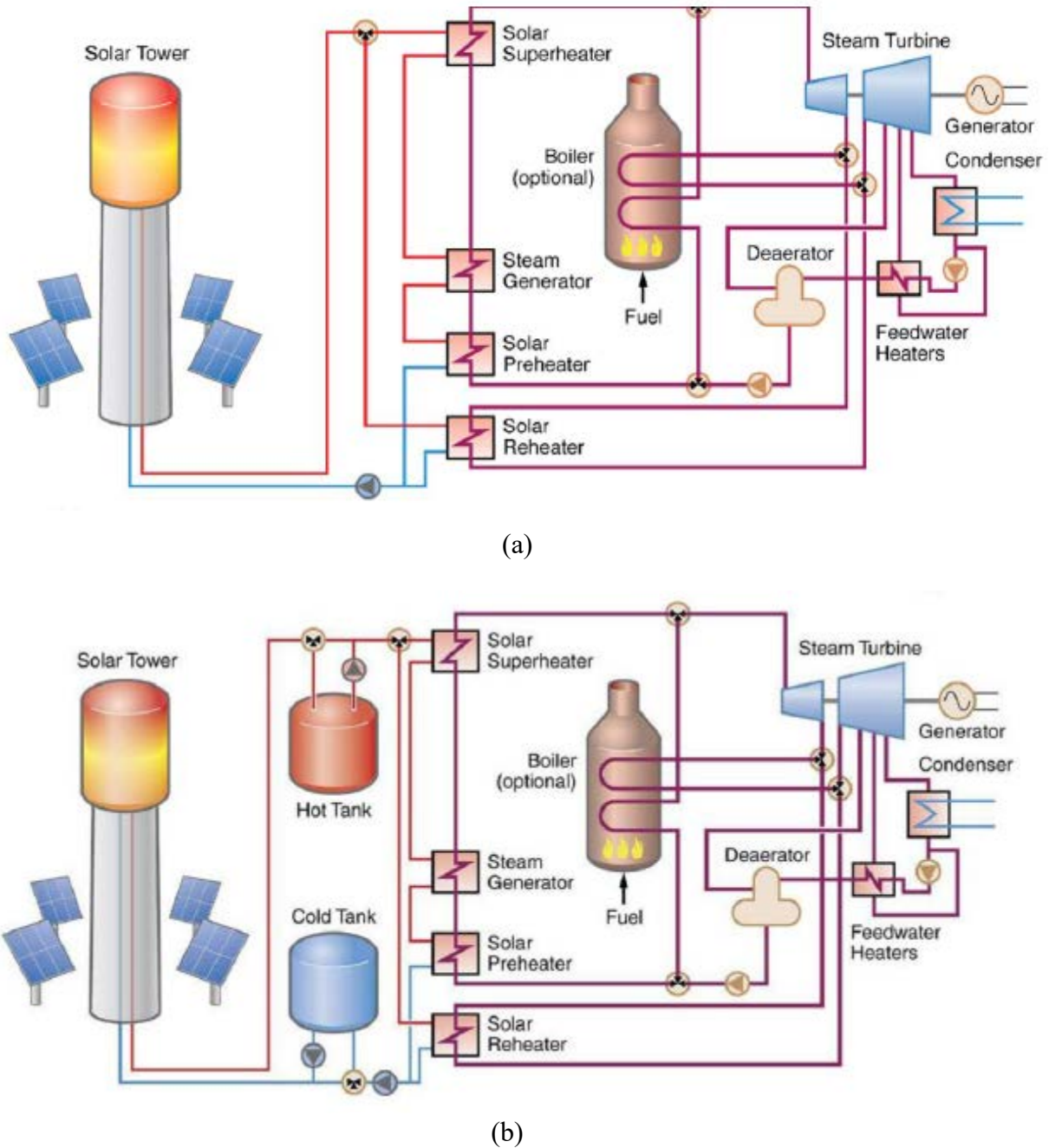


Figure 6-9
Schematics of power tower/central receiver system: (a) no storage; (b) with direct molten salt thermal energy storage

Source: EPRI [25]

Solar Photovoltaic plus Lithium Ion Batteries

Historically, solar PV coupled with BESS were primarily used in off-grid residential applications. However, in recent years, there has been significant growth in orders and installations for both utility-scale and customer-sited grid-tied solar plus storage systems. This

increase in solar PV and BESS hybrid plants is largely driven by the substantial reduction in capital costs for lithium ion BESS and solar PV.

System Coupling Configuration

There are two principal coupling configurations for solar plus storage systems that vary in the way the storage is charged from the PV or the grid.

1. **AC-coupled systems** involve electrical connection between the solar and storage at the AC output of each system's inverter or, collectively, at the step-up transformer. The battery can be charged by the solar energy or by the grid.
2. **DC-coupled systems** tie the PV and storage together on the DC side of the inverter. DC-coupled can be further categorized as monodirectional or as bidirectional based on the inverter type that is being used.
 - **Monodirectional DC-coupled system:** Power only flows out of the system to the grid and the BESS can only charge from the PV, not the grid. This type of configuration may be more common for retrofits adding BESS to existing PV plants.
 - **Bidirectional DC-coupled system:** Power can flow in both directions, thus allowing the BESS to be charged from the solar and the grid.

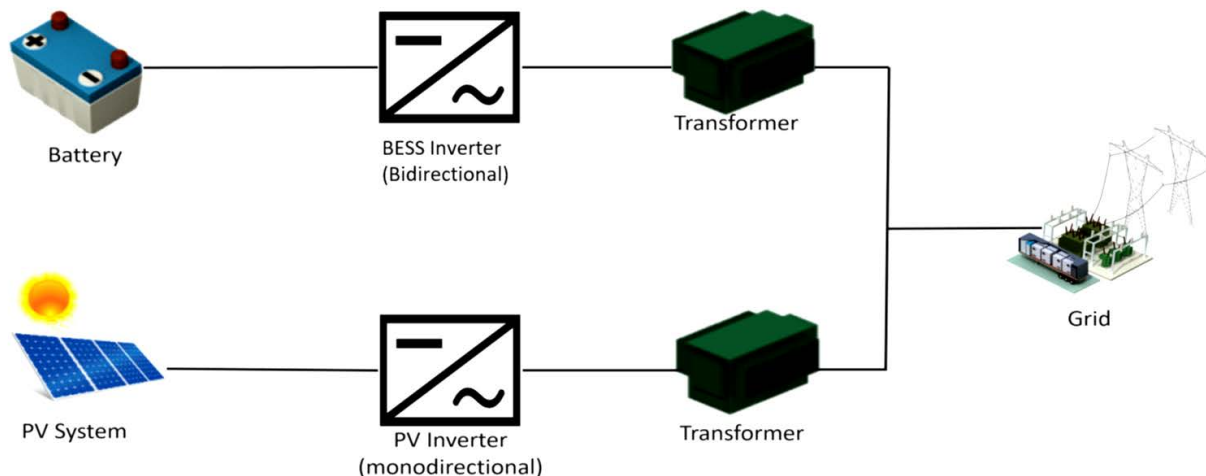


Figure 6-10
AC-Coupled solar PV plus storage system

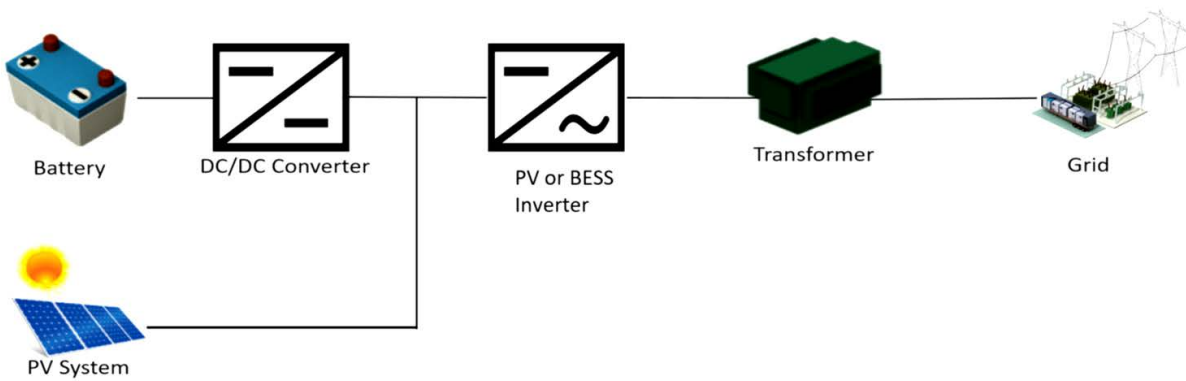


Figure 6-11
DC-Coupled solar PV plus storage system

System Coupling Configuration

There are several dimensions to sizing a solar PV plus storage system that can be optimized for a given objective and location. These include:

1. Solar PV DC:AC ratio
2. Solar PV-to-storage capacity ratio
3. Battery energy capacity

Solar PV DC:AC Ratio

The DC:AC ratio, the relationship between a solar PV system's peak DC power output and its AC power rating, is typically greater than one. Solar output fluctuates daily and seasonally, and factors like soiling and degradation further reduce output over time. To maximize the use of inverters and interconnection capacity during low irradiance periods and throughout the project's life, designers oversize the DC capacity of the solar plant. This oversizing can lead to periods when the system generates more power than its AC rating, resulting in a process called clipping, where the excess power is lost. Despite this, the decreasing cost of PV modules compared to inverters and power purchase agreements (PPAs) continues to justify the economic benefits of overbuilding systems.

The DC:AC ratio varies based on project location and whether the system is fixed tilt or tracking, though developers often design standalone utility-scale PV systems with a DC:AC ratio between 1.2 and 1.4. DC-coupled solar plus storage systems with a higher DC:AC ratio may be able to capture and store the otherwise clipped PV power in the BESS, a potential benefit that is likely to result in DC-coupled systems having a higher DC:AC ratios than AC-coupled systems. However, technical limitations, such as fault current ratings, limit how much DC power can be connected to an inverter. Figure 6-12 is an illustrative example of the output of a solar system with three different DC:AC ratios. Power above the system AC rating represents clipped power.

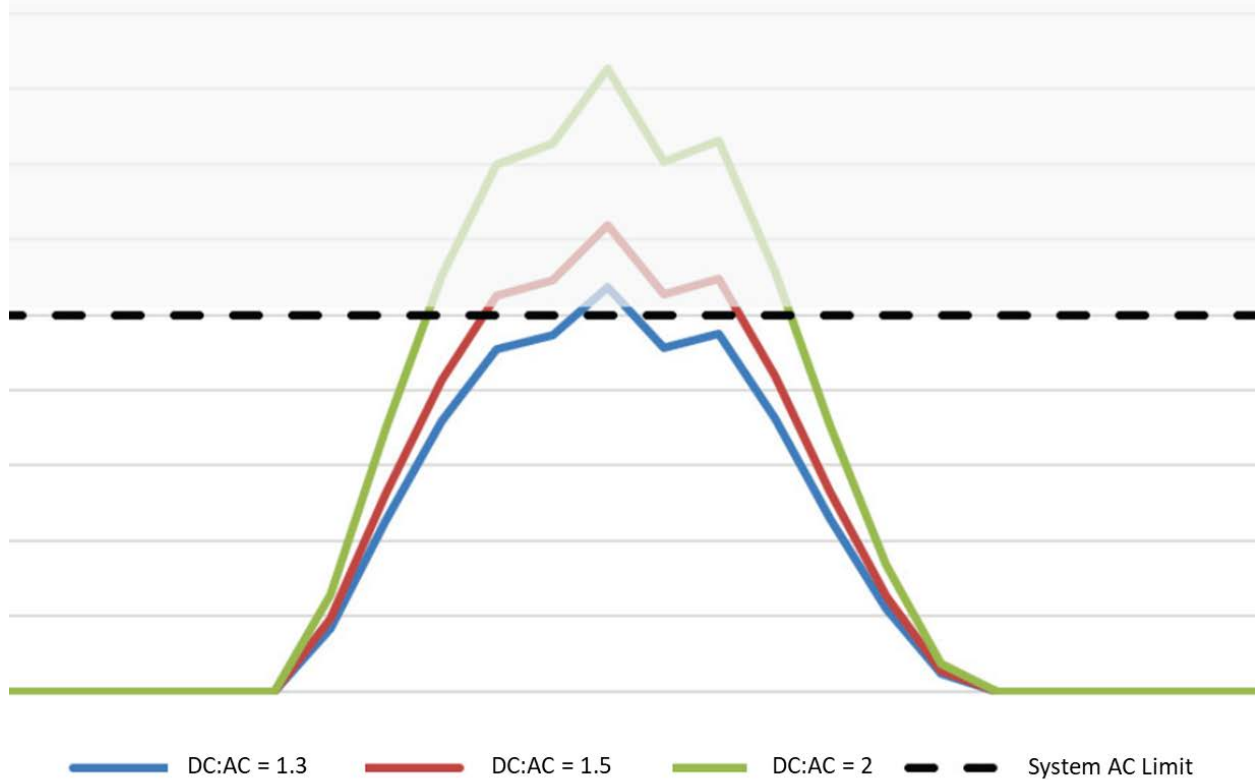


Figure 6-12
Solar PV output at different DC:AC ratio

Solar PV-to-Storage Capacity Ratio and Battery Energy Capacity

The solar PV-to-storage capacity ratio and the battery energy capacity will determine how much solar energy can be stored by the battery and dispatched later. The approach to sizing the capacity ratio and energy depends on the objective. For instance, systems with a 1:1 capacity ratio are suitable for energy shifting purposes as significant amount of solar energy can be shifted to periods where the energy is more valuable.

Applications with lower power and energy requirements, such as ramping support or smoothing, may have a higher PV-to-storage capacity ratio and lower battery energy capacity.

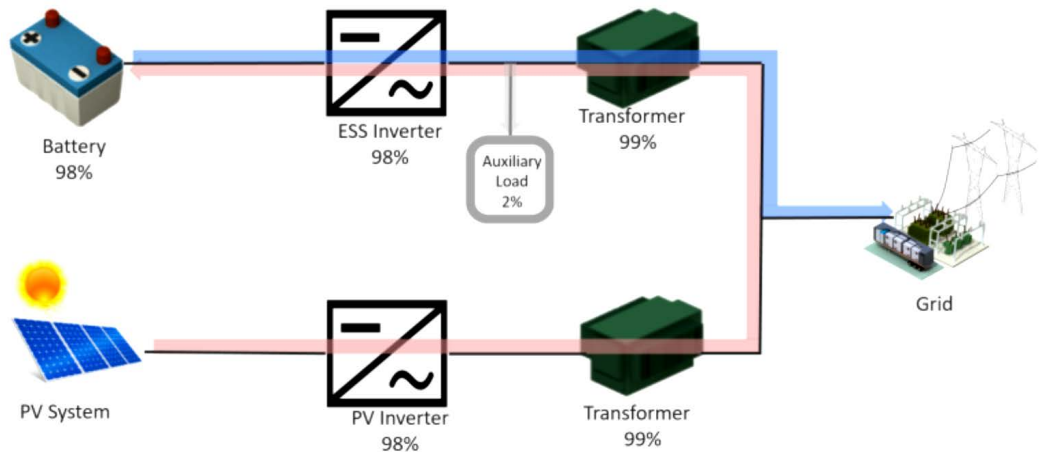
Efficiency

The roundtrip efficiency of a solar PV plus storage system is impacted by the combined system's configuration. Each conversion stage has associated energy losses that impact overall charging costs, or the amount of solar energy stored, and so a greater number of conversion stages typically results in overall lower system efficiency.

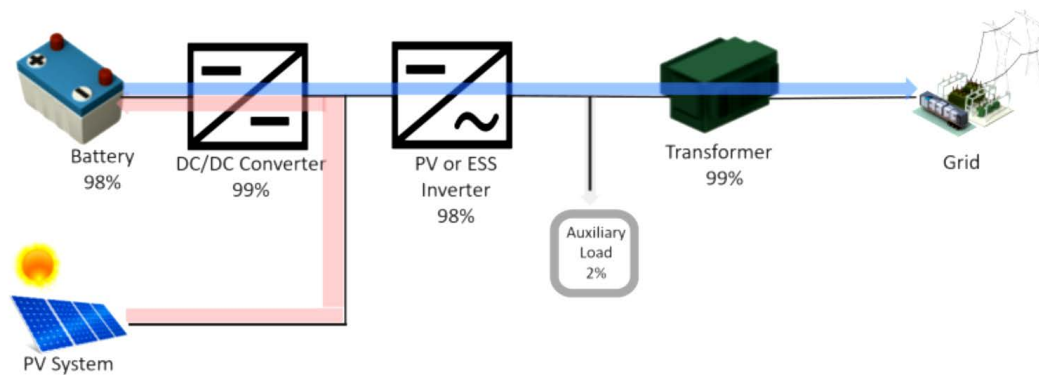
DC-coupled systems may have slightly higher efficiency when storing PV energy for later dispatch to the grid than AC-coupled systems. This is because DC-DC converters typically have a higher conversion efficiency than the combined losses of an AC-coupled system when PV output needs to be converted through a second transformer and inverter.

Converter topologies can vary within coupling configurations. A DC-coupled system with DC-DC converters on both the PV and ESS may have lower efficiency due to additional converter losses, or higher efficiency if it boosts the DC voltage, allowing the inverter to operate more optimally. An AC-coupled system connected on the high side of a transformer will have lower efficiency compared to one connected on the low side.

An example of efficiency losses and the resulting round-trip efficiency (RTE) is shown in the figure below. While RTE impacts the overall economics of the project, it typically has a lower impact compared to other cost and benefit factors.



RTE: Inverter*Transformer*Transformer*Inverter*Battery*Inverter*Transformer-Auxiliary Load
 RTE: $0.98*0.99*0.99*0.98*0.98*0.98*0.99-0.02=0.87$



RTE: DC/DC*Battery*DC/DC*Inverter*Transformer-Auxiliary Load
 RTE: $0.99*0.98*0.99*0.98*0.99-0.02=0.91$

Figure 6-13
Example efficiency of an AC-Coupled and DC-Coupled system

Applications of Solar PV plus Storage System

Solar PV plus storage system can have various potential applications that may dictate the best topology for the system. The applications could include:

Ancillary services	Frequency regulation, frequency response, and Volt-VAR regulation could be provided by the solar plus storage system.
Curtailement mitigation	During periods of oversupply, renewable resources may be curtailed, reducing their output. Storage systems can help avoid or limit curtailment required for congestion mitigation or other grid constraints, enabling more renewable energy production.
Energy time shift	Storage systems can shift solar energy production to align with peak demand. The BESS charges when energy prices are low or negative and discharges during peak pricing, providing benefits through wholesale energy market arbitrage, meeting capacity requirements, or other time-sensitive dispatches
Firm capacity	Storage can help firm the intermittency of PV and potentially capture a higher value for capacity contributions.
Low voltage harvest	Low voltage harvest happens when the PV strings' output voltage under load is too low to efficiently operate the inverter, typically in the morning and evening when the sun is near the horizon. A DC-DC converter can boost this low voltage to gradually charge the BESS. Since this condition occurs only for a few minutes at the start and end of each day and the string output is insufficient to run the PV inverter, its contributions are likely minimal compared to other benefits and costs.
Microgrid/backup power	Solar PV plus storage can be used to keep portions of the grid powered during the loss of primary grid power supply. Solar PV plus storage systems used in microgrids can supply back up power at the feeder level, communities, or individual customers.
PV clipping loss reduction	DC-coupling the BESS and solar PV allows the BESS to capture solar energy that would have been otherwise clipped or lost when the PV system voltage is outside the inverter voltage range.
PV ramp rate control	Storage can reduce the power quality impact of solar fluctuations and steep ramping to help in compliance with interconnection requirements.
Transmission and distribution (T&D) system deferral	Targeted deployment of solar plus storage can offer an alternative to T&D capital investments.

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 6-6 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 6-6
Definition of major energy storage applications [26]

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 6-7 provides definitions for key performance characteristics and their potential impact on life-cycle project costs that are covered further in this section.

Table 6-7
Energy storage definitions of performance characteristics and impacts on their use [26]

Performance Characteristics	Definition	Potential Impact
Auxiliary power	Also known as <i>housekeeping power</i> , 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 lithium 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 Lithium 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 6-7 (continued)
Energy storage definitions of performance characteristics and impacts on their use [26]

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.

Lithium ion Battery Energy Storage

Battery energy storage is sometimes viewed as the most favored energy storage technology for future power systems. Lithium 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 lithium ion technology in the consumer electronics and electric vehicle (EV) markets. This rise in demand stems from lithium ion's strong combination of performance characteristics, including energy and volumetric density, efficiency, and cycle life.

Technical/Process Description

A lithium ion battery is a type of electrochemical energy storage that stores energy during charge transfer reactions in the electrode structure. A lithium 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. 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 lithium ions. During charging, lithium 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.

The most common types of liquid lithium ion cells are cylindrical and prismatic. They are found in notebook computers and other portable power applications. Another approach, prismatic polymer lithium ion technology, is generally only used for small portable applications such as cellular phones. Rechargeable lithium ion batteries are commonly found in consumer electronic products.

A lithium 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.

Numerous lithium ion battery (LIB) chemistries exhibit distinct trade-offs concerning energy density, power capability, cycle life, cost, and safety. Selection of a particular battery chemistry is contingent upon application-specific requirements, necessitating a balance between performance, cost considerations, and safety factors. Primary LIB chemistries include:

- Lithium Cobalt Oxide (LCO)
- Lithium manganese oxide (LMO)
- Lithium Iron Phosphate (LFP)
- Lithium Nickel Manganese Cobalt (NMC) Oxide
- Lithium Nickel Cobalt Aluminum (NCA) Oxide
- Lithium Titanate Oxide (LTO)

The summary of comparison of various LIB chemistries is given in table below

Table 6-8
Summary of Lithium Ion Battery Chemistries [27]

	LCO	LFP	NMC	NCA	LMO	LTO
Applications	Consumer electronics	Consumer electronics Light-duty EVs Electric buses Stationary energy storage	Consumer electronics Light-duty EVs Electric buses Stationary energy storage	Consumer electronics Light-duty EVs Stationary energy storage	Consumer electronics Light-duty EVs Stationary energy storage	Light-duty EVs Electric buses Stationary energy storage
Anode	Graphite	Graphite	Graphite	Graphite	Graphite	LTO
Cathode	LCO	LFP	NMC	NCA	LMO	LMO, NMC
Electrolyte	Lithium salt solution	Lithium salt solution	Lithium salt solution	Lithium salt solution	Lithium salt solution	Lithium salt solution
Specific power	High	Medium	High	High	Medium	Low
Energy density	High	Low	High	High	Low	Low
Cycle life	Medium	High	Medium	High	Low	High
Self-discharge rate	High	Low	Medium	High	Low	Low
Safety	Low	High	High	Low	High	High

High-nickel cathode compounds, specifically NMC, are widely employed in lithium ion batteries (LIBs) for stationary energy storage and electric vehicle (EV) applications. Nevertheless, the emergence of alternative cathodes/chemistries, such as LFP, has significantly contributed to enhancing the overall performance and safety of LIBs. It is noteworthy that LFP batteries utilize less than half the lithium compared to NMC batteries.

Summary of Lithium Ion Battery Energy Storage Performance Characteristics

Table 6-9 summarizes select key technology performance parameters of lithium ion batteries, most of which were defined in Table 6-7.

Table 6-9
Performance characteristics of lithium 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.

Lithium 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 lithium 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 lithium 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.

Table 6-10 summarizes some of the main advantages and disadvantages of lithium ion battery technologies.

Table 6-10
Advantages and disadvantages of lithium ion battery technologies [26]

Advantages	Disadvantages
<ul style="list-style-type: none"> • High power and energy density • Low self-discharge rate • Higher RTE 	<ul style="list-style-type: none"> • 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 high energy density and relatively low weight of lithium 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), lithium 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 lithium 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 lithium 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

Lithium 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 lithium 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.

The progression of lithium ion batteries is significantly influenced by the demands of the electric vehicle (EV) industry, which surpasses stationary energy storage in both demand and profitability. Despite this, innovations originating from EV lithium ion batteries may transfer to stationary lithium ion batteries. Prospective advancements in lithium ion batteries technology are

anticipated to prioritize enhanced energy density, increased power output in lithium ion cells, heightened operational safety, cost reduction, and diminished dependence on scarce minerals. A notable ongoing development involves the adoption of solid electrolytes, replacing conventional liquid electrolytes, leading to the emergence of solid-state lithium batteries (SSLBs), offering improved energy densities and safety.

Many forecasts of lithium ion battery packs envision considerable declines over the next 10 years on a \$/kW basis, as shown by Figure 6-14 [26].

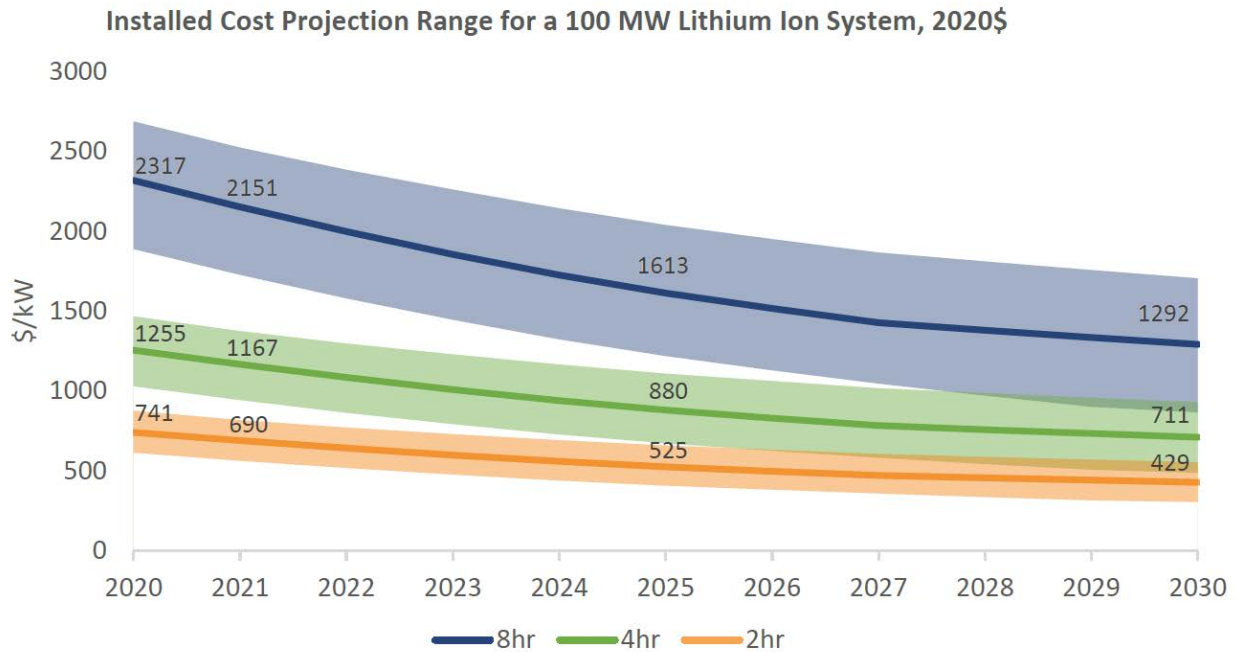


Figure 6-14
Installed cost projections for a 100-MW lithium ion system, 2020–2030

Pumped Storage Hydropower

Technical/Process Description

Over the years, Pumped Storage Hydropower (PSH) has proven to be a cost-effective means for delivering reliable large-scale balancing and grid services. Like other storage systems, PHS stores excess energy at times of low demand and delivers it when the demand is high.

PSH storage exploits gravitational potential energy to produce electricity through the controlled movement of water between an upper and lower reservoir. During periods of low demand and electricity prices, water is pumped from the lower source to the higher reservoir. Conversely, during periods of high demand and elevated prices, the stored water is released to propel a turbine in a powerhouse, generating electricity for the grid.

The energy storage capacity of a PSH facility is contingent upon the dimensions of its two reservoirs, with the power generation determined by the turbine's size.

PSH can be categorized into two main types:

- **Open-loop:** Involves a continuous connection to a naturally flowing water source, such as a river, with either an upper or lower reservoir.
- **Closed-loop:** Stores power by pumping water to an upper reservoir and generates power by flowing back to lower reservoir without relying on a significant natural inflow.

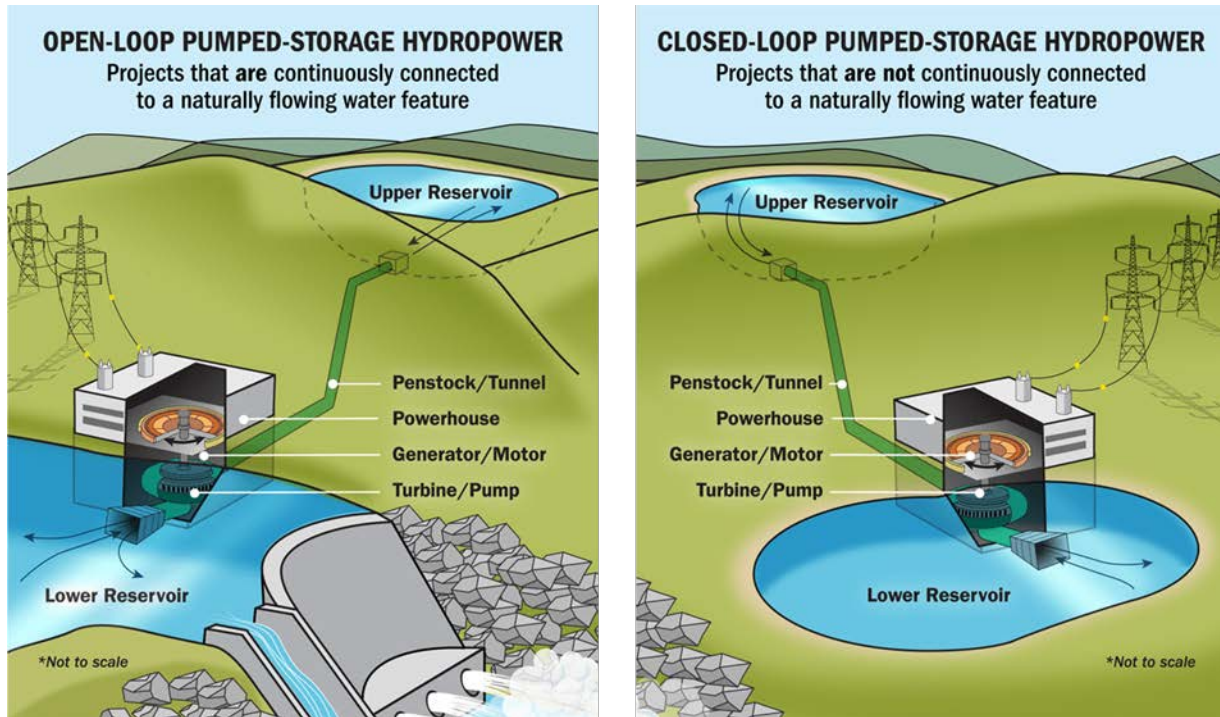


Figure 6-15
Open Loop and Closed Loop Pumped Storage Hydropower System (Source: NREL)

Applications

A PSH plant can help to compensate for the variability of renewable generation. The PHS 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.

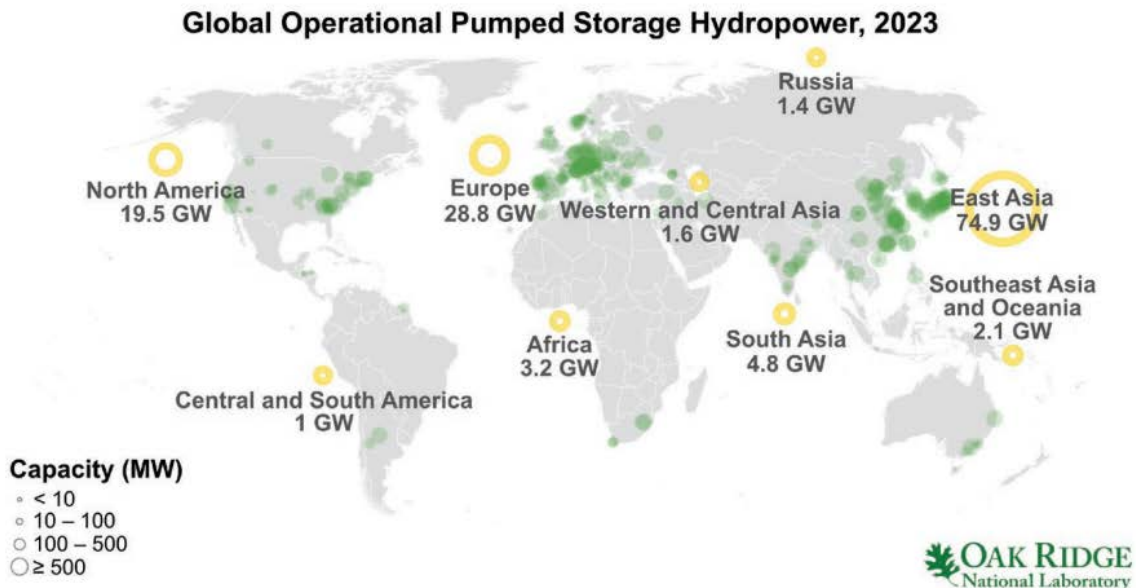
PHS plants have multifaceted role in the energy sector, spanning energy, ancillary services, and capacity markets. PHS can provide some or all of the following services:

- Energy time 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
- Voltage Support
- Contingency Reserves (Spinning and non-spinning reserves)

- 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
- Transmission Deferral
- System resilience

Status of Technology

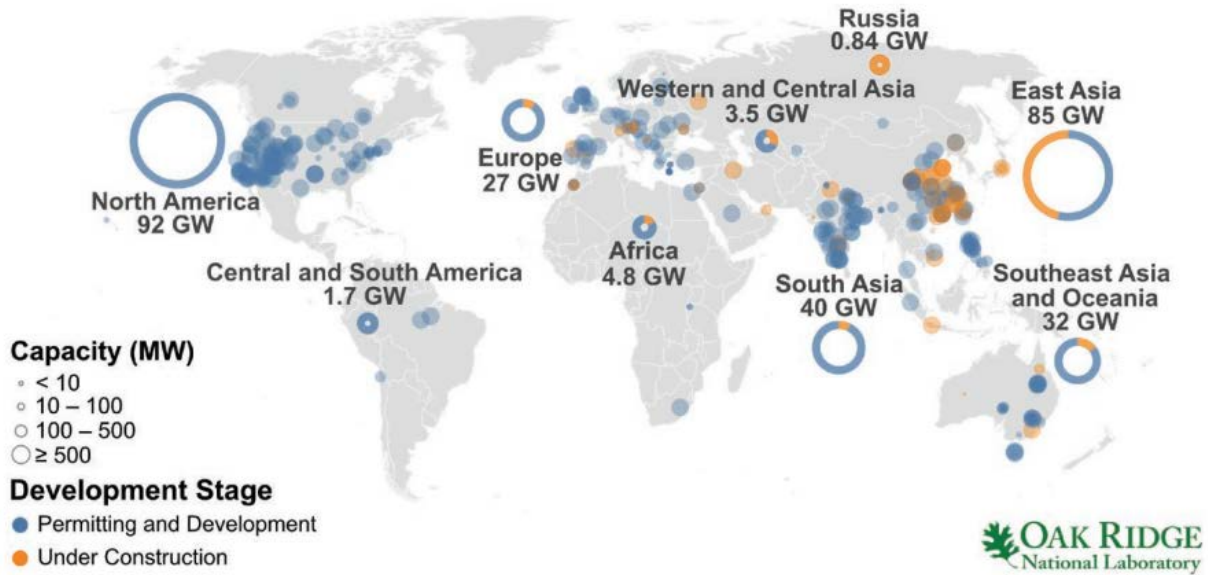
PSH represents a well-established technology with extensive worldwide implementation. As of 2022, the global PSH capacity reached 137 GW, indicating an increase of 15.9 GW from 2020 to 2022. Over the past decade (2013–2022), the average capacity growth rate for PSH has been 2.7% [27]. Notably, the years 2021 (6.5 GW) and 2022 (9.3 GW) witnessed the largest annual additions to global PSH capacity since 2013.



Source: Oak Ridge National Laboratory

By the end of 2022, the global development pipeline included 363 PSH projects, with a combined capacity of 286 GW. Among these, 56 projects are currently under construction, boasting a total rated power capacity of 52 GW. Upon completion, the new capacity from these projects will augment the global PSH fleet by 38%.

Global Pumped Storage Hydropower Development Pipeline, 2023



Source: Oak Ridge National Laboratory

Anticipated trends in PSH technology that may impact its cost include:

1. Migration to Adjustable-Speed Technology: The decreasing cost of power electronics over recent decades has made adjustable-speed electro-mechanicals and powerhouse approximately 20% more expensive than fixed-speed technology. However, the advantages of higher efficiency, superior load following capabilities, and the ability to provide frequency regulation ancillary services in pumping mode make the adjustable-speed option more appealing.
2. Increasing Plant Capacity: Over the past two decades, there has been a consistent trend of higher PSH plant capacities, and this pattern is expected to persist. This scaling up can potentially bring about economies of scale.
3. Ongoing efforts are being made to apply oil well drilling techniques for the installation of the powertrain. This approach aims to reduce powerhouse construction costs and associated contingency fees.

Table 6-11
PSH performance summary

Typical power (MW)	100–1000+ MW
Round trip efficiency	70-80%
Response time	Seconds to minutes
Calendar life	60 yr
Energy requirement (I/O) ratio	1.3

Underground Hydrogen Storage

Technical/Process Description

Underground hydrogen storage involves storing hydrogen gas in natural or artificial underground formations, such as salt caverns, depleted oil or gas fields, or aquifers. Because the demand for hydrogen fluctuates and supply may depend on intermittent renewables energy generation, storage is needed to buffer mismatches between supply and demand. Underground storage may be the only economically viable method for storing hydrogen in sufficient quantities to meaningfully shift energy seasonally and provide a firm, reliable energy source. Significant experience storing gas underground has been collected by the natural gas industry, and while hydrogen has different characteristics than natural gas which present unique challenges, some of that industry experience may be transferable [31].

Figure 6-16 shows a diagram of different types of storage facility included in this study.

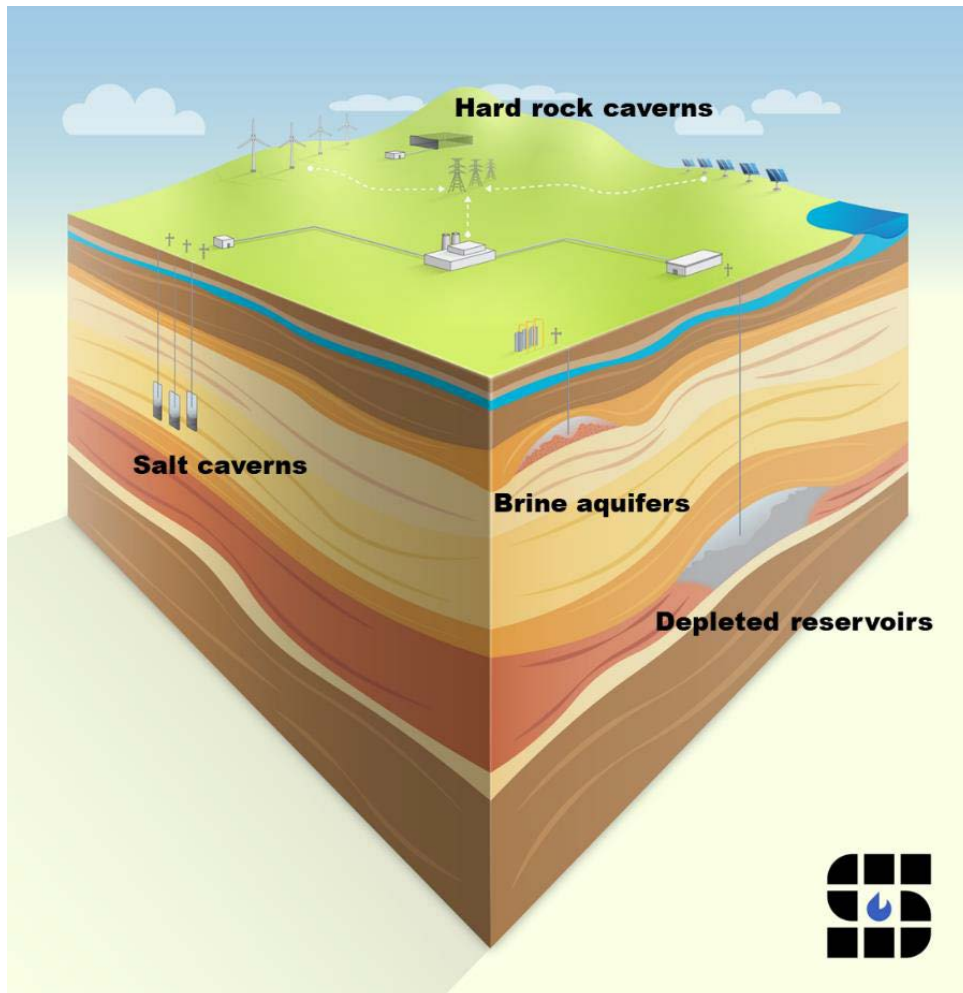


Figure 6-16
Visualization of different types of hydrogen storage.

Source: Subsurface Hydrogen Assessment, Storage, and Technology Acceleration
<https://edx.netl.doe.gov/shasta/hydrogen-subsurface-storage-overview/>

A few major components drive the cost of hydrogen storage facilities. These costs can be categorized as “room” costs which scale with the volume of hydrogen a facility can store, and “door” costs which scale with the rate at which hydrogen can be withdrawn. “Room” costs include cushion gas and site preparation. Cushion gas is the gas that is permanently stored in the facility to maintain sufficient pressure and deliverability rates. It is never withdrawn, and so is considered a capital expense. Site preparation includes costs such as solution mining for salt caverns and site characterization for aquifers. “Door” costs include wells and compressors.

Each type of underground storage facility has advantages and disadvantages.

- Salt caverns are artificial cavities created by solution mining salt formations. They have high storage capacity, low cushion gas requirements, and high injection/withdrawal rates. The high withdrawal rate makes them very valuable for supplying large volumes of hydrogen quickly when there is a spike in demand. However, the geologic site preparation, including solution mining, can be expensive, and the brine disposal must be handled appropriately to avoid environmental problems. Availability of salt formations may also present challenges in creating new salt cavern storage facilities.
- Aquifers are natural porous formations filled with water. They likely have lower environmental impact, wide geographical distribution, and large storage potential. However, their porosity means lower injection/withdrawal rates, and the cushion gas requirements are expected to be higher. There may also be higher risks of hydrogen dissolution, microbial activity, and mineral interactions.
- Depleted oil and gas reservoirs are porous formations that have been previously exploited for hydrocarbon production. They are likely to have proven storage capacity and existing infrastructure and expertise. Like aquifers, they would likely have lower injection/withdrawal rates compared to salt caverns.
- Hard rock caverns are artificial cavities excavated in competent rock formations. They have the advantage of being able to withstand higher pressures than salt caverns, which means they can store more hydrogen per unit volume, but they are more challenging and costly to construct, as they require drilling, blasting, and lining.

In order to consider underground hydrogen storage as a storage technology for electricity, this case also includes electrolysis systems and hydrogen fired aeroderivative turbines [30]. This study examines costs for two kinds of electrolysis technology. The first, alkaline, is the oldest and most mature technology, and it is currently the lowest cost option. However, though manufacturers are working on improving the operational flexibility, this technology has historically had poor minimum load and response time characteristics. A potential strategy to mitigate the minimum load limit is inter-stack management: electrolysis systems consist of multiple units, so the flexibility of a system could be improved by operating some units at standby and others at minimum load. Still, these factors could present challenges when pairing electrolysis to intermittent renewable energy sources. The other electrolysis technology studied, proton exchange membrane (PEM), is able to respond to changes in load very rapidly and lower its output to near zero, making it a viable technology to pair with renewable energy sources. But while PEM electrolyzers can theoretically follow an intermittent energy source, it may not be recommended because cycling the load is expected to increase the rate of system degradation, though this phenomenon has not yet been thoroughly quantified. PEM electrolyzers are also

notably more expensive than alkaline electrolyzers, so accelerating the stack replacement schedule could have a meaningful impact on the levelized costs of hydrogen. Finally, because the electrolysis system is capital intensive, the savings from powering the electrolyzer exclusively from a dedicated low-cost renewable source without batteries may not be worth the lower utilization of the electrolysis asset.

After the hydrogen has been produced, stored, and withdrawn, the final step is to convert it back to electricity. For this study, a hydrogen fired aeroderivative turbine was assumed for the hydrogen-to-power conversion. Though hydrogen fired turbines are not in commercial use today, there have been several demonstrations in recent years with existing natural gas turbines, and significant resources are currently being directed toward accelerating the technology readiness.

Applications

The levelized cost of the delivered electricity from electrolytic hydrogen stored underground and then converted back to electricity is likely to be very expensive, partly due to the nascency of the technology but also because of the high losses inherent in the various conversions. Round trip efficiency for the cases analyzed in this study were about 23%. Despite the expected low round trip efficiency and high final electricity cost, hydrogen may still play an important role in an electric power system as a firm power source for peaker applications. It will likely not compete with low-cost intermittent renewable assets or baseload assets, but rather against firm low capacity factor resiliency assets whose low-carbon options are also expensive.

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 [28]. 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 [29].

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 launched the Low-Carbon Resources Initiative to advance technologies and understanding across the value chain.

Within this effort EPRI is developing an integrated cost and performance assessment that includes 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 enable the identification of potential cost reductions in the future as well as the magnitude of those reductions relative to delivering low-carbon energy. Figure 6-17 is an example of the low-carbon energy carrier supply-side and infrastructure technologies being evaluated.

Production	Conversion	Infrastructure
<ul style="list-style-type: none"> • Electrolysis <ul style="list-style-type: none"> Low Temperature High Temperature • Natural Gas Reformation <ul style="list-style-type: none"> 90% Carbon Capture 99%+ Carbon Capture • Gasification with Carbon Capture <ul style="list-style-type: none"> Coal Biomass Wastes • Novel Cycles 	<ul style="list-style-type: none"> • Ammonia Synthesis <ul style="list-style-type: none"> Integrated with Production Standalone Systems • Methanation • Biofuels • Synthetic Fuels • Ammonia Cracking 	<ul style="list-style-type: none"> • Transportation <ul style="list-style-type: none"> Pipeline Trucking Marine • Storage <ul style="list-style-type: none"> Below-ground Above-ground • Distribution

Figure 6-17
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 [29].

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7

COAL TECHNOLOGIES PERFORMANCE AND COST

Pulverized Coal

Tables 7-1 and Table 7-2 summarize the cost and performance of the PC plant and coal plant conversion to gas and SMR evaluated in this study.

Table 7-1
PC plant cost and performance summary

Technology	1x591 MW, Wet Cooling with 90% CO ₂ Removal
Rated capacity, MW gross	725
Rated capacity, MW net	591
Plant cost estimates (2023)	
Total overnight cost, ZAR/kW	149,567
Lead times and project schedule (months)	48
Single unit expense schedule, % of TPC per year	10%, 25%, 45%, 20%
Fuel cost estimates	
First year (ZAR/GJ)	42
Expected escalation (beyond inflation)	0%
Fuel energy content, HHV, kJ/kg	17,850
O&M cost estimates	
Fixed O&M, ZAR/kW/year	4,999
Variable O&M, ZAR/MWh	111
Availability estimates	
Equivalent availability	92
Maintenance planned outages, %	4.8
Unplanned outages, %	3.7
Performance estimates	
Economic life, years	30

Table 7-1 (continued)
PC plant cost and performance summary

Technology	1x591 MW, Wet Cooling with 90% CO ₂ Removal
Performance estimates	
Heat rate, kJ/kWh	
100% load	13,410
75% load	13,853
50% load	15,035
25% load	21,618
Plant load factor	
Typical capacity factor	85%
Maximum of rated capacity	100%
Minimum of rated capacity	25%
Water usage	
Per unit of energy, L/MWh	4,469
For wet and dry cooling (where applicable)	3,947
Sorbent (limestone) usage	
Per unit of energy, kg/MWh	21.8
Air emissions, kg/MWh	
CO ₂	129.7
SO _x	0.63
NO _x	0.40
Particulates	0.17
Solid wastes, kg/MWh	
FGD solids	34.6
Fly ash	231.2
Bottom ash	4.5

Table 7-2
Coal plant conversion to gas and SMR – cost and performance summary

Technology	Coal-to-Gas, Dry Cooling	Coal-to-SMR, Dry Cooling
Rated capacity, MW gross	582	508
Rated capacity, MW net	569	480
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	1,114	174,584
Lead times and project schedule (months)	24	42
Expense schedule, % of TPC per year	95%, 5%	15%, 35%, 35%, 15%
Fuel cost estimates		
First year (ZAR/GJ)	261	48
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, MJ/SCM	39.3	N/A
O&M cost estimates		
Fixed O&M, ZAR/kW/year	202	5,461
Variable O&M, ZAR/MWh	40	61
Availability estimates		
Equivalent availability	92	95
Maintenance planned outages, %	4.8	4
Unplanned outages, %	3.7	1
Performance estimates		
Economic life, years	30	30
Heat rate, kJ/kWh	10,762	8,510
Plant load factor		
Typical capacity factor	65%	90%
Maximum of rated capacity	100%	100%
Minimum of rated capacity	25%	25%
Water usage		
Per unit of energy, L/MWh	Negligible	Negligible
Air emissions, kg/MWh		
CO ₂	541.1	0
SO _x	0	0
NO _x	0.46	0
CO	0.69	0
Particulates	0	0

Plant Cost Estimates

The total overnight cost for a PC plant with wet cooling and 90% carbon capture is about 149,567 ZAR/kW. The 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 most 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.

The estimated overnight cost to modify a subcritical 580-MW coal plant to add natural gas firing capability is about 1,114 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.

The estimated overnight cost to repower a coal facility to a small modular reactor (SMR) nuclear unit is about 174,584 ZAR/kW. The SMR plant evaluated in this study is a 6x80 MW plant configuration with dry cooling. It is assumed that all structures of the existing coal plant, except the switchyard, will be demolished. These structures include boiler buildings, substation, turbine buildings, screen house, pump house, coal handling facilities, oil tanks, machine shop, maintenance buildings, warehouses, and miscellaneous buildings. The decommissioning cost is not included in the overnight capital cost. The coal-to-SMR conversion project would have a forty-two-month expense and construction period, with the expected expense schedule of 15% in year 1, 35% in year 2, 35% in year 3, and 15% in year 4.

Comparing Coal-to-Gas Conversion to New Combined Cycle Gas Turbine Plant

Converting an existing coal plant to utilize natural gas is estimated to be significantly less expensive than building a new combined cycle gas turbine plant due to less equipment, materials, and labor, and shorter construction time. However, new combined cycle gas turbine plants are more efficient than converted coal plants (higher heat rates in terms of kJ/kWh). Additionally, new combined cycle gas turbine plants can be sited in locations where natural gas pipeline infrastructure can be conveniently built, whereas the locations of existing coal plants may be far from existing natural gas infrastructure and lead to additional costs for supplying fuel to the converted plant.

Fuel Cost Estimates

The South African coal used in this study has an energy content of about 17,850 kJ/kg before drying, and the cost is estimated to be 42 ZAR/GJ. The price of the coal is not expected to increase beyond general inflation. For the coal-to-gas case, the LNG cost is estimated to be 261 ZAR/GJ with a fuel energy content of 39.3 MJ/SCM. The fuel cost for the coal-to-SMR case is estimated to be 48 ZAR/GJ for the initial load and 8.5 ZAR/GJ for annual refueling.

O&M Cost Estimates

The fixed O&M cost for a PC plant with wet cooling and carbon capture is 4,999 ZAR/kW/yr, and the variable O&M cost is 111 ZAR/MWh. For this study, both maintenance labor and material costs are considered fixed costs. Additionally, property taxes and insurance costs are also included in the fixed O&M cost.

The fixed O&M for a coal-to-gas plant is 202 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.

The fixed O&M for a coal-to-SMR plant is 5,461 ZAR/kW, and the variable O&M is 61 ZAR/MWh. The lower variable O&M cost of a coal-to-SMR compared to that of a PC plant is due to savings in costs of consumables and ash disposal.

Availability and Performance Estimates

The wet-cooled PC plant with carbon capture in this study has an expected equivalent availability of 92%, a capacity factor of 85%, and the full-load heat rate of about 13,410 kJ/kWh.

The coal-to-gas plant has an expected equivalent availability of 92%, a capacity factor of 65%, and the full-load heat rate of about 10,762 kJ/kWh.

The coal-to-SMR plant has an expected equivalent availability of 95%, a capacity factor of 90%, and the full-load heat rate of about 8,510 kJ/kWh.

An economic life of 30 years is assumed for all PC plants in this study for cost of electricity calculations; however, the operating life of a coal plant can extend well beyond 30 years, as discussed in section 13.

Cost of Electricity

Table 7-3 shows a representative levelized cost of electricity for the PC plants. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 7-3
Coal plant levelized cost of electricity

Technology	1x591 MW, Wet Cooling with 90% CO ₂ Removal	Coal-to-Gas, Dry Cooling	Coal-to-SMR, Dry Cooling
Rated capacity, MW net	591	569	480
Capacity factor, %	85	65	90
Fuel cost (ZAR/MWh)	564	2,808	252
O&M (ZAR/MWh)	782	76	754
Capital (ZAR/MWh)	2,175	29	2,390
LCOE (ZAR/MWh)	3,521	2,913	3,396

Water Usage

A PC plant with wet cooling and carbon capture consumes about 4,469 L/MWh of water. The water consumption is negligible for the coal-to-gas and coal-to-SMR plants with dry cooling.

Emissions

The air and solid emissions of the coal plants evaluated in this study are listed in the preceding summary tables. With the addition of carbon capture to the PC plant, the CO₂ emission from the PC plant is lower compared to that of the coal-to-gas plant. No air or solid emissions are produced from the coal-to-SMR plant.

8

NUCLEAR TECHNOLOGY PERFORMANCE AND COST

Tables 8-1 through Table 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 (2023)		
Total overnight cost, ZAR/kW	176,885	174,681
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	15	15
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	2,837	2,627
Variable O&M, ZAR/MWh	218	218
Availability estimates		
Equivalent availability	92%	92%
Maintenance	6.7%	6.7%
Unplanned outages	1.4%	1.4%
Performance estimates		
Economic life, years	30	30
Heat rate, kJ/kWh	10,000	10,000
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 (2023)		
Total overnight cost, ZAR/kW	169,027	167,264
Lead times and project schedule (months)	72	96
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	15	15
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	3,337	2,980
Variable O&M, ZAR/MWh	195	195
Availability estimates		
Equivalent availability	93%	93%
Maintenance	5.7%	5.7%
Unplanned outages	1.4%	1.4%
Performance estimates		
Economic life, years	30	30
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	12x73 MW, SMR
Rated capacity, MW net	876
Plant cost estimates (2023)	
Total overnight cost, ZAR/kW	153,378
Lead times and project schedule (months)	48
Expense schedule, % of TPC per year	15%, 35%, 35%, 15%
Fuel cost estimates	
First year, ZAR/GJ	15
Expected escalation (beyond inflation)	0%
Fuel energy content, GJ/kg	1,299
O&M cost estimates	
Fixed O&M, ZAR/kW/year	2,623
Variable O&M, ZAR/MWh	177
Availability estimates	
Equivalent availability	92%
Maintenance	6.7%
Unplanned outages	1.4%
Performance estimates	
Economic life, years	30
Heat rate, kJ/kWh	11,500
Water usage, L/MWh	4

Plant Cost Estimates

The total overnight cost is estimated to be between 176,900 ZAR/kW and 174,600 ZAR/kW for the Areva EPR and 169,000 ZAR/kW to 167,200 ZAR/kW for the AP1000, depending on the number of units. The total overnight cost for the SMR is about 153,400 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 in the United States, they can apply to construction of nuclear and other technologies evaluated in this study in South Africa 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.

Small Modular Reactor Technology Readiness

Despite bearing the cost uncertainty risks described above, large-scale conventional nuclear is a mature, commercial technology. Small modular reactors, however, have not yet been proven at commercial scale. Some high-profile demonstration projects have seen large cost overruns and project cancelations. While this is not entirely unexpected for emerging technologies, it illustrates the technological risk small modular reactor technologies still bear. The timeline for when SMRs will be commercially available at nth-of-a-kind prices is highly uncertain, but it is reasonable to assume that this will not be achieved until the 2030s. The remainder of the 2020s will likely see additional demonstration projects and high-cost early projects (first-of-a-kind or close) as the industry scales and gains experience.

Fuel Cost Estimates

The cost of uranium is estimated to be 15 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 2,837 to 2,627

ZAR/kW/year compared to 3,337 to 2,980 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 fixed O&M estimated at 2,623ZAR/kW/year. Variable O&M costs are about 218 ZAR/MWh for the Areva EPR, 195 ZAR/MWh for the AP1000, and 177 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 operating 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 11,500 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 Table 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)	137	137
O&M (ZAR/MWh)	578	552
Capital (ZAR/MWh)	3,099	3,058
LCOE (ZAR/MWh)	3,814	3,747

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)	155	155
O&M (ZAR/MWh)	618	573
Capital (ZAR/MWh)	2,969	2,934
LCOE (ZAR/MWh)	3,741	3,661

Table 8-6
Nuclear SMR levelized cost of electricity

Technology	12x73 MW, SMR
Rated capacity, MW net	876
Fuel cost (ZAR/MWh)	158
O&M (ZAR/MWh)	509
Capital (ZAR/MWh)	2,528
LCOE (ZAR/MWh)	3,195

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 Table 9-3 summarize the cost and performance for the open-cycle gas turbine (OCGT), combined-cycle gas turbine (CCGT), and ICE plants.

Table 9-1
OCGT plant cost and performance summary

Technology	1x9F.05	1x9HA.02
Rated capacity, MW gross	302	548
Rated capacity, MW net	297	540
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	12,981	11,159
Lead times and project schedule (months)	36	36
Expense schedule, % of TPC per year	16%, 46%, 39%	16%, 46%, 39%
Fuel cost estimates		
First year (ZAR/GJ)	261	261
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, MJ/SCM	39.3	39.3
O&M cost estimates		
Fixed O&M, ZAR/kW/year	424	327
Variable O&M, ZAR/MWh	80	77
Availability estimates		
Equivalent availability	94	94
Maintenance planned outages, %	4.5	4.5
Unplanned outages, %	2.0	2.0
Performance estimates		
Economic life, years	30	30

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

Technology	1x9F.05	1x9HA.02
Performance estimates		
Heat rate, kJ/kWh		
100% load	10,624	9,453
75% load	11,078	9,970
50% load	12,840	11,289
25% load	14,349	13,399
Plant load factor		
Typical capacity factor	10%	10%
Maximum of rated capacity	100%	100%
Minimum of rated capacity	10%	10%
Water usage		
Per unit of energy, L/MWh	Negligible	Negligible
Air emissions, kg/MWh		
CO ₂	547	487
SO _x	0.00	0.00
NO _x	0.25	0.38
CO	0.23	0.16

Table 9-2
CCGT plant cost and performance summary

Technology	2x1 9F.05 Dry Cool	2x1 9HA.02 Dry Cool
Rated capacity, MW gross	945	1,627
Rated capacity, MW net	925	1,591
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	18,653	14,337
Lead times and project schedule (months)	48	48
Expense schedule, % of TPC per year	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%
Fuel cost estimates		
First year (ZAR/GJ)	261	261
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, MJ/SCM	39.3	39.3
O&M cost estimates		
Fixed O&M, ZAR/kW/year	501	363
Variable O&M, ZAR/MWh	61	58
Availability estimates		
Equivalent availability	98	98
Maintenance planned outages, %	1.5	1.5
Unplanned outages, %	1.0	1.0
Performance estimates		
Economic life, years	30	30
Heat rate, kJ/kWh		
100% load	6,900	6,541
75% load	7,016	6,700
50% load	6,984	6,594
25% load	8,092	7,839
Plant load factor		
Typical capacity factor	50%	50%
Maximum of rated capacity	100%	100%
Minimum of rated capacity	50%	50%

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

Technology	2x1 9F.05 Dry Cool	2x1 9HA.02 Dry Cool
Water usage		
Per unit of energy, L/MWh	9.1	7.5
For wet and dry cooling (where applicable)	0	0
Air emissions, kg/MWh		
CO ₂	356	337
SO _x	0.00	0.00
NO _x	0.02	0.02
CO	0.01	0.01

Table 9-3
ICE plant cost and performance summary

Technology	1x9 MW ICE	1x18 MW ICE
Rated capacity, MW gross	9.7	16.6
Rated capacity, MW net	9.5	16.2
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	61,195	50,169
Lead times and project schedule (months)	12	12
Expense schedule, % of TPC per year	100%	100%
Fuel cost estimates		
First year (ZAR/GJ)	261	261
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, MJ/SCM	39.3	39.3
O&M cost estimates		
Fixed O&M, ZAR/kW/year	3,184	2,321
Variable O&M, ZAR/MWh	126	134
Availability estimates		
Equivalent availability	95	95
Maintenance planned outages, %	3.0	3.0

Table 9-3 (continued)
ICE cost and performance summary

Technology	1x9 MW ICE	1x18 MW ICE
Unplanned outages, %	2.0	2.0
Performance estimates		
Economic life, years	30	30
Heat rate, kJ/kWh		
100% load	9,042	9,042
75% load	9,527	9,506
50% load	10,477	10,266
25% load	12,007	12,049
Plant load factor		
Typical capacity factor	10%	10%
Maximum of rated capacity	100%	100%
Minimum of rated capacity	10%	10%
Water usage		
Per unit of energy, L/MWh	Negligible	Negligible
Air emissions, kg/MWh		
CO ₂	458	470
SO _x	0.00	0.00
NO _x	0.08	0.08
CO	0.11	0.12

Plant Cost Estimates

All costs reported for the 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 the 9HA.02 turbine is 11,159 ZAR/kW, and 12,981 ZAR/kW for the 9F.05 turbine. For a combined-cycle plant with a 2x1 configuration, the total overnight cost is 14,337 ZAR/kW for the 9HA.02 CCGT and 18,653 ZAR/kW for the 9F.05 CCGT.

The total overnight cost for the 9-MW ICE unit is 61,195 ZAR/kW, and 50,169 ZAR/kW for the 18-MW ICE unit. These costs are presented for a single unit. Typically, ICE plants are deployed in blocks where multiple units are constructed within the same project. This approach would decrease the overnight cost of deploying ICE 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 is 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 16% in the first year, 46% in the second year, and 39% 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 units have an expected expense and construction period of about one year.

Fuel Cost Estimates

The cost of the LNG is estimated to be 261 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 with the 9HA.02 turbine is about 327 ZAR/kW/year, and 424 ZAR/kW/year for the 9F.05 turbine.

For a CCGT plant, the fixed O&M cost is about 363 ZAR/kW/year for the 9HA.02 plant, and 501 ZAR/kW/year for the 9F.05 plant.

For the ICE unit, the fixed O&M is about 3,184 ZAR/kW/year for the 9-MW unit and 2,321 ZAR/kW/year for the 18-MW unit.

For this study, both maintenance labor and material costs are considered fixed costs. Additionally, property taxes and insurance costs are also included in the fixed O&M cost. 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 77 - 80 ZAR/MWh for the OCGT plants, 58 - 61 ZAR/MWh for the combined-cycle plants, and 126 - 134 ZAR/MWh for the ICE units.

Availability and Performance Estimates

The equivalent availability of the plants evaluated in this study is expected to be about 94% for the OCGT, 98% for the CCGT, and 95% for the ICE plants. These gas plants are expected to have an economic life of at least 30 years.

The full-load heat rate for the 9HA.02 OCGT plant is about 9,450 kJ/kWh, and 10,625 kJ/kWh for the 9F.05 OCGT plant. At part-load an OCGT plant becomes less efficient. The combined-cycle plants have full-load heat rates ranging from about 6,540 to 6,900 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 ICE unit has a heat rate of 9,040 kJ/kWh. The OCGT and ICE plants are operated as peaking units and have an expected capacity factor of 10%. The combined-cycle plant has a capacity factor of 50%.

Cost of Electricity

Tables 9-4 through Table 9-6 show representative levelized cost of electricity for the gas plants evaluated in this study. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 9-4
OCGT levelized cost of electricity

Technology	1x9F.05	1x9HA.02
Rated capacity, MW net	297	540
Capacity Factor, %	10	10
Fuel cost (ZAR/MWh)	2,854	2,541
O&M (ZAR/MWh)	576	456
Capital (ZAR/MWh)	2,052	1,765
LCOE (ZAR/MWh)	5,482	4,761

Table 9-5
CCGT levelized cost of electricity

Technology	2x1 9F.05 Dry Cool	2x1 9HA.02 Dry Cool
Rated capacity, MW net	925	1,591
Capacity Factor, %	50%	50%
Fuel cost (ZAR/MWh)	1,866	1,759
O&M (ZAR/MWh)	176	141
Capital (ZAR/MWh)	523	403
LCOE (ZAR/MWh)	2,565	2,302

Table 9-6
ICE levelized cost of electricity

Technology	1x9 MW ICE	1x18 MW ICE
Rated capacity, MW net	10	16
Capacity Factor, %	10	10
Fuel cost (ZAR/MWh)	2,431	2,431
O&M (ZAR/MWh)	3,867	2,868
Capital (ZAR/MWh)	9,241	7,578
LCOE (ZAR/MWh)	15,539	12,876

Water Usage

The water requirement for the OCGT plants in this study is negligible due to the use of the dry low emission combustion technology, which requires no water or steam injection for NO_x control. The water consumption of the ICE plants is also negligible.

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.

Emissions

The air emissions of the gas plants evaluated in this study are shown in the preceding summary tables. The emissions produced by the CCGT plants are lower compared to those from the OCGT and ICE plants as a result of higher CCGT plant efficiencies.

10

RENEWABLE TECHNOLOGIES PERFORMANCE AND COST

Offshore Wind

Table 10-1 summarizes cost and performance for Offshore Wind technology.

Table 10-1
Offshore Wind technology performance and cost summary

Technology	Fixed Bottom Offshore Wind	Floating Offshore Wind
Rated capacity, MW	800	800
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	72,427	107,274
Lead times and project schedule (months)	36	36
Expense schedule, % of TPC per year	5%, 45%, 50%	5%, 45%, 50%
O&M cost estimates		
Fixed O&M, ZAR/kW/year	2,276	1,596
Availability estimates	93%	93%
Performance estimates		
Economic life, years	30	30
Capacity factor	49.8%	57.3%

Plant Cost Estimates

The total overnight cost for the offshore wind technology ranges from ~72,000 ZAR/kW for a fixed bottom offshore wind plant to ~107,000 ZAR/kW for a floating offshore wind plant. It is expected that the total project schedule for a wind farm would be three years.

Floating offshore projects have higher capital cost due to increases in several BOP categories resulting from the design differences in addition to the impact of water depth and distance from shore. More steel is required in floating projects than fixed offshore projects, which drives an increase in substructure and foundation costs. There are also increased complexities and uncertainties related to floating wind electrical infrastructure. Floating power systems for both

collection and export require dynamic cables designed for the bending, twisting, compression and tension forces that they will be subjected to in a floating design. Design features include additional armoring of the cables, specialized electrical connectors, as well as buoyance and support/restraint mechanisms to prevent excessive movement and loads imparted on the cables and connections. Some of these applications will be first-of-a-kind, like the high-power dynamic export cables, which are not currently commercially available. These design challenges and the associated costs increase with water depth. They also increase engineering and installation complexity. However, there are some savings with floating foundations over fixed foundations with respect to assembly and installation since the units are assembled in port and towed to the project site.

O&M Cost Estimates

First year O&M costs for offshore wind turbines range from 1,596 ZAR/kW/year for a floating offshore plant to ~2,276 ZAR/kW/year for a fixed bottom offshore plant. O&M costs cover all operating expenses following construction, including operations monitoring, performance of scheduled and unscheduled maintenance for the wind turbines and balance of plant systems, and the cost of all parts, consumables, management, labor, and equipment rental necessary to support these activities.

The variance in operating costs between project cases with fixed-bottom and floating substructure is assumed to be related to the maintenance strategy employed for each substructure type. For fixed-bottom substructures, major turbine component replacements are assumed to be performed at the project site utilizing specialized vessels capable of performing these operations at sea. Major maintenance for floating projects is conceptualized to be carried out after towing the affected unit back to the O&M port, reducing costs associated with chartering specialized vessels for performing these maintenance activities.

Availability and Performance Estimates

Offshore wind farms are expected to have an availability of 93-94%. The performance of an offshore wind turbine depends primarily on the wind resource available. The average capacity factor of the fixed bottom offshore wind turbine in this study is 49.85% and floating offshore wind turbine is 57.3%.

Cost of Electricity

Table 10-2 shows representative levelized costs of electricity of the offshore wind plants. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 10-2
Offshore Wind levelized cost of electricity

Technology	Fixed Bottom	Floating
Rated capacity, MW	800	800
Fuel cost (ZAR/MWh)	0	0
O&M (ZAR/MWh)	521	318
Capital (ZAR/MWh)	1,767	2,272
LCOE (ZAR/MWh)	2,289	2,590

Solar Thermal

Table 10-3 and Table 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 (2023)					
Total overnight cost, ZAR/kW	83,198	110,127	134,718	163,898	195,045
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	1,480	1,521	1,561	1,602	1,663
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 (2023)				
Total overnight cost, ZAR/kW	106,475	127,823	143,209	158,985
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	1,228	1,281	1,317	1,352
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 83,200 ZAR/kW for a plant without storage to 195,000 ZAR/kW for a plant with 12 hours of storage. For the central receiver, costs range from 106,500 ZAR/kW for a plant with 3 hours of storage to 159,000 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 1,480 ZAR/kW/year for a plant without storage to 1,660 ZAR/kW/year for a plant with 12 hours of storage. For the central receiver, O&M costs range from 1,230 ZAR/kW/year for a plant with 3 hours of storage to 1,350 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

Table 10-5 and Table 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. 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
O&M (ZAR/MWh)	662	536	469	400	354
Capital (ZAR/MWh)	4,626	4,837	5,060	5,124	5,164
LCOE (ZAR/MWh)	5,288	5,373	5,529	5,524	5,518

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
O&M (ZAR/MWh)	356	288	250	223
Capital (ZAR/MWh)	3,849	3,575	3,389	3,259
LCOE (ZAR/MWh)	4,206	3,863	3,639	3,482

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 square meter 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.

Solar Photovoltaic plus Lithium Ion Battery

Table 10-7 summarizes cost and performance for solar photovoltaic plus lithium ion battery technology.

Table 10-7
Solar PV plus battery cost and performance summary

Technology	Solar PV Plus Storage
PV System Size, MW _{AC}	250
PV System Size, MW _{DC}	325
Battery Energy Storage System Size, MW	100
Battery Energy Storage System Capacity, Hrs	4
Plant Cost Estimates (Jan 2023)	
Total Overnight Cost, ZAR/kW	25,272
Lead-times and Project Schedule, months	12
Expense Schedule, % of TPC per year	100%
Operation and Maintenance Cost Estimates	
Fixed O&M, ZAR/kW-yr	665
Variable O&M, ZAR/MWh	0
Availability Estimates	94-99%
Performance Estimates	
Economic Life, years	30
Capacity Factor	39%

Plant Cost Estimates

The total overnight cost of a 250MW_{AC} solar PV plus 100MW/400MWh storage system, mono-directional DC-coupled, is 25,272 ZAR/kW (1 USD = 18.35 ZAR). The cost of the solar PV system is based on South African REIPP BW6 bids and BESS costs are based on EPRI estimates for South African location. The capital cost in terms of ZAR/kW-yr for solar PV plus storage system was calculated based on the system AC capacity i.e. 250MW. The installed costs of a solar PV plus storage system are less expensive than a solar PV plant and a BESS sited separately. Savings predominantly arise from onsite efficiencies with labor, engineering, management, and contractor profit.

Solar PV plus storage project costs are dependent on coupling configuration. The cost variation between configurations can result from various sources including:

1. *ESS Installation*: The DC-coupled approach has higher costs than the AC-coupled one given that the amount of DC cabling and associated installation labor increases.
2. *Power Conversion Systems*: Cost difference between the configurations depends on solar PV plus storage sizing and component cost assumptions.

3. *Controls/SCADA*: DC-coupled systems may have fewer devices to control at a SCADA level and implementation of the SCADA (programming/configuration) may be easier, as AC-coupled systems often use different inverter models within the same project. DC-coupled plant controls often have complexities (e.g., providing a certain grid service while simultaneously optimizing PV consumption and minimizing curtailment), which may require additional controls development.
4. *AC Balance of Plant and Installation*: The AC BOP costs represent a major cost advantage for DC-coupled systems over AC-coupled systems as DC-coupled systems use a shared inverter and transformer skid, which eliminates the associated installation and medium voltage wiring.
5. *Switchyard*: AC-coupled switchyards would require additional protection to limit the output of the combined system, a function that the DC-coupled system's inverter would perform. AC-coupled systems may also require additional switching equipment and/or switching capacity increasing the cost for an AC-coupled system.

O&M Cost Estimates

The O&M cost estimates for solar PV plus storage system is estimated to be around 665 ZAR/kW-yr for 250MW_{AC} solar PV plus 100MW/400MWh storage system. The annual O&M costs for both the solar PV and BESS were estimated. Property taxes and insurance are included in O&M cost. The O&M in terms of ZAR/kW-yr for solar PV plus storage was calculated based on the system AC capacity. Potential O&M cost savings with solar plus storage compared to standalone systems are considered given anticipated improvements are achieved in managing contracts and asset management.

It is important to note that BESS degrades over time, resulting in a loss of storage capacity during the operational life. Furthermore, the calendar life of lithium ion BESS is shorter than solar PV asset life (i.e., 20 years for BESS versus 30 years for solar PV). Several strategies can be employed to maintain the energy storage capacity for 30 years, including oversizing, augmentation, and replacement. Any one of these strategies, or a combination thereof, can be employed as per project specific needs to maintain the battery capacity. The current reported O&M cost estimates include battery replacement and augmentation cost. The inverter replacement costs, battery disposal costs, and extended warranty costs are also included in battery O&M cost estimates. The figure below illustrates the BESS storage capacity over the asset life based on replacement and augmentation assumption used in this assessment.

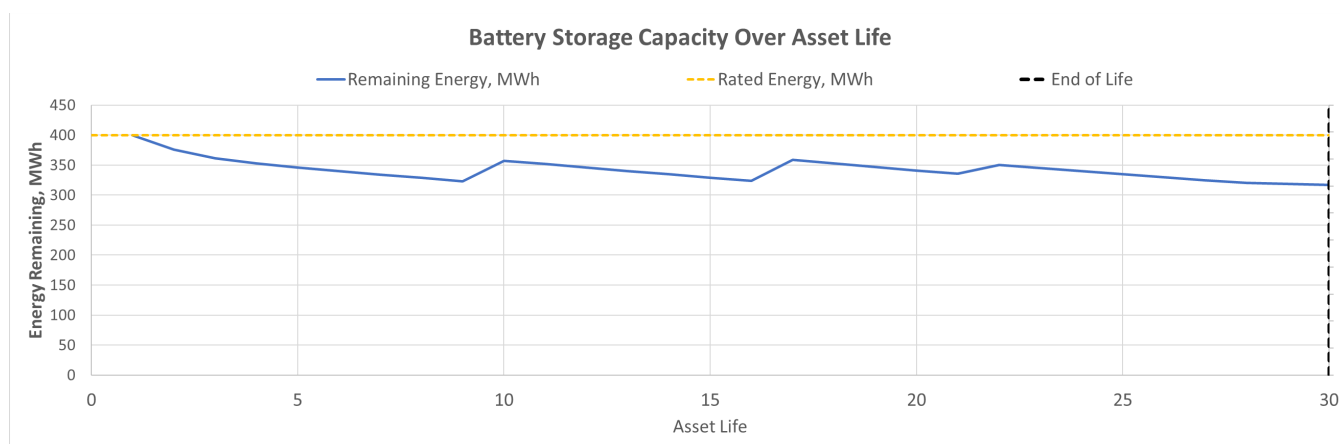


Figure 10-1
Battery storage capacity over asset life

Availability and Performance Estimates

Solar PV plants do not operate at night, this allows for some of solar PV system maintenance to take place during hours of non-operation. For BESS, both preventive and corrective maintenance are essential to ensure longevity, reliability, prevent downtime, and avoid safety hazards. Regular diagnostic checks, depending on the BESS configuration and technology, can identify degradation or performance issues, enabling targeted component replacements instead of replacing the entire system. As the industry gains more operational experience, BESS maintenance practices continue to evolve, informing both current maintenance activities and future system designs.

Due to high availability of solar PV systems and BESS systems, the utility scale solar PV plus storage systems are generally reliable with minimal downtime. The modularity of the overall system allows for individual system components to be serviced without shutting down the entire system. However, the availability of the system can be affected by extreme weather conditions, grid connectivity constraints, and maintenance approaches based on the division of responsibility between utilities and third-party providers, etc. The typical availability of the system ranges between 94-99%.

The economic life of solar PV plus storage systems is projected to be about 30 years, with a system capacity factor of 39%. Adding storage to solar PV captures excess energy that would otherwise be clipped, increasing net energy output and overall capacity factor. However, this increase is modest, as clipped energy represents a small fraction of total solar PV production for the given DC:AC ratio assumption used in this study. As discussed earlier, increasing the DC:AC ratio would also increase the clipped energy that the battery could store. Alternatively, if the battery was used to shift additional (un-clipped) output of the solar PV plus storage project from peak solar hours to when the electricity was most needed, the capacity factor might actually decrease due to the RTE of the system, but the energy available in those hours might be more valuable for the electric system as a whole.

It is less likely that solar plus storage systems will be used solely to capture clipped energy, as the cost of adding storage for this purpose is significantly higher than simply adding more solar

capacity. More importantly, storage provides additional value by shifting energy to periods of higher prices and firming solar output to ensure energy delivery at specific times.

Cost of Electricity

Table 10-8 shows representative levelized costs of electricity of the solar PV plus storage system. These are shown for illustrative purposes only and will vary based on financial assumptions.

Table 10-8
Solar PV plus battery levelized cost of electricity

Technology	Solar PV Plus Storage
Solar PV Rated capacity, MW _{AC}	250
Solar PV Rated capacity, MW _{DC}	325
Battery Energy Storage System Size, MW	100
Battery Energy Storage System Capacity, Hrs	4
Battery Energy Storage System Capacity, MWh	400
O&M (ZAR/MWh)	195
Capital (ZAR/MWh)	683
LCOE (ZAR/MWh)	877

Solar Photovoltaic and Onshore Wind

Solar photovoltaic and onshore wind were not evaluated as part of this study. The costs and performance of these asset types are presented in Table 10-9, which shows data from the South African Renewable Energy Independent Power Purchase Procurement Programme (REIPPPP) Bid Window 6. Costs are in January 2024 monetary terms, averaged across the relevant bids. None of the bids for wind capacity were awarded Preferred Bidder status.

Table 10-9
Solar photovoltaic and onshore wind costs and performance summary.

Description	BW6 Solar PV Preferred	BW6 Solar PV Compliant Bidders	BW6 Wind Compliant Bids only
Rated capacity, MW Net	166.67	175.86	178.83
Total overnight cost (including augmentation costs), ZAR/kW	15,715.17	19,756.22	26,647.47
Variable O&M Cost ZAR/MWh	18.93	18.04	24.31
Fixed O&M Cost ZAR/kW/year	269.04	256.27	366.95
Procurement time (months)	26.00	26.00	26.00
Construction time (months)	22.33	21.50	23.12
Phasing of capital based on construction times (% per year) 1st year	51.51%	49.29%	47.61%
Phasing of capital based on construction times (% per year) 2nd year	48.49%	50.71%	52.39%
Project (PPA) life (years)	20.00	20.00	20.00
Typical capacity factor	30.13%	31.07%	37.24%
Cycle efficiency (%) / Number of cycles per year	N/A	N/A	N/A

11

ENERGY STORAGE TECHNOLOGIES PERFORMANCE AND COST

Electrochemical and Mechanical Energy Storage

Table 11-1 and Table 11-2 summarize cost and performance for electrochemical and mechanical energy storage technologies.

Table 11-1
Lithium Ion Battery storage cost and performance summary

Technology	Lithium Ion Battery
System size, MW	100
Storage capacity, h	4
Energy storage, MWh	400
Plant cost estimates (2023)	
Total overnight cost, ZAR/kW	25,910
Lead times and project schedule, months	12
Expense schedule, % of TPC per year	100%
O&M cost estimates	
Fixed O&M, ZAR/kW/year	844
Variable O&M, ZAR/MWh	0
Availability estimates	
Equivalent availability	94.1
Maintenance	1.9
Unplanned outages	4.0
Energy requirements, (I/O Ratio)	1.11
Round-trip ac/ac efficiency, %	80–90%
Duty cycle	
Cycles/year	365
Hours/cycle	4
Minimum load	0%
Economic life, years	20

**Table 11-2
Pumped storage hydropower cost and performance summary**

Technology	Pumped Storage Hydropower
System size, MW	1,000
Storage capacity, h	10
Energy storage, MWh	10,000
Plant cost estimates (2023)	
Total overnight cost, ZAR/kW	40,010
Lead times and project schedule, months	96
Expense schedule, % of TPC per year	12%,12%,12%,12%,12%,12%,12%,16%
O&M cost estimates	
Fixed O&M, ZAR/kW/year	317
Variable O&M, ZAR/MWh	0
Availability estimates	
Equivalent availability	90%
Maintenance	5%
Unplanned outages	5%
Energy requirements, (I/O Ratio)	1.3
Round-trip ac/ac efficiency, %	70-80%
Duty cycle	
Cycles/year	365
Hours/cycle	10
Minimum load	0%
Economic life, years	60

Plant Cost Estimates

The total overnight cost for the lithium ion battery systems is 25,900 ZAR/kW for a 100MW system with 4 hour storage duration. Lithium ion battery costs have dropped in the last several years as mega battery supply factories have been built. The total overnight cost for the PSH system is 40,010 ZAR/kW. For PSH, the capital cost includes direct and indirect cost. The direct capital component of a conventional PSH facility includes two water reservoirs, a waterway to connect them, and a power station with one or more pumps/turbines. Indirect costs comprise engineering and construction management, financial costs such as project contingency and insurance, and development costs including permitting, licensing, and site acquisition. The PHS costs are based on a generic representative facility, but PHS projects are very geographically specific and actual costs may vary widely between locations.

The expected expense and construction period are one year for the lithium ion battery system and eight years for the PSH 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.

O&M Cost Estimates

The fixed O&M cost is about 844 ZAR/kW/year for a lithium ion system, and 317 ZAR/kW/year for PSH. Reserved funds for battery and inverter replacement, controls upgrade, and battery disposal are included in the fixed O&M cost for the battery system. PSH O&M cost include fixed labor cost and maintenance cost along with deep repair and refurbishment in which turbine is pulled out and seals are replaced. The variable O&M is zero for the lithium ion battery system and PSH.

Availability and Performance Estimates

The equivalent availability of the lithium ion battery system evaluated in this study is expected to be about 94% and is expected to have an economic life of 20 years. An important driver of the economic life of a lithium ion battery system is its rate of degradation, which is a function of many factors including charge/discharge cycles and ambient temperatures in addition to calendar life. This study assumes one cycle per day (365 cycles per year). A 4-hour battery system could cycle twice per day, but this would accelerate degradation. Accelerated degradation could be addressed through cell augmentations to maintain the rated capacity, or the plant could be decommissioned sooner resulting in a shorter economic life. The PSH plant is expected to have the equivalent availability of 90% and the economic life of 60 years.

Cost of Electricity

Table 11-3 shows a representative levelized cost of electricity for the lithium ion and PSH 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	Lithium ion	PSH
System size, MW	100	1,000
Storage capacity, h	4	10
Fuel cost (ZAR/MWh)	0	0
Charging cost (ZAR/MWh)	1,392	1,483
O&M (ZAR/MWh)	578	127
Capital (ZAR/MWh)	2,335	2,312
LCOE (ZAR/MWh)	4,305	3,921

Water Usage

The water uses for the lithium ion battery system is zero. For closed loop PSH, water is required initially to fill up the reservoir. This water is not actually consumed—it cycles indefinitely between the upper and lower reservoirs. After completion and filling of the reservoirs, evaporation losses need to be replaced. In many places, annual rainfall and evaporation over the reservoir area are approximately balanced. Therefore, the water requirement for a PSH is insignificant.

Emissions

No air emissions are associated with lithium ion and PSH storage technology.

Hydrogen Energy Storage

Tables 11-4 through Table 11-6 summarize cost and performance for hydrogen energy technologies. These cases consist of three major components: electrolysis, underground hydrogen storage, and hydrogen-fired turbine.

Table 11-4
Electrolyzer cost and performance summary

Technology	Alkaline	PEM
System Size, MW	104	115
System Size, kg H ₂ /day	50,000	50,000
Plant cost estimate (2023)		
Total overnight costs, ZAR/kW	25,164	51,687
Total overnight costs, ZAR/kg H ₂ /day	52,427	118,446
Lead times and project schedule, months	24	24
Expense schedule, % of TPC per year	45%, 55%	45%, 55%
Fuel cost estimates		
Cost of firm electricity, ZAR/MWh	2,296	2,296
Cost of variable electricity, ZAR/MWh	1,186	1,186
O&M cost estimates		
Fixed O&M, ZAR/kg H ₂ /year	1,811	3,956
Variable O&M, ZAR/kg H ₂	0.388	0.388
Stack replacement in year 10, ZAR/kg H ₂ /year	7,286	18,611
Availability estimates		
Equivalent availability	90%	90%

Table 11-4 (continued)
Electrolyzer cost and performance summary

Technology	Alkaline	PEM
Performance estimates		
Economic life, years	20	20
Efficiency, kWh/kg H ₂	50	55
Water usage		
Total water usage, L/kg H ₂	1,131	1,511
Electrolysis, L/kg H ₂	30	37
Equipment cooling, L/kg H ₂	1,101	1,473

Table 11-5
Underground hydrogen storage cost and performance summary

Technology	Salt Cavern	Depleted Oil & Gas Reservoir	Hard Rock	Aquifer
Storage capacity, tonnes H ₂ (working gas)*	1,912	1,912	1,912	1,912
Injection rate, kg H ₂ /hr*	2,960	2,487	2,960	2,487
Withdrawal rate, kg H ₂ /hr*	4,920	2,487	4,920	2,487
Plant cost estimates (2023)				
Room overnight cost, ZAR/kg	404	115	778	267
Cushion gas cost, ZAR/kg	60	114	60	114
Site preparation cost, ZAR/kg	344	0	718	152
Door overnight cost, ZAR/kg/day	7,489	9,637	7,729	10,057
Compressors cost, ZAR/kg/day	7,214	9,514	7,214	9,514
Wells cost, ZAR/kg/day	274	122	516	543
Lead times and project schedule, months	36	36	36	36
Expense schedule, % of TPC per year	40%, 50%, 10%	40%, 50%, 10%	40%, 50%, 10%	40%, 50%, 10%
Fuel cost estimates				
Cost of firm electricity, ZAR/MWh	2,296	2,296	2,296	2,296
Cost of variable electricity, ZAR/MWh	1,186	1,186	1,186	1,186
O&M cost estimates				
Fixed O&M, ZAR/kg/day/year	10.98	4.91	0.00	21.72
Variable O&M, ZAR/kg	0.39	0.39	0.39	0.39
Availability estimates				
Equivalent availability	90%	90%	90%	90%
Performance estimates				
Economic life, years	30	30	30	30
Energy requirement, kWh/kg H ₂	2.2	2.2	2.2	2.2
Water usage				
Per unit of hydrogen, L/kg H ₂	50	50	50	50

*Indicative sizes used in original study. Specific costs have been calculated and used for different appropriately sized facilities in LCOE calculations.

Table 11-6
Hydrogen fired turbine cost and performance summary

Technology	Aeroderivative H ₂ Combustion Turbine
Rated capacity, MW gross	40
Rated capacity, MW net	39.1
Plant cost estimates (2023)	
Total overnight cost, ZAR/kW	30,502
Lead times and project schedule (months)	36
Expense schedule, % of TPC per year	35%, 45%, 20%
Fuel cost estimates	
H ₂ cost is a function of electricity source and electrolyzer technology	
Fuel energy content, MJ/kg	120
O&M cost estimates	
Fixed O&M, ZAR/kW/year	1,818
Variable O&M, ZAR/MWh	-
Availability estimates	
Equivalent availability	90%
Performance estimates	
Economic life, years	30
Heat rate, kJ/kWh	9,115
Fuel consumption, kg H ₂ /MWh	76
Plant capacity factor	
Capacity factor	10%
Water usage	
Raw water, L/MWh	350
Machinery cooling water, L/MWh	2,975
Total water usage, L/MWh	3,325

Plant Cost Estimates

Capital costs for electrolysis facilities can be reported in terms of their electricity load or their hydrogen output. The total overnight cost of an alkaline electrolysis facility is 25,164 ZAR/kW or 52,427 ZAR/kg H₂-day. The total overnight cost of a PEM electrolysis facility is 51,687 ZAR/kW or 118,446 ZAR/kg H₂-day. The expected expense and construction period is two years for an electrolysis facility.

Capital costs for energy storage facilities can be separated into “room” costs that scale with the amount of energy that can be stored and “door” costs that scale with the rate at which energy can be discharged. For underground hydrogen storage facilities, “room” costs are driven by cushion gas and site preparation and are reported in cost per kg H₂, and “door” costs are driven by compressors and wells and are reported in cost per kg H₂/day. The total overnight cost of an underground hydrogen storage facility is 404 ZAR/kg H₂ and 7,489 ZAR/kg H₂/day for salt caverns, 115 ZAR/kg H₂ and 9,637 ZAR/kg H₂/day for depleted oil and gas reservoirs, 778 ZAR/kg H₂ and 7,729 ZAR/kg H₂/day for hard rock caverns, and 267 ZAR/kg H₂ and 10,057 ZAR/kg H₂/day for aquifers. The expected expense and construction period is three years for an underground hydrogen storage facility.

The total overnight cost for a hydrogen fired aeroderivative turbine is 30,502 ZAR/kW, and the expected expense and construction period is two years.

Hydrogen Technology Cost Uncertainty

A significant amount of cost uncertainty exists for “power-to-hydrogen-to-power” energy storage. Many of the components of this process may not be technologically mature. While alkaline electrolyzers are very highly mature and have been used for large-scale hydrogen production for decades, the technological maturity of PEM electrolyzers is more variable. Numerous hydrogen blending demonstrations have been conducted in recent years for existing turbines, but state-of-the-art, high-efficiency, utility-scale combustion turbines may only be able to co-fire up to 30% hydrogen by volume without significant modification, and 50% with combustor upgrades. The three largest turbine manufacturers (GE, Siemens, and MHI) have made commitments to develop advanced technologies by 2030 or sooner that would enable additional models of new heavy-duty CTs to fire 100% hydrogen.

Uncertainty is also high for underground storage. Most industry knowledge of underground gas storage comes from the natural gas industry, and hydrogen may present additional challenges. These storage facilities are also highly dependent on the geology of the site, so only certain locations may be able to host an underground hydrogen storage facility, and those sites may be quite different from the indicative cases on which the costs in this report were based.

Lastly, the costs included here for “power-to-hydrogen-to-power” energy storage do not include the costs of hydrogen pipelines and other hydrogen transportation infrastructure. If the major components were located very close together, this omission may not affect the total costs greatly, but if they are located far apart there could be significant costs not accounted for here. Given the low round trip efficiencies and high capital costs of using hydrogen to store electricity, there may be other industries for which hydrogen offers a greater value proposition. If electrolysis capacity and hydrogen pipelines and storage were built for these industries first, the economic case for using hydrogen as a fuel source for peaking power generation may be stronger, as the infrastructure costs would be shared more broadly.

O&M Cost Estimates

The fixed O&M costs for electrolysis facilities are about 1,811 ZAR/kg H₂/year for alkaline and 3,956 ZAR/kg H₂/year for PEM. The variable O&M costs are about 0.388 ZAR/kg H₂ for both technologies. A stack replacement is assumed at year 10, which is estimated to cost 7,286 ZAR/kg H₂/year for alkaline and 18,611 ZAR/kg H₂/year for PEM.

The fixed O&M costs for underground hydrogen storage facilities is estimated to be 10.98 ZAR/kg H₂/day/year for salt caverns, 4.91 ZAR/kg H₂/day/year for depleted oil and gas reservoirs, and 21.72 ZAR/kg H₂/day/year for aquifers. The variable O&M is estimated to be 0.39 ZAR/kg H₂ for all cases.

Hydrogen fired combustion turbines are estimated to have fixed O&M costs of 1,818 ZAR/kW/year and negligible variable O&M costs.

Availability and Performance Estimates

The equivalent availability of all components of the “power-to-hydrogen-to-power” system is assumed to be 90%, though capacity factors of the electrolyzers and storage facilities will vary by use case. The combustion turbine is assumed to operate as a peaking asset with a capacity factor of about 10%. The economic life of the electrolyzers is assumed to be 20 years, and the economic life of the storage facilities and combustion turbines is assumed to be 30 years.

Cost of Electricity

Table 11-7 shows a representative levelized cost of electricity for two “power-to-hydrogen-to-power” systems with different use cases. The first case assumes a PEM electrolysis facility with a 90% capacity factor powered by firm electricity from a small modular nuclear reactor plant. The second case assumes a PEM electrolysis facility with a 36.3% capacity factor powered by variable electricity from an onshore wind plant. In both cases, the PEM electrolysis facility has an output capacity of 50,000 kg H₂ per day. Both cases assume a salt cavern hydrogen storage facility and a combustion turbine plant both appropriately sized to use all the hydrogen generated from the electrolysis facility with a power generation capacity factor of 10%. The levelized costs of electricity are highly dependent on these assumptions and are presented here only for illustrative purposes.

Table 11-7
Hydrogen energy storage levelized cost of electricity

Technology	PEM, SMR	PEM, wind
Power generation system size, MW	247	100
Storage capacity, h	876	876
Capacity factor	10%	10%
Charging cost (ZAR/MWh)	9,980	5,154
O&M (ZAR/MWh)	1,428	3,419
Capital (ZAR/MWh)	11,358	15,601
LCOE (ZAR/MWh)	22,766	24,174
Round trip efficiency	23%	23%

Water Usage

For the hydrogen production itself, alkaline electrolysis is expected to consume 30 liters of water per kg H₂, and PEM electrolysis is expected to consume 37 liters of water per kg H₂. In addition, electrolysis facilities are assumed to consume water for cooling purposes, though dry cooling may also be an option. Alkaline electrolysis is assumed to use 1,101 L/kg H₂ for cooling, and PEM electrolysis is assumed to use 1,473 L/kg H₂ for cooling. Underground hydrogen storage is assumed to consume 50 L/kg H₂ and turbines are assumed to consume 3,325 L/H₂.

12

TECHNOLOGY COST PROJECTIONS

Figure 12-1 and Figure 12-2 present projected total overnight cost from 2023 (the start year of this report’s writing) through 2040 for the gas turbine and advanced fossil and nuclear technology cases featured earlier in this report. Figure 12-1 and Figure 12-2 reflect a “reference” or “base” trajectory (rather than “conservative” or “optimistic”). Figure 12-3 presents projected total overnight cost for the two offshore wind cases featured earlier in this report, with base, conservative, and optimistic cost trajectories. Figure 12-4 presents projections for selected solar thermal cases featured earlier in this report. Figure 12-5 presents projected total overnight costs (on a power capacity basis) for a 100-MW/4-hour lithium ion battery energy storage system with base, conservative, and optimistic trajectories. The optimistic and conservative trajectories further include $\pm 5\%$ error bars to capture additional uncertainty at the ends of the projected cost range. Figure 12-6 presents projected total overnight costs for onshore wind and solar photovoltaic based on REIPPPP Bid Window 6 with base, conservative, and optimistic trajectories.

All projections were developed using future technology cost factors from EPRI’s U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model²⁵, which were themselves derived from the opinions of selected EPRI technology and modeling experts. The factors are based on U.S. technology costs but are considered representative of overall cost trends. All values shown in Figures 12-1 through Figure 12-6 are based on an 18.35 ZAR/USD exchange rate, consistent with the cost-estimating approach taken for the entirety of this research.

The years from 2020 to 2022 saw sharp price increases for many energy system technologies due to pandemic-related supply chain issues. Due to the inherently unpredictable nature of such shocks, these projections do not seek to anticipate their occurrence or effects, but unforeseen events could cause actual prices to materialize well outside projected ranges. Relatedly, price is a function of supply and demand, so if energy systems throughout the region or world begin procuring certain technologies at the same time, the demand could outpace supply and prices could materialize higher than projected.

²⁵ More information on EPRI REGEN can be found at <https://esca.epri.com/models.html>.

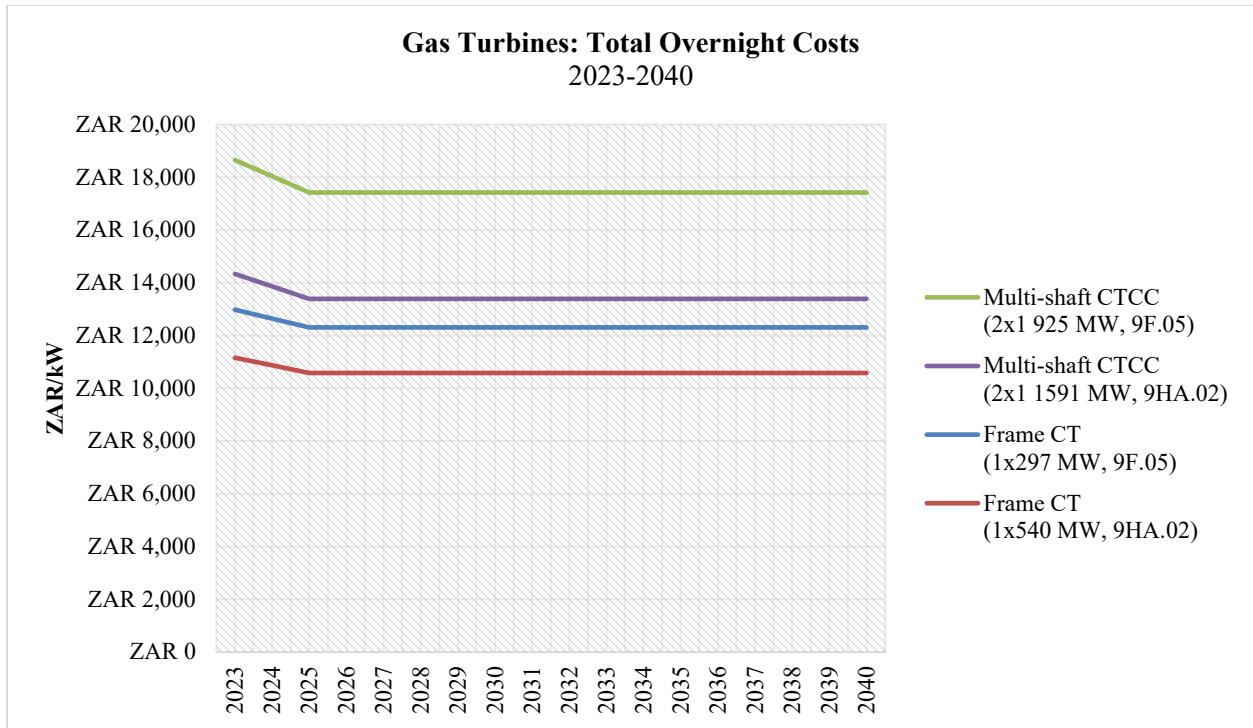


Figure 12-1
Projected capital costs for gas turbines

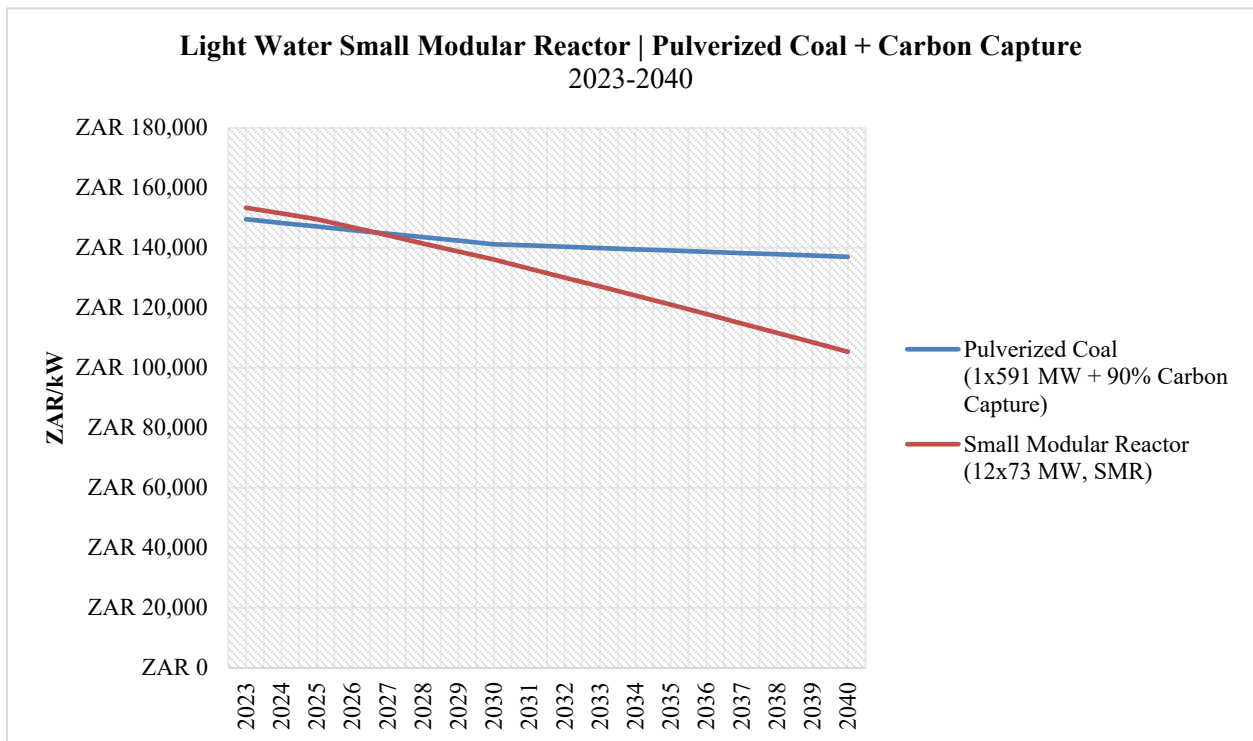


Figure 12-2
Projected capital costs for advanced nuclear and coal technologies

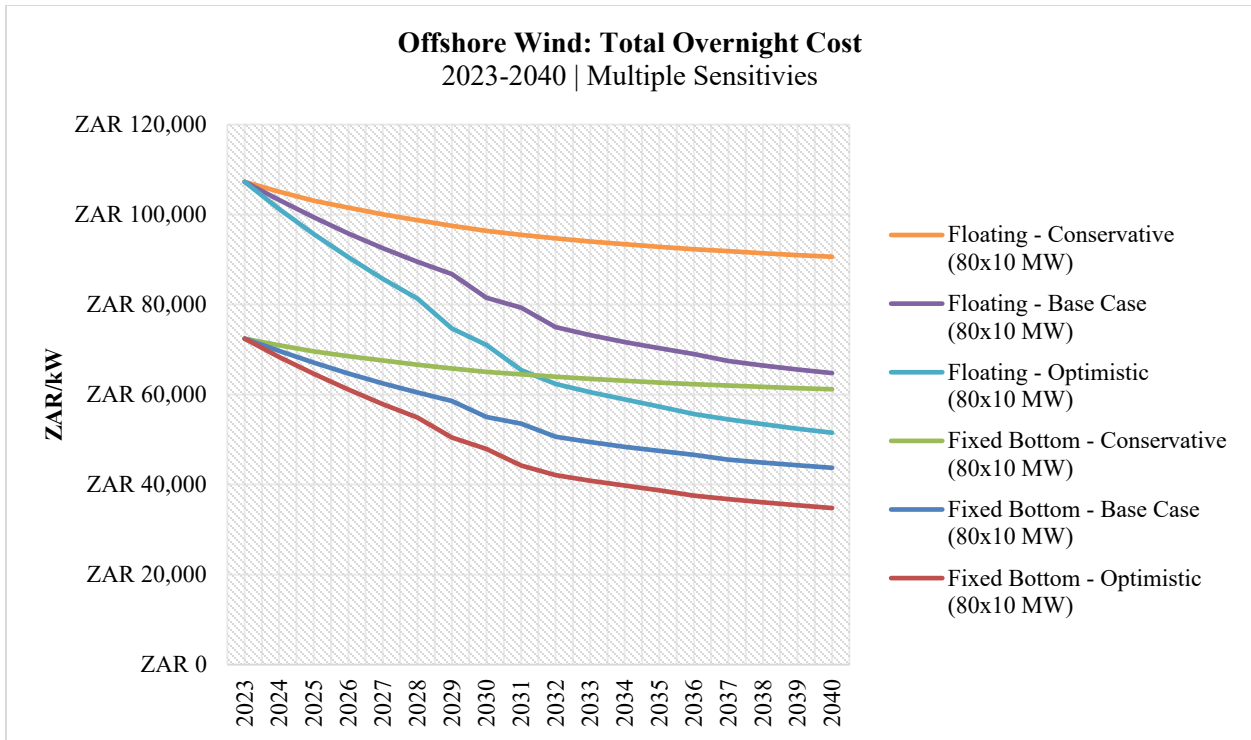


Figure 12-3
Projected capital costs for offshore wind

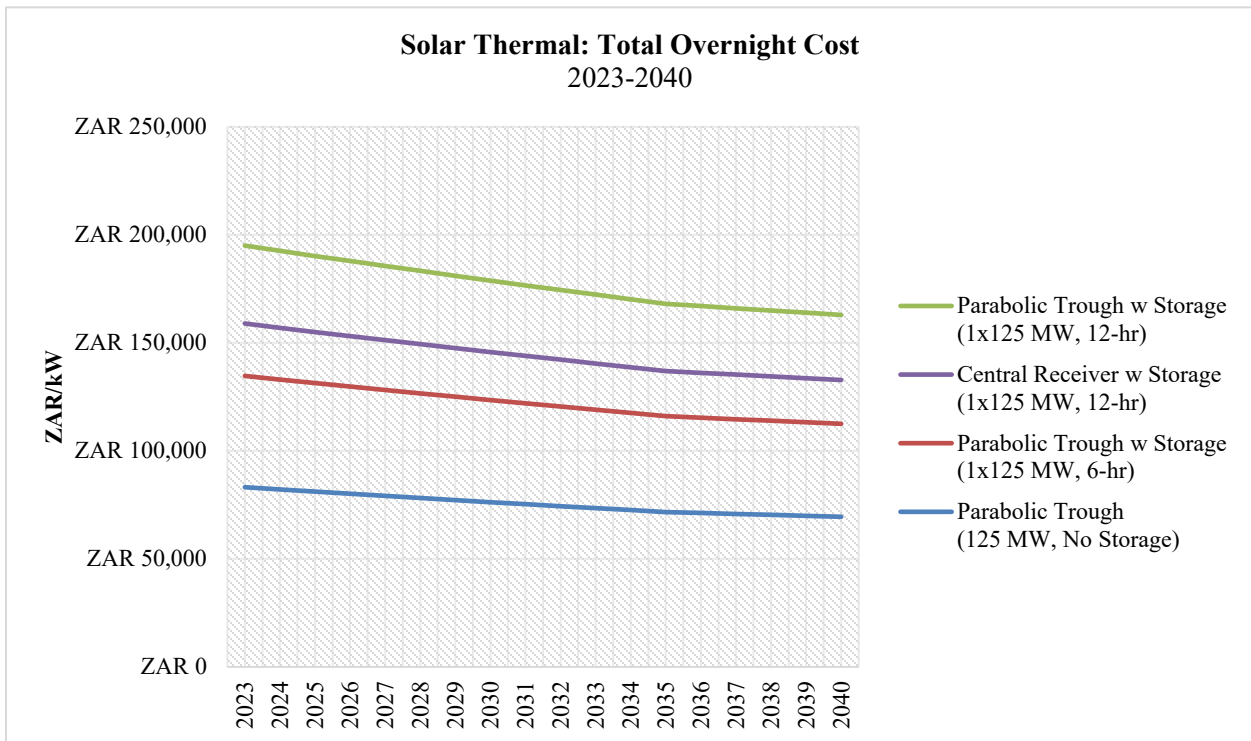


Figure 12-4
Projected capital costs for solar thermal technology

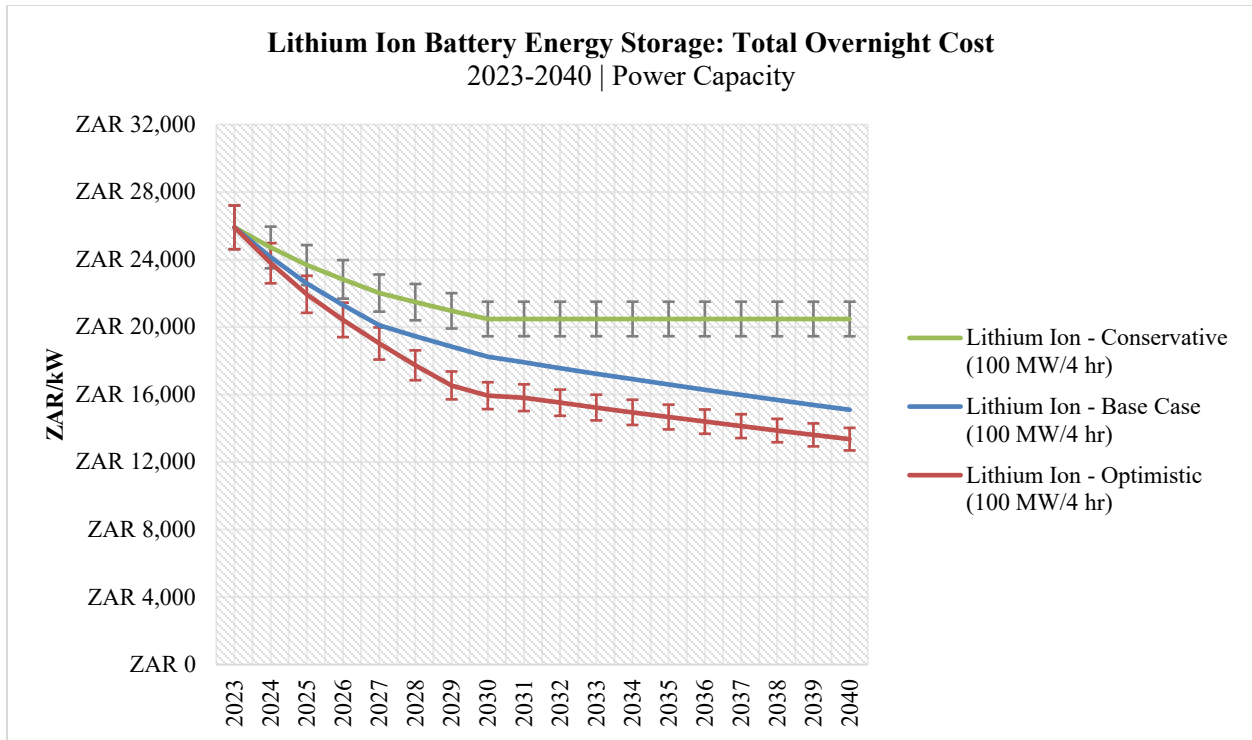


Figure 12-5
Projected capital costs for lithium ion battery energy storage

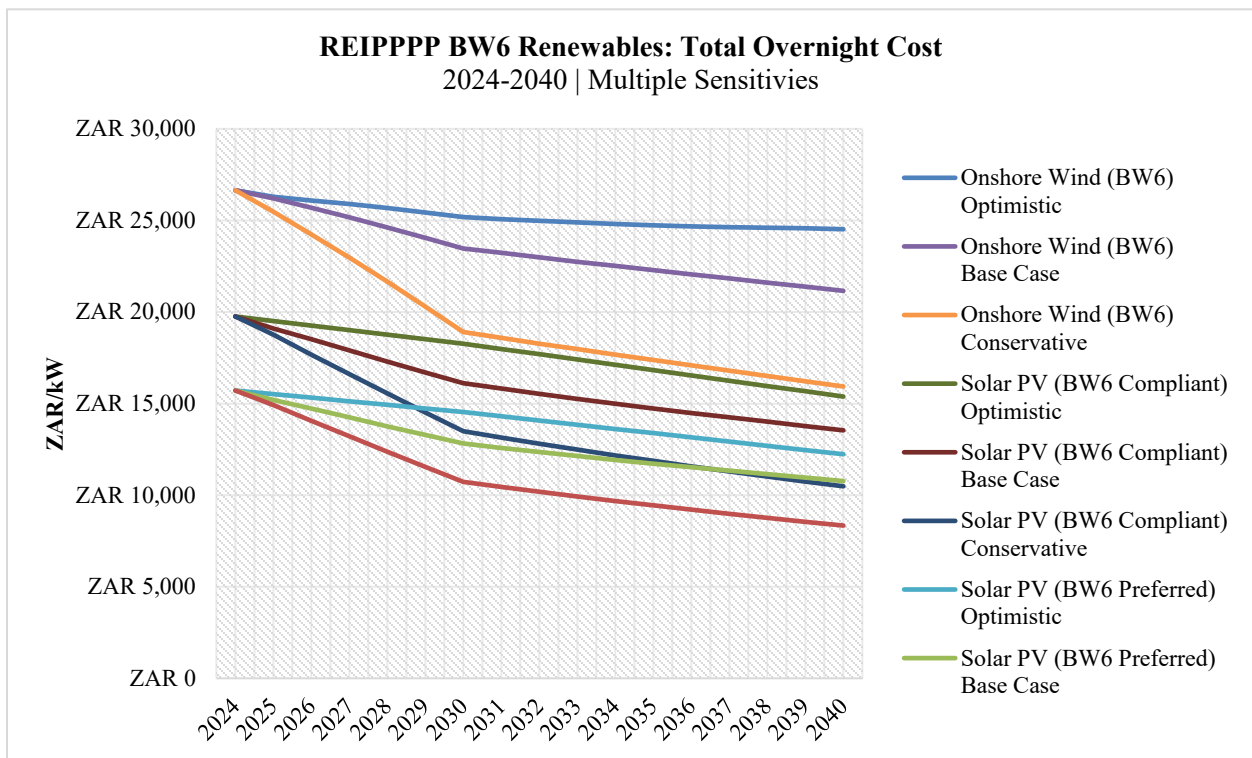


Figure 12-6
Projected capital costs for onshore wind and solar PV

13

LIFE EXTENSION OF COAL-FIRED POWER PLANTS

Background

The prevailing electricity generation infrastructure within the domain of Eskom is reliant upon coal-fired power plants, wherein coal generation constitutes a substantial proportion of the total generation capacity. Specifically, 36GW out of a total generation capacity of 44GW comprises to coal-based generation²⁶. The details of coal-fired power station along with their installed capacity is given in Table 13-10. This reliance on coal as a primary energy source is tempered by the fact that several of these coal-fired power plants have reached or are nearing their end-of-life operational phases.

Eskom is considering the extension of the operational lives of select coal-fired power plants. The section outlines the typical roadmap of life extension program and important consideration during the implementation of plant life-extension. The suggested roadmap is not comprehensive in its scope and does not specifically embody any particular life extension initiative. It should be noted that the approach does not adhere to a singular life extension strategy; rather, it serves as a general strategy intended for customization to meet the specific requirements of Eskom.

Overview of Life Extension Process

Traditionally, coal-fired generating stations have been designed with an assumed nominal and economic life of about 30-years. Some utilities have extended the operational life of these units beyond 30 years, for instance the average age of coal units in the US is 45 years old, considering the economic and system planning benefits of continued power production from older plants.

The useful life of a generating unit is not confined to a predefined design or economic lifespan but is determined by the total cost of maintaining the unit in service at a specified level of reliability in comparison to the total cost of alternative sources of generation. A rational decision on life extension necessitates the integration of performance metrics (availability, reliability, and heat rate) with cost factors (capital equipment, operations, and maintenance), along with ancillary considerations such as environmental and regulatory issues.

The process of life extension is typically carried out progressively, commencing with corporate and system planning, followed by plant life assessment addressing specific plant-related issues, and culminating with life extension implementation involving in the evaluation of individual components of plant. The primary objective is to enhance or prolong one or more facets of plant performance, such as availability, reliability, or heat rate, in a cost-effective manner. The major phases involved in the planning and execution of life extension for a coal fired power plant are

²⁶ Eskom.com

summarized below. The subsequent sub-section elaborates each phase of life extension program for a coal-fired power plant.

Table 13-1
Key phases and action items of life-extension process

Corporate & System Planning	Devise a life-extension strategy
	Rank candidate plants/units
	Estimate costs and schedules
Life Assessment (Plant) Planning	Information gathering
	Rank candidate components-set priorities
	Refine costs and schedules
Component Life Assessment and Refurbishment	Estimate remaining lives
	Identify components requiring refurbishment or replacement
	Refine costs and schedule and take run/repair/replace decisions
Post Refurbishment	Update schedules for future actions
	Maintain data base of equipment condition
	Provide information for on-going corporate forecasts and risk evaluation

Corporate and System Planning

The first phase involves examining corporate and system issues that are critical to the initiation of the life extension program. It takes into consideration system data gathering, benefits of life extension, and the costs of life extension. The main output from the phase will be a ranking of units or projects to be considered for the life extension program along with an estimate of costs and schedule for implementation.

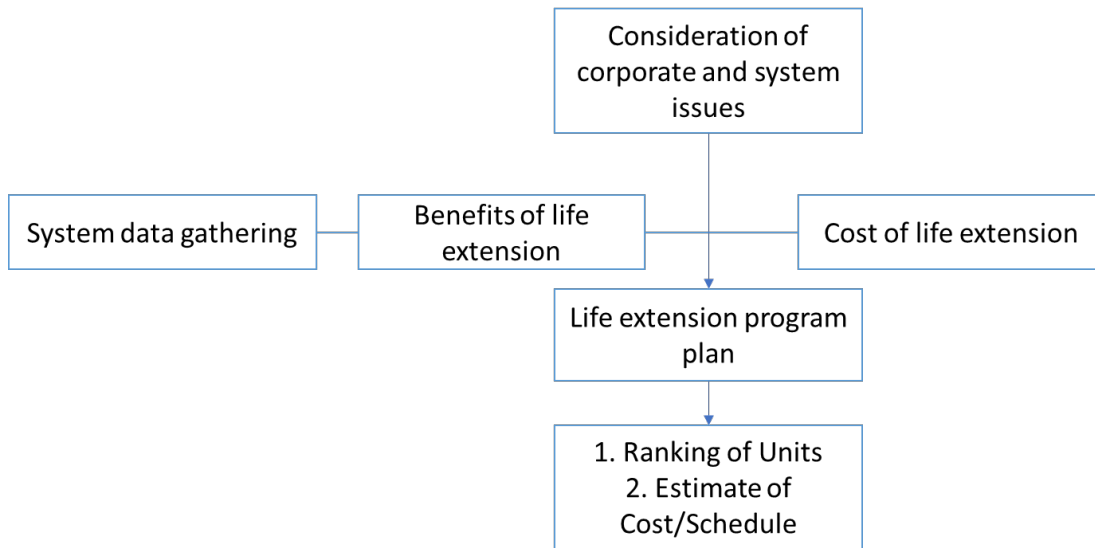


Figure 13-1
Corporate and System Planning

Life Assessment (Plant) Planning

After the identification of potential plants for life extension, the subsequent step involves prioritizing the components within these plants for life extension considerations. This necessitates a thorough assessment of the historical performance of the plant and its key components, coupled with an evaluation of their current operational status. This information can be leveraged to categorize the plant into major systems and, subsequently, to further subdivide these systems into their individual components, allowing for a systematic assessment of component conditions.

Most utility companies employ a categorization system distinguishing plant components into two primary categories: "critical" and a secondary category, variably referred to as "non-critical," "influence," "experience," or "reactive," among others. The purpose of this classification is to identify those components categorized as "critical" that demand immediate attention in the current and subsequent life extension activities. Conversely, components classified as "influence" are typically unit or utility-specific and are considered in later stages. It is important to note that all components will ultimately undergo evaluation at some level of detail; this classification framework primarily serves to identify components that require early attention (see <https://www.epri.com/research/products/000000003002028149>).

To elaborate further, critical components are those whose failure can necessitate an extended outage, jeopardize the safety of plant personnel, or entail extended lead times and high costs for repair and replacement. In contrast, non-critical/influence components may experience a significant degradation in unit performance upon failure but are unlikely to trigger a forced outage, pose risks to personnel safety, or result in widespread secondary damage. Table 13-2 provides a typical breakdown of critical and influence components:

Table 13-2
Categories of Typical Components

	Critical Components	Influence Components
Boiler	Drums Superheater Headers Reheater Headers Waterwall Headers Economizer Inlet Headers Downcomers Main Steam Piping Hot Reheat Piping	Superheater Tubing Reheater Tubing Waterwall Tubing Ductwork Precipitators Ash Handling
Turbine	Rotor Valves Steam Chest	Blades Diaphragms Nozzle Blocks Casing and Shells
Generator	Rotor Shaft Stator Windings Stator Insulation Retainer Rings	Stator Winding Bracing DC Excitor Voltage Regulator
Balance of Plant	Intake & Discharge Structure Structural Steel Stack Liners Station Main Transformers	Condenser Feedwater Heaters Controls Auxiliary Switchgear

After system components have been delineated, it is crucial to adopt an equipment ranking methodology for assigning priorities to individual equipment. The ranking methodology can be utility specific based on various criteria e.g., remaining life of equipment, shortest payback period, value of reliability, corporate financing constraints, risk of forced outage, risk of technology obsolescence etc. Once equipment priorities have been established, preliminary estimates of plant schedules and associated costs can be made. Moreover, plant refurbishment can be conducted using two primary approaches: a phased approach and a front-end approach. In the phased approach, life extension stages are executed incrementally without extending regular maintenance outages. Conversely, the front-end approach involves a single extended outage during which the majority of major life extension work is carried out. In cases where a front-end approach is employed for life extension, the initial schedule should be accommodated within a single major outage. Conversely, when following a phased approach, the initial schedule should align with planned maintenance outages. Equipment priorities and the initial inspection timetable should be adjusted to align with the available outage periods, necessitating judgment concerning the interrelated analyses and schedules.

To minimize the incremental downtime incurred by life extension activities, a common practice involves synchronizing scheduled turbine-generator major overhauls with the necessary

inspections for life extension. This optimization strategy helps to ensure efficiency in the overall maintenance and extension process.

Figure 13-2 below summarizes the key steps in Life Assessment Planning phase.

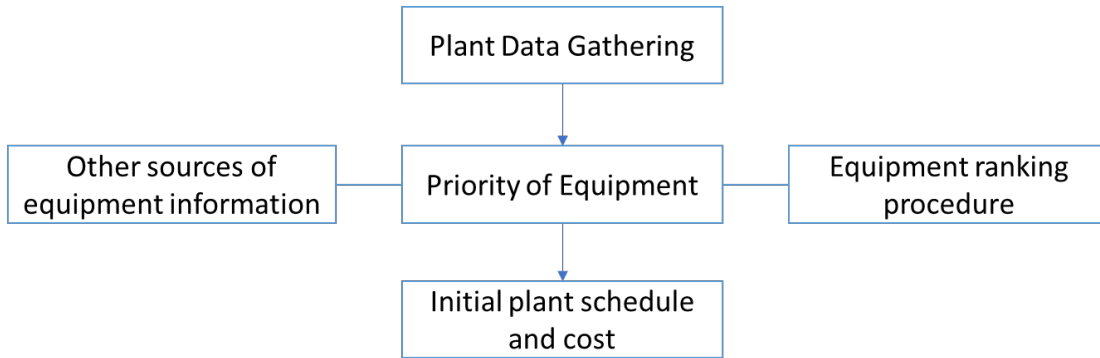


Figure 13-2
Life assessment planning

Component Life Assessment and Refurbishment

Following the data collection process for each unit, the subsequent phase involves the assessment of individual component's condition and the determination of remaining life, which will assist in the run/repair/replace decision. This assessment plays a pivotal role in the pursuit of life extension, with the overarching goal of enhancing plant safety, reliability, and economic performance.

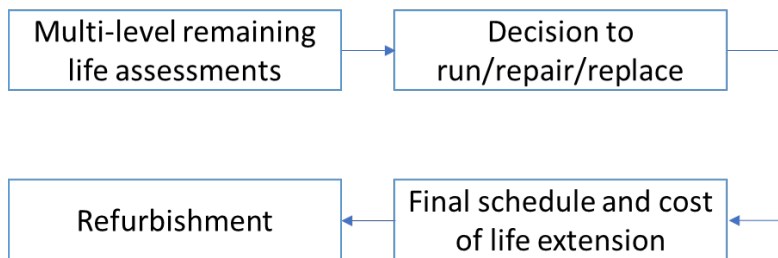


Figure 13-3
Component life assessment and refurbishment

It is worth mentioning that for many coal-plants, operating practices such as load following, cycling, low-NO_x operation, off-design and low-grade fuels, subject components to conditions not anticipated in their original design. In practice, these operational challenges require the plant to maintain high reliability and availability, avoiding forced outages and extending major maintenance outage intervals. Extension of outage intervals allows fewer opportunities to inspect and repair (or replace) damaged components. This can translate into greater risk of component failure.

In the context of condition assessment or remaining life evaluation, which are often used interchangeably in this section, the process hinges upon the consideration of three essential pieces of information:

- The present nature and extent of damage existing within the component.
- The pace at which damage accumulates over time.
- The threshold level of damage required to instigate component failure.

Thus, if an estimate of current damage, along with a rule for damage accumulation and a failure criterion, are known, then remaining life of the component can be estimated. Damage mechanisms that may affect a range of critical and influence components of major systems of a coal fired power plant are summarized below, encompassing various mechanisms such as erosion, corrosion, fatigue, creep, among others.

Table 13-3
Key Boiler Components and their in-service damage mechanisms

Component	Damage Mechanism					
	Creep	Fatigue	Corrosion	Internal Erosion/ FAC	External Erosion/ corrosion	Thermal/ Mech'l Deformation
Waterwall Tubing		X	X		X	X
Superheater (SH) and Reheater (RH) Tubing	X	X	X		X	X
Economizer Tubing		X	X	X	X	X
Superheater Headers	X	X	X			X
Reheater Headers	X	X	X			X
Steam and Lower Drums		X	X			X
Waterwall Headers		X	X			X
Downcomers		X	X			X
Economizer Inlet Headers		X	X	X		X
Main Steam Piping	X	X	(2)			X
Hot Reheat Piping	X	X	(2)			X
Superheater Crossover Piping	(1)	X	X			X
Cold Reheat Piping		X	X			X
Attemperators	X	X	X	X		X
Deaerators		X	X	X		X
Feedwater Heaters		X	X	X		X
Blowdown Vessels		X	X	X		

May occur with high outlet temperature from primary SH.

May occur with cyclic operation due to oxide scale formation and shedding or condensation combined with contaminants from attemperator or drum conveyor.

Table 13-4
Turbine Components and their in-service damage mechanisms

Component	Damage Mechanism					
	Creep	Fatigue	Erosion (Mech. & Elec)	Corrosion	Dielectric Breakdown	Rubbing Wear
Rotor	X	X				
Shell	X	X				
Steam Chest	X	X	X			
Casing	X	X				X
Blades		X	X	X		

Table 13-5
Generator Components and their in-service damage mechanisms

Component	Damage Mechanism					
	Creep	Fatigue	Erosion (Mech. & Elec)	Corrosion	Dielectric Breakdown	Rubbing Wear
Rotor		X				
Stator Windings		X	X			
Insulation			X		X	
Retaining Rings				X		

Table 13-6
Balance of Plant Components and their in-service damage mechanisms

Component	Damage Mechanism					
	Creep	Fatigue	Erosion (Mech. & Elec)	Corrosion	Dielectric Breakdown	Rubbing Wear
Intake and Discharge Structure			X	X		
Structural Steel				X		
Stack Liners				X		
Station Main Transformers				X	X	
Condenser			X	X		
Feedwater Heaters			X	X		
Instrumentation and Controls					X	X
Auxiliary Switchgear					X	X

The condition assessment approach recommended by EPRI uses a multi-level structure in which component evaluations become progressively more detailed as needed (Figure 13-4). Specifically, a three-level structure enables the estimated remaining life (RL) of a component to be iteratively compared with its desired life (DL). The outcome of this assessment dictates whether the equipment should continue operating for a designated period until the next inspection or replacement (run), whether component repair is warranted (repair), or if immediate replacement is necessary (replace). The reinspection interval is contingent upon the equipment's condition and may be extended to align with the desired extended operational lifespan of a coal-fired plant. Moreover, the acceptable DL will depend upon number of factors depending on utility specific need. These may typically include desired unit life extension, inspection or maintenance interval for the component, ease of repair or replacement in the case of failure etc.

This iterative methodology permits the optimization of data acquisition costs while maximizing their value. Table 13-7 illustrates the escalating levels of complexity associated with advancing from Level I to II and III life assessments. A Level III assessment is typically advisable when the utmost confidence in the Remaining Life (RL) of a specific component is imperative.

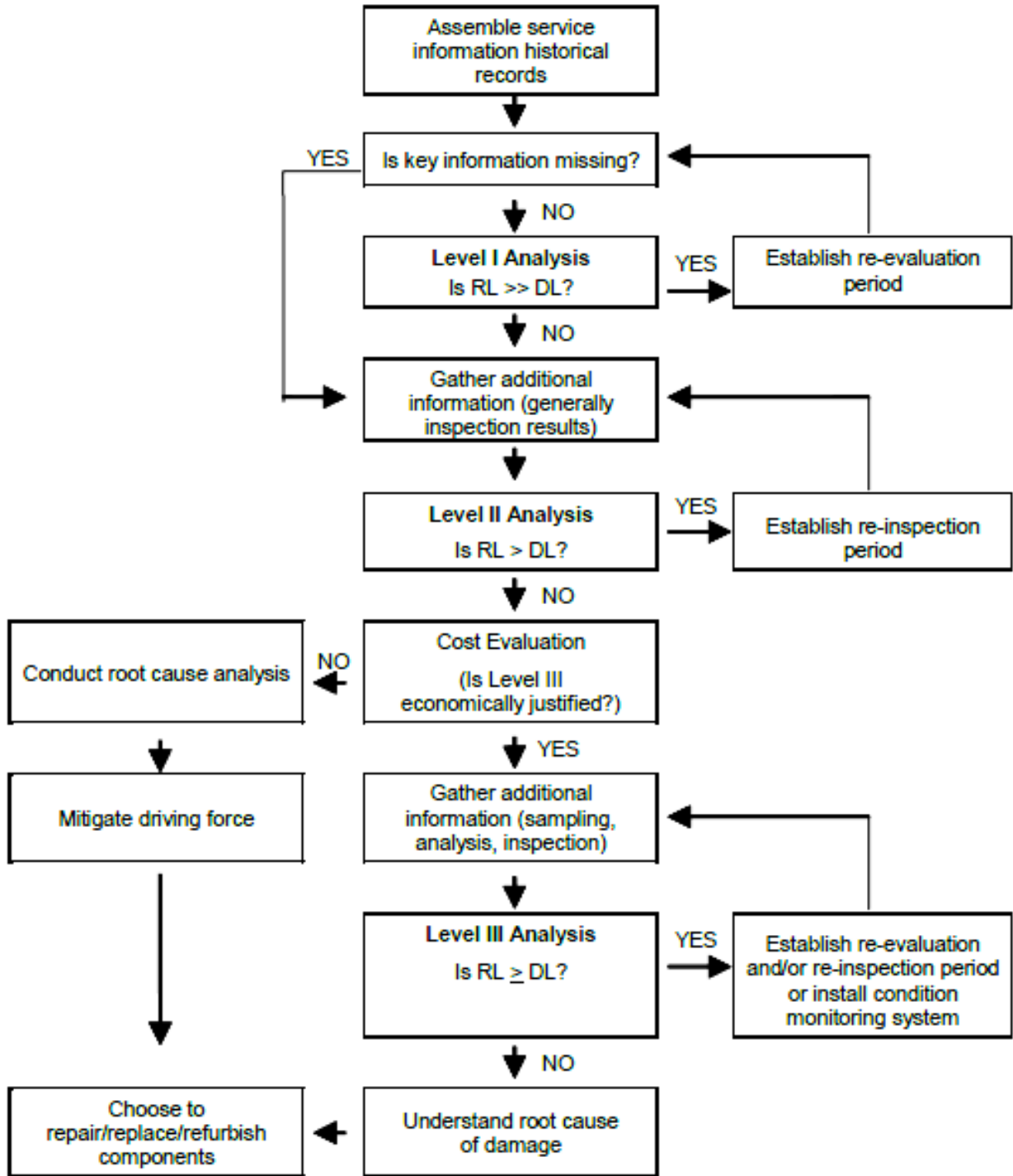


Figure 13-4
General Procedure for Component Life Assessment

**Table 13-7
Data Requirements for the Multi-Level Life Assessment Approach**

Feature	Level I	Level II	Level III
Failure History in Components/Plants with Similar Design Details	Plant Records, Company Records, Guidelines and Reports, Condition Assessment Database, Peer Contacts	Plant Records, Company Records, Guidelines and Reports, Condition Assessment Database, Peer Contacts	Plant Records, Company Records, Guidelines and Reports, Condition Assessment Database, Peer Contacts
Dimensions	Design or Nominal	Measured or Nominal	Measured
Condition	Records or Nominal	Inspection	Detailed Inspection
Temperature and Pressure	Design or Operational	Operational or measured	Measured
Stresses	Design or Operational	Simple Calculation	Refined Analysis
Material Properties	Minimum	Minimum	Actual Material
Material Samples Required?	No	No	Yes

More Rigorous Assessment.
 More accurate operation data required.
 More accurate estimate of equipment RL.

The subsequent subsection will elucidate the application of the three-level condition assessment methodology in a practical context, with a focus on determining the remaining life of Boiler Drums, encompassing both supply and rising piping components. The roadmap of condition assessment is show in Figure 13-5. Accompanying Table 13-8 offers essential information to support various aspects of the condition assessment process, aiding in the nuanced decision-making process regarding whether to run, repair, or replace components.

Table 13-9 delineates a set of recommended actions that have demonstrated effectiveness in averting or mitigating the ongoing accumulation of damage in steam and lower drums, enhancing the overall integrity and performance of these critical components.

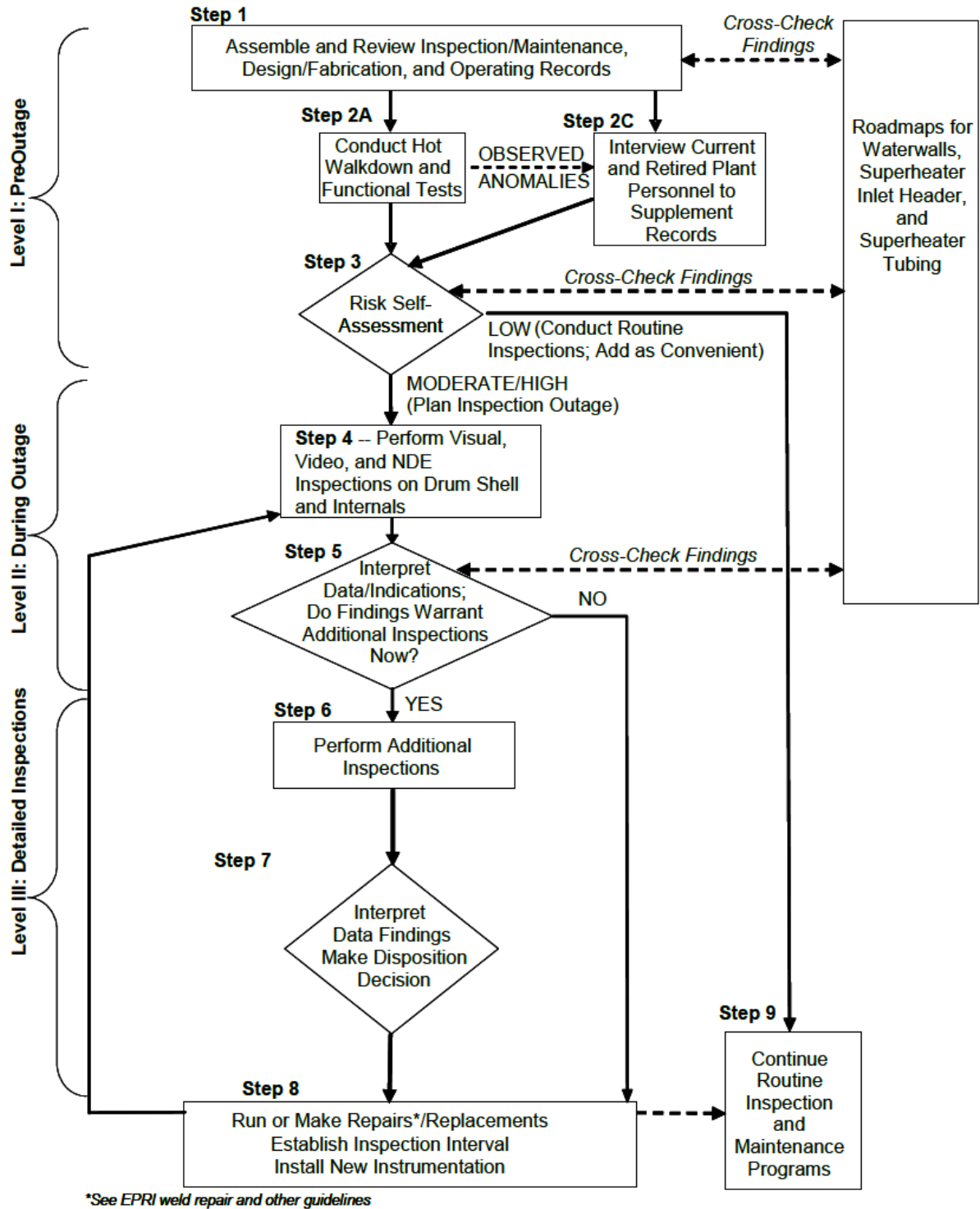


Figure 13-5
Condition Assessment Roadmap for Steam Drums and Lower Drums (including Supply and Riser Piping)

**Table 13-8
Analysis and Disposition for Steam Drums and Lower Drums (including Supply and Riser Piping)**

Component/Location	Permissible Flaw Size	Recommended Analytical Techniques and Disposition
<p>Internal surface corrosion and thermal/corrosion fatigue cracking (at bore hole ligaments, major shell welds, downcomer/feed water nozzles & attachments, miscellaneous penetrating nozzles & attachments to drum shell welds)</p>	<p>No cracking is permissible unless continued safe operation is demonstrated by an integrity analysis.</p> <p>Maintain minimum wall thickness & reinforcement per American Society of Mechanical Engineers (ASME) Code</p>	<p>If warranted, grind out cracks and pits to eliminate stress concentrators. Weld repair to restore wall thickness and reinforcement as necessary.</p> <p>If repair is not practical or warranted, perform a fracture/integrity assessment to demonstrate safe continued operation and determine appropriate inspection interval.</p> <p>Determine and address root cause(s) of corrosion and fatigue mechanisms</p>
<p>Drum Internal Components and Hardware (non-pressure boundary)</p>	<p>Must maintain adequate strength and geometry for functional performance</p>	<p>Damage to drum internal component and hardware does not usually impact vessel integrity directly but can affect operating performance.</p> <p>Determine and address root cause(s) of deformation and corrosion and fatigue mechanisms</p>

**Table 13-9
Potential Preventive Actions for Steam Drums and Lower Drums (including Supply and Riser Piping)**

Damage Mechanism	Preventive Actions
Corrosion	Optimize cycle chemistry per EPRI guidelines to minimize corrosion and redeposition
Corrosion-fatigue	<ul style="list-style-type: none"> • Review cycle chemistry monitoring process and procedures. Remedy shortcomings. • Review operator training on procedures and importance of cycle chemistry. Remedy shortcomings. • Review design, function, and condition of cycle chemistry monitoring instrumentation. Remedy shortcomings. • Review chemical cleaning procedures. Remedy shortcomings. (Shortcomings in chemical cleaning process may involve inappropriate cleaning agent, overly strong concentration, long cleaning time, temperature too high, failure to neutralize, breakdown of inhibitor, or inadequate rinse.) • Review frequency of chemical cleaning • Review procedures and monitoring capability prior to shutdown/layup: <ul style="list-style-type: none"> ○ Monitor water quality before/during shutdown ○ Monitor moisture and other air quality parameters during shutdown/layup ○ Ensure plentiful supply of nitrogen or clean, dry air • Review and monitor oxygen scavenger injection quantity and locations
Fatigue	<ul style="list-style-type: none"> • Review/improve startup and shutdown procedures to minimize rate and magnitude of temperature, pressure, and stress transients. • Evaluate and remedy shortcomings in boiler system operating and control systems/procedures and operator training. • Avoid forced cooling of the boiler
Drum Humping	<ul style="list-style-type: none"> • Consider using preheated feedwater for startups • Consider installing a furnace off-load circulating pump to equalize temperature in drums, waterwalls, and downcomers during shutdown • Equalize temperature distributions of waterwall tubing. Evaluate and remedy temperature imbalances due to ash fouling, slagging, deslagging/soot blowing, burner settings, and other furnace operating parameters. • Modify drum internals to reduce temperature stratification and prevent contact of cold makeup water with drum walls, especially in ligament areas • Evaluate and remedy shortcomings in design, setting, function, and maintenance of supports and restraints • Redesign tubing and downcomer attachments to improve flexibility
Brittle Fracture	<ul style="list-style-type: none"> • Always perform hydrostatic tests at metal temperatures high enough to avoid brittle fracture especially if cracking present. <ul style="list-style-type: none"> ○ Determine Drum Material Fracture Toughness ○ Perform Integrity Analysis (<i>stress analysis & fracture mechanics</i>) to determine critical crack (A_c) size for onset of instability or failure. ○ Based on the above identify appropriate inspection interval

It is important to underscore that a similar assessment framework can be adapted and implemented for evaluating other key components within a power plant. However, due to the comprehensive nature of such assessments, their detailed inclusion within this section of the report is not feasible. The focus, therefore, remains on the illustrative example of Boiler Drums as a representative case study.

EPRI has published numerous technical reports and other resources relevant to damage mechanisms, condition assessment, and failure prevention. A list of references is given at the end of this section.

Post Refurbishment

As discussed in previous subsection, the outcomes of component condition assessments serve as the basis for decisions regarding the continued operation of equipment until the next inspection or replacement, the repair of the component, or immediate replacement. The life extension is a continuous process and to maximize the benefits of life extension, it is crucial for the process to remain iterative following refurbishment activities. This entails the following key post-refurbishment activities:

Equipment Condition Baseline: The condition assessment process primarily focuses on a comprehensive analysis of the actual operating conditions for most plant equipment. In some cases, it may necessitate the implementation of monitoring systems. These systems are instrumental in establishing baseline data for the plant, enabling operators to assess whether the refurbishment successfully achieved the performance objectives established prior to the program. Additionally, ongoing monitoring of the post-refurbishment plant can aid in the early detection of emerging defect conditions in components that may not have been refurbished, potentially averting unexpected outages.

Maintenance and Inspection Scheduling: Another valuable post-refurbishment activity involves using inspection data and the results of condition assessment studies to establish maintenance and inspection intervals. Most assessment techniques will provide recommendations for re-inspection periods. The master schedule will also delineate when inspections for lower-priority equipment, which may not have been inspected during initial outage periods, should be conducted.

Changes in Unit Operation: The information derived from the analysis, measurements, and testing associated with condition assessment, combined with ongoing condition assessments, grants the plant operator the opportunity to operate specific components and the entire unit in a more tightly controlled manner than was previously feasible. Over time, this enhanced control is expected to improve both the heat rate and availability of the unit, thus enhancing the plant's reliability.

ESKOM Coal Fired Power Station

Table 13-10
List of coal fired power stations

Coal-fired Stations	Location	Total installed capacity (MW)
Arnot	Middelburg	2352
Matimba	Lephalale	3990
Duvha	Emalahleni	3600
Majuba	Standerton	4110
Hendrina	Mpumalanga	1893
Lethabo	Sasolburg	3708
Tutuka	Standerton	3654
Kendal	Emalahleni	4116
Kriel	Kriel	3000
Matla	Bethal	3600
Camden	Ermelo	1561
Grootvlei	Balfour	1180
Komati	Middelburg	1000
Kusile	Emalahleni	4800 ²⁷
Medupi	Lephalale	794

References

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²⁷ The power station consists of 6 units of 800MW each. However, all units are not commissioned yet.

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A

COST AND PERFORMANCE DATA

Tables A-1 through Table A-24 provide a summary of the technologies that were evaluated in this study.

Table A-1
Coal and coal-to-gas cost and performance data

Technology	PC - 90% CO ₂ Wet cooling	Coal to Gas Dry cooling
Rated capacity, MW net	591	569
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	149,567	1,114
Lead times and project schedule (months)	48	24
Expense schedule, % of TPC per year	10%, 25%, 45%, 20%	95%, 5%
Fuel cost estimates		
First year, ZAR/GJ	42	261
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, GJ/kg	17,850	53,370
O&M cost estimates		
Fixed O&M, ZAR/kW/year	4,999	202
Variable O&M, ZAR/MWh	111	40
Availability estimates		
Equivalent availability	92%	92%
Maintenance	4.8%	4.8%
Unplanned outages	3.7%	3.7%
Performance estimates		
Economic life, years	30	30
Heat rate, kJ/kWh	13,410	10,762
Water usage		
Per unit of energy, L/MWh	4,469	0.0

Table A-2
Coal and coal-to-gas levelized cost of electricity estimates

	PC - 90% CO₂ Wet cooling	Coal to Gas Dry cooling
Rated capacity, MW net	591	569
Capacity factor	85%	65%
Fuel cost (ZAR/MWh)	564	2,808
O&M (ZAR/MWh)	782	76
Capital (ZAR/MWh)	2,175	29
LCOE (ZAR/MWh)	3,521	2,913

Table A-3
Gas turbine cost and performance data

Technology	9F.05 Dry cooling	9HA.02 Dry cooling	2x1 9F.05 Dry cooling	2x1 9HA.02 Dry cooling
Rated capacity, MW net	297	540	925	1591
Plant cost estimates (2023)				
Total overnight cost, ZAR/kW	12,981	11,159	18,653	14,337
Lead times and project schedule (months)	36	36	48	48
Expense schedule, % of TPC per year	16%, 46%, 39%	16%, 46%, 39%	4%, 17%, 51%, 29%	4%, 17%, 51%, 29%
Fuel cost estimates				
First year, ZAR/GJ	261	261	261	261
Expected escalation (beyond inflation)	0%	0%	0%	0%
Fuel energy content, GJ/kg	53,370	53,370	53,370	53,370
O&M cost estimates				
Fixed O&M, ZAR/kW/year	424	327	501	363
Variable O&M, ZAR/MWh	80	77	61	58
Availability estimates				
Equivalent availability	94%	94%	98%	98%
Maintenance	4.5%	4.5%	1.5%	1.5%
Unplanned outages	2.0%	2.0%	1.0%	1.0%
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh	10,624	9,453	6,900	6,541
Water usage				
Per unit of energy, L/MWh	0.0	0.0	9.1	7.5

Table A-4
Gas turbine levelized cost of electricity estimates

	9F.05 Dry cooling	9HA.02 Dry cooling	2x1 9F.05 Dry cooling	2x1 9HA.02 Dry cooling
Rated capacity, MW net	297	540	925	1,591
Capacity factor	10%	10%	50%	50%
Fuel cost (ZAR/MWh)	2,854	2,541	1,866	1,759
O&M (ZAR/MWh)	576	456	176	141
Capital (ZAR/MWh)	2,052	1,765	523	403
LCOE (ZAR/MWh)	5,482	4,761	2,565	2,302

Table A-5
Internal combustion engine cost and performance data

Technology	9 MW ICE Dry cooling	18 MW ICE Dry cooling
Rated capacity, MW net	9.5	16.2
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	61,195	50,169
Lead times and project schedule (months)	12	12
Expense schedule, % of TPC per year	100%	100%
Fuel cost estimates		
First year, ZAR/GJ	261	261
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, GJ/kg	53,370	53,370
O&M cost estimates		
Fixed O&M, ZAR/kW/year	3,184	2,321
Variable O&M, ZAR/MWh	126	134
Availability estimates		
Equivalent availability	95%	95%
Maintenance	3.0%	3.0%
Unplanned outages	2.0%	2.0%
Performance estimates		
Economic life, years	30	30
Heat rate, kJ/kWh	9,042	9,042
Water usage		
Per unit of energy, L/MWh	0.0	0.0

Table A-6
Internal combustion engine levelized cost of electricity estimates

	9 MW ICE Dry cooling	18 MW ICE Dry cooling
Rated capacity, MW net	10	16
Capacity factor	10%	10%
Fuel cost (ZAR/MWh)	2,431	2,431
O&M (ZAR/MWh)	3,867	2,868
Capital (ZAR/MWh)	9,241	7,578
LCOE (ZAR/MWh)	15,539	12,876

Table A-7
Large-scale nuclear cost and performance data

Technology	1x1600 MW, AREVA	2x1600 MW, AREVA	1x1117 MW, AP1000	2x1117 MW, AP1000
Rated capacity, MW net	1,600	3,200	1,117	2,234
Plant cost estimates (2023)				
Total overnight cost, ZAR/kW	176,885	174,681	169,027	167,264
Lead times and project schedule (months)	72	84	72	96
Expense schedule, % of TPC per year	15%, 15%, 25%, 25%, 10%, 10%	10%, 10%, 25%, 25%, 10%, 10%, 10%	15%, 15%, 25%, 25%, 10%, 10%	10%, 10%, 25%, 25%, 10%, 10%, 10%
Fuel cost estimates				
First year, ZAR/GJ	15	15	15	15
Expected escalation (beyond inflation)	0%	0%	0%	0%
Fuel energy content, GJ/kg	1,299	1,299	1,299	1,299
O&M cost estimates	0	0	0	0
Fixed O&M, ZAR/kW/year	2,837	2,627	3,337	2,980
Variable O&M, ZAR/MWh	218	218	195	195
Availability estimates				
Equivalent availability	92%	92%	93%	93%
Maintenance	6.7%	6.7%	5.7%	5.7%
Unplanned outages	1.4%	1.4%	1.4%	1.4%
Performance estimates				
Economic life, years	30	30	30	30
Heat rate, kJ/kWh	10,000	10,000	11,250	11,250
Water usage, L/MWh				
Cooling (once-through seawater), L/MWh	1,514	1,514	1,514	1,514
Boiler makeup, L/MWh	Negligible	Negligible	Negligible	Negligible

Table A-8
Large-scale nuclear levelized cost of electricity estimates

Technology	1x1600 MW, AREVA	2x1600 MW, AREVA	1x1117 MW, AP1000	2x1117 MW, AP1000
Rated capacity, MW net	1,600	3,200	1,117	2,234
Capacity factor	90%	90%	90%	90%
Fuel cost (ZAR/MWh)	137	137	155	155
O&M (ZAR/MWh)	578	552	618	573
Capital (ZAR/MWh)	3,099	3,058	2,969	2,934
LCOE (ZAR/MWh)	3,814	3,747	3,741	3,661

Table A-9
Small modular nuclear reactor cost and performance data

Technology	12x73 MW, SMR Dry cooling	Coal to SMR, 6x80 MW Dry cooling
Rated capacity, MW net	876	480
Plant cost estimates (2023)	73	
Total overnight cost, ZAR/kW	153,378	174,584
Lead times and project schedule (months)	48	42
Expense schedule, % of TPC per year	15%, 35%, 35%, 15%	15%, 35%, 35%, 15%
Fuel cost estimates	0	
First year, ZAR/GJ	15	48
Expected escalation (beyond inflation)	0%	0%
Fuel energy content, GJ/kg	1,299	N/A
O&M cost estimates	0	
Fixed O&M, ZAR/kW/year	2,623	5,461
Variable O&M, ZAR/MWh	177	61
Availability estimates	0	
Equivalent availability	92%	95%
Maintenance	6.7%	4%
Unplanned outages	1.4%	1%
Performance estimates	0	
Economic life, years	30	30
Heat rate, kJ/kWh	11,500	8,510
Water usage, L/MWh	4	Negligible
Decommissioning of existing plant*		
Total Overnight Cost, ZAR/kW	N/A	1,015
Project schedule (months)	N/A	12-26
Expense Schedule	N/A	50%, 50%

*not included in overnight capital costs or LCOE calculations

Table A-10
Small modular nuclear reactor levelized cost of electricity estimates

Technology	12x73 MW, SMR Dry cooling	Coal to SMR, 6x80 MW Dry cooling
Rated capacity, MW net	876	480
Capacity factor	90%	90%
Fuel cost (ZAR/MWh)	158	252
O&M (ZAR/MWh)	509	754
Capital (ZAR/MWh)	2,528	2,390
LCOE (ZAR/MWh)	3,195	3,396

Table A-11
Wind cost and performance data

Technology	OSW, fixed	OSW, floating
Rated capacity, MW	800	800
Plant cost estimates (2023)		
Total overnight cost, ZAR/kW	72,427	107,274
Lead times and project schedule (months)	36	36
Expense schedule, % of TPC per year	5%, 45%, 50%	5%, 45%, 50%
O&M cost estimates		
Fixed O&M, ZAR/kW/year	2,276	1,596
Availability estimates	93%	93%
Performance estimates		
Economic life, years	30	30
Capacity factor	49.85%	57.26%

Table A-12
Wind levelized cost of electricity estimates

Technology	OSW, fixed	OSW, floating
Rated capacity, MW	800	800
Capacity factor	50%	57%
Fuel cost (ZAR/MWh)	0	0
O&M (ZAR/MWh)	521	318
Capital (ZAR/MWh)	1,767	2,272
LCOE (ZAR/MWh)	2,289	2,590

Table A-13
Solar thermal, parabolic trough cost and performance data

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 (2023)					
Total overnight cost, ZAR/kW	83,198	110,127	134,718	163,898	195,045
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	1,480	1,521	1,561	1,602	1,663
Variable O&M, ZAR/MWh	0.7	0.7	0.5	0.5	0.5
Availability estimates	95%	95%	95%	95%	95%
Performance estimates					
Economic life, years	30	30	30	30	30
Capacity factor (in Upington, SA)	25.6%	32.5%	38.0%	45.6%	53.9%
Water usage					
Per unit of energy, L/MWh	84.2	80.8	78.6	78.1	78.2

Table A-14
Solar thermal, parabolic trough levelized cost of electricity estimates

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
Hours of storage	0	3	6	9	12
Capacity factor	26%	33%	38%	46%	54%
Fuel cost (ZAR/MWh)	0	0	0	0	0
O&M (ZAR/MWh)	662	536	469	400	354
Capital (ZAR/MWh)	4,626	4,837	5,060	5,124	5,164
LCOE (ZAR/MWh)	5,288	5,373	5,529	5,524	5,518

Table A-15
Solar thermal, molten salt tower cost and performance data

Technology	3 h Storage	6 h Storage	9 h Storage	12 h Storage
Rated capacity, MW net	125	125	125	125
Plant cost estimates (2023)				
Total overnight cost, ZAR/kW	106,475	127,823	143,209	158,985
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	1,228	1,281	1,317	1,352
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%	69.6%
Water usage				
Per unit of energy, L/MWh	81.9	87.0	86.3	84.6

Table A-16
Solar thermal, molten salt tower levelized cost of electricity estimates

Technology	3 h Storage	6 h Storage	9 h Storage	12 h Storage
Rated capacity, MW net	125	125	125	125
Hours of storage	3	6	9	12
Capacity factor	39%	51%	60%	70%
Fuel cost (ZAR/MWh)	0	0	0	0
O&M (ZAR/MWh)	356	288	250	223
Capital (ZAR/MWh)	3,849	3,575	3,389	3,259
LCOE (ZAR/MWh)	4,206	3,863	3,639	3,482

Table A-17
Solar PV + Storage (DC-Coupled, Mono-directional) cost and performance data

Technology	Solar + Storage
Solar PV, MWac	250
Solar PV, MWdc	325
Storage Capacity, MW	100
Energy storage, MWh	400
Plant cost estimates (Jan 2023)	
Total overnight cost, ZAR/kW	25,272
Lead times and project schedule, months	12
Expense schedule, % of TPC per year	100%
O&M cost estimates	
Fixed O&M, ZAR/kW/year	665
Variable O&M, ZAR/MWh	0
Availability estimates	94
Performance Estimates	
Economic life, years	30
Capacity Factor	39.0%

Table A-18
Solar thermal, molten salt tower levelized cost of electricity estimates

Technology	Solar + Storage
System size	250MW Solar PV, 100MW/400MWh BESS
Storage capacity, h	4
Capacity factor	32.8%
Fuel cost (ZAR/MWh)	0
O&M (ZAR/MWh)	195
Capital (ZAR/MWh)	683
LCOE (ZAR/MWh)	877

Table A-19
Energy storage cost and performance data

Technology	Lithium ion	Pumped Hydro Storage
System size, MW	100	1000
Storage capacity, h	4	10
Energy storage, MWh	400	10,000
Plant cost estimates (January 2021)		
Total overnight cost, ZAR/kW	25,910	40,010
Lead times and project schedule, months	12	96
Expense schedule, % of TPC per year	100	12%,12%,12%,12%,12%,12%,12%,16%
O&M cost estimates		
Fixed O&M, ZAR/kW/year	844	317
Variable O&M, ZAR/MWh	0	0
Availability estimates		
Equivalent availability	94.1%	90%
Maintenance	1.9%	5%
Unplanned outages	4.0%	5%
Energy requirements, (I/O Ratio)	1.11	1.3
Round-trip ac/ac efficiency, %	80-90%	70-80%
Duty cycle		
Cycles/year	365	365
Hours/cycle	4	10
Minimum load	0	0%
Economic life, years	20	60

Table A-20
Energy storage levelized cost of electricity estimates

Technology	Lithium ion	PHS
System size, MW	100	1,000
Storage capacity, h	4	10
Capacity factor	17%	29%
Charging cost (ZAR/MWh)	1,392	1,483
O&M (ZAR/MWh)	578	127
Capital (ZAR/MWh)	2,335	2,312
LCOE (ZAR/MWh)	4,305	3,921

Table A-21
Electrolyzer cost and performance data

Technology	Alkaline	PEM
System Size, MW	104	115
System Size, kg H ₂ /day	50,000	50,000
Plant cost estimate (2023)		
Total overnight costs, ZAR/kW	25,164	51,687
Total overnight costs, ZAR/kg H ₂ /day	52,427	118,446
Lead times and project schedule, months	24	24
Expense schedule, % of TPC per year	45%, 55%	45%, 55%
Fuel cost estimates		
Cost of firm electricity, ZAR/MWh	2,296	2,296
Cost of variable electricity, ZAR/MWh	1,186	1,186
O&M cost estimates		
Fixed O&M, ZAR/kg H ₂ /year	1,811	3,956
Variable O&M, ZAR/kg H ₂	0.388	0.388
Stack replacement in year 10, ZAR/kg H ₂ /year	7,286	18,611
Availability estimates		
Equivalent availability	90%	90%
Performance estimates		
Economic life, years	20	20
Efficiency, kWh/kg H ₂	50	55
Water usage		
Total water usage, L/kg H ₂	1,131	1,511
Electrolysis, L/kg H ₂	30	37
Equipment cooling, L/kg H ₂	1,101	1,473

Table A-22
Underground hydrogen storage cost and performance data

Technology	Salt Cavern	Depleted Oil & Gas Reservoir	Hardrock	Aquifer
Storage capacity, tonnes H ₂ (working gas)*	1,912	1,912	1,912	1,912
Injection rate, kg H ₂ /hr*	2,960	2,487	2,960	2,487
Withdrawal rate, kg H ₂ /hr*	4,920	2,487	4,920	2,487
Plant cost estimates (2023)				
Room overnight cost, \$/kg	404	115	778	267
Cushion gas cost, \$/kg	60	114	60	114
Site preparation cost, \$/kg	344	0	718	152
Door overnight cost, \$/kg/day	7,489	9,637	7,729	10,057
Compressors cost, \$/kg/day	7,214	9,514	7,214	9,514
Wells cost, \$/kg/day	274	122	516	543
Lead times and project schedule, months	36	36	36	36
Expense schedule, % of TPC per year	40%, 50%, 10%	40%, 50%, 10%	40%, 50%, 10%	40%, 50%, 10%
Fuel cost estimates				
Cost of firm electricity, ZAR/MWh	2,296	2,296	2,296	2,296
Cost of variable electricity, ZAR/MWh	1,186	1,186	1,186	1,186
O&M cost estimates				
Fixed O&M, \$/kg/day/year	10.98	4.91	0.00	21.72
Variable O&M, \$/kg	0.39	0.39	0.39	0.39

Table A-22 (continued)
Underground hydrogen storage cost and performance data

Technology	Salt Cavern	Depleted Oil & Gas Reservoir	Hardrock	Aquifer
Availability estimates				
Equivalent availability	90%	90%	90%	90%
Performance estimates				
Economic life, years	30	30	30	30
Energy requirement, kWh/kg H ₂	2.2	2.2	2.2	2.2
Water usage				
Per unit of hydrogen, L/kg H ₂	50	50	50	50

*Indicative sizes used in original study. Specific costs have been calculated and used for different appropriately sized facilities in LCOE calculations.

Table A-23
Hydrogen fired combustion turbine cost and performance data

Technology	Aeroderivative H ₂ Combustion Turbine
Rated capacity, MW gross	40
Rated capacity, MW net	39.1
Plant cost estimates (2023)	0
Total overnight cost, ZAR/kW	30,502
Lead times and project schedule (months)	36
Expense schedule, % of TPC per year	35%, 45%, 20%
Fuel cost estimates	
H ₂ cost is a function of electricity source and electrolyzer technology	
Fuel energy content, MJ/kg	120
O&M cost estimates	
Fixed O&M, ZAR/kW/year	1,818
Variable O&M, ZAR/MWh	-
Availability estimates	
Equivalent availability	90%
Performance estimates	
Economic life, years	30
Heat rate, kJ/kWh	9,115
Fuel consumption, kg H ₂ /MWh	76
Plant capacity factor	
Capacity factor	10%
Water usage	
Raw water, L/MWh	350
Machinery cooling water, L/MWh	2,975
Total water usage, L/MWh	3,325

Table A-24
Hydrogen energy storage levelized cost of electricity estimates

Technology*	PEM, SMR	PEM, wind
System size, MW	247	100
Storage capacity, h	876	876
Capacity factor	10%	10%
Charging cost (ZAR/MWh)	9,980	5,154
O&M (ZAR/MWh)	1,428	3,419
Capital (ZAR/MWh)	11,358	15,601
LCOE (ZAR/MWh)	22,766	24,174
Round trip efficiency	23%	23%

*These are power-to-H₂-to-power cases including electrolyzers, H₂ storage, and H₂-fired power generation. The two cases in the LCOE table represent PEM electrolysis powered by SMR or wind (at different electricity price and availability) and salt cavern storage.

Figures A-1 through Figure A-3 provide a comparison of the overnight capital costs and levelized costs of electricity from this study. 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 18.35 ZAR to 1 U.S. dollar.

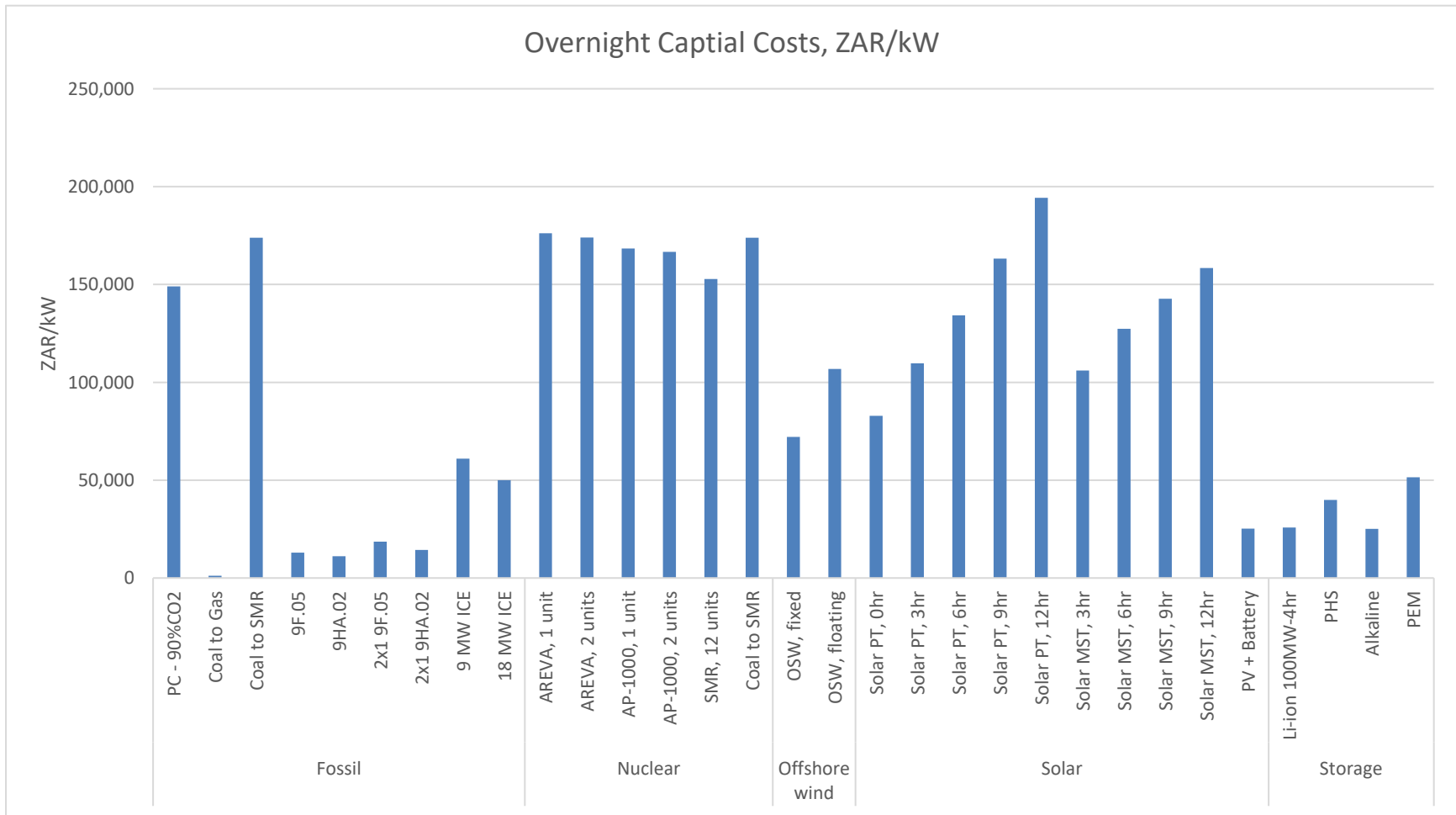


Figure A-1
Comparison of overnight capital costs

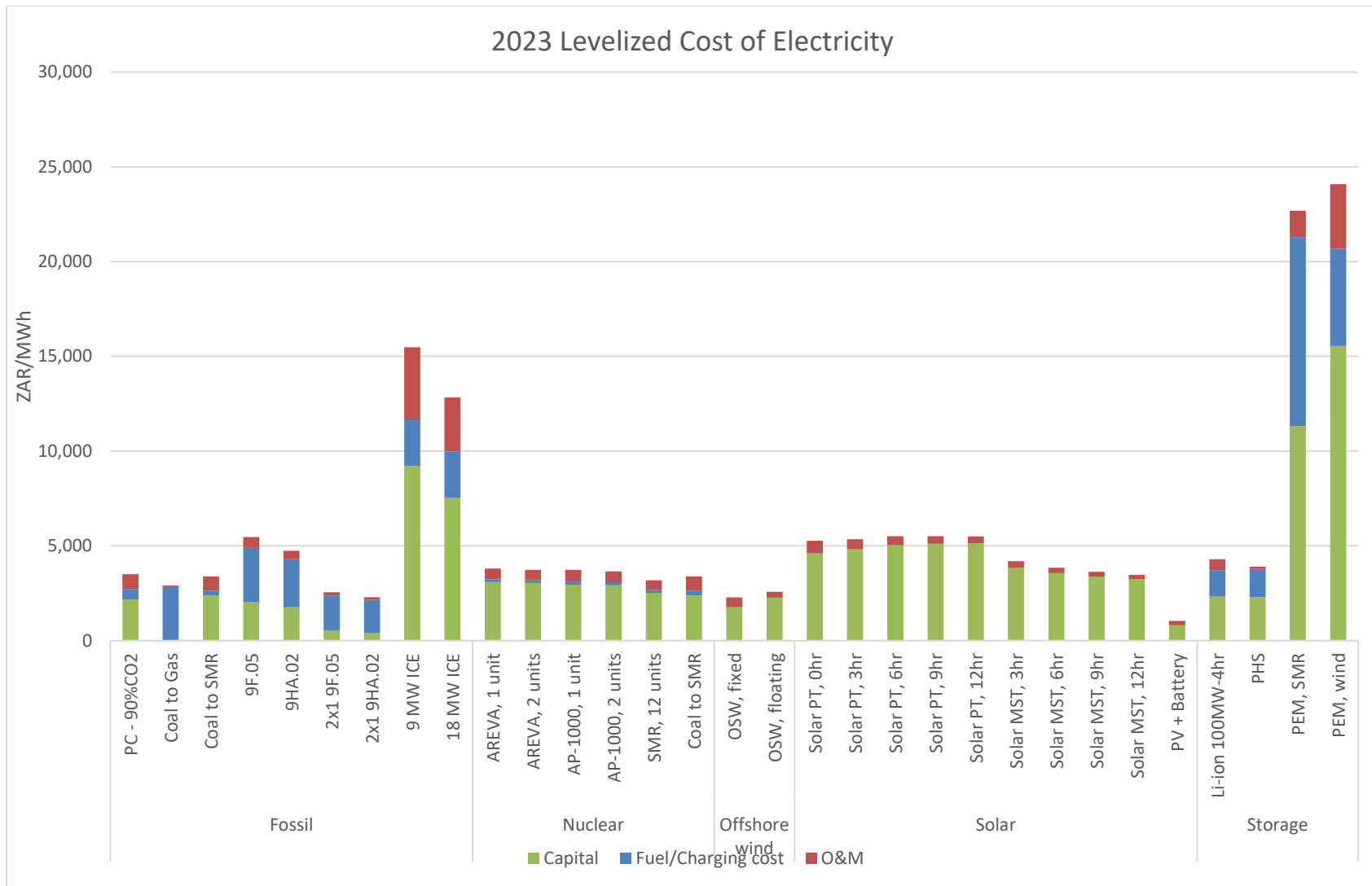


Figure A-2
Levelized cost of electricity estimates

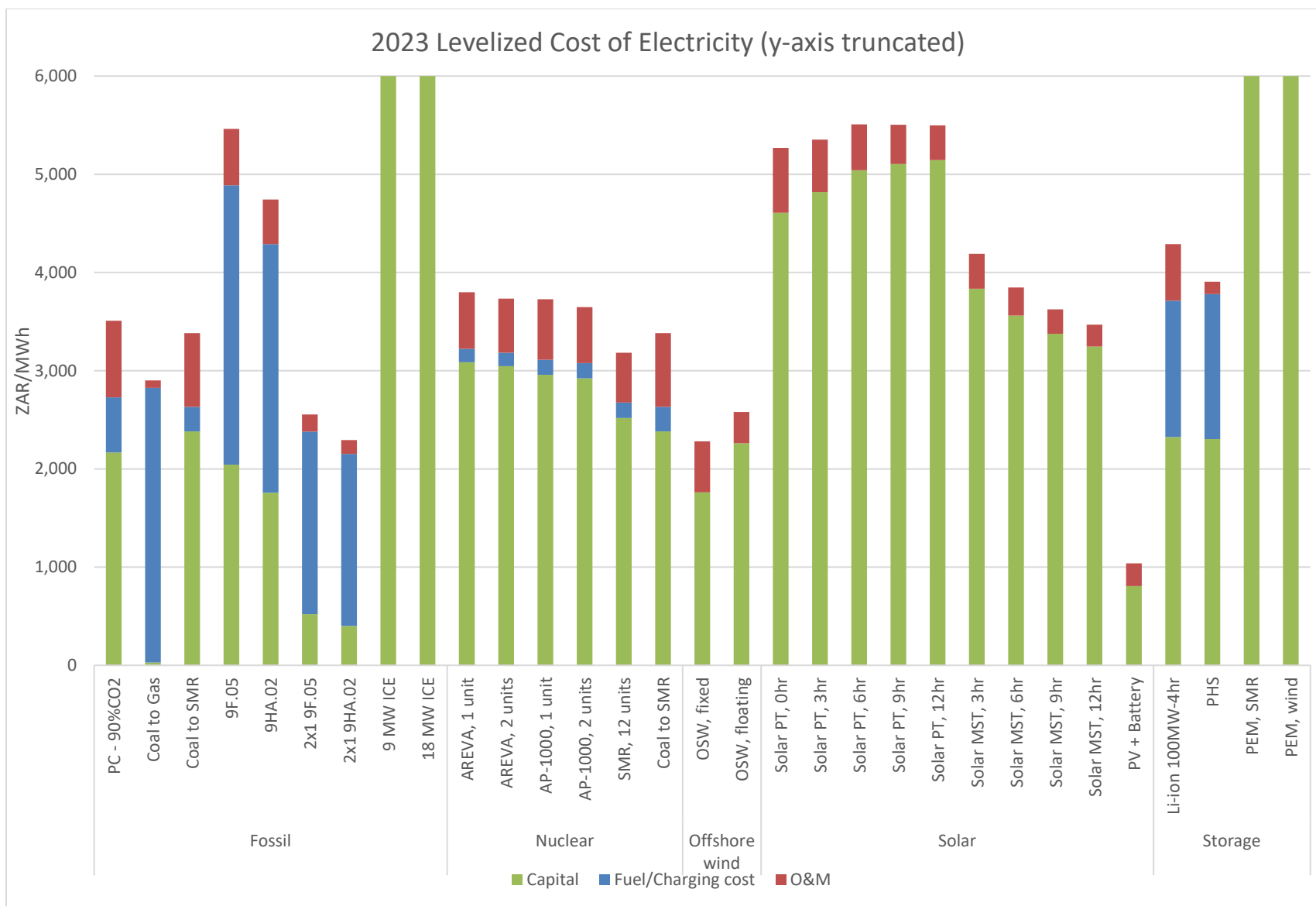


Figure A-3
Levelized cost of electricity estimates (the y-axis has been truncated for clarity)



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