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COMPRESSED AIR ENERGY STORAGE IN SOUTH AFRICA

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A research report submitted to the Faculty of Engineering and the Built Environment, University of the Witwatersrand, Johannesburg, in partial fulfilment of the requirements for the degree of Master of Science in Engineering

Johannesburg, 2013

Abstract

The suitability of Compressed Air Energy Storage (CAES) as a source of peaking plant capacity in South Africa is examined in this research report. The report examines the current state of CAES technology including examples of operational and planned facilities. It further evaluates the potential challenges and benefits of the use of CAES in South Africa. A high level proposal for plant design capacity is documented, and potential costs for construction thereof are estimated. The cost of a CAES plant is compared to generating options using the Levelised Cost of Energy (LCOE) method.

The study proposes that by 2018 additional peaking plant capacity will be required and that a CAES plant able to provide additional capacity up to 3 500MW would help to alleviate the potential shortfall which may be experienced at this time. The report further proposes conversion of underground mines for use as air receivers for high pressure storage of large volumes of compressed air required for CAES.

The research report concludes that CAES presents a feasible solution to the potential future shortfall in peaking plant capacity in South Africa, and that site identification and construction of a suitable storage cavern presents the main obstacle to the implementation of this technology.

Declaration

I declare that this research report is my own unaided work. It is being submitted to the degree of Master of Science in Engineering to the University of the Witwatersrand, Johannesburg. It has not been submitted before for any degree or examination to any other University.

_____

Signed: Mark Robert Stanford

24th day of October 2013

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Nomenclature

	Definition
CAES	Compressed Air Energy Storage
CES	Chemical Energy Storage
CPI	Consumer Price Index
DMP	Demand Market Participation
DSM	Demand Side Management
EAF	Energy Availability Factor gives a measure in % of the available quantity of the total generating capacity.
EES	Electrical Energy Storage
g	Acceleration due to gravity (m/s^2)
GT	Gas Turbine
h	Difference in vertical height (m)
HHV	Higher Heating Value - The higher heating value, defined as the amount of heat released by a specified quantity (initially at 25 °C) once it is combusted and the products have returned to a temperature of 25 °C.

IPP	Independent Power Producers
ISO	Independent System Operator
LCOE	Levelised Cost of Energy
LHV	Lower Heating Value
MES	Mechanical Energy Storage
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
NRR	Net Rate of Return
P	Pressure (Pa)
Peak Demand/Load	This is periods when the highest consumption of electrical energy occurs.
PHS	Pumped Hydro Storage
OR	Operational Reserve
RMRCT	Refrigerated Mined Rock Cavern Technology

Reserve Margin	The amount of unused available capability of an electric power system (at peak load for a utility system) as a percentage of total capability.
SMES	Superconducting Magnetic Energy Storage
Storage Efficiency	Electrical Energy Output / Total Electrical Energy Input
TES	Thermal Energy Storage
UA	Unplanned-Outage Allowance
β	Compression Ratio
ρ	Density (kg/m^3)

1 INTRODUCTION

The world over, electricity availability and continuity of supply is a key focus area. Every country has a critical need for electrical energy; we use it to build cities, drive factories and businesses, provide transport, light and heat homes, prepare and process food, and provide clean running water. Electrical energy has become essential to virtually everything that we do and only a short disruption is required to remind us how heavily we depend on having electricity available.

However, the ever increasing demand for electricity has placed supply under pressure. Universally the ability to meet growing energy demands is causing concern with focus on increasing electricity generating capacity and the efficient use of electricity produced and South Africa is no exception. Because the demand for electricity varies continuously, power plants too must vary keeping up with demand. Electricity producers do this with two main types of power plants; base load and peaking plant. Base load plant runs continuously and supplies the majority of electrical demand while peaking plant is only used when demand exceeds the level that the baseload plant can supply. Peaking plant such as Gas Turbines (GT) are significantly more expensive to operate than baseload plant, so it is economical to use baseload plant as far as possible. The ability to store this cheaper baseload plant power allows producers to access this energy at times of high demand without the need to operate peaking plant with high operating costs.

Compressed Air Energy Storage (CAES) stores energy in large volumes of compressed air in a similar way to how pumped hydro storage plants store energy in large elevated water reservoirs. CAES does this by using electricity during periods of low demand to compress and store air which is then released through a modified gas turbine at times of high demand to provide additional electrical capacity. CAES plants require large storage caverns for the volumes of air required to operate the plant. CAES compressor and turbine components utilise technology similar to that of gas turbines and other turbo-equipment, but differ in that the compression of the air used to generate electricity and the electricity production do not occur simultaneously.

Two CAES plants are currently operating commercially, Huntorf in Germany and McIntosh in the USA proving that the concept is feasible, and various new CAES plants are planned for construction in the near future.

Presently there are factors that make CAES specifically relevant to the South African power network. South Africa is currently experiencing a shortfall in the peak level of electricity available which is eroding reserve capacity, and this is expected to continue until new plant comes online some years in the future. This shortfall is particularly serious during winter months when peak electricity usage levels are at their greatest. A CAES plant would therefore provide much needed additional generating capacity to deal with maximum loads, which could also be used as an alternative to other peaking plant which may be more expensive to operate.

South Africa also has a great number of mines as a significant proportion of the local economy is driven by mining and associated activities. The underground workings produced by underground mining activities could potentially be suitable for use as storage caverns for a CAES plant. Many mine sites with old workings are located around South Africa.

The objectives of the study are as follows:

1. Review the current state of CAES technology.
2. Investigate the potential need for additional generating capacity for the South African power network
3. Evaluate the suitability of a CAES plant to fill a potential need for additional generating capacity.
4. Investigate potential sites in South Africa where large volumes of compressed air required to supply the CAES plant could be stored.
5. Propose a generating capacity for a potential CAES plant in South Africa.
6. Investigate costs that would be associated with constructing a CAES plant compared with alternative peaking plant types.

The level of detail of this study will be limited to a desktop examination of the current state of CAES as a technology, and an examination of the suitability of the use of CAES in South Africa.

2 LITERATURE REVIEW

2.1 Thermodynamic analysis of CAES/TES systems for renewable energy plants (Grazzini and Milazzo, 2007)

The thermodynamic analysis presented in Grazzini and Milazzo (2007) evaluates the theoretical efficiency of a Compressed Air Energy Storage (CAES) Unit without combustion making use of thermal energy storage (TES) to heat the expanding air. It gives a first principles view of the energy recovery efficiency that can be expected from this type of CAES system. The importance of energy storage with a growing shift toward renewable sources of supply such as wind energy which have unpredictable generation with respect to time is also highlighted.

Grazzini and Milazzo (2007) propose that the thermal energy expelled as heat during compression should be recovered and reintroduced into the gas during expansion in order to optimise the overall system efficiency. The absence of combustion advances the process nearer to the “Adiabatic CAES” model.

The study briefly examines other forms of energy storage and illustrates the relative storage capacities and power outputs that are typically achievable as shown in Figure 1 - Performance of Various Energy Storage Technologies. The figure illustrates that currently only Pumped Hydro Storage (PHS) and Compressed Air Energy Storage (CAES) are capable of commercial scale installations as other systems suffer from low availability, high cost, low power output or can operate only for a short duration.

Regarding the storage pressure that should be used, Grazzini and Milazzo (2007) observe that, for an assumed constant air temperature, it is sensible to have a design pressure of at least 50 times that of ambient (i.e. a compression ratio (β) of at least 50:1). This is due to the exponential nature of the decrease in required volumetric capacity for a given desired energy storage capacity with Compression Ratio β, referring to Figure 2.

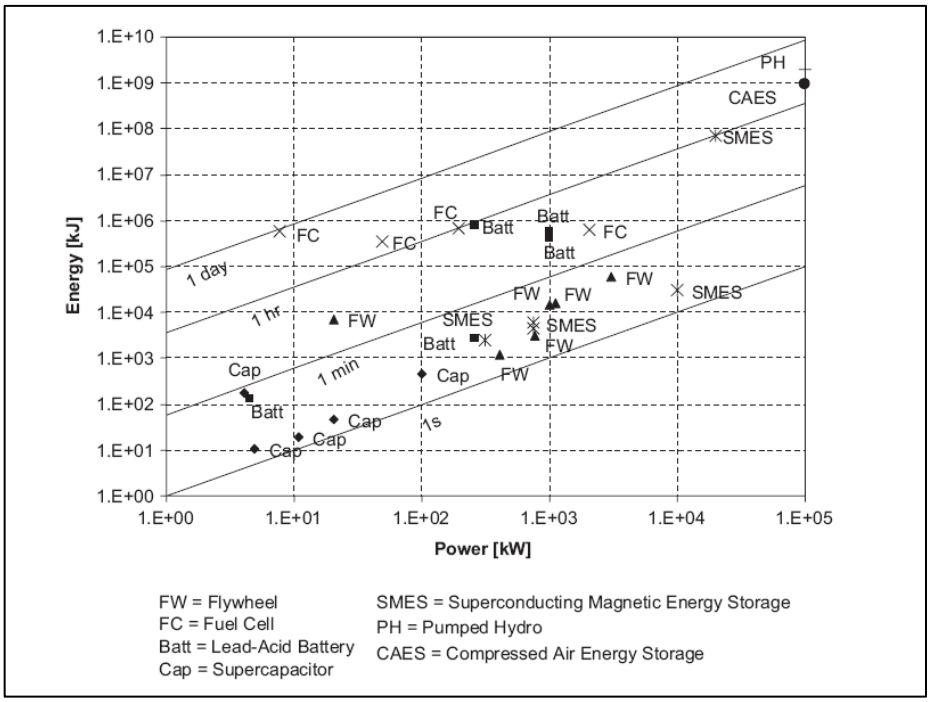


Figure 1 - Performance of Various Energy Storage Technologies (Grazzini and Milazzo, 2007)

There is a lengthy analysis on the optimisation of the reservoir with reference to the required energy storage capacity, but as the author notes in the case of natural underground storage to which this study is limited, the system capacity and associated costs are simply given by the nature of the underground volume available. As a result and thus will not be discussed any further, but will examine the possibility of typical facilities being able to withstand a Compression Ratio of 200:1 with regard to atmosphere (i.e. approximately 20 MPa)

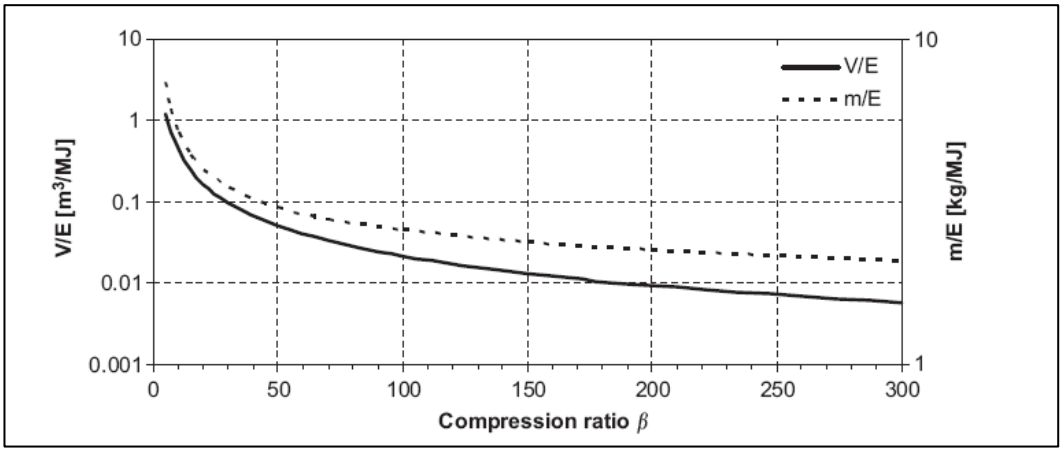


Figure 2 - Specific Air Volume and Mass for constant temperature energy storage (Grazzini and Milazzo, 2007)

The analysis assumes the following parameters:

Table 1 - Grazzini and Milazzo (2007) assumed parameters

Input Power:	500kW
Charging Period:	8 hrs
Stored Energy: (Based on Energy = Power x Time)	14 400MJ
Heat Exchanger Efficiency:	70%
Energy Input:	16 500MJ
Energy Output:	11 800MJ

and assumes the following process parameters:

- Intercooled compression is used to reduce the work input
- Irreversibilities in the process are ignored
- Steady state

Grazzini and Milazzo (2007) continue with what is essentially a simulation having assumed the parameters listed in Table 1. The findings present a strong case for compressed air energy storage as opposed to other energy storage methods though the efficiencies shown are dependent on the use of a thermal energy storage system.

A theoretical adiabatic compressed air energy storage system would have the benefit of eliminating the need to burn fuel to heat the expanding air, which would have cost/commercial and environmental benefits.

The study highlights a useful arrangement for compressors to allow fast charging at low pressures and high pressure reservoir charging with the same equipment by varying the arrangement of the compressors by altering the path of the gas flow. Initially when large volumes of air are required to charge the chamber at low pressure, the compressors would be arranged in parallel, and then to achieve the high pressure required, the same compressors could then be arranged in series to allow multi-stage compression. The principle is illustrated in Figure 3 below:

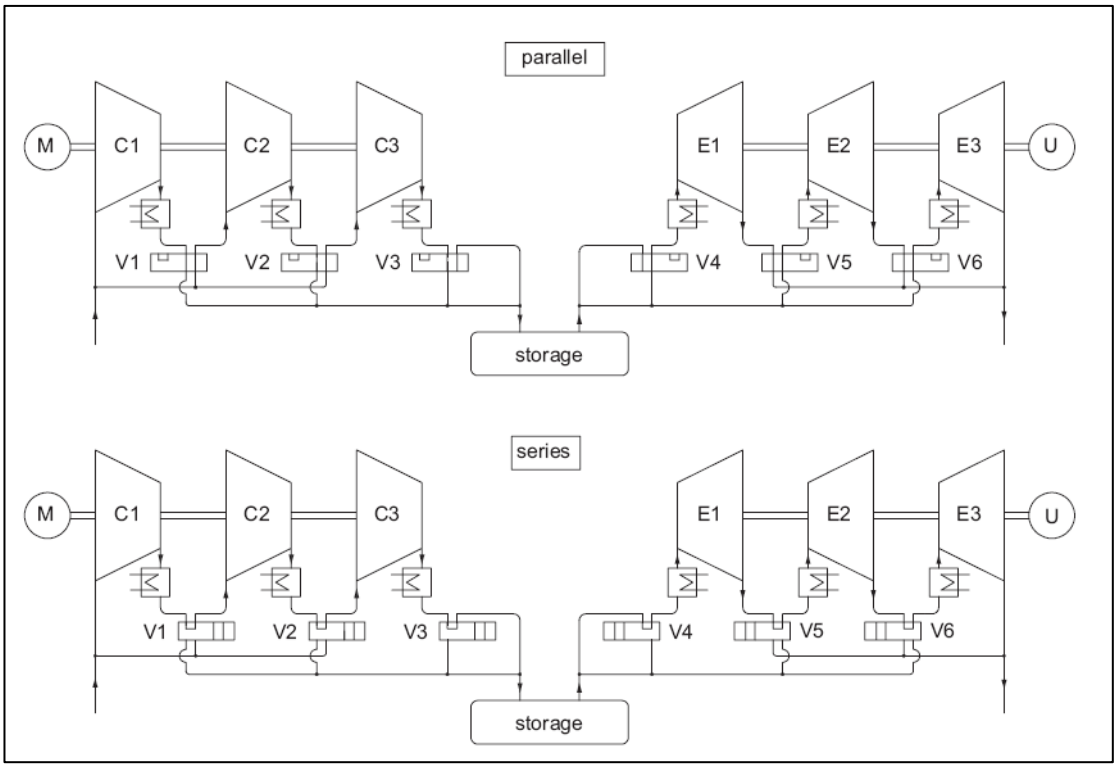


Figure 3 - CAES system with thermal storage (Grazzini and Milazzo, 2007)

The findings present a strong case for the economic viability of using compressed air as a storage medium. The study also notes that five inter-cooling stages would be a practical compromise between the increase in work recovery efficiency with an increasing number of stages, and the increased cost and complexity of having multiple inter-cooling stages.

The study does not evaluate the economic viability of such a system but indicates that the overall efficiency of the system is approximately 72%, which the authors note is unrealistically high, due to the following limitations:

- Efficiency values are given for a compression ratio of 200:1. This is not a constant value as the pressure in the chamber reduces air consumed by the process.
- The study assumes inter-cooling between compression stages to reduce the exit temperature as far as possible which in practice may be costly and impractical to implement.
- Steady state of the gas at all times.
- Constant fluid characteristics

- Constant efficiencies for all equipment regardless of other conditions
- Pressure loss along piping and heat exchangers are not considered.

Grazzini and Milazzo (2007) note that although this does not provide realistic values for expected system efficiencies, the result warrants further development of the concept.

2.3 The role of compressed air energy storage (CAES) in future sustainable energy systems (Lund and Salgi, 2009)

Lund and Salgi (2009) conducted a research project at the Technical University of Denmark (DTU) that focuses on the problem of balancing supply and demand of electricity in environments with highly variable supply, as is typically the case with wind energy power and other renewable source plants. Denmark has experienced excess electricity supply problems and the study examines CAES as an application to potentially store this surplus energy until it is required. The study uses a deterministic model to analyse the system economic potential of a CAES plant and compares this with other storage options and examines the Danish case in 2007, extrapolating current trends to 2030. The methodology used in this analysis was conducted using the EnergyPLAN Model, which can be viewed in greater detail at www.EnergyPLAN.eu. (Last accessed March 2010).

The study focuses on the economic benefits of improving the integration of wind power compared with the capital outlay and operating costs for plant incorporating a CAES system. The real benefit lies in the comparison of the results with other similar technologies such as pumped hydro storage.

The economic review examines two cases:

1. Spot market prices for power
2. Regulated power markets

Assumptions of the study:

1. The study assumes isentropic efficiencies of the turbine and compressor equipment.
2. The storage cavern is assumed to be airtight and have a uniform wall temperature of 35°C.

Lund and Salgi (2009) note that due to the fact that CAES is essentially an extension of Gas Turbine Technology, the basic technology is readily available, proven and reliable, as has been demonstrated at the commercially operated plants in the US and Germany. Also historically CAES has been viewed in conjunction with nuclear and coal generation technologies where it is used primarily as a means for load levelling and for fuel saving applications, though

with renewable energy becoming increasingly common around the world the technology is more commonly being viewed as a means to better integrate variable supplies into mainstream power grids, as in the case of wind energy where periods of peak generating ability seldom align with periods of peak demand.

Table 2 - Technical and economic data of alternatives to CAES plants (Lund and Salgi, 2009)

Technology	Description	Annual investment and fixed operation costs (interest 3%)
CAES	360 MW turbine, 216 MW compressor, 1478 MWh storage, lifetime = 30 years	14 million EUR/year
EB, electric boiler in CHP plants	1300 MW electric boiler 0.13 million EUR/MW Lifetime = 20 years Operation costs = 1–2%	14 million EUR/year
HP, Large-scale heat pumps in CHP plants	85 MW-e heat pump 2.1 million EUR/MW-e COP = 3.5 Lifetime = 20 years Operation costs = 1%	14 million EUR/year
ELC, electrolysers to replace Ngas with hydrogen in CHP plants	535 MW electrolysers 0.25 million EUR/MW-e Lifetime = 20 years Operation costs = 3% 360 GWh H_2 storage 0.05 million EUR/GWh Lifetime = 25 years Operation costs = 0% Efficiency = 0.72 H_2 + 0.1 Heat	14 million EUR/year
H_2 electrolysers, H_2 storage and fuel cells	180 MW electrolysers 120 GWh H_2 storage 90 MW Fuel cell 0.8 million EUR/MW-e Lifetime = 20 years Operation costs = 6% *Efficiencies:* Electrolyser + storage: 0.72 Fuel cell: 0.56 Total: 0.4	14 million EUR/year

The study reviews technical and economic alternatives to CAES plants, as illustrated in Table 2.

This case is somewhat different to the current South African situation as Denmark currently receives 20% of its total electrical energy requirement from wind energy and the analysis rests heavily on this assumption, though the author does also consider the German case that is far more heavily reliant on coal burning steam turbine stations for their supply needs which is more similar to South Africa.

The results of this study indicate that as a pure sink for oversupply of electrical energy from renewable sources, the size of plant that would be required and the cost thereof are so significant that CAES alone cannot provide a solution. However, when one considers that this energy is available at a later stage, thus reducing future requirements for generating capacity, a CAES system becomes a more economically feasible option.

2.4 Progress in Electrical Energy Storage Systems: A critical review (Chen et al, 2009)

Chen et al (2009) provide a review of energy storage technologies available, reviewing aspects such as maturity of the technology, implementation and operating costs, operating capacities for time and power output amongst others, and reviews typical applications for the technologies.

The study highlights the importance of energy storage, particularly when considering intermittent power generation supply sources as is the case with renewable energy sources. It also highlights the advantage that power can be generated at a constant or variable rate at times of low demand and/or cost, and used at a different variable rate at times of high demand, high generation cost or when no other generation capacity is available. This depends on the storage and generating capacity of the equipment.

Chen et al (2009) examine energy storage technologies with reference to stationary applications like power generation and distribution, which makes it particularly relevant to CAES as a load levelling means. The study makes reference to the shift of governments to invest in energy storage and that the anticipated storage level for energy is expected to increase by 10-15% of installed capacity in developed nations.

Making the comparison with other commodities, electrical energy producers typically have little or no storage capacity forcing them to sell exactly at the time of production which forces them to be price takers. The ability to store energy and supply as desired has the potential to fundamentally change the power production business model. The need to always be able to meet demand also leads to expensive overdesign of plants. Figure 4 illustrates the difference between peak shaving and load levelling and shows that plants could be designed for average energy required as long as there is sufficient storage capacity for the energy.

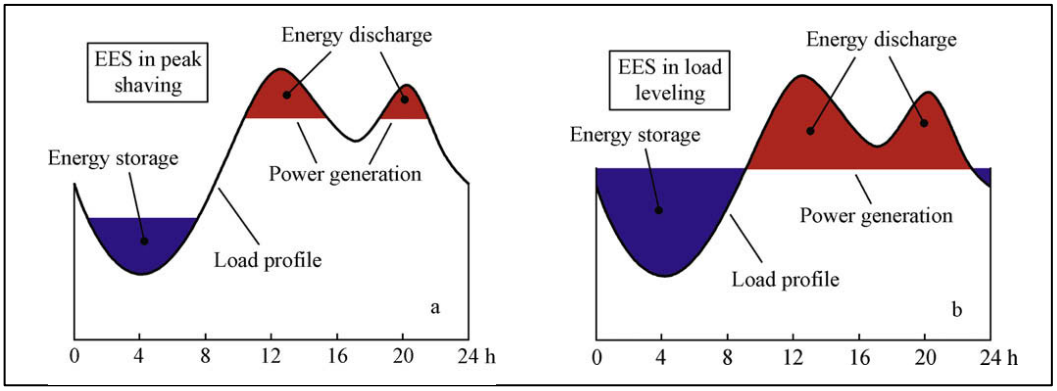


Figure 4 - Load profile of a large-scale electricity storage system. (a) EES in peak shaving (b) EES in Load Levelling (Chen et al, 2009)

This operating strategy is of particular relevance to plants that operate best at relatively constant output such coal fired power plants, or constantly at near full capacity for economic reasons as is the case with nuclear power plants. The study again notes the importance of electrical energy storage systems to sources of intermittent supply as with many renewables like wind and photovoltaic solar power, where surplus power can be stored at times of high output to compensate for lower output periods when demand exceeds generating capacity.

The study classifies energy storage into 4 main types:

1. **Electrical Energy Storage (EES):** This includes electrostatic energy storage using capacitors and super capacitors, and magnetic/current energy storage including Super Conducting Energy Storage (SMES).

2. **Mechanical Energy Storage (MES):** Further subdivided into:
   a) Kinetic energy storage such as flywheels.
   b) Potential energy storage such as Pumped Hydro Storage (PHS) and Compressed Air Energy Storage (CAES).

3. **Chemical Energy Storage (CES):** Further subdivided into:
   a) Electro-chemical energy storage such as conventional batteries e.g. lead-acid, nickel metal hydride, lithium ion and flow-cell batteries such as zinc bromine and vanadium redox.

b) Chemical energy storage such as fuel cells, molten-carbonate fuel cells (MCFCs) and Metal-Air batteries, and thermo-chemical energy storage such as solar hydrogen, solar metal, solar ammonia dissociation–recombination and solar methane dissociation–recombination.

4. **Thermal Energy Storage (TES):** Further subdivided into:
   a) Low temperature energy storage such as aquiferous cold energy storage and cryogenic energy storage.
   b) High temperature energy storage such as steam or hot water accumulators, graphite, hot rocks and concrete, and latent heat systems such as phase change materials.

The study identifies PHS and CAES as the two energy storage technologies currently capable of providing storage facilities with capacities greater than 100MW. Figure 5 below illustrates the operating principle of CAES and main system components as described by Chen et al (2009):

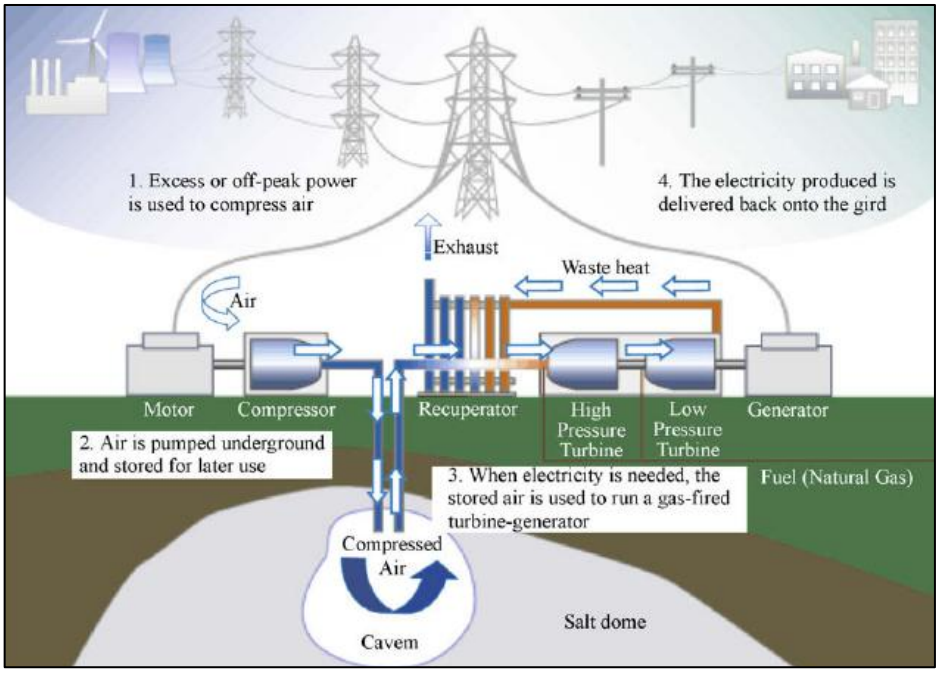


Figure 5 - Diagram of CAES principle (Chen et al, 2009)

Chen et al (2009) note that CAES is a relatively mature technology as it operates on similar principles to conventional gas turbine systems and highlights that

CAES systems are designed to be able to operate efficiently during partial load conditions and to be frequently cycled, (typically daily).

Table 3 - Comparison of Technical Characteristics of EES Systems (Chen et al, 2009)

Systems	Power rating and discharge time		Storage duration		Capital cost		
	Power rating	Discharge time	Self discharge per day	Suitable storage duration	$/kW	$/kWh	¢/kWh-Per cycle
PHS	100–5000 MW	1–24 h+	Very small	Hours–months	600–2000	5–100	0.1–1.4
CAES	5–300 MW	1–24 h+	Small	Hours–months	400–800	2–50	2–4
Lead-acid	0–20 MW	Seconds–hours	0.1–0.3%	Minutes–days	300–600	200–400	20–100
NiCd	0–40 MW	Seconds–hours	0.2–0.6%	Minutes–days	500–1500	800–1500	20–100
NaS	50 kW–8 MW	Seconds–hours	~20%	Seconds–hours	1000–3000	300–500	8–20
ZEBRA	0–300 kW	Seconds–hours	~15%	Seconds–hours	150–300	100–200	5–10
Li-ion	0–100 kW	Minutes–hours	0.1–0.3%	Minutes–days	1200–4000	600–2500	15–100
Fuel cells	0–50 MW	Seconds–24 h+	Almost zero	Hours–months	10,000+		6000–20,000
Metal-Air	0–10 kW	Seconds–24 h+	Very small	Hours–months	100–250	10–60	
VRB	30 kW–3 MW	Seconds–10 h	Small	Hours–months	600–1500	150–1000	5–80
ZnBr	50 kW–2 MW	Seconds–10 h	Small	Hours–months	700–2500	150–1000	5–80
PSB	1–15 MW	Seconds–10 h	Small	Hours–months	700–2500	150–1000	5–80
Solar fuel	0–10 MW	1–24 h+	Almost zero	Hours–months	–	–	–
SMES	100 kW–10 MW	Milliseconds–8 s	10–15%	Minutes–hours	200–300	1000–10,000	
Flywheel	0–250 kW	Milliseconds–15 min	100%	Seconds–minutes	250–350	1000–5000	3–25
Capacitor	0–50 kW	Milliseconds – 60 min	40%	Seconds–hours	200–400	500–1000	
Super-capacitor	0–300 kW	Milliseconds – 60 min	20–40%	Seconds–hours	100–300	300–2000	2–20
AL-TES	0–5 MW	1–8 h	0.5%	Minutes–days		20–50	
CES	100 kW–300 MW	1–8 h	0.5–1.0%	Minutes–days	200–300	3–30	2–4
HT-TES	0–60 MW	1–24 h+	0.05–1.0%	Minutes–months		30–60	

Systems	Energy and power density				Life time and cycle life		Influence on environment	
	Wh/kg	W/kg	Wh/L	W/L	Life time (years)	Cycle life (cycles)	Influence	Description
PHS	0.5–1.5		0.5–1.5		40–60		Negative	Destruction of trees and green land for building the reservoirs
CAES	30–60		3–6	0.5–2.0	20–40		Negative	Emissions from combustion of natural gas
Lead-acid	30–50	75–300	50–80	10–400	5–15	500–1000	Negative	Toxic remains
NiCd	50–75	150–300	60–150		10–20	2000–2500		
NaS	150–240	150–230	150–250		10–15	2500		
ZEBRA	100–120	150–200	150–180	220–300	10–14	2500+		
Li-ion	75–200	150–315	200–500		5–15	1000–10,000+		
Fuel cell	800–10,000	500+	500–3000	500+	5–15	1000+	Negative	Remains and/or combustion of fossil fuel
Metal-Air	150–3000		500–10,000			100–300	Small	Little amount of remains
VRB	10–30		16–33		5–10	12,000+	Negative	Toxic remains
ZnBr	30–50		30–60		5–10	2000+		
PSB	–	–	–	–	10–15			
Solar fuel	800–100,000		500–10,000		–	–	Benign	Usage and storage of solar energy
SMES	0.5–5	500–2000	0.2–2.5	1000–4000	20+	100,000+	Negative	Strong magnetic fields
Flywheel	10–30	400–1500	20–80	1000–2000	~15	20,000+	Almost none	
Capacitor	0.05–5	~100,000	2–10	100,000+	~5	50,000+	Small	Little amount of remains
Super-capacitor				2.5–15	500–5000	10–30		100,000+
20+		100,000+	Small	Little amount of remains				
AL-TES	80–120		80–120		10–20		Small	
CES	150–250	10–30	120–200		20–40		Positive	Removing contaminates during air liquefaction (Charge)
HT-TES	80–200		120–500		5–15		Small	

The study concludes that CAES (when compared with other energy storage systems described by Chen et al (2009)) provides:

- A relatively long energy storage period (periods up to a year have been recorded), assuming the cavern is sufficiently airtight.
- Relatively low capital costs
- Large storage capacity (typically 100's of MW)

The following drawbacks are also noted:

- Economic feasibility is highly dependent on favourable geography for a suitable storage reservoir such as salt deposits
- The need for heating of the escaping stored gas, typically through combustion of fossil fuels, makes the technology less attractive.

Chen et al (2009) provide the summary shown in Table 3 illustrating the relative capacities and costs of the various energy storage technologies, and goes on to describe many other energy storage technologies in a level of detail not relevant to this report.

Chen et al, (2009) conclude with the following observations regarding energy storage:

1. Energy Storage is desperately required by conventional electricity generation industry

2. No single energy storage system emerges as the clear favourite in all applications and each system has its own relative benefits.

3. CAES is favourable as it is suitable in an energy management application, is technically developed and commercially available has a relatively high cycle efficiency, has a long cycle life, and is the technology most likely to rapidly develop commercially (especially in countries with favourable geology for the storage caverns).

2.5 Parametric Study of Payoff in Applications of Air Energy Storage (CAES) Plants – An Economic Model for Future Applications (DeCorso et al, 2006)

DeCorso et al (2006) examine possible reasons for the lack of development of commercial scale CAES plants in the U.S.A., despite the relative success of McIntosh, the U.S.A.'s first CAES peaking plant installed by the Alabama Electric Cooperative.

The study further aims to compare the profitability of a CAES and natural gas fired peaking plant while varying parameters affecting the relative profits of these two systems The study notes that the American Energy Storage Council estimates that energy storage could positively impact the American economy by $175 billion over a fifteen year period and highlights that pumped hydro storage has become the energy storage technology of choice despite suitable sites for CAES greatly outnumbering those available for pumped hydro storage.

The study examines a Gas Turbine (GT) peaking plant with the following output:

Table 4 - Conventional GT Peaking Plant Basic Data (DeCorso et al, 2006)

Power Output	160 MW
Heat Rate	10450 BTU/kWh (LHV)

In comparison, the study assumes the following CAES plant data (modelled on the McIntosh installation)

Table 5 - AES Plant Basic Data (DeCorso et al, 2006)

Cavern Storage Volume	538 020 m^3
Cavern Type	Salt – Solution Mined
Maximum Cavern Pressure	7.5 MPa
Minimum Cavern Pressure (@110MW)	4.6 MPa
Ratio of Compression to Running Time	1.6
Continuous Run Time	26 hours
Heat Rate BTU/kWh (LHV)	4100 BTU/kWh @ 110MW 4500 BTU/kWh @ 22MW

Using a spread sheet, the economic parameters that would justify the building of CAES plants in favour of conventional GT plants were calculated assuming a plant life of 20 years.

The two systems were evaluated based on their Net Return Rate (NRR), which is equal to the percentage of the quotient of the Net Present Value and Discounted Total Capital.

The spread sheet was set up in such a way that the following factors could be altered and the effects thereof examined:

1. Natural gas price
2. Off-peak power price
3. Ratio of peak to off-peak power price
4. Off-peak power pumping discount
5. Power production (time for which the plant is producing power)

The study assumes three scenarios:

Scenario 1:

The parameters used for this scenario are shown in Table 6:

Table 6 - Scenario 1 Parameters (DeCorso et al, 2006)

Parameter	Value	Units
Off-Peak Power	$57.14	/MWh
Peak/Off-Peak Ratio	1.50	/MWh
Power Production	50	hours/week
Off-Peak Power Pumping Discount	0.65	-
Cap. Factor	29.8%	%

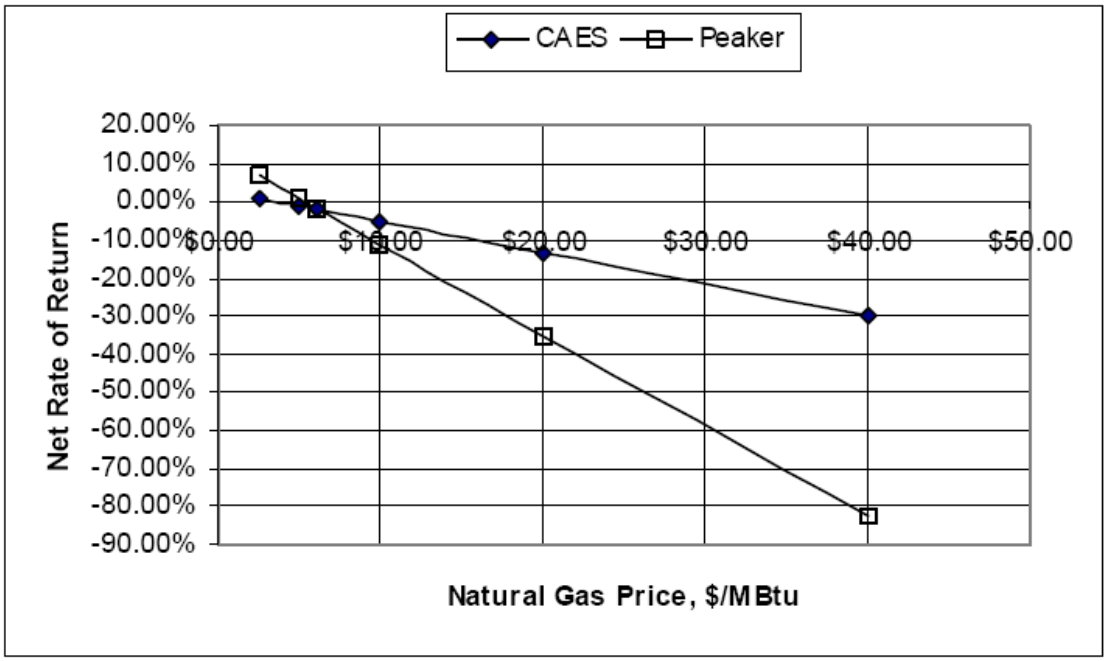


Figure 6 - NRR Plots for Scenario 1 (DeCorso et al, 2006)

Figure 6 indicates that as the price of natural gas rises, the NRR of CAES quickly overtakes conventional peaking plant. In this example, the two systems have equal profitability at $6.40/MBtu. This model assumes that the price of electricity remains fixed, causing both these systems to become unprofitable at a very early stage. In reality however an increasing gas price would also drive up electricity costs.

Scenario 2:

Scenario 2 examines the effect when the ratio of peak to off-peak power changes, as is the case when there are power shortages and utilities are attempting to encourage large users to shift less important activities such as pumping to off-peak hours.

Table 7 - Scenario 2 Parameters (DeCorso et al, 2006)

Parameter	Value	Units
Off-Peak Power	$57.14	/MWh
Peak/Off-Peak Ratio	3.00	/MWh
Power Production	50	hours/week
Off-Peak Power Pumping Discount	0.25	-
Cap. Factor	29.8%	%

The effect for the CAES plant is that electricity is converted into compressed air at a significant discount.

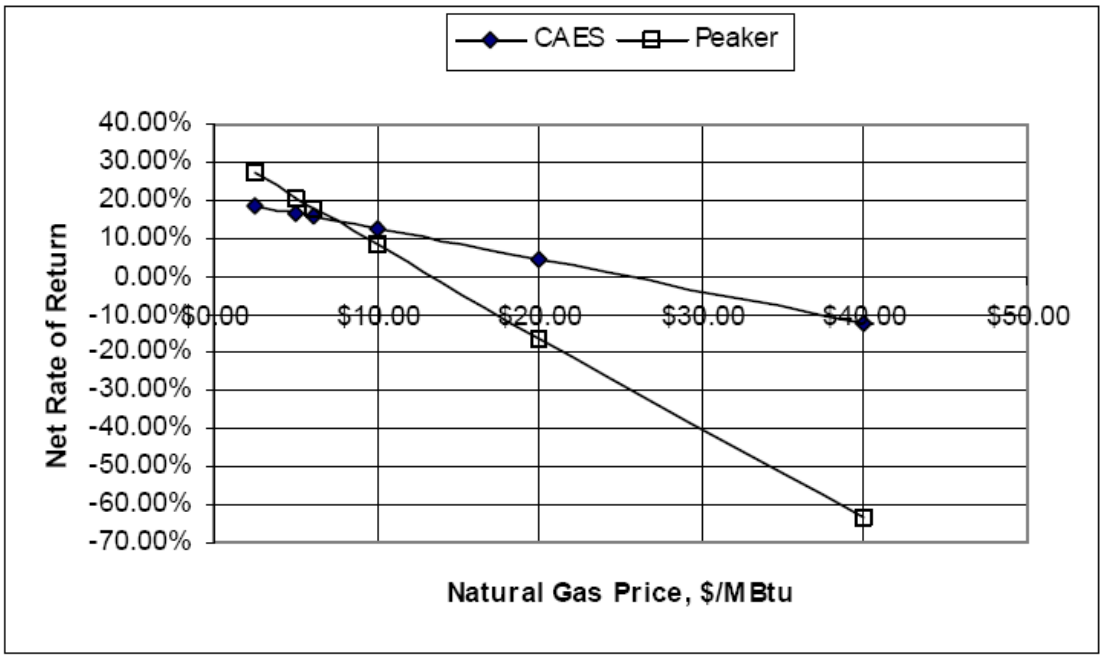


Figure 7 - NRR for Scenario 2 (DeCorso et al, 2006)

In this scenario too the CAES overtakes the peaking plant, with the NRR of each system equal at a gas price of $7.60/MBtu. This demonstrates the significance of the ability to utilise cheaper electricity during off-peak hours for generating compressed air.

Scenario 3:

In Scenarios 1 and 2 the natural gas price was varied keeping other parameters fixed, but it is proposed that the price of electricity would rise along with an increase in gas prices. Scenario 3 considers this case by increasing the cost of off-peak electricity by 20% for each doubling of the natural gas price. This modification more accurately models the profitability of CAES over conventional peaking plant.

Table 8 - Scenario 3 Parameters (DeCorso et al, 2006)

Parameter	Value	Units
Off-Peak Power	$57.14	/MWh
Peak/Off-Peak Ratio	Varies	/MWh
Power Production	50	Hrs/week
Off-Peak Power Pumping Discount	0.25	$/$
(Cap. Factor	29.8%	%

Figure 8 indicates the sustained profitability of a CAES plant with respect to increasing natural gas prices.

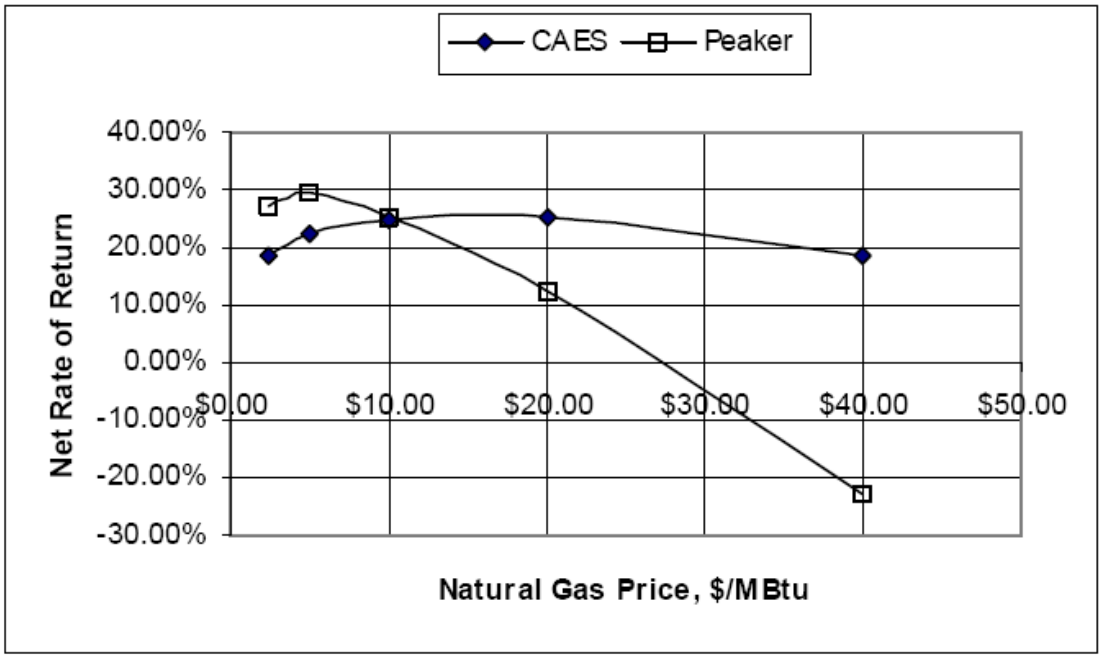


Figure 8 - NRR for Scenario 3 (DeCorso et al, 2006)

All the scenarios illustrate that the profitability of CAES over conventional peaking plant occurs at a gas price of between $6-$10/MBtu, and the effect of the improvement when increasing gas prices are simulated. This results from the ability to sell electricity during peak times at a higher price as natural gas prices rise. In this case the CAES overtakes the gas peaking plant, with the NRR of each system equal at a gas price of $10.00/MBtu

DeCorso et al (2006) demonstrate that the profitability of a gas turbine peaking plant is primarily driven by the cost of natural gas, which is logical given that this

is the major cost associated with operating this type of plant. The model for a CAES plant is more complex as there are various options for compressing the air as this can be done at various times of day with varying costs.

DeCorso et al (2006) conclude with these additional considerations of CAES compared with Gas Turbine Peaking Plant:

- Base Load Power Price: The study assumed various ratios of peak power to base load power prices. When the CAES plant is utilised within an integrated power generating system and the system has a surplus of base load power, then the ratio can be far higher than the assumptions, the limiting case being where the price of base load power for compressing air is zero. Furthermore, if the CAES plant can be operated with sufficient flexibility, it may be possible to selectively choose compression hours to correspond to times when off-peak power is priced at its lowest. Many of the regional ISO's have "day-ahead" markets for electricity that will reveal these low priced (sometime even negatively priced) off-peak hours on a day ahead basis.

- Emission advantage: Considering a CAES plant in isolation, it will have lower emissions than a gas turbine peaking plant, assuming that power for compressing the air is generated outside of the system. When the compressed air for a CAES plant is produced by an emission free source (such as wind or nuclear) it will have significantly lower overall emissions compared with an equivalent GT.

- Green plant: Unfired CAES plants can be conceived. In such a case, where no fuel is burned and if it is pumped up by windmill or nuclear power, the plant will have a zero emission profile, including zero CO2 output. For comparison with a CAES plant, the GT may require a scheme to sequester exhaust CO2.

- Fuel Flexibility: Natural gas is assumed in this study for both the GT peaking and the CAES plant. But the CAES plant is fuel flexible, which would be advantageous where alternate fuel costs are less than natural

gas. Use of alternate fuels in the CAES may also affect plant evaluations where renewable fuel considerations come into play.

- Operational Advantages: Operational advantages of CAES include: black plant start capability, quick start capability, ability to operate at part load with high efficiency, reliability, resilience, and system stabilisation capabilities.

DeCorso et al, (2006) concludes by noting that many factors must be considered when selecting a preferred type of peaking power plant. In addition due consideration must be given to the many factors associated with selecting a suitable site location such as availability, local and national regulations, fuel availability and cost present and future, electrical costs and the availability of existing base load plants and green considerations for the future.

2.6 CAES Monitoring to Support RMRCT (CAES Development Co., 2004)

CAES Development Co. (2004) examines Refrigerated Mined Rock Cavern Technology (RMRCT) with the aim of developing proof of concept data providing a means to directly determine rock mass response during cyclic loading.

The study examines a room and pillar mine developed in rock as a pressure vessel. The American Department of Energy examined the potential of using RMRCT for storage of natural gas in granite rock. The concept is to mine a void in unfractured rock, and then store natural gas by chilling and compressing it in order to reduce the storage space required.

The study aimed to quantify the effects of this pressurisation on rock mass displacements. The author notes the similarity of the storage of compressed natural gas to CAES, and noted the intention to apply the findings to pressure induced deformation modelling expected at the Norton facility.

The study aims to reduce the technical risk associated with large scale cyclic pressurisation of the mined cavern. In this study, the pressure in the cavern cycled from 9500 kPa to 2000 kPa.

Table 9 - Property Comparison of Granite vs. Columbus Limestone (CAES Development Co., 2004)

Property	Granite[1]	Limestone[2]
Unconfined compressive strength	2,000-20,000 psi; Average=10,000 psi	27,000 psi
Tensile strength	700 psi	1600 psi
Young's modulus	7,500,000 psi	8,400,000 psi
Poisson's ratio	0.27	0.25
Bulk density	2.80 g/cc	~2.7g/cc
Porosity	1%	0.75%
Average RQD index value	85 at 3,000 foot depth	80-90
Permeability	10^{-16} m^2	10^{-19} m^2
Vertical Stress	3030 psi	3030 psi
Horizontal Stresses (anisotropic)	3030, 6060psi	3630, 6110psi
Temperature	73°F at 3,000 ft	90°F at 2,200 ft
Working Temperature	-20°F	90°F
Gas storage pressure, maximum	1370 psi	1650 psi
Gas storage pressure, minimum	250 psi	800 psi
	[1]estimated and assumed ref. 1	[2]measured ref. 4-15

The study proposes using the Norton mine as a suitable model to examine the effects of compressed air on an underground facility for RMRCT. There are

significant similarities between the granite structure proposed for the RMRCT and the limestone CAES at Norton as Table 9 illustrates.

The study proposes monitoring displacements across rooms with extensometers, with the cross room measurements providing rock mass displacements. It motivates that the CAES facility would serve as a suitable model for the RMRCT.

The study ends abruptly with the author noting that “This study ended without completely getting off the ground. The work was terminated solely because of a hiccup in national economics within the energy sector, resulting in a delay in the compressed air energy project. The work presented clearly connects the RMRCT and CAES projects in terms of the needs to further understand large-scale rock mass response. The information in this report, and the fact that the work was funded, further demonstrates the technical feasibility, constructability, etc. of the CAES project in Norton, Ohio. The fundamental rationale for a rock mass monitoring system, and the sensitivities, ranges and the layout of that system in the facility have been detailed.”

2.7 Conversion of Abandoned Collieries in Southern Belgium into Low-Pressure Gas Storage Units, with Description of Special Plugging of the Various Shafts (Buttiens, 1978)

Buttiens (1978) highlighted Belgium as a suitable location for examining the concept of converting collieries into low-pressure gas storage sites as several collieries were closed in Southern Belgium during the 1970's. It is noted that the main challenge with this approach is the gas tight plugging of the shafts. Buttiens (1978) goes on to recommend a suitable method for constructing a gas tight plug for the shaft.

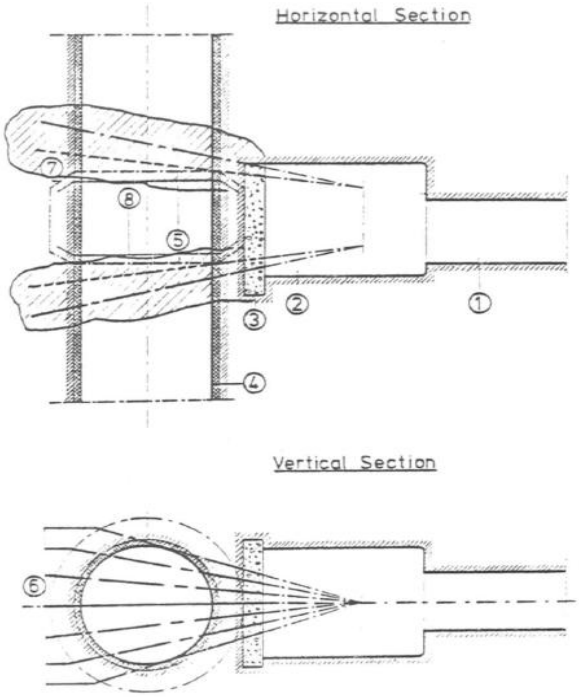


Fig.1. Description variant (a). *1* = Work gallery; *2* = Drilling chamber; *3* = Concrete wall; *4* = Shaft lining; *5* = Shaft-plug; *6* = Freeze tubes; *7* = Plug seats; *8* = Concrete reinforcement

Figure 9 - General Arrangement of Shaft Plug Installation (Buttiens, 1978)

The method described made use of freeze tubes to freeze the roof and floor around the plug. The common practice in Belgium appears to be filling of the shaft with any available material. Waste from dumps and any other low cost material is used, but this type of filling method does not provide a gas tight seal to the shaft. Also because of this filling practice installation of a gas tight concrete plug presents dangers from the random material and the instability thereof in the shaft.

The method described accesses the existing shaft adjacently in the horizontal plane. A small gallery is created to access the area to be plugged. Holes are drilled above and below the plugged area, into which freeze tubes are inserted. These freeze tubes then freeze a section of ground above and below the plug area to a thickness of 2.5m - 3 m. This frozen section provides a stable base onto which the cement plug can be constructed. Buttiens (1978) goes on to describe the process of installing and operating the freeze tubes and layering of the concrete to create the shaft plug.

Buttiens (1978) concludes that the process of freezing the heterogeneous mass around the shaft was very successful. He believes that the described method of plugging abandoned shafts is a solution for providing a plug that is gas and water tight, while providing a safe solution for the personnel installing the plug. However, examination of the actual pressure that this type of plug can withstand is not explored.

2.8 The Installation and Operation of an Underground Air Receiver on 13 Level Pioneer Shaft (Van Der Merwe, 1983)

Van der Merwe (1983) discussed the use of an underground air receiver to improve the compressed air supply to underground equipment on Buffelsfontein Mine. The installed compressors at the time were not able to deliver a sufficient supply of compressed air for underground equipment to operate optimally. Pressure at the compressors stations on surface supplied compressed air at 560kPa, but this pressure dropped as low as 340kPa when it had arrived at the underground equipment.

The study examines three possible solutions to increasing the supply pressure to the underground operations by:

1) Installation of additional compressor capacity on surface.
2) Construction of an underground air receiver with constant pressure output.
3) Construction of a variable pressure type underground air receiver.

It was shown that a variable pressure output was the most cost effective means of solving the problem and was selected as the go forward option.

An underground air receiver was constructed in twin haulages underground at the Buffelsfontein Gold Mine. The haulages were each 3m x 3m and 360m in length providing a total storage volume of 6480m^3.

The project involved the design and construction of two plugs required to seal off the haulages to contain compressed air. Limited information is provided as to the method and type of construction of the two plugs, but the paper states that the air receiver was charged to a pressure of 2 200kPa. After a period of 48 hours the pressure in the air receiver had dropped by 200kPa which was due to cooling of the air from the compressor discharge temperature of 65°C to ambient underground temperature of approximately 28°C. The plugs appeared to be free of leaks for practical purposes, which was supported by visual and auditory inspections. The paper goes on to describe the types of compressors and cooling equipment installed for charging of the air receiver.

The air receiver provided an increased supply pressure to the underground operation reducing the pressure loss to a minimum delivery pressure of 465kPa, which consequently increased production rates after the air receiver was installed. Table 10 shows the supply pressure to equipment before and after the air receiver was installed during a morning shift period until 12:00.

Table 10 - Compressor Station Pressure

Shift Time	January 1982 (kPa)	January 1983 (kPa)
07:00	550	550
08:00	485	524
09:00	440	490
10:00	420	470
11:00	420	465
12:00	435	470

It is not stated if this data is for a single day or averaged for a longer period. The study provides production data for a limited period from December 1982 to February 1983, with various other factors that could have affected the production rates during this period. The author however does attribute the increase in production rates to the installation of the underground air receiver.

3 ELECTRICITY PRODUCTION AND ENERGY STORAGE

This chapter examines the two basic plant types for electricity production (Baseload and Peaking Plant) and discusses the role of energy storage in large scale power systems.

3.1 Electricity Production

Electrical power plants are divided into two main categories:

a) Base Load Plant
b) Peaking Plant

Based Load Plants are designed to operate at a relatively stable electrical output on an on-going basis. These plants typically provide the bulk of electrical supply, and operate at relatively steady state with a low load following capability. These plants are typically cheaper to operate than peaking plants.

Peaking Plants serve the purpose of generating electrical power only when demand exceeds a level that base load plant is able to supply. They are designed to be operated with short ramp-up times to meet periods of high demand, and switched off again when demand drops to a level that the more economical base load plant can meet.

In Figure 10, the electricity demand under the red line will be supplied by baseload plant, with higher power requirements during the day (above the red line) needing to be met by peaking plant capacity. In South Africa, baseload supply is comprised mainly of coal fired power stations with a small percentage made up by nuclear and hydroelectric power plants. When total electrical demand reaches the total available output of the baseload power plant, peaking plant is brought online to supply the shortfall typically in the form of pumped hydro storage and/or gas turbines. Baseload plant is typically far cheaper to operate and therefore it is desirable to meet demand through cheaper baseload sources as far as possible.

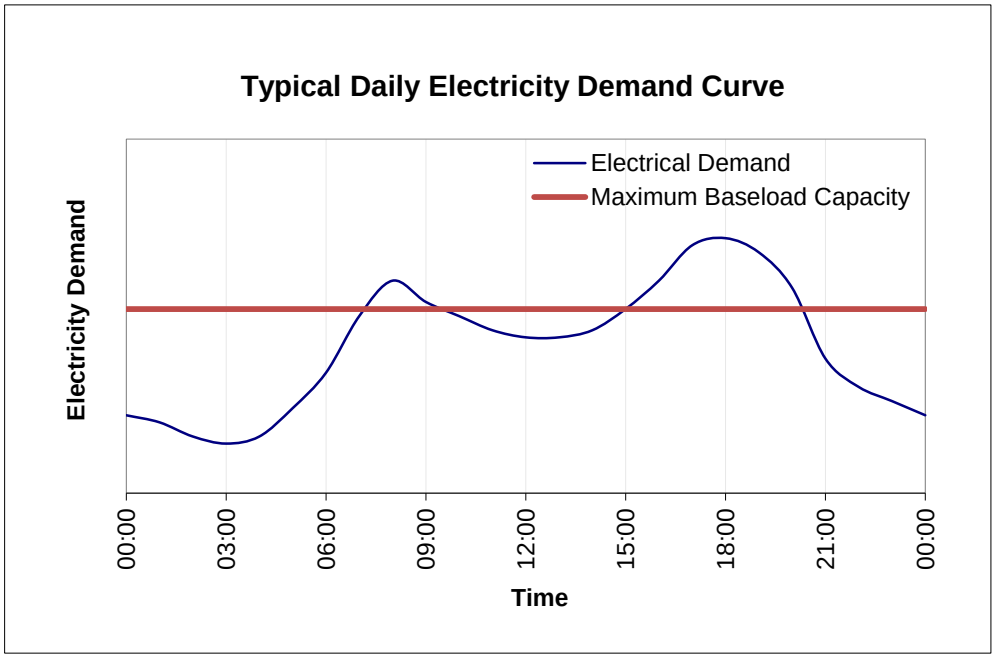


Figure 10 - Typical Daily Electricity Demand Curve

A balance is therefore required between having sufficient base load plant available to meet the majority of consumers' energy needs, and also enough peaking plant to make up the difference when necessary. Energy storage provides the ability to store cheaper baseload power to be used at times of increased demand without having to draw supply from peaking plant which is expensive to operate.

3.2 Energy Storage

The technology of energy storage incorporates methods of storing energy when there is surplus supply available. The ability to generate and store energy at these times of low overall demand and to be accessed during periods of high demand allows the total generating capacity of the base load plant to be reduced.

Energy can be stored in various forms:

- Electrical Energy Storage: Storing charge in a capacitor is an example of storing electrical energy

- Chemical Energy Storage: Conventional batteries and fuel cells are examples of energy stored chemically that can be converted into electrical energy through a chemical reaction.

- Thermal Energy Storage: Steam and hot water accumulators are used to store thermal energy which is converted through a process to electrical energy.

- Kinetic Energy Storage: Flywheels store the spinning motion of a mass, which can be converted into electrical energy by using this to drive a conventional generator

- Potential Energy Storage: Hydroelectric plants are an example of storing potential energy in water, which is available to be converted into electrical energy by passing it through a turbine-generator when required. Compressed Air Energy storage plants also store energy in air which is compressed and converted to electrical energy when required.

The difficulty in “storing” electricity is increased when doing so on a large scale, as when meeting the electricity demands of a country. A country’s electrical supply network at its peak capacity should be able to meet the total electrical demand. Simply put, national electrical supply must be able to meet the electrical demand needs of all customers all the time, though electrical supply installations come at significant cost.

Energy storage is analogous to charging a battery (by converting electrical energy into chemical potential energy) and then retrieving the electrical supply from the battery when needed. Though instead of charging a battery this study examines the approach of storing energy by converting available surplus electrical energy to compressed air in a process known as Compressed Air Energy Storage (CAES).

4 COMPRESSED AIR ENERGY STORAGE OVERVIEW

4.1 CAES Process

Compressed Air Energy Storage (CAES) stores surplus off-peak electrical capacity produced by base load plants, such as coal or nuclear plants, to be used later during periods of peak demand. CAES uses surplus electricity to compress air with compressors, and this compressed air is stored in a suitable receptacle, typically an underground void or cavern. The energy contained in the compressed air is later recovered by routing this air to a turbine. Since the air is already compressed, the turbine does not require the compressor section usually required to compress air prior to mixing with fuel and combustion. In a typical gas turbine, approximately two-thirds of the available work generated by the turbine is consumed by the compressor section in compressing air required for combustion. Thus the output of a turbine without its compressor is approximately three times higher than would ordinarily be possible.

Referring to Figure 11, the process of converting and recovering energy from CAES plant is as follows:

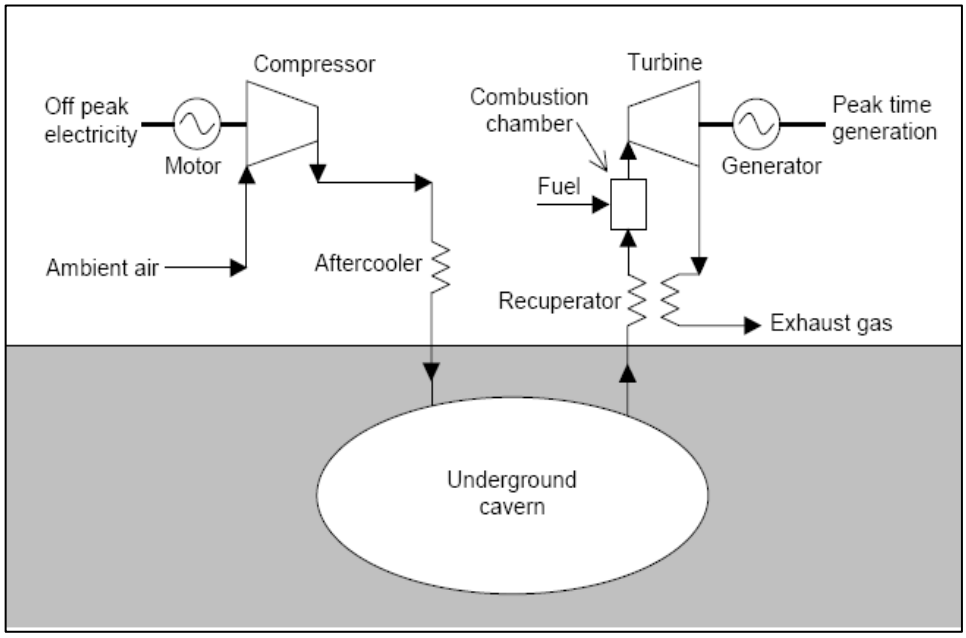


Figure 11 - Process Flow of a Compressed Air Energy Storage System (Valenti, 2010)

1. During periods of available surplus electrical capacity, an electrically powered compressor is used to compress ambient air into a suitable storage receptacle, typically an underground cavern. During this compression cycle which occurs in multiple stages to reach the high storage pressures required, Intercoolers are used between compression stages to lower the temperature of the compressed gas exiting the compressor and aftercoolers are used to further cool the compressed air prior to entering the cavern. This serves to ensure that the temperature of the gas inside the cavern does not exceed design parameters and also to maximise the mass of air stored.

2. When electrical demand increases to a level exceeding available supply from base load plant and additional electrical capacity is required, compressed air is drawn from the cavern and heated on exit to the required inlet temperature for the turbine. A recuperator can be used to transfer waste heat from the turbine exhaust gases to the air entering the turbine reducing the heating requirement by other means and increasing the overall system efficiency.

3. Fuel is mixed in the preheated air and burned in a combustion chamber and the expanding gases pass through the turbine.

4. The gases turn the turbine shaft that drives a coupled electrical generator producing electricity.

4.2 CAES Plant Equipment

This section examines the main components of a CAES system.

4.2.1 Primary CAES Plant Components

The main equipment items of a CAES system are:

- Compressors: Electrically driven used to compress air into the storage cavern
- Turbine & Combustion Chamber: Receives the compressed air and burn fossil fuel to generate power in an ordinary gas turbine cycle.

- Motor-Generator System: Converts mechanical work from the turbine into electrical energy which can also serve as an electric motor used to drive the compressors
- Auxiliary Heat Exchanger Equipment: Used to heat or cool air in the system

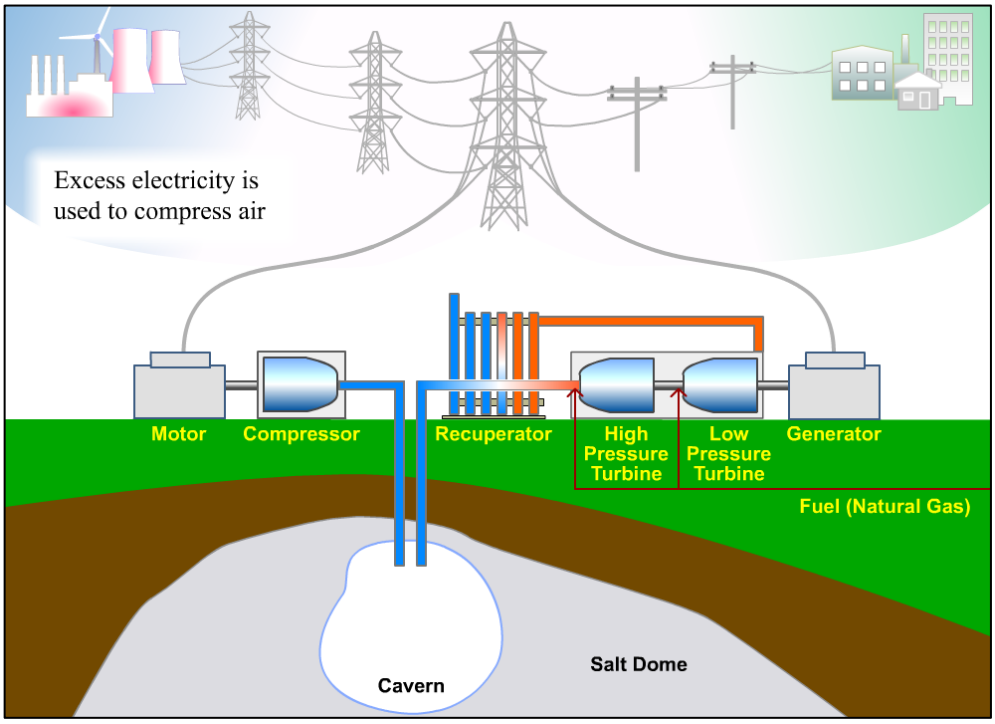


Figure 12 - Typical CAES equipment arrangement (Ridge Energy Storage, 2006)

4.2.2 Compressors

Compressor equipment used for CAES plants does not need to be uniquely adapted for the purpose. CAES plants require equipment that is able to provide pressure typically in excess of 70 bar and with relatively high flow rates to charge the cavern as quickly as is practical.

Huntorf utilises a low pressure axial and a centrifugal high pressure compressor to achieve the 72 bar maximum cavern pressure. McIntosh uses four stage compression with axial, centrifugal and reciprocating compressors to reach a final pressure of 77 bar.

Ter-Gazarian A (1994) notes that the highest pressure ratio available at the time for uncooled industrial compressors is 17:1 with final air temperature at 430-450°C which can be achieved with two axial machines in series operating from an inlet at atmospheric pressure. The high pressure end would utilise typical radial compressors. Ter-Gazarian A (1994) also notes that his experience limits the compressor's power to 70 MW for a delivery pressure of approximately 75 bar due to gearbox constraints.

Alternatively conventional multistage compressors can be utilised with low, intermediate and high pressure sections.

The compressor specifications can be derived from the operating parameters of the CAES plant and there appears to be no technical constraints restricting the compressor equipment for a CAES.

Multi stage compressors are used to reach the final discharge pressure to the storage cavern.

4.2.3 Turbines

The manufacturers of the generating equipment for Huntorf and McIntosh were BBC Mannheim (now ABB) and Dresser Rand respectively. Huntorf utilises a high and low pressure turbine which jointly produce the total 290MW output. McIntosh too uses multistage turbines to produce its 110MW.

Since turbine technology for a CAES plant is similar to gas turbines, some gas turbine manufacturers have produced CAES equipment also. Dresser Rand also supplied the expanders, compressors, motor generator, clutches and gearboxes and control systems for the McIntosh plant. Table 11 shows CAES generating equipment currently available:

Table 11 - CAES Generating Plant Summary (Valenti, 2010)

Equipment Manufacturer	Plant Size (MW)	Minimum Inlet Pressure (kPa)	Total Min Flow Rate (kg/s)
ABB/Alstom	290	1380	18
Dresser Rand	110	5722	160
Alstom ET11NM	300	6205	359
Westinghouse (501D5)	350	5171	419
Westinghouse (501F)	450	5171	539

Any configuration of the turbines listed in Table 11 could be suitable for use in a South African CAES plant with preference given on the basis of efficiency, availability and cost of equipment. With the proposed CAES plant having similar plant requirements to the Norton Plant, where Alstom ET11NM turbines were planned to be used, the ET11NM turbines could potentially be suitable for a 3500MW plant.

For the ADELE project, General Electric (GE) has been involved in developing the turbo-machinery though details on the actual generating capacity have not yet been released; refer to chapter 4.3 - CAES with Thermal Energy Storage (TES) for further info on the ADELE Project.

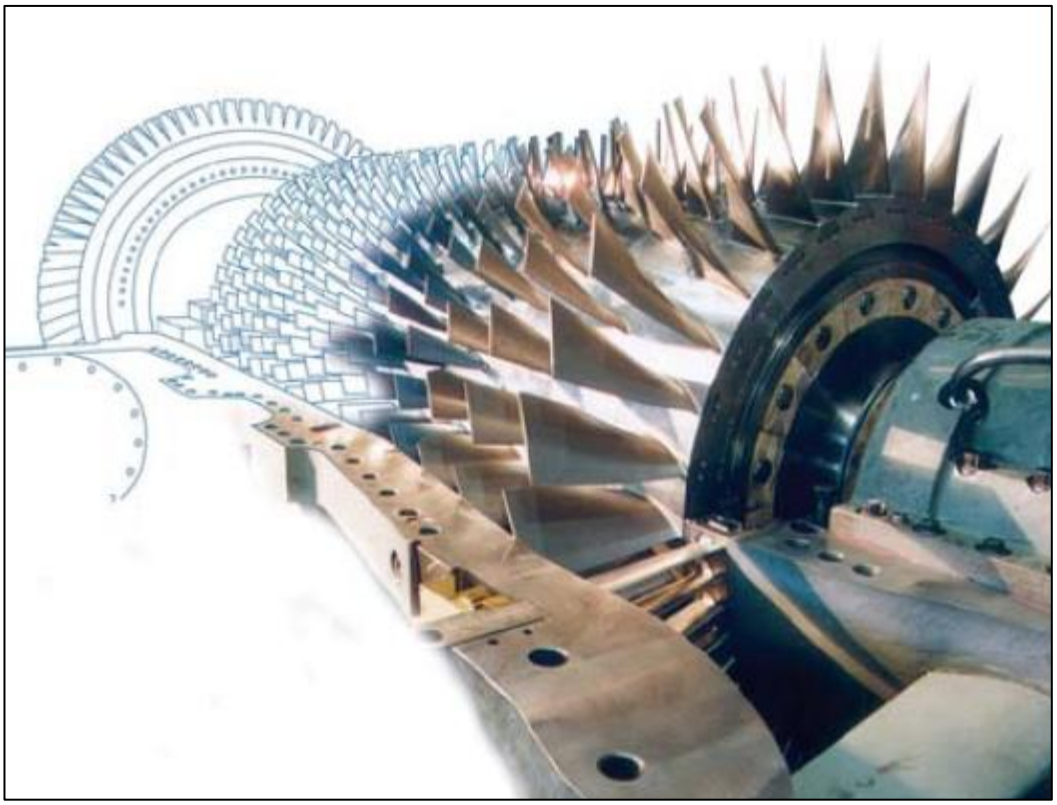


Figure 13 - GE CAES Turbine for ADELE (RWE Power, 2010)

Various options are available for the turbine end of a proposed CAES plant. With CAES technology continuously developing, early consultation of potential equipment suppliers such as Alstom or GE would be critical.

4.2.4 Motor-Generator

At the Huntorf and McIntosh plants a combined motor-generator unit is used. For combined units, the motor that drives the compressor also functions as the generator used to produce electricity. Clutches control how the motor generator is coupled with it being coupled to the turbine when required to produce power, and driving compressors when functioning as a motor.

Dresser Rand developed “SMART CAES” which separates this function into a dedicated motor which drives the compressor and a dedicated generator coupled to the turbine. The individual motor and generator operate with a higher efficiency than a combined unit.

4.2.5 Auxiliary Heat Exchangers

The CAES mechanical equipment includes a number of heat exchangers. These are used to remove heat from the air during compression, and to return heat to the air when expanded.

McIntosh utilises intercooler heat exchangers between each of the four compression stages and also utilises an aftercooler heat exchanger which cools the compressed air to 50°C prior to entering the cavern.

Unlike Huntorf, McIntosh also uses a recuperator which transfers waste heat from exhaust gases to the expanding air from the cavern. Dresser Rand claim an efficiency of 85% in terms of heat transfer effectiveness for the recuperator unit which in turn increases the overall system efficiency.

4.3 CAES with Thermal Energy Storage (TES)

Thermal Energy Storage (TES) is the transfer of thermal energy to a device used to collect and store heat to be used at a later time. CAES plants can employ TES by storing the heat energy produced during the process of compressing the air to be reintroduced when the air is expanded. This reduces the need to heat expanding air by other means and increases the overall efficiency of the system.

The ADELE CAES plant (see Figure 14) will be the first example of CAES with TES, construction of which is scheduled to start in 2013. The project plans to capture the heat produced during compression in ceramic materials which will be able to return the heat to the air during the expansion cycle by means of large heat exchangers.

The overall efficiency of the Huntorf and McIntosh plants is compromised by the heat energy which is lost when air is compressed prior to entering the cavern, since energy must be reintroduced to the air when it is expanded. Ideally the thermal energy removed from gas by the intercooler should be stored and returned when air is released from the cavern.

Since the expanding air from the cavern is typically heated by combustion of fossil fuel, TES not only increases the overall system efficiency but also reduces the carbon dioxide emissions of a plant.

The ADELE plant will be owned and operated by RWE, Germany's largest power producer. The plant's main function is to store energy produced from RWE's wind and photovoltaic solar power plants.

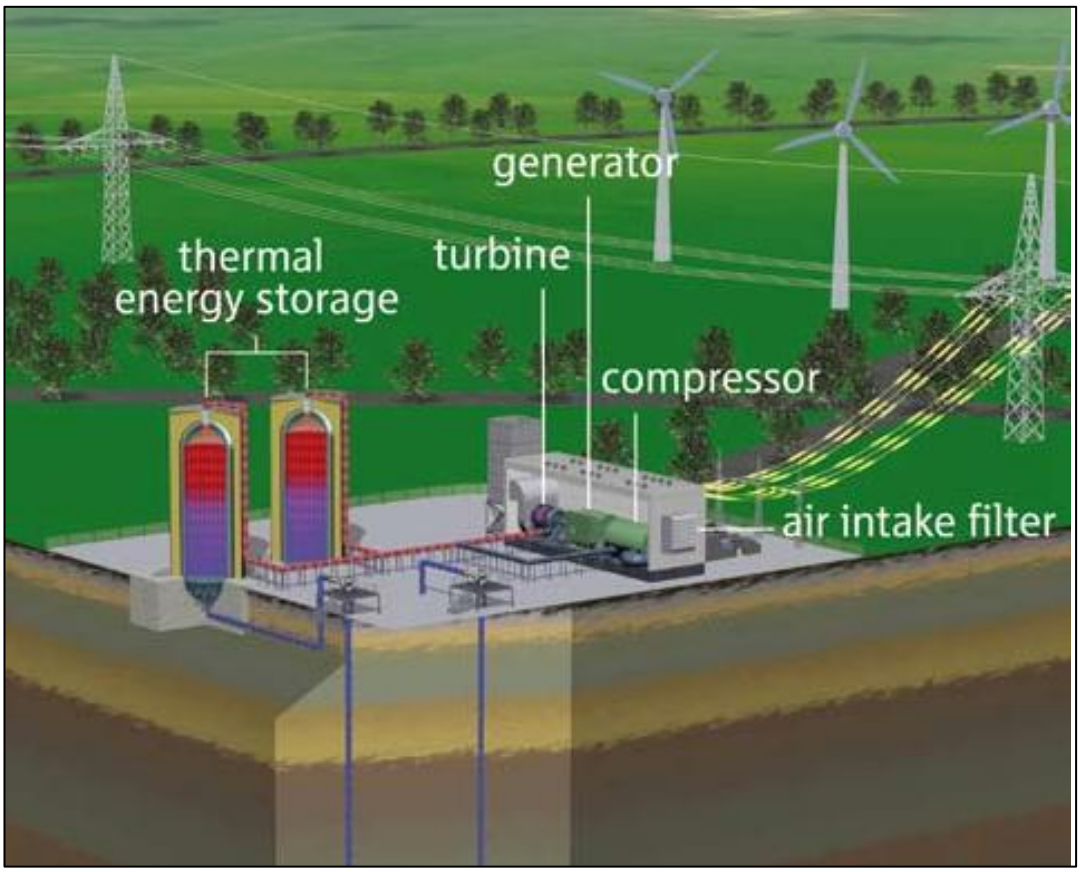


Figure 14 - Proposed ADELE CAES Plant in Germany (RWE Power, 2010)

The ADELE project has some unique engineering features with the compressor unit, under development by GE, discharging air at 100 bar and 600°C to the TES units. This hot air will pass over beds of ceramic moulded bricks where this heat will be stored until the cooler expanding air is passed over these ceramic bricks to be heated.

Utilisation of TES technology for CAES increases the overall system efficiency to approximately 70% (RWE Power, 2010) making it comparable with pumped hydro plants. The quoted total system efficiency of 70% requires verification.

4.4 CAES System Efficiency Verification

The efficiency of various CAES systems are noted in this report as shown in Table 12. The following section examines the quoted efficiency figures.

Table 12 – Summary of Quoted CAES System Efficiencies

CAES Plant/Project	Quoted Overall System Efficiency
Huntorf	42%
McIntosh	54%
ADELE	70%

Egidi R. (2011) discusses three approaches to define the CAES efficiency:

1. Equivalent fuel basis: The CAES plant might use more than one type of energy source, e.g., electrical from wind and thermal from natural gas. All of these energies are converted to a fuel-basis based on the heating value of the fuel and the plant performance.

2. Equivalent electricity basis: Various types of energy are converted to equivalent electricity based on the fuel heating value and the plant performance.

3. Adjusted equivalent electricity basis: This method adjusts the “equivalent electricity basis” by subtracting out the assumed contribution to the electrical output attributable to the fuel.

The adjusted equivalent electricity basis is considered the most realistic efficiency index for the compressed energy storage systems as it accounts for the fuel contribution to the electrical output and fuel contribution can be accounted for by estimating how much electricity could be produced by the fuel consumed by the process and the index can further be adjusted to account for fuel used for

compression. This approach suggests that CAES efficiencies are in the range between 66-82%.

Inputs to a CAES system include work required to compress gas, heat input for heating of expanding air (in the case of diabatic CAES) and fuel input for combustion in the turbine. Various losses will occur within the CAES system including non-isentropic compression of air, combustion in the turbine (a process with low efficiency estimated at 35%), mechanical equipment efficiencies and process losses. Elmegaard and Brix (2010) discuss the cooling and exergy losses associated with CAES air cooling, and conclude that the total system efficiency of a CAES plant is between 25-40%.

While the derivations of the efficiencies shown in Table 12 are unknown, it appears that the stated figures may be optimistic. Elmegaard and Brix (2010) conclude (using exergy analysis) that for diabatic plants storage efficiency is less than 45% for a basic diabatic CAES system. It is further noted however that adiabatic CAES systems may reach efficiencies of more than 70% for practical applications, supporting the efficiencies quoted by RWE, 2010.

4.5 CAES Storage Caverns

For a CAES system to function it requires a suitable storage receptacle in which to store the typically large volumes of compressed air at the high pressure required. As the compressor (or charging) cycle is underway, the pressure in the cavern will rise (indicated by the blue areas in Figure 15).

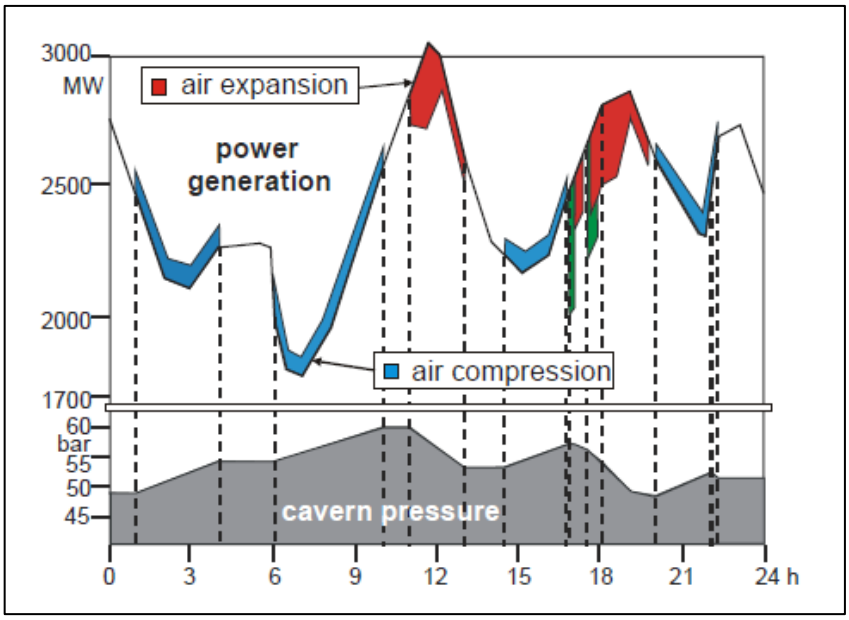


Figure 15 - Compression and expansion cycles for a CAES plant during a typical day (Crotogino, 2001)

The blue areas on the graph indicate periods when demand is low and surplus electrical power is available to compress air increasing cavern pressure. When the CAES plant is required to generate electricity, air is released from the cavern resulting in a drop in the stored air pressure indicated by the red areas in Figure 15.

4.5.1 CAES Storage Cavern Types

Cavern storage systems can be divided into two groups: Constant Volume and Constant Pressure types.

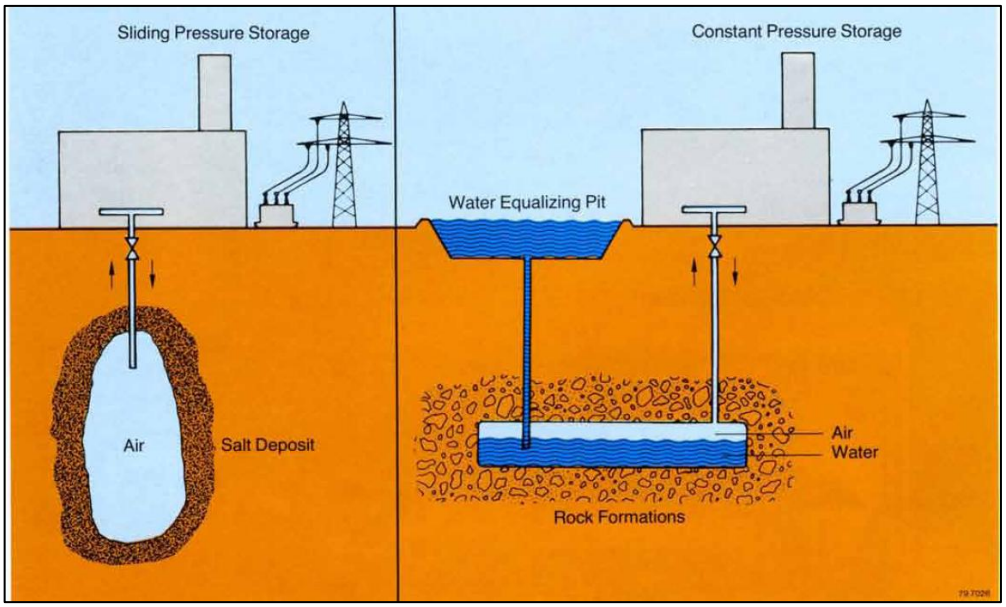


Figure 16 - Constant Pressure vs. Constant Volume Air Storage (BBC, 1990)

Constant Volume Cavern Storage Systems

Constant volume cavern storage systems are those for which there is no appreciable change in volumetric capacity of the air receiver with varying pressure. A rigid tank used to store compressed air is an example of a constant volume storage system. For this cavern type, regardless of the pressure contained within the vessel, for all practical purposes the volume remains constant. When air is allowed to escape from the vessel, the pressure in the cavern will drop accordingly.

Figure 17 shows the variation that occurs in a constant volume cavern as air is allowed to escape.

Since turbo machinery cannot typically accommodate large variations in the inlet pressure to the turbine, the compressed air in the cavern needs to be stored at a pressure higher than this minimum turbine inlet pressure and throttled down to the required pressure unfortunately with associated losses.

The cavern must therefore be large enough to supply compressed air to the turbine for the required duration without dropping below the lower design pressure limit.

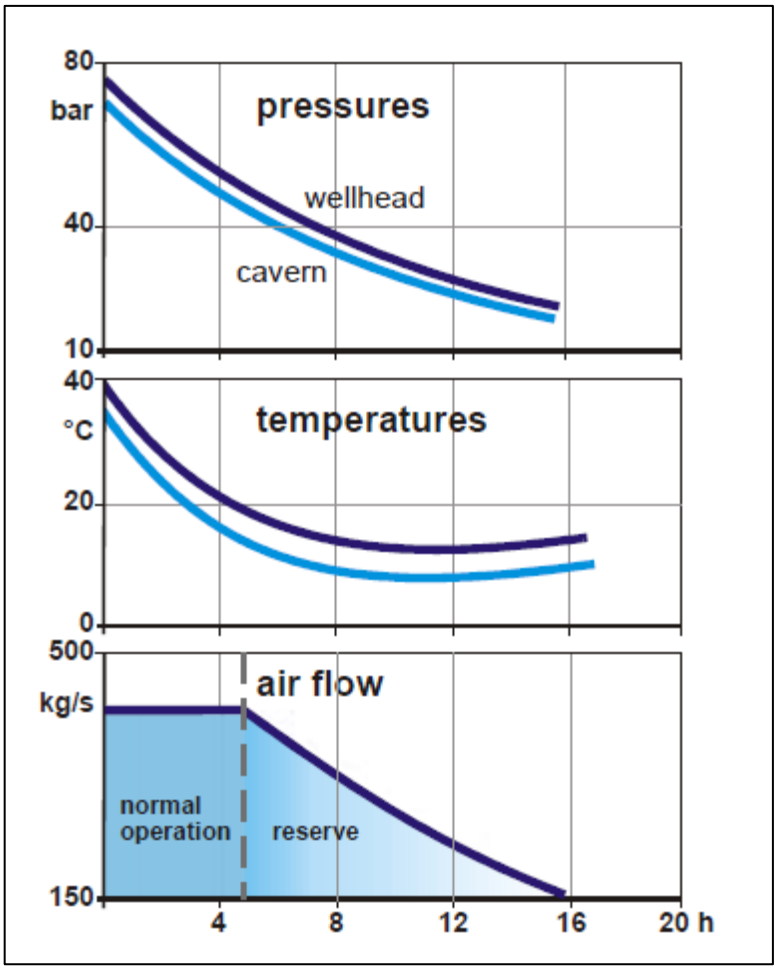


Figure 17 - Huntorf Cavern Operating Characteristics During Expansion (Crotogino, 2001)

Advantages of Constant Volume Caverns

1. Construction is typically simple as it does not require a mechanism for pressure regulation or compensation.
2. Since no fluids are introduced to the cavern, materials (such as salt) that would otherwise degrade with exposure to fluids can be utlised.

Disadvantages of Constant Volume Caverns

1. The required size of constant volume caverns is far greater when compared with constant pressure caverns and are consequently more expensive to construct.
2. Throttling losses are inherent in the system due to the requirement to reduce the pressure on exit from the cavern to the required turbine inlet pressure.

Constant Pressure Cavern Storage Systems

A constant pressure storage cavern is able to supply compressed air at a constant pressure by varying the effective volume of the storage cavern. This type of storage cavern arrangement requires a reservoir (known as a pressure equalising pit) on surface to supply the medium (usually water) that will fill the space of the escaping air. The process is as follows: (refer to Figure 16)

When the cavern is at atmospheric pressure (i.e. storing no compressed air) the water equalising pit is empty and cavern below is flooded. As air is pumped down into the cavern, it displaces the water and forces it up to the water equalising pit. This continues until the cavern is fully charged with compressed air and the water equalising pit will be at its highest level. When power generation begins and air starts to escape from the cavern, water will return to the cavern under the natural head created by the difference in elevation of the cavern and water equalising pit. This process will continue for as long as there is reserve water on surface and will provide air at constant pressure from the cavern.

The ability to deliver compressed air at constant pressure to the turbine is desirable as gas turbines typically have a narrow range of operating pressure that can be supplied to the inlet.

The pressure that is supplied from this type of cavern remains constant and is a function of the difference in height between the surface reservoir and the underground cavern, ignoring the transient change in heights of the reservoirs between full and empty. The pressure in the cavern is governed by the static pressure head equation:

$$\boldsymbol{P = \rho g h} \qquad \textbf{(1)}$$

Advantages of Constant Pressure Caverns

1) The total volume requirement for constant pressure caverns is far lower compared with constant volume caverns. A constant pressure cavern can be approximately one quarter the size of a constant volume cavern in order to provide compressed air for a given duration (BBC, 1990). Lower

capital costs are required for the cavern construction due to the smaller size.

2) The pressure that is supplied from this type of cavern remains constant, and is a function of the difference in height between the surface reservoir and the underground cavern.
3) The constant pressure has advantages for the generating equipment as the inlet pressure to the turbine can be maintained virtually constant. This method also reduces throttling losses associated with reducing pressure from a constant volume cavern prior to entry into the turbine.

Disadvantages of Constant Pressure Cavern

1. The operating pressure of the cavern is difficult to change as this is a function of the difference in elevations of the surface plant and cavern.
2. The costs of constructing the water equalising pit would increase the overall project budget.
3. The material in which the cavern is constructed becomes an important consideration as this material must accommodate the repeated exposure to the equalising medium (typically water). This type of storage would be unsuitable in salt for example as the water would continue to erode the walls of the cavern making its volume ever larger. Rock would be more suitable to this type of cavern.
4. Due to the presence of water, escaping air will contain a high concentration of water vapour which will need to be removed prior to entering the turbine to avoid damaging equipment and additional costs for drying equipment would therefore increase project cost.

4.5.2 Single and Multi-Cavern Configurations

As the name implies, storage of compressed air in a single space is known as a *single-cavern system* and the full volume of the compressed gas is contained within a single cavity which operates at the same pressure.

Multiple cavern systems are made up of more than one cavern. These caverns could be operated independently of one another, with a valve controlled connecting line between caverns to allow air flow if desired. Multiple caverns

have the benefit that there is redundancy during maintenance and cavern shutdown.

4.5.3 Types of Underground Storage

For all practical purposes it is not possible to build tanks large enough for a commercial CAES plant and so underground storage is the only feasible option for storing the required large volumes of compressed air. This section considers potential options for storing large quantities of compressed air underground.

Types of cavities or caverns previously used to store large volumes of gas which could potentially be adapted to compressed air storage are:

1. Depleted Natural Gas Reservoirs
2. Salt domes
3. Aquifers
4. Disused Mines

Depleted Natural Gas Reservoirs

Depleted natural gas reservoirs are existing underground formations from which natural deposits of gas have been harvested. There are several installations around the world where these depleted reservoirs are used to store natural gas. This practice of storing natural gas in depleted gas reservoirs has been used for some time, the first example being in Weland County, Ontario, Canada in 1915. Some reconditioning of the cavity is usually required to make it suitable for storing natural gas, though this approach is usually a far more cost effective option than creating an underground cavity. It is feasible that this type of underground storage could be used to store compressed air and depleted reservoirs usually also have the advantage that their geological characteristics are already known.

There is a risk however that natural gas could continue to seep into the cavity and mix with the compressed air during storage, which could present an explosion risk. Monitoring of natural gas concentration would be necessary if a depleted natural gas reservoir were to be used for compressed air storage.

Salt Domes

Using solution mining for creating underground caverns from salt deposits has become accepted practice for storage of various hydrocarbon products and for disposal of non-hazardous wastes (USA DOE, 2012). This solution mining process is carried out with two concentrically arranged pipes installed through a bore hole down to the required the depth of the cavern. Water is pumped down through the inner pipe dissolving the exposed salt deposit forming a saturated brine solution. The salty brine solution is extracted from the cavern through the other pipe leaving behind a cavity. This process is continued until a cavity of the desired size is formed. Controlling the shape of the cavern is achieved by filling the chamber with buffer gas which is forced at pressure into the cavern. This buffer gas is neutral with respect to the salt and does not cause any further dissolution, and the level of the brine is controlled in this way using the pressurised buffer gas.

Solution mining a cavity in a salt deposit is the only proven method of creating a compressed air reservoir for a CAES plant, with both Huntorf and McIntosh using salt domes formed in this way. Salt caverns are ideal for compressed air storage as they provide an ideal balance of structural integrity but are elastic enough to accommodate the stress induced by the compressed air in the cavern walls. Salt also is typically airtight requiring no other sealing to prevent leakage and appears to be an ideal storage medium for compressed air.

Aquifers

Aquifers are underground porous permeable rock formations that act as natural water reservoirs. The naturally occurring water is pumped out leaving an underground space remaining. This underground cavern can then be equipped to store compressed gas. Dewatering of aquifers for underground gas storage can be risky as the aquifer must be dewatered before structural integrity and permeability can be tested. Permeable rock is not a desirable characteristic for storage of compressed air as losses as a result of this permeability are likely. The capacity of the aquifer can be difficult to estimate as there are often connections to other underground formations making the effective volume of these underground voids larger than anticipated. The connections can be difficult to detect prior to dewatering, following which these may require sealing at additional

cost. Additionally there are potentially considerable environmental impacts for dewatering of underground water deposits as this may have knock-on effects on the level of the surrounding water table.

Aquifer storage for natural gas is typically a more expensive method when compared with salt domes and depleted natural gas reservoir storage.

Disused Mines

Disused mines can be used for underground gas storage. Examples of compressed LP Gas being stored underground in disused hard rock mines did exist in the US according to the US EIA (2004), though none were in commercial operation when the document was written in 2004. Referring to Chapter 2.7 - Conversion of Abandoned Collieries in Southern Belgium into Low-Pressure Gas Storage Units, with Description of Special Plugging of the Various Shafts, Buttiens (1978) advocates the use of disused collieries for low pressure gas storage though does not examine the pressures that such facilities may withstand. As a result of South Africa's extended mining history, there are a number of disused mines in existence that could potentially be used for underground gas storage.

Forming a hard rock cavern for gas storage is typically more expensive than a salt cavity of equal capacity as a result of the equipment and labour required to develop the reservoir, though proven mining methods could be used making the process technically achievable. Hard rock caverns do have the advantage that they can accommodate a constant-pressure water compensated system which would reduce the required size of the reservoir to a quarter of that of a constant volume pressure reservoir (BBC, 1990).

4.6 Existing CAES Plants

This section describes the two existing commercial plants currently in operation.

The two commercial CAES plants currently operating are Huntorf (Germany) and McIntosh (USA). At the time of writing there are a number of CAES projects in various stages of development as follows:

Table 13 - CAES Plant Summary (Ter-Gazarian, 1994).

CAES Plant	Country	Generating Capacity (MW)	Status
Huntorf	Germany	290	Commercial Operation
McIntosh	USA	110	Commercial Operation
Norton	USA	2700	On hold
ADELE	Germany	-	Design
Markham	USA	540	Planning
Sesta	Italy	25	Planning
-	Japan	35	Unconfirmed
-	Israel	300	Unconfirmed
-	Russia	1050	Unconfirmed

4.6.1 Huntorf

Table 14 - Huntorf Summary

Owner/Operator	E.N. Kraftwerke
Cavern Type	Salt Dome
Cavern Capacity	Total - 300 000m^3 (2 caverns 150 000m^3 each)
Generating Capacity	290MW
Generating Duration	2 hours
Compressor Demand	60MW for 8 hours
Total System Efficiency	42%
Cavern Pressure Range	72 – 52 Bar
Commissioning Date	1978

Situated near Niedersachen approximately 30km North West of Bremen, Huntorf is the world's first commercial CAES Plant, commissioned in 1978. Able to produce 290MW this plant is owned and operated by Nordwest Deutsche Kraftwerke AG. The compressor equipment was designed and supplied by BBC Mannheim who also supplied the heavy electrical and process control equipment. Construction of the cavern was awarded to Kavernen Bau-und Betriebs-GmbH. The total volume of the two caverns is 300 000m^3. The caverns were solution mined in salt deposits. The plant uses a motor/generator that is able to drive the compressors to compress air, and also to generate electricity when driven by the turbine.

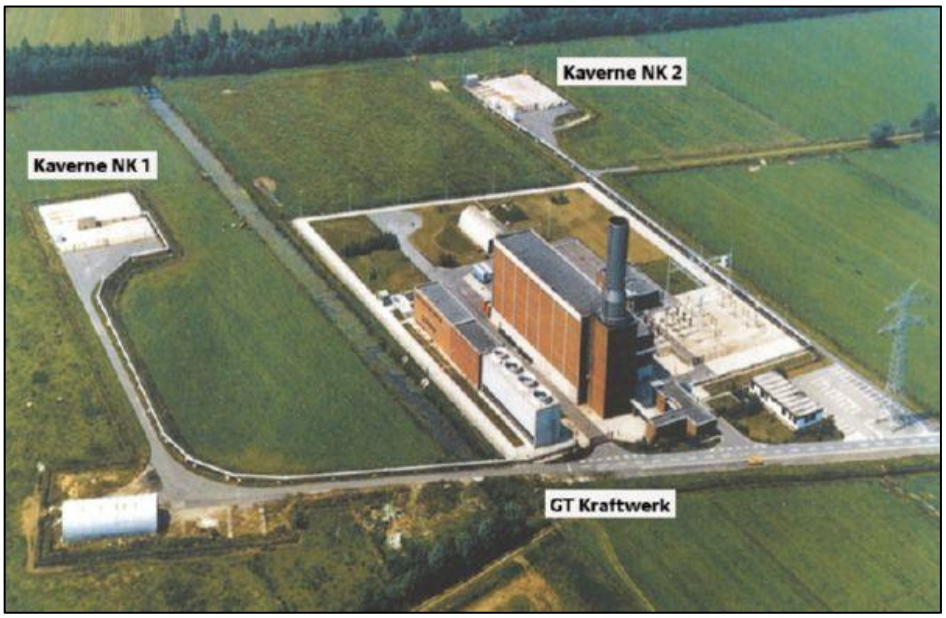


Figure 18 - Aerial View of the Huntorf Plant (BBC, 1990)

Huntorf Mechanical Equipment - BBC Mannheim

Huntorf's mechanical equipment was designed and supplied by BBC Mannheim. The turbine equipment is designed to operate at an inlet pressure of 42 bar. The turbine arrangement has a high and low pressure turbine with the high pressure turbine extracting energy from 42 bar to 11 bar, and the low pressure from 11 bar to 1 bar.



Figure 19 - Workshop Assembly of the Huntorf Turbine (BBC, 1990)

During normal operation the pressure in the cavern drops at a rate of 10 bar/hour with the plant able to operate for maximum duration of two hours before recharging of the cavern is required. The maximum cavern pressure is 72 bar dropping to 52 bar over a 2 hour period. Recharging back to 72 bar requires approximately 8 hours.

The compressor arrangement at Huntorf comprises a low pressure axial compressor and a high pressure centrifugal compressor with a total drive requirement of 60 MW.

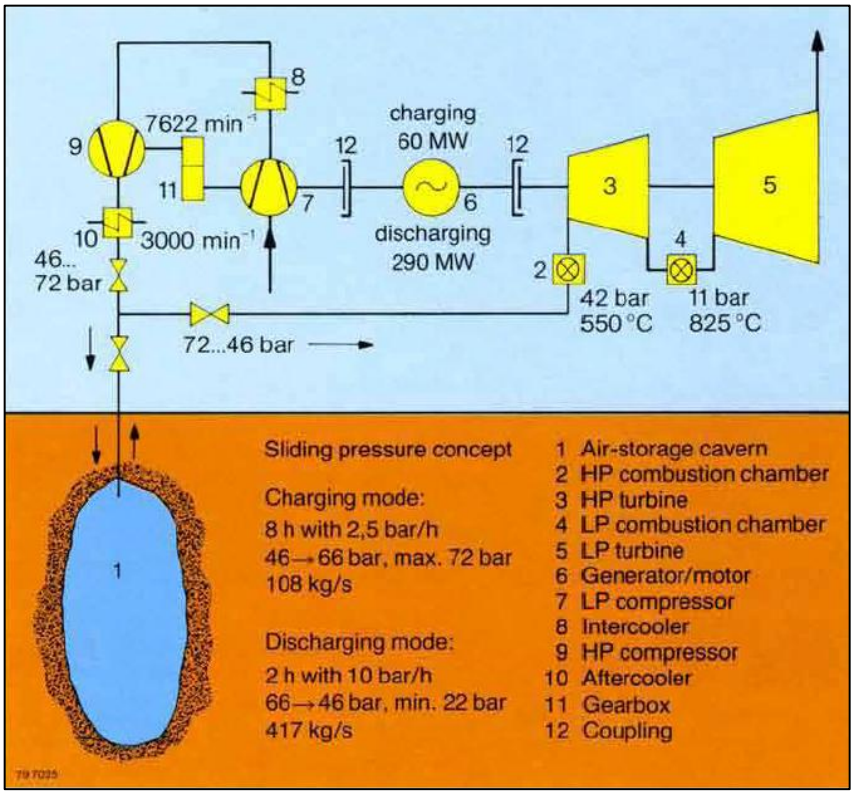


Figure 20 - Process Flow diagram of Huntorf CAES Plant (BBC, 1990)

The expanding air from the cavern is heated using natural gas. During cavern charging the compressed air is cooled to 50°C using an after-cooler prior to entering the cavern. The motor generator serves a dual role performing the function of a motor during the compression cycle driving the compressors, and a generator during the generating cycle engaged and disengaged by clutches.

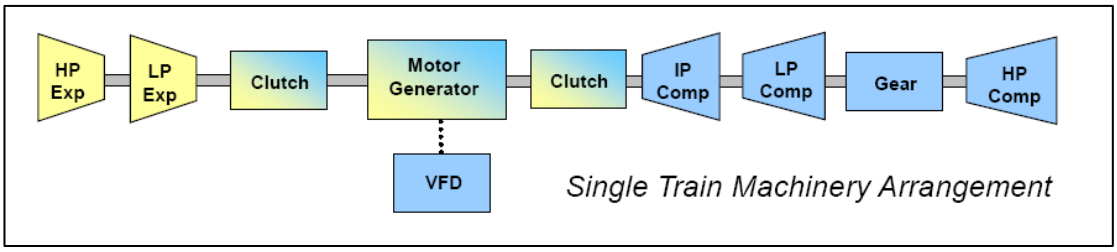


Figure 21 - Huntorf Single Train Equipment Configuration (HEID, 2010)

Equipment start up for the generating cycle takes place by spinning the turbine up to synchronous speed using compressed air from the cavern, ensuring a soft start and requiring no starter motor. The turbine and generator are coupled via clutch when synchronous speed is reached allowing the generator to supply electricity at the correct voltage and frequency to the grid. The low pressure combustion chamber is ignited only when the turbine is loaded. The start-up process to full load at synchronous speed requires approximately 11 minutes.

When generation is no longer required or when the cavern requires recharging, the turbine is used to run the compressor up to synchronous speed. Once synchronous speed is achieved the compressor is coupled to the motor-generator and the turbine is uncoupled and charging of the cavern begins. This process requires approximately 6 minutes.

The pressure range from 40 bar to 60 bar is significantly higher than the inlet pressure of conventional gas turbines, which typically operate at a pressure of around 11 bar. A conventional axial gas turbine (the largest available at the time) running at synchronous speed of 3000 rev/min, is used only for the low-pressure turbine and combustor to utilise the pressure drop from 11 bar to 1 bar. The pressure drop from 46 bar to 11 bar had to be achieved by an HP turbine but no examples of such gas turbines were available in 1976. Consequently, the high pressure turbine was based on a steam turbine design with high pressure inlet of 46 bar and at 550°C inlet temperature.

Huntorf Cavern

The Huntorf plant has two fixed volume storage caverns with a combined storage volume of 300 000m^3 and a maximum storage pressure of 72 bar. The two

caverns are situated at depths of 650m and 800m, with diameter and height of approximately 40m and 150m respectively in the form of upright cylinders.

4.6.2 McIntosh

Table 15 - McIntosh Summary

Owner/Operator	Alabama Electric Cooperative (AEC)
Cavern Type	Salt Dome
Cavern Capacity	540 000m^3
Generating Capacity	110MW
Generating Duration	26 Hours
Compressor Demand	-
Total System Efficiency	54%
Cavern Pressure Range	45-76 Bar
Commissioning Date	1991

The McIntosh plant is owned and operated by the Alabama Electric Cooperative Inc. and was commissioned in May 1991. This CAES facility is currently only the second commercially operated plant in the world after Huntorf. The facility has a maximum production output of 110MW which can be sustained for a period of 26 hours. The cavern at McIntosh was solution mined in a salt deposit. The plant was declared commercially operational on 1991/05/31 and is the first and currently the only CAES plant in the USA. McIntosh incorporates the use of a recuperator which extracts heat from the turbine exhaust gases to heat expanding air from the cavern during power generation. The recuperator provides a 25% reduction in the quantity of fossil fuel required to heat expanding air from the cavern during operation, and assists in increasing the overall system efficiency of the McIntosh plant to 54%.

The McIntosh cavern is a fixed volume cavern 67m in diameter, 305m tall and situated at a depth of 457m. The maximum pressure in the cavern is 76 bar reducing to a minimum of 45 bar in its discharged state. With the plant consuming compressed air at a rate of 154kg/s, the cavern can provide the 110MW generating unit with compressed air for 26 hours from full charge.

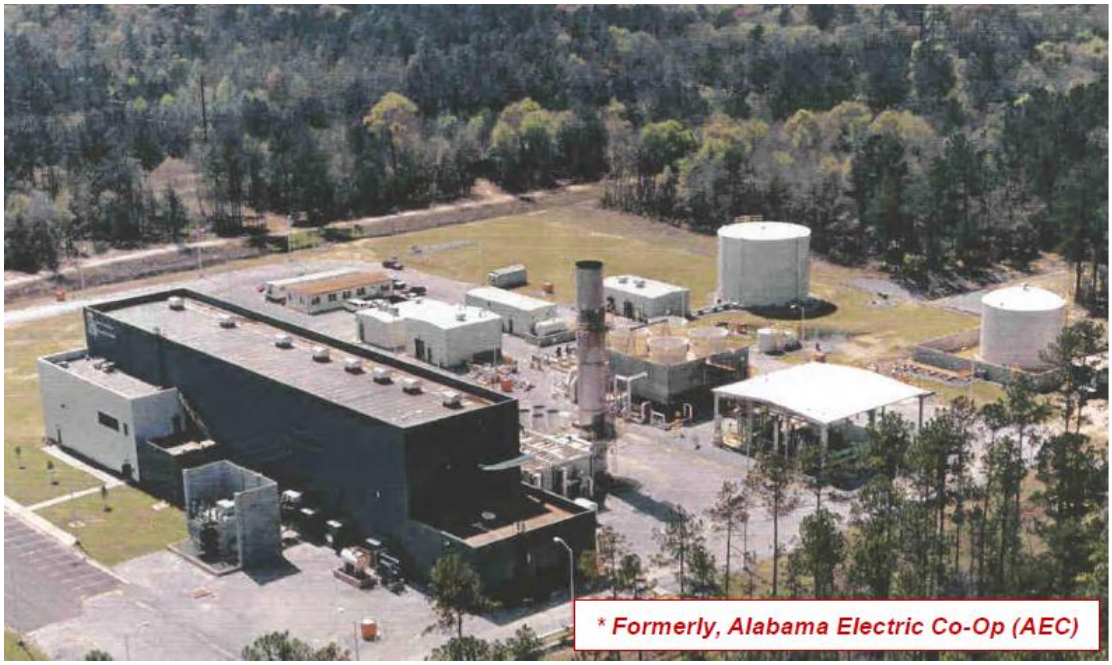


Figure 22 - Aerial View of the McIntosh Plant (HEID, 2010)

Per kilowatt of energy produced by the plant, 4853 kJ of fuel and 0.82 kWh of electrical energy is required. The equipment used to generate the power (including the expanders, compressors, motor generator, control system, clutches and gears) was fabricated by Dresser Rand. The project duration was 2 years and 9 months.

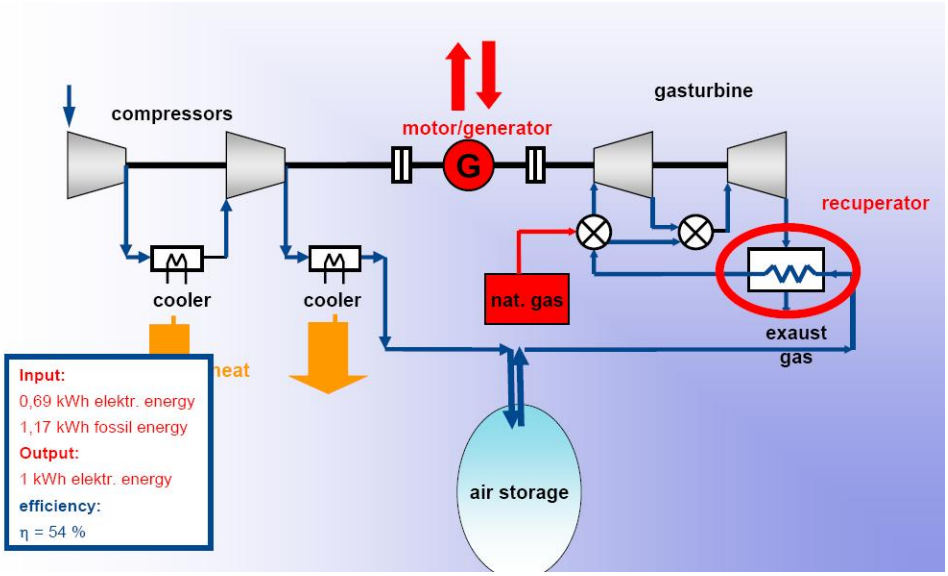


Figure 23 - Process Flow Diagram of McIntosh CAES System

McIntosh Mechanical Equipment - Dresser Rand

Dresser Rand provided the complete power island including high and low pressure turbo-expanders with integrated combustion system, motors, generator, compressors, clutches, heat exchangers (recuperators, intercoolers and aftercoolers), pollution abatement (SCR system with carbon monoxide abatement), plant controls and auxiliaries.

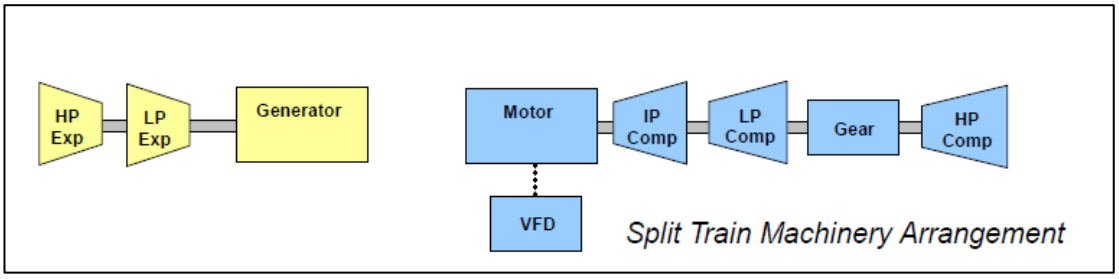


Figure 24 - McIntosh Split Train Equipment Configuration (HEID, 2010)

The McIntosh equipment separates the compression equipment from the generating equipment, and does not make use of a common motor-generator unit as does the Huntorf plant. This allows increased efficiency as the motor and generator can be specified for a single function. The generating plant is able to produce varying output power between 25%-100% of load levels making the plant flexible in terms of its output. Cold start-up to full generating capacity requires approximately 10 minutes and start up to full compression requires approximately 5 minutes. The full cycle from compression to power generation is achievable in less than 15 minutes, and power generation to compression is achievable in less than 5 minutes using a Variable Frequency Drive (VFD) with braking capabilities.

Table 16 - McIntosh Plant Ramp-Up/Down Rates

Cycle shift	**Time required (minutes)**
Start-up - Full generation	**<10**
Start-up - Full compression	**<5**
Compression to generation	**<15**
Generation to compression	**<5**

This equipment had a total generation time in 2010 of 500 000MWh of generation, and in February 2010 Dresser Rand published the following performance results for the equipment installed at McIntosh:

Table 17 - McIntosh Plant Reliability

Cycle	Starting Reliability	Running Reliability
Generation	**95%**	**97%**
Compression	**96%**	**100%**

The Dresser Rand plant has provided a high level of starting and running reliability since commissioning.

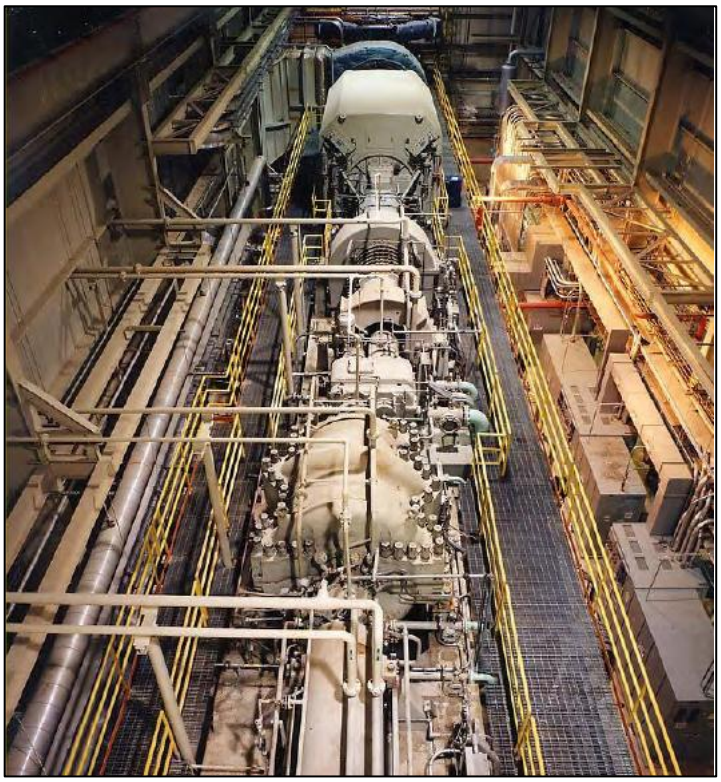


Figure 25 - Turbine Train at McIntosh (HEID, 2010)

McIntosh Cavern

The McIntosh cavern was solution mined in a salt deposit. McIntosh has only a single cavern with a total volume of 540 000m^3. The cavern is situated at a depth of approximately 457m, and is in the form of an upright cylinder 67m in diameter

with a height of 305m. The cavern has a maximum storage pressure of 76 bar reducing to 45 bar over a period of 26 hours of operation.

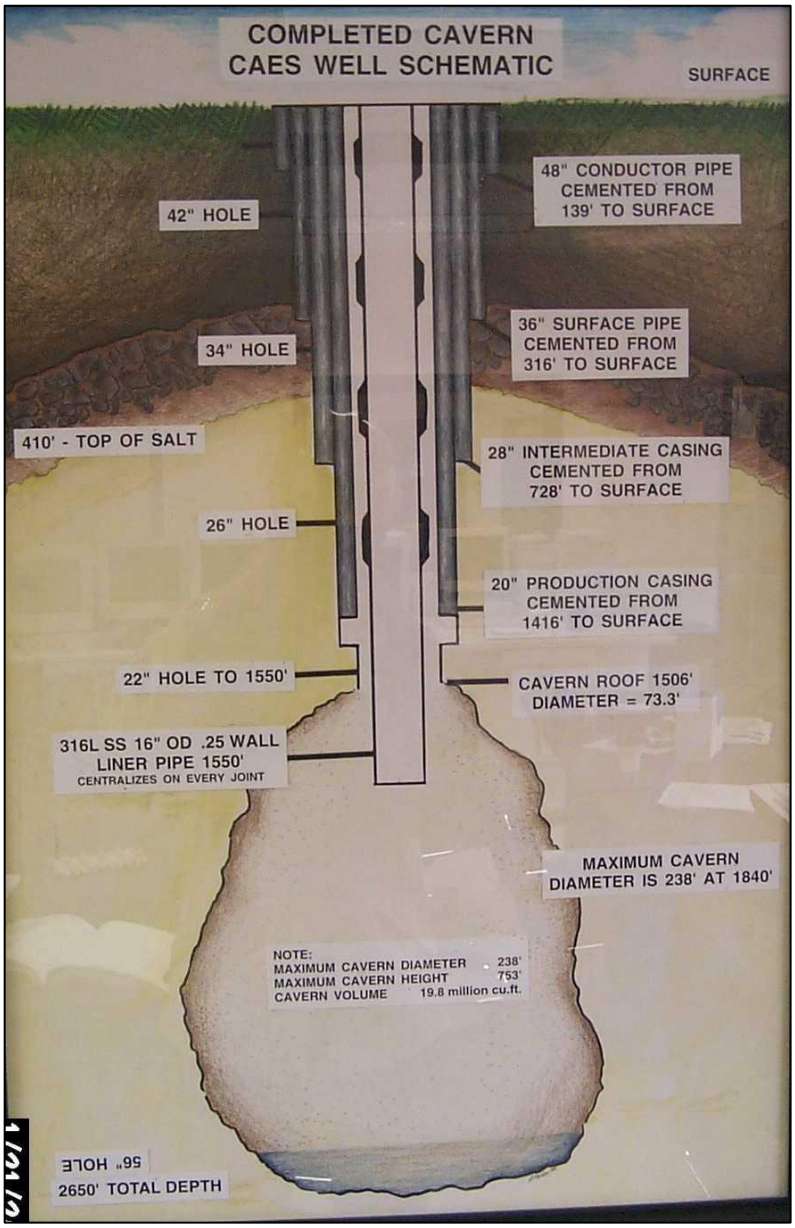


Figure 26 - Schematic of McIntosh Cavern (Email from Alabama Electric Cooperative)

4.6.3 Norton (Not Constructed)

Table 18 - Norton Summary

Owner/Operator	First Energy
Cavern Capacity	10 000 000m^3
Generating Capacity	2 700MW for 192 hours
Input requirements	-
Total System Efficiency	54%
Pressure Range	-
Commissioning Date	-

The Norton CAES Project is currently on hold due to funding issues following the financial crisis of 2008, but reached advanced design stages and is as a result mentioned. The Norton CAES plant in Ohio USA, developed by Haddington Ventures Inc. and rights to which were sold to First energy in November 2009 was to be the largest CAES storage plant in the world with the plant capable of generating 2 700MW at maximum capacity.



Figure 27 - Schematic of Planned Norton Facility (Shepard, 2001)

This would have made it one of the USA's largest bulk energy storage facilities, even when compared with pumped hydro storage schemes. The 2 700MW capacity was to be comprised of nine identical 300MW generating modules which were to be supplied with compressed air by an underground limestone cavern with capacity of 10 000 000m^3. To handle the charging of the massive cavern, each 300MW CAES module was matched with a 200MW compressor (made up of 4 x 50MW units) to charge the cavern.

There were further plans to double the total capacity of this plant to 5 400MW, also in increments of 300MW generating units, which would be relatively simple given the modular design of the plant.

Norton Mechanical Equipment

The Norton design did not reach a stage whereby a manufacturer of its mechanical equipment was identified. It was anticipated that the output of each generating unit would be 300MW, with a sequential commissioning of each turbine until the total design capacity of 2700MW was online.

Norton Cavern

The cavern design for the Norton CAES plant planned to make use of an existing disused limestone mine. The mine is situated 670m deep, with a foot print of 1600m x 2500m, and a storage capacity of 10 000 000 m^3.

The limestone was mined in a room and pillar configuration. Plans for converting the limestone mine into an air storage vessel are well developed. The two vertical shafts that access the mine were to be sealed with impermeable plugs. The Hydrodynamics Group LLC and Sandia National Laboratories completed field and laboratory studies to confirm the integrity of the Norton Mine as an air storage vessel. The focus of these studies was to confirm that the mine would hold air at the high storage pressures and the results of these studies show that it is feasible to develop the Norton Mine for use as an air storage vessel.

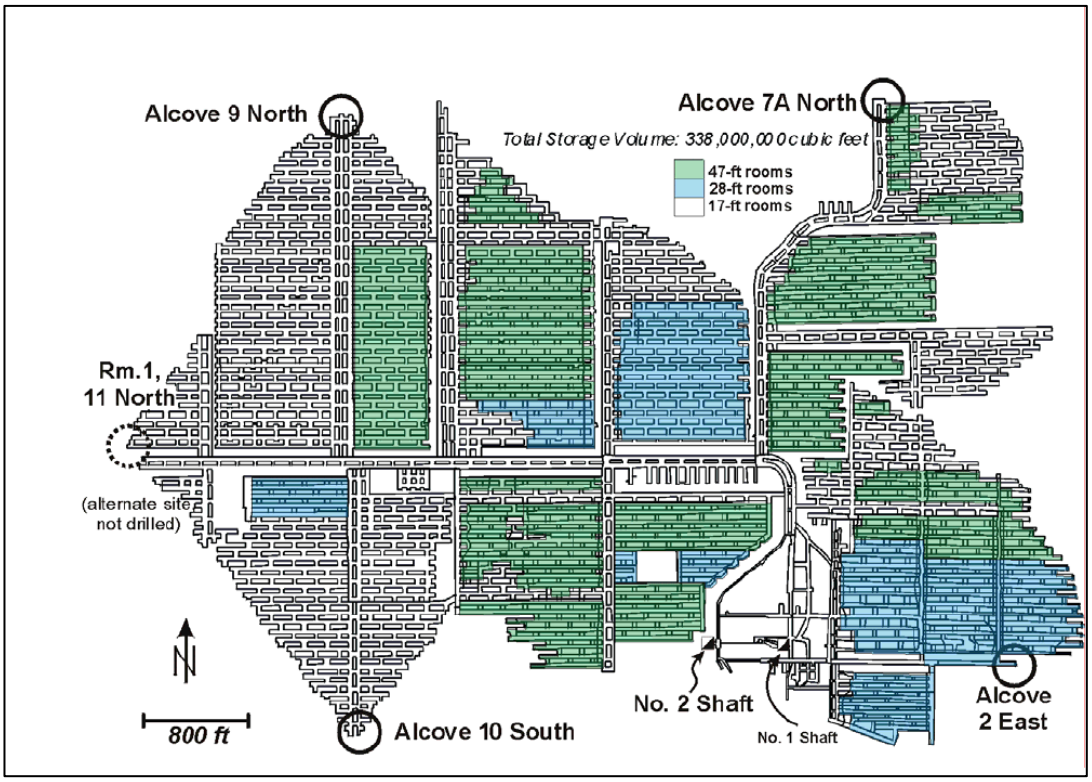


Figure 28 - Footprint of Norton Mine, showing location and distribution of room sizes

The limestone is generally homogeneous with very few discontinuities that would significantly affect air storage ability. The study modelled the stability under dynamic pressure loads and results indicate that the integrity of the mine walls would not be compromised as a result of the cyclic pressurisation. The limestone and shale cap-rock (occurring above the limestone layer) have an extremely low permeability improving the mine's ability to store compressed air without losses. Air migration through the mine host rock is predicted to be extremely low, based on the homogeneity of the limestone and shale, and on the results of air permeability testing.

The effective permeability in the materials is extremely low with the quantity of air that will migrate into the pore space of the mine host rock as cushion gas expected to be approximately 4% of the total volume of air initially injected into the mine in 10 years. The mine was developed laterally from the shaft areas using a system of rooms and pillars. This room and pillar mine configuration is remarkably stable, owing to a combination of careful application of drill and blast

mining methods, 40-50% extraction ratio, and a very competent and relatively unfractured host rock mass.

The Norton Mine has been a stable structure under ambient atmospheric conditions for the past 57 years and geological engineering studies show the mine is stable as a pressure vessel. The stability of the Norton Mine as a pressurised air storage vessel is due to a number of factors, including the depositional history, rock composition, structural geology, earth-induced stresses in the rock, mine geometry, mine construction method, and hydraulic conditions.



Figure 29 - Room and Pillar Mining layout of the Norton Mine providing the CAES Cavern - Ohio

The overall conclusion drawn from this study is that the Norton mine is uniquely well-suited to the requirements of a compressed air storage facility. Air migration rates would to be extremely low with the compressed air predicted to advance not more than 20m into the surrounding rock after 50 years of pressurisation.

5 SOUTH AFRICAN ELECTRICAL GENERATING CAPACITY

This chapter considers the total electrical generating capacity in South Africa focusing on peaking plants owned and operated by Eskom, South Africa's primary electricity producer.

5.1 South Africa's Total Electrical Generating Capacity

The total generating capacity available to South Africa is made up of various sources and types though the main electrical producer in South Africa by a significant margin is Eskom, being the largest producer in Africa and 7th largest in the world (Eskom Website, 2012). The locations of the Eskom power plants are shown in Appendix A - Eskom Power Station Locations.

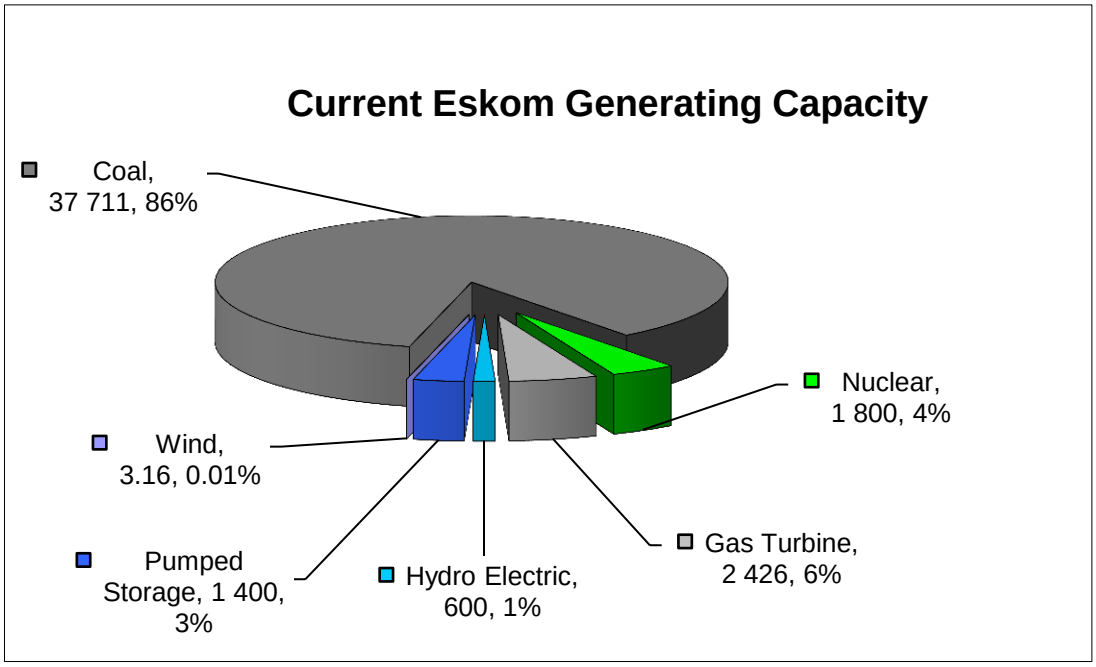


Figure 30 - Current Eskom Generating Capacity (Apr 2012)

South Africa's maximum generating capacity in April 2012 was approximately 43 937 MW, and is made up as illustrated in Figure 30. Refer to Appendix B - Eskom Power Station Plant Summary for details of the full fleet of Eskom generating capacity, current and planned. A significant proportion (86%) of the supply is made up by coal fuelled sources, with Gas Turbines (6%), Nuclear (4%),

and Pumped Storage (3%) making up the majority of the balance. The total peaking plant capacity is 4 426 MW, or approximately 10.1% of total generating capacity.

With the Medupi and Kusile Coal Plants currently under construction and the Ingula Pumped Hydro Storage scheme planned to come online in 2014, the total capacity of the system will increase by 25% to 54 860 MW by 2018 when all this plant is planned to be commissioned. Of this 54 860 MW, the total peaking plant capacity will be 5 758 MW, approximately 10.5% of total capacity.

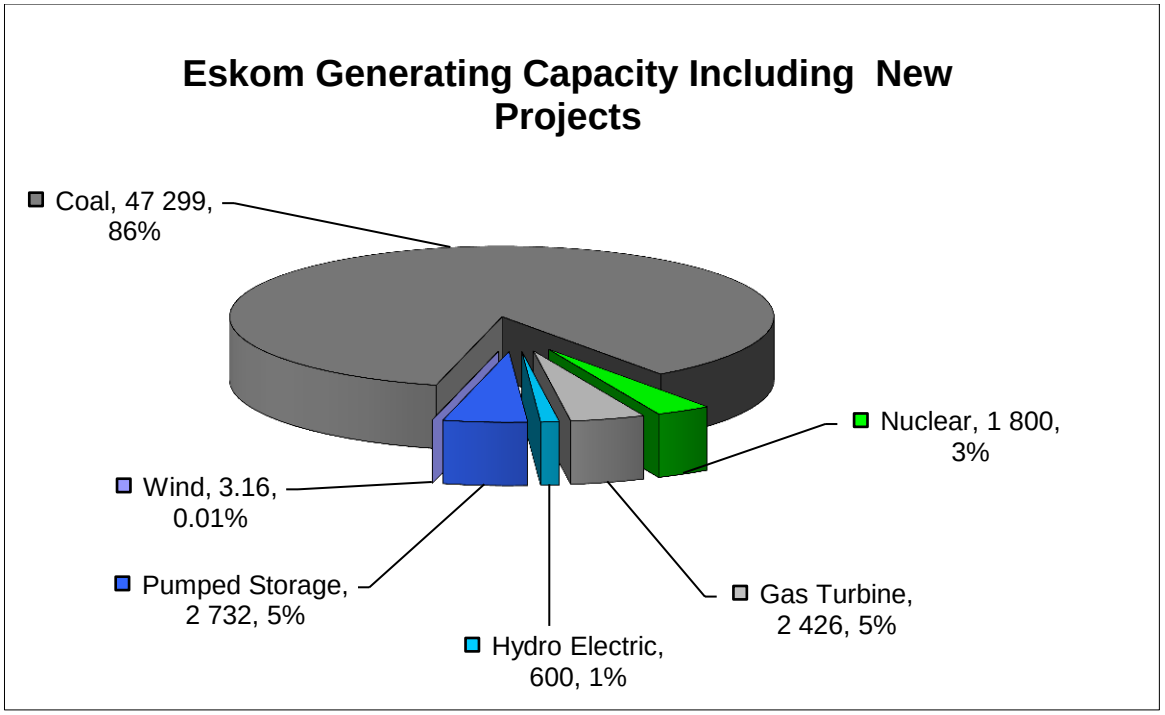


Figure 31 - Total Eskom generating capacity including new build projects currently under construction

Figure 31 above shows the sources of supply of the total generating capacity after the new plants currently under construction come online.

Table 19 shows that the ratio of base-load to peaking plant remains virtually unchanged at approximately 10% when the new plant comes online. The proportion of coal fuelled generating plant to the total output too is virtually unchanged at approximately 86%, though when Medupi and Kusile are fully commissioned, they will represent a 25% increase in the coal fuelled base load

generating capacity. The increase in capacity of pumped hydro peaking plant will increase 95% from 1 400 MW to 2 732 MW with Ingula coming online.

Table 19 - Overall South African Electricity Production Capacity

Current vs. Future Generating Capacities	Type	Current Capacity (MW)	% of Total Current Capacity	Future Capacity (MW)	% of Total Future Capacity	% Increase Over Current Capacity
Coal	Base Load	37 711	85.8%	47 299	86.2%	25%
Nuclear	Base Load	1 800	4.1%	1 800	3.3%	0%
Gas Turbine	Peak	2 426	5.5%	2 426	4.4%	0%
Hydro Electric	Peak	600	1.4%	600	1.1%	0%
Pumped Storage	Peak	1 400	3.2%	2 732	5.0%	95%
Wind	Either	3.16	0.01%	3.16	0.01%	0%
Base Load Total		**39 511**	**89.9%**	**49 099**	**89.5%**	**24%**
Peak Plant Total		**4 426**	**10.1%**	**5 758**	**10.5%**	**30%**
Total		**43 937**	**100.0%**	**54 860**	**100.0%**	**25%**

Ankerlig and Gourikwa were commissioned in 2007, before which only the Acacia and Port Rex gas turbine stations were installed with a total generating capacity of 342 MW. With Ankerlig and Gourikwa's combined capacity at 2084.3 MW, their installation increased the total Gas Turbine peaking plant capacity by 509%, and increased the total peaking capacity by 89% to 4 426 MW.

There is foreign import of supply which makes up 4%-6% of the total energy consumed per year in South Africa with a 1500 MW supply available from the Cahora Bassa Hydro-Electric Scheme in Mozambique, operated by *Hidroelectrica de Cahora Bassa.*

5.2 South African Peaking Plant Capacity

South Africa currently has peaking plant with a total capacity of 4 426 MW in the proportion shown in Figure 32:

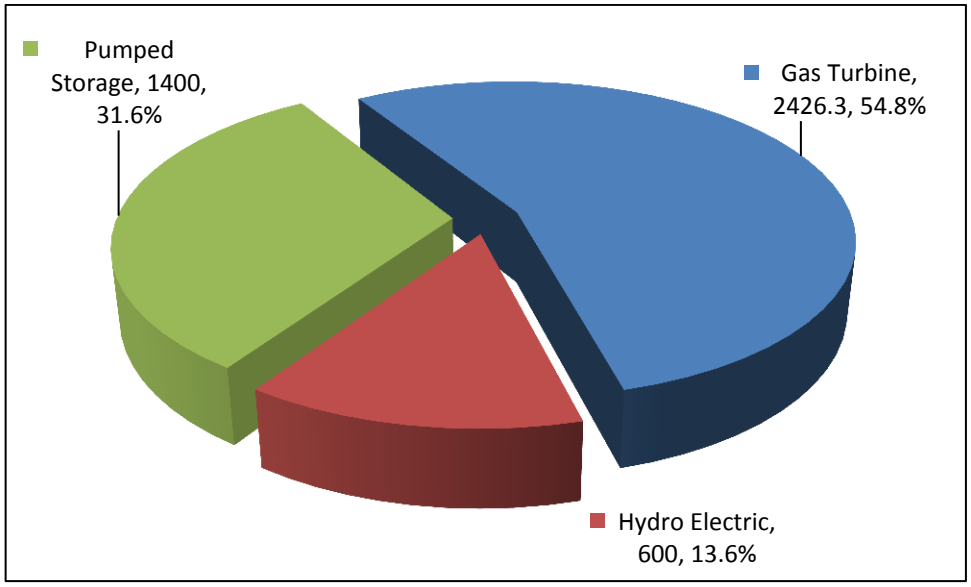


Figure 32 - Current Composition of Eskom Peaking Plant Types

The majority of Eskom's current peaking plant is made up by Gas Turbine stations with a total generating capacity of 2446.3 MW which represent 54.8% of the total peaking plant capacity.

Table 20 - Eskom Peaking Plant Summary

Current Eskom Peaking Plant	Plant Type	Total Capacity (MW)	% of Plant Type	% of Total Peaking Plant
Port Rex	Gas Turbine	171	7%	4%
Acacia	Gas Turbine	171	7%	4%
Ankerlig	Gas Turbine	1338.3	55%	30%
Gourikwa	Gas Turbine	746	31%	17%
Total Gas Turbine		2426.3	100%	54.8%
Gariep	Hydro Electric	360	60%	8%
Vanderkloof	Hydro Electric	240	40%	5%
Total Hydro Electric		600	100%	13.6%
Drakensberg	Pumped Storage	1000	71%	23%
Palmiet	Pumped Storage	400	29%	9%
Total Pumped Storage		1400	100%	31.6%
Total Peaking Plant		**4426.3**		**100%**

Gas turbines are typically very expensive to operate compared with Hydro Electric and Pumped Hydro Storage plants due to the high fuel consumption rate.

From an economic perspective, the gas turbine plant should therefore be run as little as possible.

5.2.1 Gas Turbines

5.2.1.1 Port Rex and Acacia

Port Rex and Acacia are gas turbine stations owned by Eskom situated in East London and on the outskirts of Cape Town respectively.

The plants are modular industrial type having three gas turbine generators per station. Both plants were commissioned in 1976, with each unit able to produce 57.1 MW, a total of 171 MW of peaking capacity per station. Start-up occurs within approximately 3 minutes. The gas turbines typically run on kerosene, consuming 5.7 litres per second, though these units can run on a variety of fuels. The overall thermal efficiency of these plants is quoted as 30.3%. The average availability of Port Rex from 2009 to 2011 was 98.7%, and the average annual production of from 2009 – 2011 was 0.48 GWh. The average availability of Acacia from 2009 to 2011 was 99.1%, and the average annual production from 2009 – 2011 was 0.15 GWh.

5.2.1.2 Ankerlig

Ankerlig is an open cycle gas turbine plant commissioned in 2009. The Ankerlig Project began when it became clear in 2004 that Eskom would run low on capacity during the winter peaks of 2007.



Figure 33 - Ankerlig Open Cycle Gas Turbine Plant

Ankerlig has a total of nine units, the first set of four commissioned generating 149.2 MW each, and the last five generating 148.3 MW with a total generating capacity of 1338.3 MW.

This plant makes use of the Siemens V94.2 turbine. The thermal efficiency of this plant is quoted at approximately 35%.

5.2.1.3 Gourikwa

Gourikwa is an open cycle gas turbine plant commissioned in 2009. The Gourikwa Project began when it became clear in 2004 that Eskom would run low on capacity during the winter peaks of 2007.



Figure 34 - Gourikwa Open Cycle Gas Turbine Plant

Gourikwa has a total of 5 units, each generating 149.2 MW with a total generating capacity of 746 MW.

This plant makes use of the Siemens V94.2 turbine. The thermal efficiency of this plant is quoted at 35%.

5.2.2 Pumped Hydro Storage

5.2.2.1 Drakensburg Pumped Storage Scheme

The Drakensburg Pumped Storage Scheme is situated in the Drakensburg Mountains in Kwazulu-Natal. The scheme has 4 units each generating 250MW

with a total generating capability of 1000MW. The plant was commissioned in 1982.



Figure 35 - Drakensburg Pump/Turbine Hall

The average availability of the plant from 2009 to 2011 was 94%. The system is designed to generate power for 10 hours per day, and pump water to the upper reservoir for 9 hours per day.

5.2.2.1 Palmiet Pumped Storage Scheme

The Palmiet Pumped Storage Scheme is situated near Grabouw in the Western Cape. The scheme has 2 units each able to generate 200MW, with a total generating capability of 400MW. The plant was commissioned in 1988.



Figure 36 - Palmiet Pumped Storage

When the plant is running 185 000 litres of water pass through the turbines each second. The power station operates on a weekly cycle and power is generated at peak periods from Monday to Friday. The water used for generation is only partially pumped back to the upper reservoir daily resulting in a gradual lowering of the water level during the course of the week from Monday to Friday. Over weekends when demand is low, water is pumped back to the upper reservoir at an average rate of approximately 126m^3/s over a period of about 33 hours to restore the reservoir to full capacity.

5.2.2.2 Ingula Pumped Storage – Future Installation

At time of writing the Ingula Pumped Storage Scheme (previously named Braamhoek) is being constructed in the escarpment of the Little Drakensberg range. Ingula is projected to be complete by the end of 2013. It consists of an upper and a lower dam which are complete, both with capacity to hold approximately 22 million cubic metres of water. When commissioned the scheme will be made up of four 333 MW pump turbines, with a total output of 1332 MW.



Figure 37 - Ingula Pumped Hydro Storage Scheme

The project is scheduled to come online during 2014.

When this project is commissioned, the composition of Eskom's Peaking Plant will shift significantly making Pumped Hydro Storage the main contributor to peaking plant capacity, as shown in Figure 38:

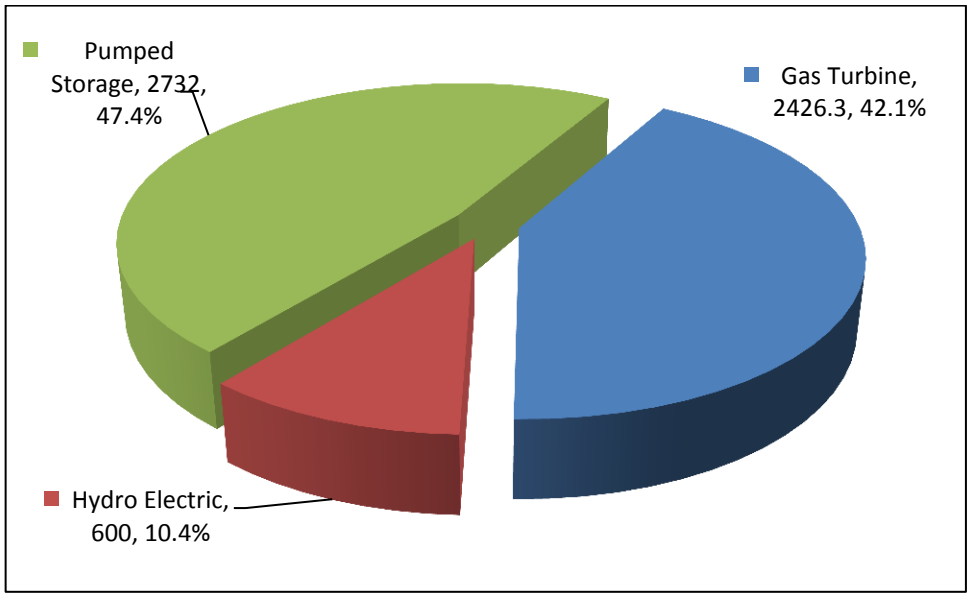


Figure 38 - Future Composition of Eskom Peaking Plant Types

Table 21 - Summary of Future Eskom Peaking Plant

Future Eskom Peaking Plant	Plant Type	Total Capacity (MW)	% of Plant Type	% of Total Peaking Plant
Port Rex	Gas Turbine	171	7%	4%
Acacia	Gas Turbine	171	7%	4%
Ankerlig	Gas Turbine	1338.3	55%	30%
Gourikwa	Gas Turbine	746	31%	17%
Total Gas Turbine		2426.3	100%	42.1%
Gariep	Hydro Electric	360	60%	8%
Vanderkloof	Hydro Electric	240	40%	5%
Total Hydro Electric		600	100%	10.4%
Drakensberg	Pumped Storage	1000	37%	23%
Palmiet	Pumped Storage	400	15%	9%
Ingula	Pumped Storage	1332	49%	30%
Total Pumped Storage		2732	100%	47.4%
Total Peaking Plant		**5758.3**		**100%**

This will make pumped hydro the predominant peaking plant type in the Eskom network. Eskom's future peaking plant capacity after Ingula is commissioned is summarised in Table 21:

5.2.3 Hydro-electric schemes (Eskom, HY 0005 2010)

South Africa's hydro-electric plant is currently made up by two installations:

- Gariep Power Station
- Venderkloof Power Station

Both of these installations received water from the Orange River. Although these stations are traditionally considered peaking plant, the stations do produce base load energy during times of flood risk to prevent the dams from spilling water and to take advantage of an opportunity for low cost energy production.

5.2.3.1 Gariep Hydro-Electric Power Station

The Gariep Hydro-Electric Power Station is located on the Orange River between the Eastern Cape to the south and the Free State to the north in South Africa, and is adjacent to the Gariep dam. The Gariep Dam is the largest water reservoir in South Africa storing 5 670 million m^3 of water.



Figure 39 - Gariep Hydro Electric Power Station

Gariep Hydro-Electric Power Station has a total of four units each generating 90 MW with a total generating capacity of 360 MW. Commissioning of the plant was completed in 1977.

5.2.3.2 Vanderkloof Hydro-Electric Power Station

The Vanderkloof Hydro-Electric Power Station is built adjacent to the Vanderkloof dam in the Northern Cape Province of South Africa. The Vanderkloof Dam is the second largest water reservoir in South Africa storing 3 236 million m^3 of water.



Figure 40 - Vanderkloof Hydro Electric Power Station

Vanderkloof Hydro-Electric Power Station has a total of two units each generating 120 MW with a total generating capacity of 240 MW. Commissioning of the plant was completed in 1977.

5.2.4 Wind Energy (Eskom - RW 0002, 2011)

5.2.4.1 Klipheuwel Wind Energy Facility

Eskom has a single experimental Wind Energy Facility where it erected three turbines at Klipheuwel on South Africa's West Coast near Cape Town. The facility is experimental and used mainly for research purposes, though it is managed and operated by Eskom's Peaking Generation Division and the energy is fed into the regional distribution network. The plant was commissioned in 2002/3.



Figure 41 - Klipheuwel Wind Energy Facility

The three turbines that were erected at Klipheuwel are described in Table 22:

Table 22 - Wind Turbines installed at Klipheuwel

Type	Rating (kW)	Commission Date	Rotor Diameter (m)	Blade Length (m)	Hub Height (m)
Vestas V47	660	August 2002	47	23	40
Vestas V66	1 750	December 2002	66	32	60
Jeumont	750	February 2003	48	23	46

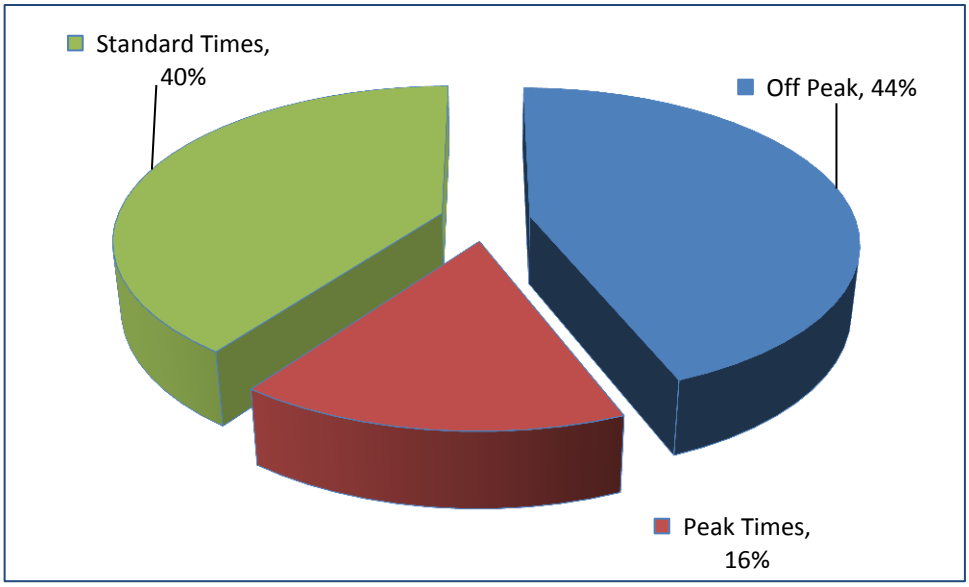


Figure 42 - Generating Periods for Klipheuwel Plant

The maximum potential output of the total system is 3.16 MW which is produced at wind speeds between 47 km/h and 57 km/h. The various models were selected so that relative performance of the different types could be evaluated.

Usage figures indicate that the majority of production occurs during off-peak and standard times with only 16% occurring in peak times as indicated in Figure 42. This highlights the importance of the ability to store energy produced from renewable sources that cannot be guaranteed to produce power when required.

The concept of energy storage is becoming an important aspect of wind energy generation, due to the highly unpredictable nature of the energy source. This is highlighted in Lund H and Salgi G (2009) who note CAES as a suitable means of storing the intermittent supply. However there is increasing focus on wind plants due to environmental concerns regarding noise pollution and the undesirable visual impact to landscapes.

5.2.5 Independent Power Producers (IPP's)

Eskom is currently reviewing options with regard to purchasing capacity from Independent Power Producers outside of the Eskom Company. This initiative is currently being developed with the South Africa Department of Energy and is focusing on growing the capacity of renewable energy production. There is a target for total renewable capacity operated by IPP's of 3725 MW though no target date is mentioned (Independent Power Producers (IPP's), (2012)).

However, these are currently all planned facilities and are subject to agreements by both Eskom and the IPP's. The potential capacity that these suppliers may produce will be excluded from the analyses in this report as the way forward for these projects could not be confirmed.

This subject is noted since if a CAES plant were to be built in South Africa, the possibility exists that it could be privately constructed and operated and would therefore be considered an IPP.

6 PEAK ELECTRICAL DEMAND IN SOUTH AFRICA

This chapter considers the peak electrical demand currently experienced in South Africa and examines some of the measures that are in place to manage peak demand.

6.1 Annual Peak Electricity Demand

The demand for electricity fluctuates on a continuous basis. Figure 43 shows the variation in demand for electricity during 2008. The mean shows the average monthly demand for power. This demand begins to increase during the cooler months of May and June, peaking in mid-winter in July, and steadily decreasing to its minimum in December to January. The average annual consumption does not reveal the full requirement for peaking plant since it must fulfil the generation requirement at times of maximum demand.

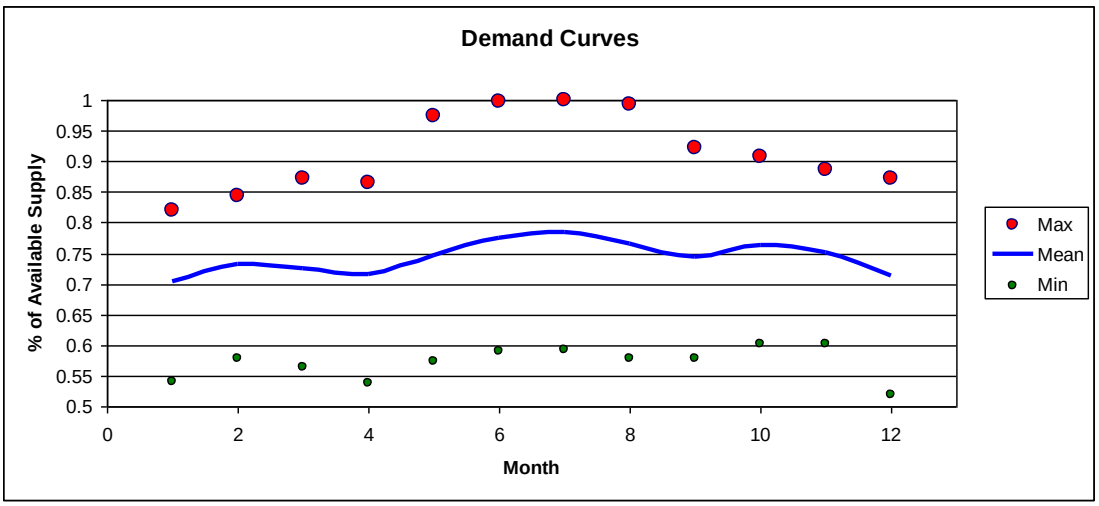


Figure 43 - Annual Demand Curve

Examining the peak demand experienced on an annual basis from 2007 to 2011 (refer to Figure 44) there was a decrease during 2008-09 and an increase thereafter. Following on from 2008 the country experienced an economic recession, which led to lower demand for electricity nationally. This is reflected in the drop in peak demand for power from 2008 to 2010.

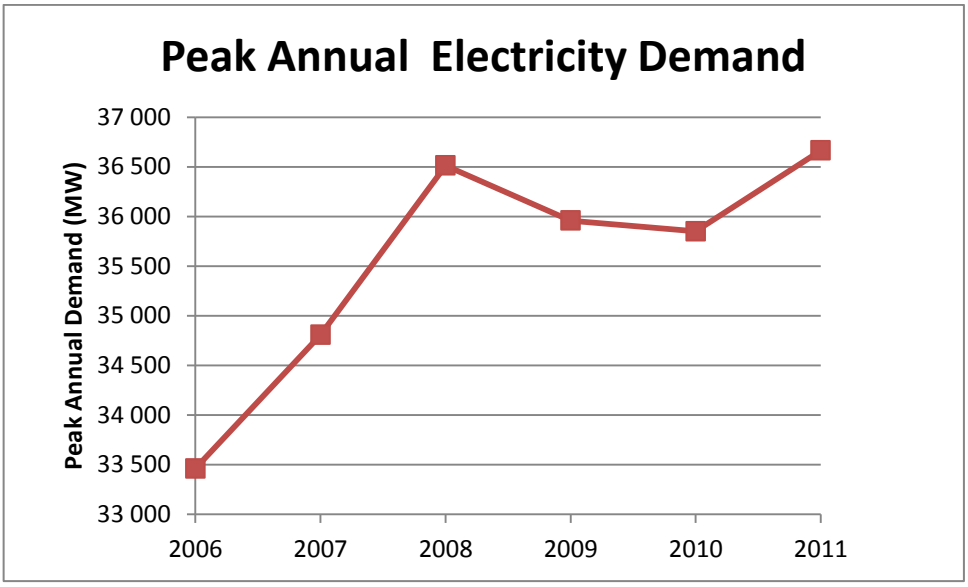


Figure 44 - South African Peak Annual Electricity Demand 2006 - 2011

The peak demand levels seen it 2008 took three years to recover only returning above 36 500 MW in 2011, though DSM and DMP programs also had some effect on reducing the total peak power requirement over this period.

6.1.1 Peak Electrical Demand

Figure 45 shows a screenshot of the Eskom Adequacy Report for Week 35, 2012 and shows that from mid-October 2012 there existed an electrical supply deficit.

Eskom

Eskom Generation Medium Term Adequacy Report

2012 : Week 35

Month Ahead Weekly Peak Capacity / Demand Forecast

Week Start	Week	MW Forecast	MW Available Capacity	MW Available Capacity (Less OR and UA)	% Capacity Reserve Margin	MW Operational Surplus / Deficit	MW Risk
03-Sep-12	36	32653	40772	31888	-2.40%	-765	
10-Sep-12	37	32292	39002	32602	0.95%	310	
17-Sep-12	38	32140	40122	33722	4.69%	1582	
24-Sep-12	39	32097	39032	32632	1.64%	535	
01-Oct-12	40	31894	39087	32687	2.43%	793	
08-Oct-12	41	31940	38959	32559	1.90%	619	
15-Oct-12	42	31904	38173	31773	-0.41%	-131	
22-Oct-12	43	32032	38163	31763	-0.85%	-269	
29-Oct-12	44	32240	37523	31123	-3.59%	-1117	
05-Nov-12	45	32511	37148	30748	-5.73%	-1763	
12-Nov-12	46	32382	37483	31083	-4.18%	-1299	
19-Nov-12	47	32567	37143	30743	-5.93%	-1824	
26-Nov-12	48	32430	37046	30646	-5.82%	-1784	
03-Dec-12	49	32264	37174	30774	-4.84%	-1490	

Notes

Assumptions critical:

Planned maintenance: Current schedule for Eskom and Apollo (Max 1500 MW at Apollo)

Available Capacity: Installed - Maintenance - Gx Constraints

Operating Reserve (OR) from Gx: 1 900 MW

Unplanned Outage Allowance (UA): 4 500MW

Reserves: OR + UA = 6 400MW

Forecast: Current operational forecast in use.

Installed Capacity: 43 176 MW.

Figure 45 - Eskom Generation Adequacy Report 2012: Week 35

This is as a result of Eskom carrying out maintenance on plant and equipment in the months of lower demand after winter's high demand peaks. It is evident that there is shortage in available electricity supply which additional peaking plant could help to reduce.

In the near future this deficit is expected to increase as the commissioning dates for new generating plant are still some years away. There is clearly scope for additional peaking plant currently.

6.1.2 Load Shedding

In January 2008, the South African Department of Minerals and Energy released a document addressing the electricity shortage issue that had become known as "Load Shedding" (DME, 2008). This document described Load Shedding as a last resort measure to prevent a collapse of the national electricity supply system. The document goes on to describe the erosion of South Africa's reserve margin from a period in 2002 when the reserve margin was at 25% to 2008 when the reserve margin had reduced to 8%. During the winter months of 2007, South Africa experienced load shedding on a regular basis as Eskom struggled to meet peak electricity demands.

As a result of the economic downturn in 2008-09 and the associated decrease in electricity demand, to date Eskom has not needed to re-implement load shedding and maintained a small and shrinking reserve margin, though Figure 45 indicates that this may again become necessary.

6.1.3 Reserve Margin

The U.S. Energy Information Administration defines *Reserve Margin* as follows: *"The amount of unused available capability of an electric power system (at peak load for a utility system) as a percentage of total capability".*

DME (2008) states that: *The targeted reserve margin for South Africa is a minimum of 15%. This allows time for maintenance throughout the year as well as power plant to be operated at levels where equipment is not highly stressed,* though in the short term Eskom set a more modest target of maintaining 10% reserve margin through Demand Side Management (DSM) and Demand Market

Participation (DMP). Eskom's target of 15% reserve margin is supported by Chen et al, (2009) who state that developed nations are aiming to have between 10% and 15% of total capacity available as reserve margin.

6.1.4 Energy Availability Factor (EAF)

Due to planned and unplanned outages, the total amount of installed capacity is not available at all times. There is always a portion of installed capacity that is not available due to either planned maintenance or unplanned equipment failures.

Eskom have defined the Energy Availability Factor (EAF) to monitor and record the availability of installed capacity, which is published on the Eskom website www.eskom.co.za as part of the of document published weekly called the *Adequacy Reports*. These adequacy reports monitor a variety of metrics including:

- Week-on-week Net Energy Sent Out
- Week-on-week Peak Demand
- Historic Weekly Outage Statistics by Month
- Month Ahead Weekly Peak Capacity / Demand Forecasts
- Status of New Build Programme
- Medium Term Peak Demand / Capacity Forecasts

The Energy Availability Factor (EAF) provides a measure of the percentage of plant that is available for generation. Table 23 shows the annual average Energy Availability Factor from 2006 to 2011.

Table 23 - Average Energy Availability Factor (EAF) 2006 - 2011

Year	Energy Availability Factor (%)
2006	87.48%
2007	85.53%
2008	85.32%
2009	85.03%
2010	84.08%
2011	84.43%
Average	**85.31%**

The data shows that the average EAF from 2006 to 2011 is approximately 85%, which is in line with Eskom's plan to target reserve margin of 15%. The data shows a constant decline in the EAF which is a decline in the availability of Eskom's plant. This can be attributed to the continuous heavy load to which the plant has been subjected and the consequent unplanned maintenance that is required. This means that on average between 2006 and 2011 approximately 85% of Eskom's generating capacity was available. As Eskom tend to carry out planned maintenance during the summer months when peak demand is typically lower, EAF does vary during the year. The variance in EAF during a year typically fluctuates from lows of approximately 70% in summer months as a result of planned maintenance to highs of approximately 90% in winter months.

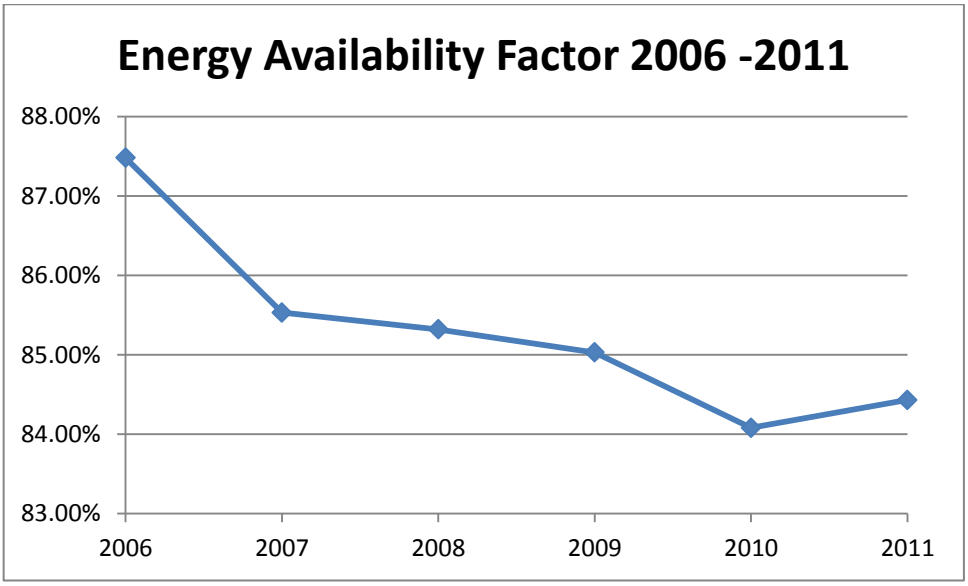


Figure 46 - Energy Availability factor (EAF) 2006 - 2011

The gradual decline of the average EAF from 2006 to 2011 may be symptomatic of increased unplanned maintenance as a result of extended duty cycles of operational plant. This is a cycle of deterioration since as the EAF decreases, the operational generating plant will need to be operated at higher capacity to compensate for the plant out of commission. This increased load requirements on operational plant increases the likelihood of further equipment failures and an overall reduction in EAF.

In the calculation Eskom use for EAF and other metrics, 4 500 MW is reserved for Unplanned-Outage Allowance (UA) and an additional 1 900 MW is reserved for Operational Reserve (OR). Currently this constitutes 14.6% of the total available capacity, based on the current total capacity of 43 937 MW referring to Table 19, which correlates with a reserve margin of 15%.

Eskom is targeting an EAF of 90%, but for the purposes of this study an EAF of 85% will be assumed in line with prior performance, http://financialresults.co.za/2011/eskom_ar2011/gb_overview.php.

However, since base load plant is responsible for 98% of total electricity production by volume (in GWh), this study will assume that the EAF is applicable to baseload plant and that peaking plant has an availability of 98%, which is supported by performance data for Eskom's peaking plant shown in Appendix B - Eskom Power Station Plant Summary.

Once commissioning of the plants currently being constructed begins (Medupi and Kusile Coal Power Stations and Ingula Pumped Hydro Storage) the EAF is expected to increase as a result of having new plant with high availability in the system. In addition, the commissioning of new plant will afford maintenance time to plant that Figure 46 suggests is in need of maintenance. It is expected that this too will have a positive effect on the overall EAF of the Eskom plant. It is possible that these factors have influenced the EAF for 2011 positively as some new and re-commissioned plant has already come online.

6.2 Managing Peak Power Requirements

Due to the limited availability of electricity in South Africa and diminishing reserve margin, and with capacity from new stations still several years away Eskom have examined means of managing the peak electricity requirements through various means. Foreign Import Power is one such means and South Africa imports 1500 MW from the Cahora Bassa Hydro-Electric Scheme in Mozambique, operated by *Hidroelectrica de Cahora Bassa.* This 1500 MW is considered part of reserve margin capacity. South Africa has imported approximately 10 000GWh each year since 2006. *(*http://www.hcb.co.mz/eng, last accessed May 2012).

Demand Side Management (DSM) initiatives were also rolled out to reduce overall demand with some success. DSM aims to reduce user demand through alternate technologies requiring less electricity. Eskom implemented programs for CFL light bulb exchanges whereby the public could exchange their ordinary incandescent light bulbs for energy saving CFL bulbs free of charge, and offered incentives through subsidies to homeowners for installation of heat pumps and solar geysers in place of ordinary geysers with heating elements. Eskom has claimed a reduction in peak electrical demand as a result of DSM as follows:

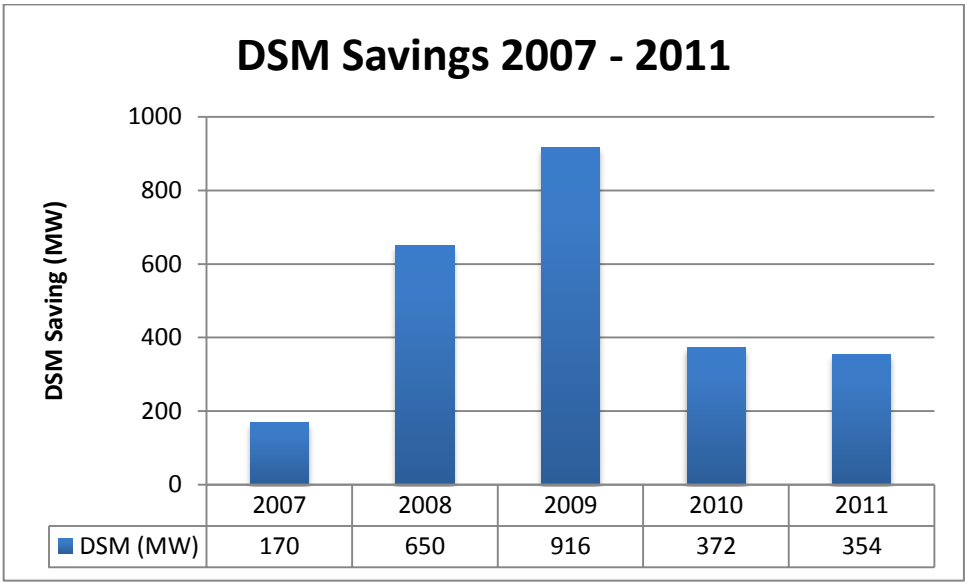


Figure 47 - Demand Side Management Savings 2007 – 2011

The total target was a reduction of 3 000 MW by 2012 through DSM, (http://www.eskom.co.za/c/article/164/what-is-surplus-capacity/, 2012). Eskom claims a total savings of 2 462 MW from 2007 – 2011 referring to Figure 47. However, energy reduction from DSM is not a sustainable means of reducing demand side power as the opportunity for saving is eroded as these systems are implemented. This may explain the decrease in savings in 2010 and 2011 as these energy saving initiatives run their course. The positive result of greener technologies are that the rate of increase of peak demand is reduced as products such as solar geysers and heat pumps become more commonplace in new homes and buildings.

Demand Market Participation (DMP) is another peak management tool implemented by Eskom. Demand Market Participation refers to a mechanism whereby electricity supply to certain customers is interrupted by agreement during periods of high demand. (http://www.eskom.co.za/c/article/167/demand-market-participation/:, 2012).

Eskom describe System Management as follows: (http://www.eskom.co.za/c/11/load-management/, 2012)

- A last resort measure. Only when all other options at its disposal have been exhausted, such as running its power stations at maximum capacity and interrupting supply to industrial customers with special contracts, will Eskom cut supply to other customers.

- A controlled way of rotating the available electricity between all customers. System Management schedules are drawn up to ensure that a outages are shared by users and that durations can be limited. By spreading the impact, affected areas are not interrupted for more than two hours at a time, and in most cases customers can be informed of interruptions in advance.

- An effective way to avoid blackouts. Shortages on the electricity system unbalance the network, which can cause it to collapse. By rotating the load in a planned and controlled manner, the system remains stable.

Agreement is reached in the form of a supply agreement between Eskom and customers. In return for this arrangement Eskom provide these customers with a rebate on the tariff.

DSM entails voluntary reduction of demand (customer loads) to assist with the balancing of electricity supply and demand. Customers who participate in the DMP programme are remunerated/compensated for their efforts to assist the System Operator to manage the power system.

While DSM and DMP do not add capacity to the grid in real terms, it is an effective measure to protect the system at times when demand is at dangerously

high levels. DMP however is not a desirable practice and negative impact to Eskom customers through loss of production and associated revenue have been reported. An example is a loss of production described by Reuters (2012), whereby South African ferrochrome producer Merafe suffered a loss in output of 21% in the first quarter of 2012 after their furnaces were suspended as a result of their DMP agreement.

DSM and DMP are not long term solutions to the shortage in peak power supply but they have gone some way in reducing peak demand while additional capacity is constructed.

Currently initiatives are underway to increase capacity from external power suppliers, as discussed in 5.2.5 - Independent Power Producers (IPP's). The target for total installed capacity operated by IPP's is 3 725 MW, though no target date is currently identified (Independent Power Producers (IPP's), 2012). This additional capacity will come from various suppliers and sources. Details of the type of power plants to be constructed and new operators are not clear at time of writing. In addition, the likelihood of this power being available by 2018, while not a challenging timeline from a technical perspective, is doubtful due to the lengthy administrative and bureaucratic process that IPPS's will need to complete prior to supplying power to the national grid. For the purposes of this study, the potential electricity supply capacity from IPP's in 2018 will be excluded.

7 DESIGN CAPACITY OF A POTENTIAL CAES PLANT IN SOUTH AFRICA

This chapter examines the potential future state of the electrical supply network in 2018 when new power plants currently being constructed will be complete in order to determine whether there will be need for additional peaking capacity thereafter that could be provided by a CAES plant.

The design capacity for a potential CAES plant in South Africa in terms of the generating capacity (in MW) and the quantity of power this plant should provide per day and per year (in GWh) is examined. The requirements for Eskom's future peak electricity requirements are examined, and from that various approaches to determining a suitable plant capacity are discussed.

It is estimated that a CAES plant would require approximately 6 - 8 years to design, construct and commission. The reserve capacity that will be considered will therefore be based on the forecast supply and demand parameters in 2018, which is 5 years from date of writing and coincides with the completion of the Kusile Power Station which is the last significant generation project currently planned by Eskom.

7.1 Future Peaking Plant Capacity

This section examines the need for further peaking plant capacity.

By 2018, there will be a projected total of 5 758.3 MW of peaking plant installed referring to Table 21 - Summary of Future Eskom Peaking Plant. Referring to the average availability of the peaking plant shown in Appendix B - Eskom Power Station Plant Summary is approximately 98%. As data on the availability of the current and future plant is not available, the analysis will assume that all peaking plant has an availability of 98%, and that all base load plant has an availability of 85% in line with the average published Energy Availability Factor. (EAF)

The installed capacity of a system is the total maximum output that is possible if all plant and equipment is running at full capacity. As discussed, this is very rarely the case due to equipment maintained and unplanned outages. As discussed in

section *6.1.4 - Energy Availability Factor*, the availability factor for Eskom plant is typically 85% meaning that on average 85% of installed capacity is available. At the end of 2011 Eskom's installed capacity was 41 965 MW. Considering the average EAF for 2011 was 84.43%, this means that on average only 35 431 MW was available.

In addition to Eskom's own generating plant, it also has imported power which in 2011 provided for additional capacity of 1 500MW from the Cahora Bassa Hydro Electric scheme in Mozambique.

Eskom currently reflects the capacity available through its DSM and DMP as additional capacity which increases the reserve margin. However, this report will not consider these as additional capacity as switching off users is not truly available capacity, and since little information is available as to verify the figures quoted in this regard.

Table 24 shows that on average when the EAF is considered a significant shortfall exists in the available supply of power that must be made up by imported power, DSM, DMP and non-Eskom generation. Without these elements the actual reserve margin is far lower than reported.

Table 24 - Total Electricity Supply Data

Year	Forecast Annual Peak Demand (MW)	Total Eskom Operational Capacity (MW)	Total Average Available Capacity EAF 85% (MW)	Equivalent Reserve Margin	Eskom EAF Available + Imports + DSM and DMP + Non Eskom Generation	Equivalent Reserve Margin	Eskom Total Available + Imports + Non Eskom Generation	Equivalent Reserve Margin	Eskom Published Reserve Margin*
2010	37 240	40981	35 367	-5.0%	39 907	7.2%	37 369	0.3%	24.8%
2011	38 058	41201	35 556	-6.6%	41 568	9.2%	39 018	2.5%	30.8%
2012	39 391	42869	36 996	-6.1%	43 223	9.7%	40 658	3.2%	26.4%
2013	41 441	44257	38 194	-7.8%	44 441	7.2%	41 856	1.0%	23.3%
2014	43 294	47813	41 263	-4.7%	47 510	9.7%	44 925	3.8%	26.4%

*Referring to http://www.eskom.co.za/c/article/963/adequacy-report-week-19-2012/

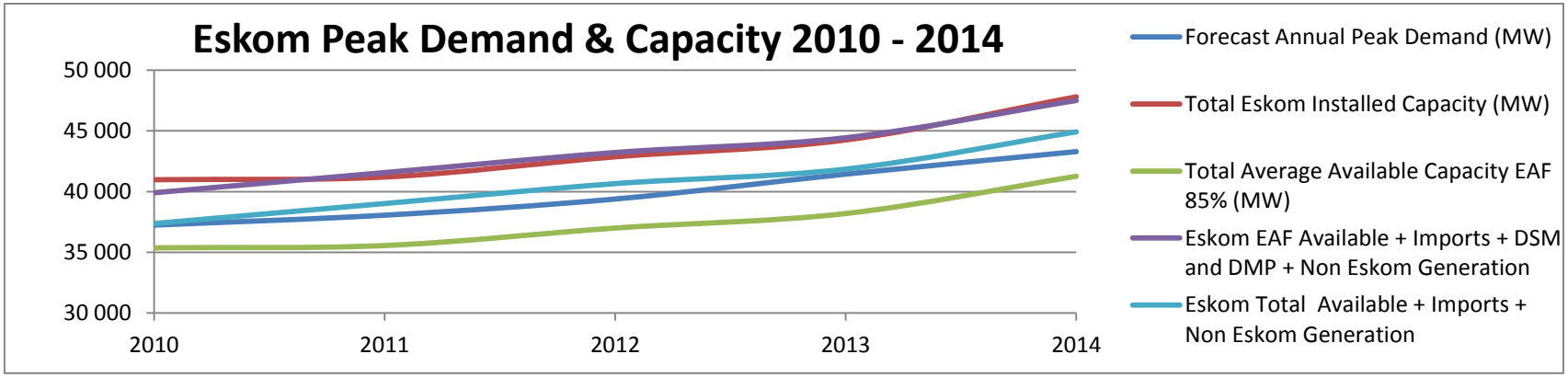


Figure 48 - Eskom Peak Demand & Capacity 2010 - 2014

Figure 48 illustrates that the total installed capacity factored by EAF is below the projected peak demand curve. When including the capacity available from imports and non-Eskom generation the capacity is marginally sufficient to meet the projected demand to 2014.

DSM and DMP provide some meaningful reserve, but that is only achieved by interrupting supply to customers and cannot be considered a sustainable way forward.

This suggests that additional peaking capacity may be required to meet growing electrical demand.

7.2 Forecast Peaking Plant Production Requirement

If a CAES plant were to be constructed in South Africa, its purpose would be to provide increased peaking plant capacity and to meet a projected shortfall in generating capacity with respect to peak demand in 2018. To estimate the production capacity of a potential CAES plant, the following will be considered:

1. The rate at which the peak demand for electricity is expected to increase to 2018.
2. The corresponding peak power requirement at the time a plant would be available in 2018.
3. The projected status of the available power supply network in 2018 and the potential requirement for additional peaking plant.

7.2.1 Forecast rate of increase in peak demand to 2018

Forecasting the actual maximum electricity requirement in 2018 is at best an estimate. In order to obtain a sensible estimate, the study considers various approaches to arrive at a reasonable forecast which are discussed in the following subsections.

Eskom Forecast Demand

Eskom publishes a forecast annual growth projection and also historical annual actual maximum annual demand recorded on their website, www.eskom.co.za. The forecast and actual increase in peak power is shown in Table 25.

Table 25 - Forecast and actual peak power requirements 2008 - 2011

Year	Forecast Annual Peak Demand (MW)	Forecast Annual Increase in Peak Power (%)	Recorded Actual Peak Demand (MW)	Actual Annual Increase in Peak Power (%)
2008	36 139	-	36 513	-
2009	35 910	-1%	35 959	-2%
2010	37 240	4%	35 850	0%
2011	38 058	2%	36 664	2%

Figure 49 shows the variance between the Eskom forecast and the actual peak demand experienced illustrating the difficulty of accurately forecasting peak electrical demand, though this short period provides only limited data.

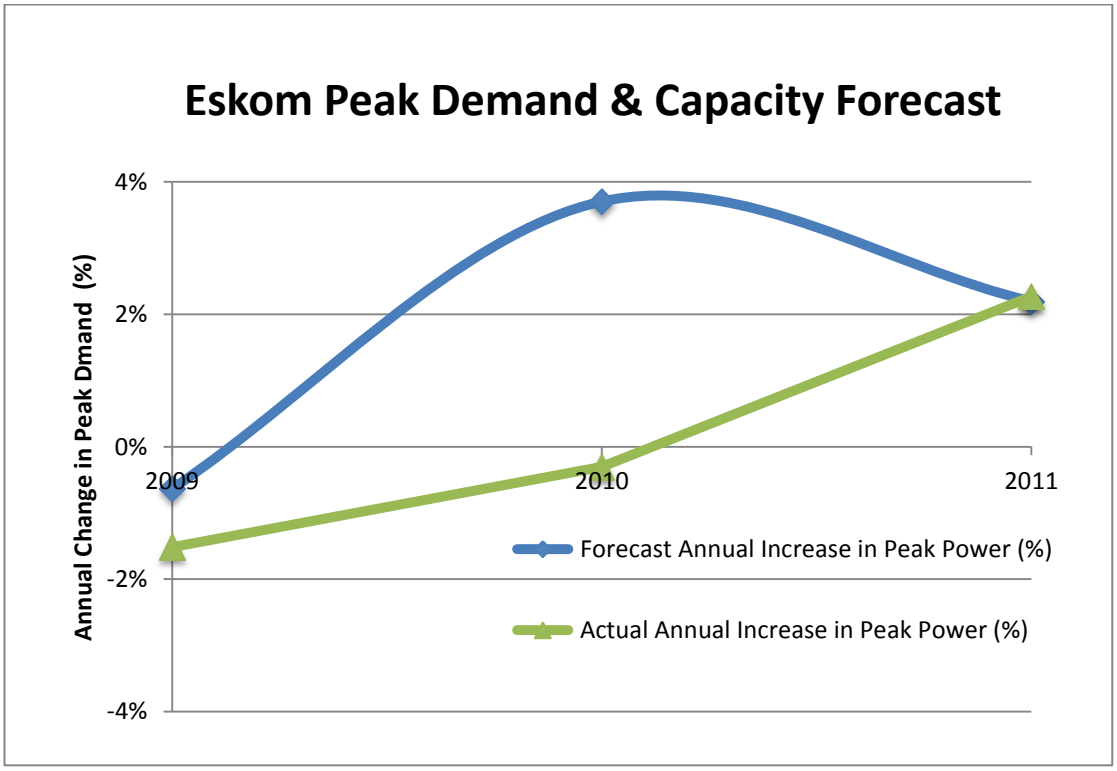


Figure 49 - Forecast and actual peak power requirements 2008 - 2011

Table 25 shows that there is a predicted annual increase in peak electrical demand of 4 - 5% leading up to 2014.

Industry Forecast of Future Demand

The Mbendi Information Services website, http://www.mbendi.com/indy/powr/af/sa/p0005.htm, states that *"As from 2010,*

South Africa will need to increase its power-generation capacity by 1 200 MW a year to keep up with the demand". The maximum generating capacity available in 2010 was 40 981 MW referring to Table 24, thus 1 200 MW represents a 2.9% increase for 2011, reducing to a 2.4% annual increase in 2018.

Eskom and industry forecast a range of annual increase in peak power demand from 2-5%. Extrapolating these increases from the peak demand experienced in 2011 of 36 664 MW, the following maximum peak demands are projected:

Table 26 - Forecast Annual Peak Demand 2011 - 2018

Year	2% Annual Increase in Peak Demand (MW)	3% Annual Increase in Peak Demand (MW)	4% Annual Increase in Peak Demand (MW)	5% Annual Increase in Peak Demand (MW)
2011	36 664	36 664	36 664	36 664
2012	37 397	37 764	38 131	38 497
2013	38 145	38 897	39 656	40 422
2014	38 908	40 064	41 242	42 443
2015	39 686	41 266	42 892	44 565
2016	40 480	42 504	44 607	46 794
2017	41 290	43 779	46 392	49 133
2018	42 115	45 092	48 247	51 590

The difference between 2% and 5% represents approximately 9 500 MW difference which is significant, especially when one considers that this is approximately equal to the total combined output of the Medupi and Kusile Power Stations.

Figure 50 illustrates the forecast annual peak demand curve plotted against the actual peak demand quoted by Eskom to 2011. It can be seen that the forecast is consistently higher than the actual experienced. Therefore, the analysis will examine an annual increase of 2-5% from the actual peak level experienced in 2011.

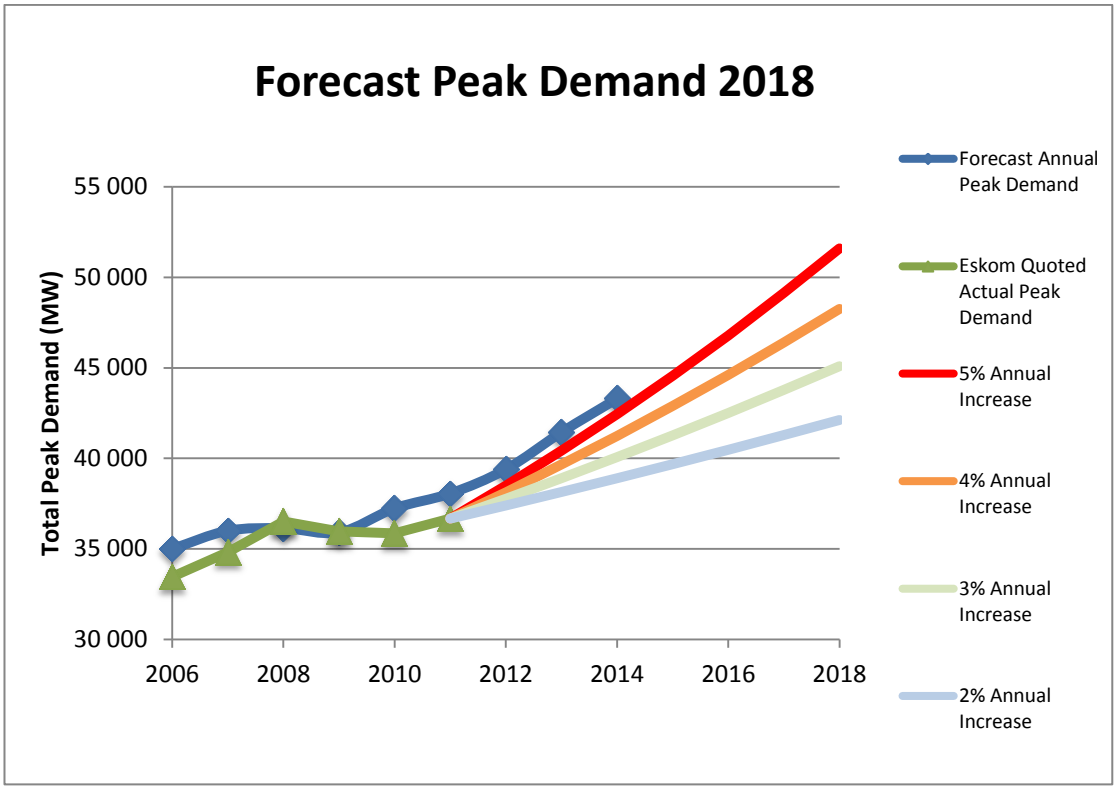


Figure 50 - Forecast Peak Demand to 2018

Figure 50 also shows that by increasing the Eskom's annual peak demand forecast to 2014 from this level, even the most aggressive forecast of 5% annually does not reach Eskom prediction for 2014.

7.2.2 Projected status of the available power supply network in 2018 and the potential requirement for additional peaking plant

In 2018 the total installed capacity of the Eskom network is projected to be 54 860 MW with Medupi, Kusile and Ingula being commissioned by this date. Considering EAF, this reduces to 47 345 MW of which approximately 5 758 MW is made up of peaking plant (which is assumed to have 98% availability). Including 1 500 MW available from Cahora Bassa and 2 162 MW from domestic non-Eskom generating plants, a total available capacity of approximately 51 007 MW is projected for 2018.

With the projected maximum annual demand between 42 000 MW and 52 000 MW, it is unclear whether 51 007 MW will be sufficient to meet the needs at the time. However, considering that Eskom is targeting a reserve margin of 15%,

Table 27 shows that unless an average growth rate below 3% is sustained, 51 007 MW will not be sufficient to provide a 15% reserve margin.

Table 27 – Projected Peak Power Requirement 2018

Peak Power Requirement 2018	Potential Peak Demand (MW)	Additional Capacity required for 15% Reserve margin (MW)	Total Required Installed Capacity (MW)	Shortfall from 2018 Available Peak Capacity (MW)
2% Annual Increase in Peak Demand (MW)	42 115	6 317	48 433	2 574
3% Annual Increase in Peak Demand (MW)	45 092	6 764	51 856	-849
4% Annual Increase in Peak Demand (MW)	48 247	7 237	55 484	-4 477
5% Annual Increase in Peak Demand (MW)	51 590	7 738	59 328	-8 321

Therefore depending on actual rate of increase for peak demand, there may be scope for additional plant to be constructed to assist Eskom to achieve the targeted 15% reserve margin. Depending on the level of certainty, the plant must provide up to 8 500 MW in the event of 5% annual growth, though this would make it the largest single power plant for Eskom. It is more feasible to model this potential plant after the Norton plant in the US with a capacity of 3 500 MW. This would fulfil the needs of South Africa's peak demand and providing 15% reserve margin, and a total available peak demand capacity of 54 507 MW which would account for an average annual growth of peak capacity of 3.7% (interpolating linearly).

Therefore the plant design will assume a capacity of 3 500 MW and will provide a 15% reserve margin if the average annual growth rate in peak demand to 2018 is 3.7%.

7.3 Determination of Plant Production Capacity

With the assumption of a 3 500 MW capacity plant, the period for which this peak capacity is to be supplied must be determined. This will be a function of the total electricity production requirement in 2018, which similarly to the total peak electricity demand requirement is at best an estimate.

Since data on the cycle durations that Eskom peaking plant has been operated historically is not available, this section examines possible operating durations based the annualised data available.

7.3.1 Total Annual Electricity Production in South Africa

This section examines the total annual electricity consumption of South Africa.

The total power produced annually by Eskom varied between 2007 and 2011 as shown in Table 28, with the total annual production divided between base load and peaking plant.

Table 28 - Total Annual Electricity Production Base Load and Peaking Plant 2007 - 2011

Total Annual Electricity Production - Base Load, Peaking Plant and Import Volume	2007 (GWh)	2008 (GWh)	2009 (GWh)	2010 (GWh)	2011 (GWh)
Total Electricity Production	**243 069**	**250 107**	**238 106**	**242 859**	**251 043**
Base Load Production	217 654	223 659	213 023	217 214	222 179
Peaking Plant Production	14 791	15 450	15 921	15 598	15 251
Foreign Import Volumes	10 624	10 998	9 162	10 047	13 613

The quantity of electricity produced annually in South Africa is driven by the demand of consumers. Referring to Figure 51, the effect of the economic slowdown is apparent from the reduced demand in 2008 - 2009. Excluding the 2009 data, the increase in total electricity production increased annually by 2-3% over this period.

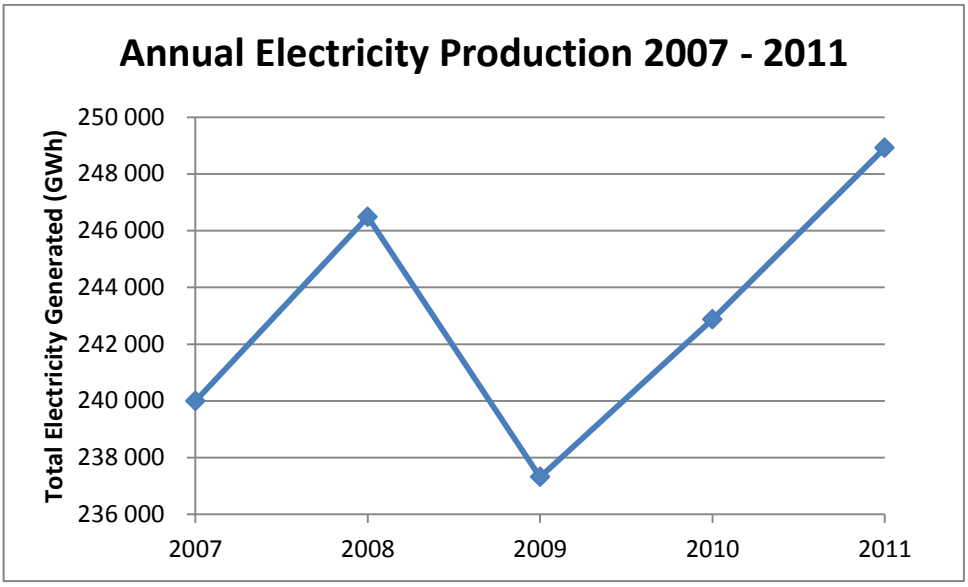
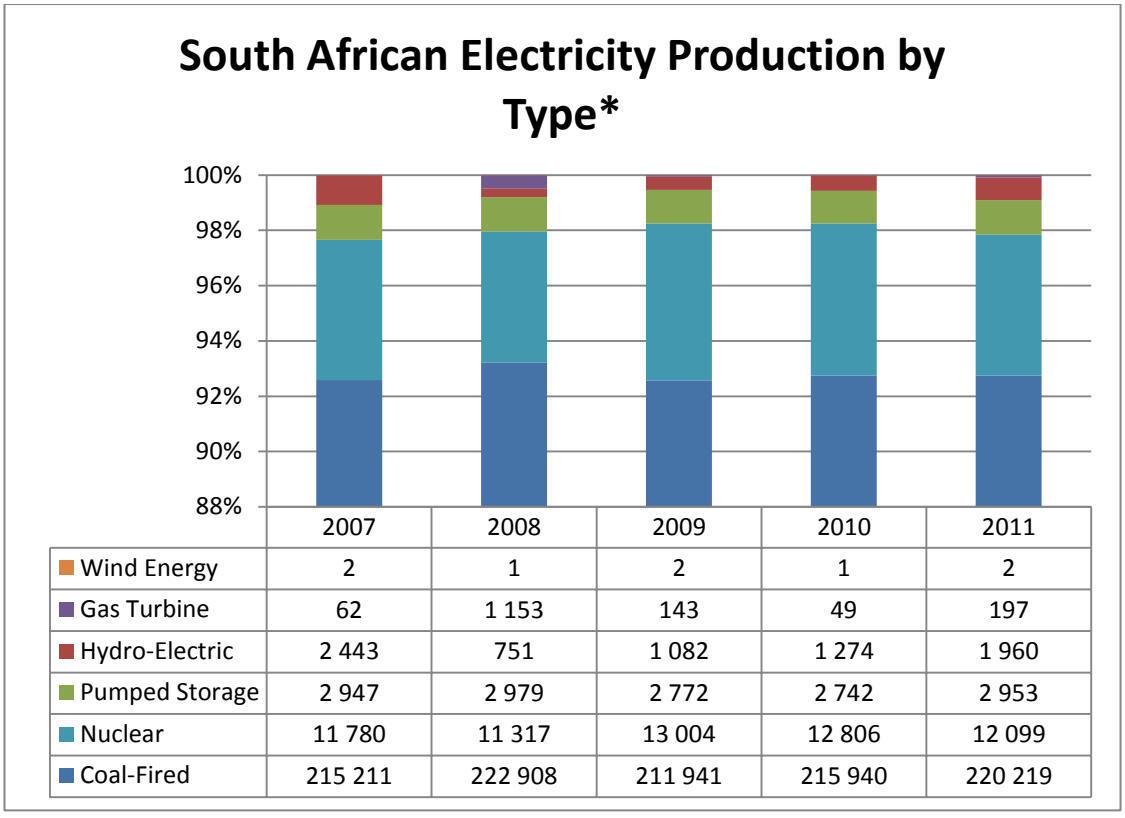


Figure 51 - Total Annual Electricity Production

Figure 52 illustrates that approximately 98% of the total power produced each year is provided by base load stations, made up by coal and nuclear power plants.



	2007	2008	2009	2010	2011
Wind Energy	2	1	2	1	2
Gas Turbine	62	1 153	143	49	197
Hydro-Electric	2 443	751	1 082	1 274	1 960
Pumped Storage	2 947	2 979	2 772	2 742	2 953
Nuclear	11 780	11 317	13 004	12 806	12 099
Coal-Fired	215 211	222 908	211 941	215 940	220 219

Figure 52 - South African Electricity Generation by Type

*(Values in GWh)

Figure 52 shows the total electricity generated per year by various types of power plants. Of the total annual production only a small proportion of power is produced by peaking plant.

Table 29 - Total Electricity Consumption 2007 - 2011

Electricity production by own stations and electricity purchased by Eskom	2007	2008	2009	2010	2011
Coal-fired (GWh)	215 211	222 908	211 941	215 940	220 219
Nuclear (GWh)	11 780	11 317	13 004	12 806	12 099
Hydro-electric (GWh)	2 443	751	1 082	1 274	1 960
Pumped storage (GWh)	2 947	2 979	2 772	2 742	2 953
Gas turbine (GWh)	62	1 153	143	49	197
Wind energy (GWh)	2	1	2	1	2
Total production (GWh)	**232 445**	**239 109**	**228 944**	**232 812**	**237 430**
Baseload (GWh)	**226 991**	**234 225**	**224 945**	**228 746**	**232 318**
Peak (GWh)	**5 454**	**4 884**	**3 999**	**4 066**	**5 112**
% Peak of Total	**2.3%**	**2.0%**	**1.7%**	**1.7%**	**2.2%**

Table 29 indicates that the ratio of total baseload to peaking power generated remained fairly constant at approximately 2% on average. It is possible therefore that in 2018 the total energy produced (in GWh) by peaking plant may also be approximately 2% of the annual total.

7.3.2 Total Peaking Plant Production 2007 - 2011

Table 30 shows the total number of production hours at maximum capacity by generating plant type. On average, the gas turbine equipment is only run 0.4 hours per day, though provision has been made by Eskom for the plant to run 8 hours per day (Moodley, 2007).

Table 30 - Total Annual Average Plant Running Time 2007 - 2011

Total generating duration	Hours of Annual Production	Average Hours/day	Total plant utilisation
Coal-Fired	6 777	18.6	77%
Hydro-Electric	2 503	6.9	29%
Pumped Storage	2 056	5.6	23%
Gas Turbine	132	0.4	2%
Nuclear	7 975	21.8	91%
Wind Energy	506	1.4	6%

Since the CAES plant could be constructed to take over part or all of the current duty of the Gas Turbine plant which may be more expensive to operate, the duty may be very low being required to run only one half hour per day on average. However, this daily quantity is based on average annual production and it is more likely that this plant would run for several hours at a time in mid-winter and hardly at all during summer. Ideally data on the number of hours per day that peaking plant is run should be evaluated to determine the capacity of future peaking plant. Unfortunately this data does not appear to be in the public domain. The design capacity for a potential CAES plant will therefore be designed to run for a duration of 8 hours in line with maximum running time for gas turbine equipment. This design therefore represents a total capacity of 28 000MWh based on a plant capacity of 3 500MW.

8 STORAGE CAVERN OPTIONS

This chapter considers the following criteria required of a cavern in order to support a CAES plant in South Africa:

1. The types of underground storage suitable to South African conditions
2. The volumetric capacity and physical dimensions of a potential cavern
3. Characteristics of potentially suitable sites in South Africa for a CAES cavern

The approach of using underground caverns to store compressed air for CAES is similar in principle to storing natural gas underground, a practice used extensively by energy companies around the world. Since 1915, the natural gas storage industry in the US has operated over four hundred storage reservoirs and a further one thousand salt caverns and seventy excavated caverns for storage of liquid hydrocarbons (including petrol and diesel for strategic purposes) and liquid petroleum gas with various European examples discussed by Evans (2008).

A suitable storage cavern type and site must be identified for the CAES plant. Ideally, a site should be located that already has a large open volume that can accommodate the quantity of air required to run a CAES plant (alternately there must exist potential to create the required open space), the size being dependant on the electrical output required and the operating duration.

8.1 Suitability of Existing Storage Types of Underground Gas Storage to South Africa

This chapter examines the suitability of the most common underground gas storage methods for a potential CAES Plant in South Africa.

8.1.1 Salt Domes

The use of salt deposits for storage of oil, natural gas and compressed air has been implemented successfully in the past. Salt domes are the storage caverns used for the Huntorf and McIntosh Plants and have proved to be a very suitable medium for storing compressed air.

Unfortunately South Africa‘s salt resources are limited to underground brines associated with inland saltpans, coastal saltpans and seawater and there are no known economical rock salt deposits in the country. The majority of the salt in the deposits occurs at a depth of approximately 3m (DME, 2001) which is obviously unsuitable for compressed air storage.

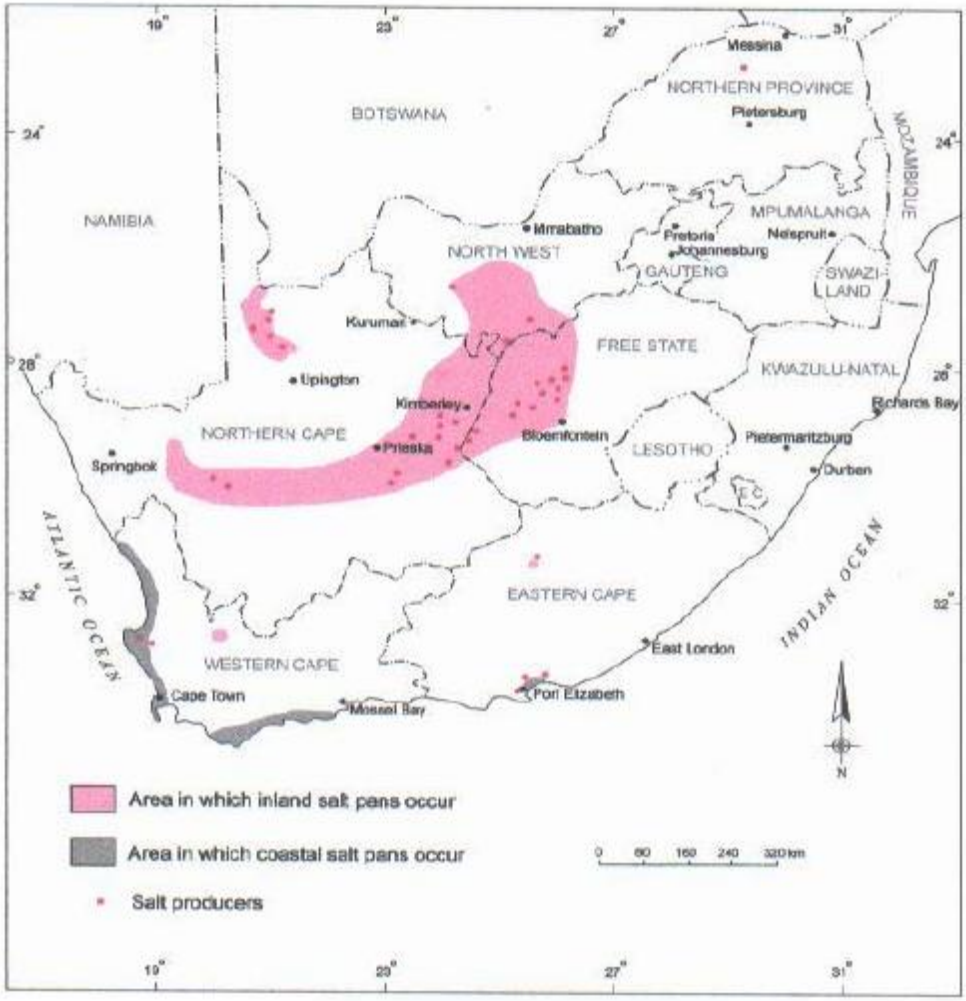


Figure 53 - Distribution of Salt Pans in South Africa

Unless previously unidentified underground salt deposits are located in South Africa, a salt dome is not a viable option for underground storage of compressed air due to the lack of suitable sites.

8.1.2 Depleted Natural Gas Reservoirs

Depleted gas reservoirs are considered the most economical types of underground gas storage means for CAES (Pangea Exploration, 2011). This is mainly due to their ease of conversion to compressed air storage.

South Africa has a relatively small number of natural gas deposits with most of these being off-shore in the region of Mossel Bay in the Western Cape (Rembursi, 1998).

Using an underwater natural gas reservoir to store compressed air, though not technically impossible, has associated challenges that would increase costs for compressed air storage, and is also not a proven means of gas storage. Due to the limited depleted natural gas reservoir sites and the difficulty associated with converting an underwater reservoir for compressed air storage, this is not likely to be the most feasible option for a CAES plant in South Africa.

8.1.3 Aquifer

Aquifers have been used to store natural gas in various cases as discussed in Section 4.5, and similar principles can be applied for storage of compressed air in aquifers.

A proposed CAES installation in Iowa originally planned to make use of an aquifer as a storage cavern for compressed air. The aquifer was comprised of porous sandstone. An aquifer was located in Fort Dodge, Iowa that seemed suitable for compressed air storage and was ideally located near an existing transmission grid and gas pipeline.

However, further studies showed that the aquifers were not suitable due to low air recovery rate through the porous sandstone to meet the consumption requirements of turbo equipment and the project was terminated in 2011 (Midwest Energy News, 2011). The aquifer covered an area of approximately 2.5km^2, was 30m in height and located 1km underground. The use of aquifers for storage of compressed air to date has not been successfully implemented. Additionally there are environmental considerations in the impact to ground water levels.

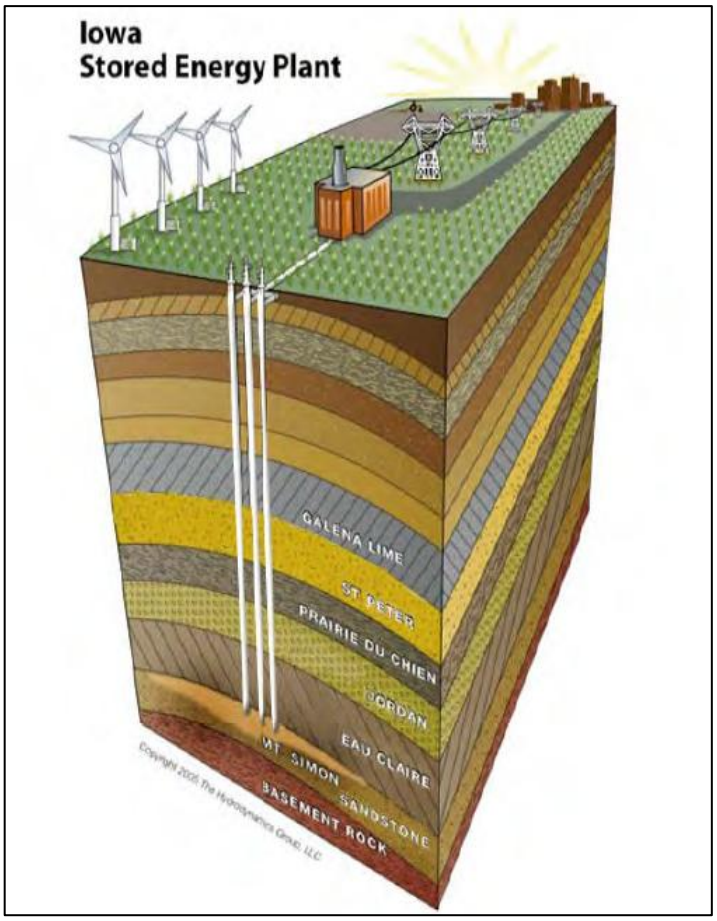


Figure 54 - Iowa CAES Aquifer Storage (ISEP, 2011)

Due to technical difficulty and associated costs, aquifer storage is not anticipated to be a suitable storage method for compressed air in South Africa.

8.1.4 Disused Mines

South Africa has a number of disused mines as a result of its mining history with various types available. Disused coal mines are abundant in the Mpumalanga region with depths varying from a few metres below surface (which become opencast mines) to deepest levels at around 150m. Gold Mines in Western Gauteng are among the deepest mines in the world with Mponeng going down to 3 900m. South Africa also has an assortment of base metal and diamond mines.

Pangea Exploration (2011) suggests that rock caverns are approximately 60% more expensive to mine from virgin rock than salt caverns (Pangea Exploration,

2011), so the use of an existing excavated cavity in the form of a disused mine would be a more cost effective option, assuming the site is suitable for compressed air storage. Egidi R. (2011) proposes that equipping a hard rock mine may be as high as 30 times more than an equivalent solution mined salt cavern.

Converting disused mines into suitable storage caverns for compressed air may potentially be a technically challenging and costly undertaking. Considerations such as sealing the underground open workings to create a gas tight space such that will contain the compressed air is a major focus area. Fractures that exist within the mine walls too must be sealed to prevent or minimise losses of compressed air as far as possible. This could be a particular challenge in the typically fractured rock structures often found in the highly stressed deep level South African mines.

The material composition of the mine walls floor and roof that will contain the compressed air must be considered for structural integrity. Two main mine types are considered for storing compressed air:

1. Coal Mines – Coal mines are significantly shallower, typically less than 120m. Coal is often found with sandstone which is a soft rock type.

2. Hard Rock Mines - These mines typically occur at depths in excess of 500m. These mines are typically an ore-body such as gold, platinum, diamonds or other base metals surrounded by hard rock.

8.1.4.1 Coal Mines

South Africa has large quantities of coal reserves. Due to decades of coal mining, particularly in the Mpumalanga area, there are also large mined out areas in old coal mines. Coal is often mined in a room and pillar configuration in open expanses that would likely be large enough to provide the compressed air storage capacity required for a CAES plant. The structural integrity of coal would need to be considered with respect to the forces exerted by the stored compressed air.

Methane gas often occurs with coal deposits. Mixing of methane gas with the stored compressed air could potentially pose a serious explosion risk as the mix passes through equipment en route to the turbine. The presence of methane could also negatively affect the operation of the turbine.

The major challenge with using South African coal mines for storage of compressed air would be depth. As a minimum, as advised by Sovereign Hydro, a mine must be of a depth that the overburden is sufficient to balance the vertical forces exerted by the compressed air stored underground. Assuming that coal has an overburden of 100% sandstone with an average specific gravity of 2 400 kg/m^3 the depth of the coal mine required to contain 50-70 bar is 212-297m respectively. Since there are no known coal mines in South Africa at this depth, disused South Africa coal mines are not likely to be able to contain the forces exerted by the compressed air. Buttiens (1978) considers the use of coal mines for low pressure gas storage, but the suitability of coal to contain 50-70 bar in the case of existing CAES plants would need more detailed evaluation.

8.1.4.2 Hard Rock Mines

There are currently no known commercially operational examples of hard rock mines that have been used to store gas underground. However, South African examples of underground air receivers used to store relatively small quantities of compressed air for production equipment have shown that storage of air in hard rock mines is possible. Van Der Merwe (1983) describes the installation and operation of an underground air receiver with a volume of 6 480m^3 with maximum operating pressure of 22 bar in a South African Gold Mine. Although the volume of this air receiver is significantly smaller, and the operating pressure is approximately a third of what would be required for a CAES plant it proves conceptually that compressed air storage in underground hard rock mines is possible.

It is anticipated that the main focus area for evaluating hard rock mines for compressed air storage would be the potential for air to escape through fractures and other discontinuities.

Many hard rock mines make use of retreat mining methods which allow the controlled collapse of the roof or hanging wall. Such mines would not be suitable for compressed air energy storage since the effective available storage volume would continually be decreasing and these areas are inherently unsafe.

Hard rock mines could potentially be used as a constant pressure cavern, assuming the rock is not affected by water, and would need to be situated at a depth of approximately 510-715m to supply constant pressure of 50-70 bar.

Disused hard rock mines appear to offer the only feasible solution for storing the pressure and quantities of compressed air required for a CAES plant in South Africa.

8.2 Capacity of Potential CAES Storage Cavern

A CAES plant requires a suitably large storage cavern for compressed air to allow generating equipment to operate for the design duration, without a pressure drop significant enough to affect the operating parameters of the turbine and mechanical equipment (in the case of a fixed volume cavern). As determined in Section 7.3 - Determination of Plant Production Capacity the design capacity for the purposes of this study will assuming a running time of 8 hours. Therefore, since the plant output is 3 500 MW, the total plant capacity is 28 000 MWh.

Using the ideal gas law: PV=nRT where:
P = Pressure (Pa)
V = Volume (m^3)
n = Quantity of moles of gas
R = Universal gas constant (J/K/Mol)
T = Temperature (K)

For compressed air at 70 bar, and 30°C the density of the air is 80.46kg/m^3. The 300MW Gas Turbine referred to by Valenti (2010) consumes air at a rate of 1.2kg/s/MW. Since the parasitic effect of the compressor for a similar unit modified for CAES, it is assumed that the air consumption rate would decrease with the proportional increase in output power. Therefore a consumption rate of 0.4kg/s/MW is assumed. Therefore further assuming the turbines have a

minimum inlet pressure of 55 bar and consume air at a rate of 0.4kg/s/MW, the 3 500 MW plant would consume air at a rate of 1 400kg/s. Therefore during an 8 hour run time, 40.3×10^6 kg of air will be consumed.

Assuming the air will have a density of 57.47kg/m^3 at 50 bar, an approximate total volume of 700 000 m^3 is required to store the required quantity of air for 8 hours of operation.

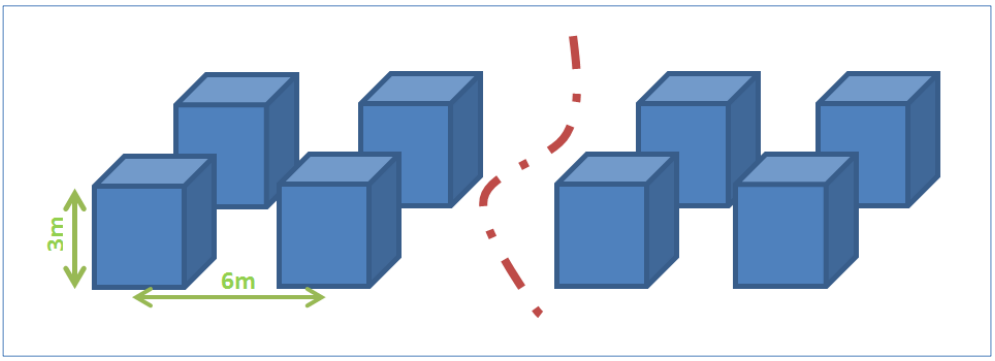


Figure 55 - Assumed Room and Pillar Configuration

Since room and pillar mine is a common mining method, this method will be assumed for this section with a roof height of 3m and pillar centres of 6m. Therefore for this even room and pillar arrangement, approximately half the area would be made up of air storage volume and a footprint of 684m x 684m would be required to store the total 700 000 m^3 of compressed air.

8.3 Potential South African Sites for a CAES Cavern

There were 4 772 officially listed abandoned mines in South Africa in November 2006 (Engineering News, 2006). This was five times the number of operational mines at the time. There are many sites that could be evaluated for suitability as a potential CAES storage site. From the preceding sections, the most suitable mine would have the following characteristics:

Table 31 - Parameters for mines to be used for CAES caverns

Cavity Parameters	
Depth	500m – 700m
Mine Layout	Room and Pillar
Total Volume	700 000 m^3

Area Foot Print*	468 000 m^2
Length of side of area if square*	684 m
* Depending on Pillar Height	

Additionally the rock mass should be as uniform as possible with few discontinuities that could allow compressed air to dissipate and non-permeable to prevent seepage.

Considering the option of sealing up sections of a room and pillar mine to limit the working volume increases the number of potentially suitable sites as this negates the need to find a site with the desired storage volume. Sovereign Hydro demonstrated through trials the possibility of sealing up a room and pillar mine for gas storage.

Roberts (2012) confirmed that from a rock mechanics perspective, the concept of storing compressed air in underground hard rock mines is feasible, and referred to the example of the Underground Air Receiver constructed at Buffelsfontein, discussed in Chapter 2.8 - The Installation and Operation of an Underground Air Receiver on 13 Level Pioneer Shaft (Van Der Merwe, 1983). He further confirmed that a depth of approximately 300m would be required to contain a pressure of 70 bar and that grouting around bulk heads, described in Chapter 8.3.1 would be the correct approach for sealing underground room and pillar mines.

8.3.1 Sovereign Hydro Bulkhead Design

Sovereign Hydro was involved in the sealing of a limited section of the Lyons room and pillar salt mine in Kansas. The test involved sealing up an opening 8m wide x 5m high. The concrete bulkhead that was constructed was 5m thick. The total concrete used for construction of the bulkhead was 300m^3.

The major technical challenges associated with sealing of a room and pillar mine are the structural design of the concrete bulkhead to withstand the pressure and the transfer of forces onto the mine walls, and establishing a competent seal between the bulkhead and mine walls.

Hydrostatic testing of the bulkhead to 80 bar was successful. The depth of this mine was 300m, which successfully contained compressed air 80 bar.

8.4 Further Work in Cavern Design and Selection

As the underground dimensions of mines are not freely available, some further work in identifying sites that satisfy the criteria set out in Table 31 is required. In addition, the suitability of a rock type to contain air would also need to be considered in terms of the following parameters:

- Rock Mass Strength
- Permeability (hydraulic conductivity)
- Stability
- Depth
- Thickness

The work undertaken by Sovereign Hydro and the use of underground air receivers in South African hard rock mines provide a basis for designing a suitably large air receiver for a CAES plant.

9 COST OF CAES VS. OTHER ENERGY STORAGE METHODS

A full quantitative examination of the costs associated with constructing and operating a CAES plant in South Africa is beyond the scope of this study. This chapter considers the qualitative costs of building and operating a CAES plant and compares these to costs associated with other energy storage options and peaking plant options, and examines literature on the Levelised Cost of Energy (LCOE) for CAES.

9.1 Levelised Cost of Energy (LCOE)

Levelised Cost of Energy is defined as the price at which electricity must be generated from a specific source to break even over the lifetime of the project. It provides a means to carry out an economic assessment of the cost of an energy generating system with lifetime costs including initial investment, operating and maintenance costs, fuel, and cost of capital. However, review of available literature suggests that there is little consistency in the approach to generating LCOE. This must be considered when comparing different LCOE studies and the sources of information, as LCOE for a given energy source is highly dependent on assumptions made, financing terms and technological deployment analysed.

Literature on the subject for CAES states significantly varied results, which is assumed to be as a result of varying underlying assumptions. McGrail et al (2013) calculate LCOE value for CAES at 6.4c(US)/kWh, while the results produced by Barrows et al (2009) reflect a far lower LCOE for CAES of 3.4c(US)/kWh, a significant variance.

Figure 56 shows CAES to have a relatively low LCOE compared with other technologies, though the parameters of the calculations are not provided by McGrail et al (2013) and require verification. LCOE values presented by Barrows et al (2009) present a different mix of technologies with CAES LCOE relatively high in comparison, referring to Table 32.

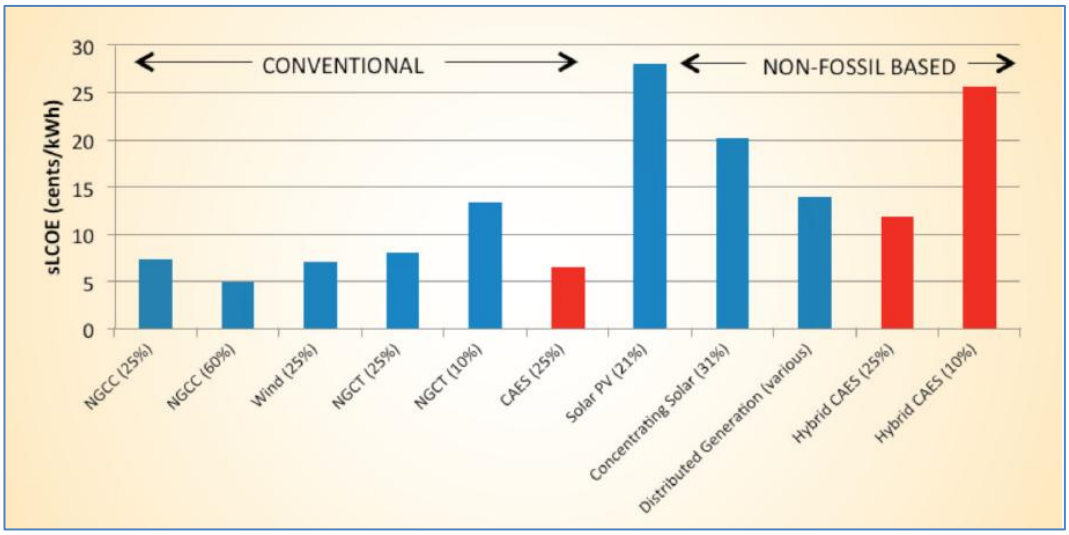


Figure 56 – Levelised Cost of Energy for Various Technologies (McGrail B et al, 2013).

Barrows et al (2009) also note that the cost for an assumed 100MW system including a CAES plant did not produce an economically viable model as a result of the high capital costs for storage, with low revenue generated by wind alone contributing to unprofitability of the system.

Table 32 – Levelised Cost of Energy Production and Storage Technologies (Barrows et al, 2009)

Energy Generation or Storage Option	Levelized Cost of Energy [$/kWh]
Pumped-hydro Storage (PHS)	$0.010/kWh
Compressed Air Energy Storage (CAES)	$0.034/kWh
Wind Generator	$0.026/kWh
Natural Gas Non-Peaking Generator	$0.038/kWh
Coal Generator	$0.045/kWh
Natural Gas Peaking Generator	$0.387/kWh

It appears then that available literature on LCOE provides little guidance as to the real value of CAES, particularly in the South African environment, and further work in determining a substantiated value with known variables is required.

9.2 Capital Costs

Without carrying out an in-depth costing exercise to forecast construction costs of constructing a 3 500 MW CAES plant, this section examines costs of previous projects and current costing for projects in South Africa.

The Ingula Project currently underway in the Drakensburg has a project cost of R21.4bn, which excludes borrowing costs capitalised. (http://www.engineeringnews.co.za/article/ingula-on-schedule-2011-06-09). The total capacity of the plant is 1 333 MW. The Ingula Scheme therefore has a cost of approximately R16m/MW.

McIntosh cost $65m to construct in 1991, (http://en.wikipedia.org/wiki/Compressed_air_energy_storage). Escalating these costs to 2012 using the American CPI index (135.200 in 1995 and 230.085 in May 2012) results in a current project cost of $110.6m. Assuming an rate of exchange of R8 to $1, this equates to approximately R884.8m and R8.0m/MW

Though the project costs of Huntorf are not known, it is noted that construction cost considerably less than an equivalent Gas Turbine plant of the same capacity at the time of construction in 1978 (Ter-Gazarian, 1994). A new development in Iowa in the USA intends to build a 270 MW facility and expects to spend approximately $400m on the construction thereof. (ISEP, 2011).

Table 33 - Capital Costs for Peaking Plant (Egidi R, 2011)

Plant	Generation Type	Location	Construction Cost (R/MW)
Ingula	Pumped Hydro	SA	R16m
Iowa*	CAES	USA	R11m
McIntosh*	CAES	USA	R8.0m
Ankerlig/Gouriwa	Gas Turbine	SA	R2.6m
* Assuming $1 equal to R8.			

The capital costs for construction of a CAES plant appear to be comparable with those of Pumped Hydro Storage, though if the costs were increased to account

for construction in the South African environment these costs may increase significantly.

CAES appears to be far more expensive than construction of a Gas Turbine plant, though details of the project costs for Ankerlig and Gourikwa were not available to provide a comparative reference. Gas Turbine plants are however typically very expensive to operate due to fuel costs. This assessment is not based on a full comparative assessment of plant and construction costs in South Africa at the present time.

Geschler (2010) states that construction of a CAES plant is typically around 30 months which is roughly a quarter of that required to build a pumped hydro storage plant reducing the overall project costs for a CAES plant. He goes on to say that the current capital cost (in 2010) for pumped hydro facilities is 2700 - 3000 USD/kW compared with 600 - 700 USD/kW for CAES plants larger than 100 MW.

Therefore for a 3 500 MW CAES plant in South Africa, the project costs could be expected to be approximately R38.5bn, though this number would be significantly influenced by the underground storage cavern and the extent of commissioning work required.

9.2.1 Costs for sealing a room and pillar mine

A large proportion of the costs associated with a CAES facility could be made up of converting the underground cavity to store compressed air. The actual costs would be dependent on several factors such as the type of underground cavity selected, the amount of structural reinforcing required to contain the forces from the pressurised air, and the amount of plugging and sealing work that would be required to render the cavity gas tight.

Since the only apparent viable option in South Africa is a disused underground hard rock mine, this section examines the costs that may be associated with sealing of a hard rock room and pillar mine. The costs are based on advice offered by Sovereign Hydro who were involved in plugging of a single opening of a salt mine on Lyons Kansas USA, refer to Section 8.3.1 for more details. Sealing

up a room and pillar mine would require sealing off the opening of the rooms to constrain a cavity volume to the desired capacity. This is accomplished by constructing *bulkheads* between adjacent pillars.

The Sovereign Hydro project involved sealing up a single space 8m wide x 5m high between adjacent pillars. The concrete bulkhead constructed was 5m thick and a total of 300m^3 of concrete used for its construction. Five tonnes of steel reinforcing was also required.

A summary of the costs for the bulkhead are outlined in Table 34 below. These costs were sourced from the South African mining industry and were accurate as of June 2012.

Table 34 - Sealing Bulkhead Cost Breakdown

Item	Qty	Unit	Supply Rate	Place	Amount
1) 40 MPa Concrete	300	m3	R 850	R 1 247	R 629 100
2) Reinforcing	5	tonne	R 8 500	R 3 384	R 59 420
3) Formwork - (Supply & Fix)	80	m2	R 675		R 54 000
4) Sealant (supply and place)	1	-	R 836 400		R 836 400
TOTAL					**R 1 578 920**

Therefore the cost to seal each bulkhead is approximately R1 600 000, costs based on rates at June 2012. Assuming that two sides of the total volume of an underground room and pillar mine were required to be sealed and the openings were 8m wide (as was the case for the Lyons mine but which would be very large for a deep level South African hard rock mine) this would require that approximately 43 openings on each exposed edge were sealed. At a rate of approximately R1.6m each, only sealing of the pillars could account for costs in excess of R137.6m.

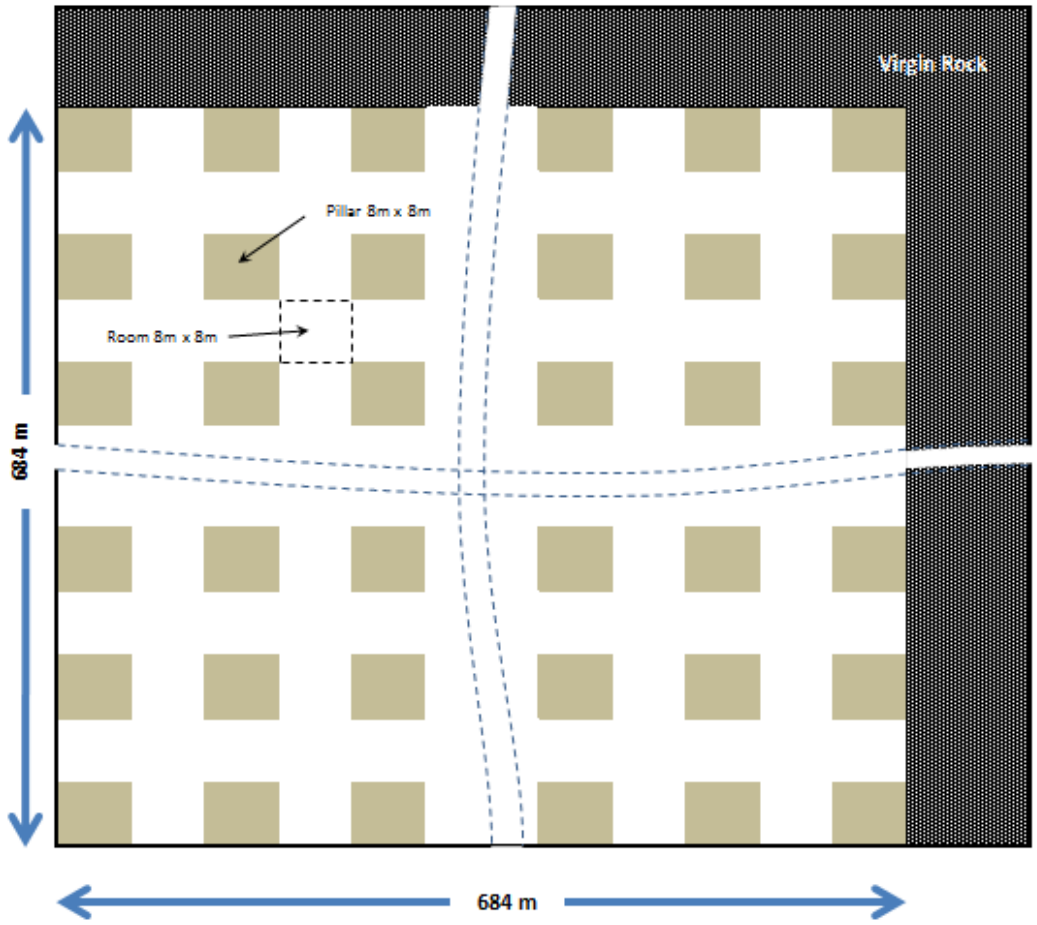


Figure 57 - Sealing Requirements for Room and Pillar Hard Rock Mine

There is therefore significant merit in identifying a volume underground as close to the desired volume as possible.

Egidi (2011) propose costs for sealing caverns with various types of geology, as shown in Table 35.

Table 35 - Estimated Capital Costs for Varying Geologies (Egidi R, 2011)

Geology	Capital Cost of Energy Storage Component
Salt Cavern / Solution Mined	$1/kWh
Salt Cavern / Dry Mined	$10/kWh
Hard Rock / Excavated & Existing Mines	$30/kWh
Porous Rock / Aquifer	$0.10/kWh
Abandoned Limestone or Coalmines	$10/kWh

Using $30/kWh as a basis for a hard rock excavation, the assumed plant parameters represent 28 000MWh with a resulting capital cost of $840m. Details of these costs are not provided but clearly costs for sealing of the cavern represent a significant proportion of the overall capital required for such a project, and the design thereof requires due consideration. The ratio of 30:1 for costs of salt caverns vs. hard rock may explain why there are no existing hard rock CAES caverns in use, while both CAES plant in operation utilise salt caverns.

9.3 Operating Costs

Shepard (2001) discusses the typical heat rate for the 300 MW Alstom turbines planned for the Norton installation and states this to be 4 000 Btu/kWh. In contrast, the Gas Turbines of similar size require upward of 6 000 Btu/kWh even for combined cycle plants.

The Ankerlig and Gouriwa turbines consume diesel at a rate of 57 000 litres per turbine per hour with each turbine producing approximately 150 MW (Venter, 2008). Assuming a diesel cost of R10/litre, the fuel cost per hour is R570 000 or R3.80 per kWh. Since the average selling price of electricity to customers is generally far lower that this amount at the time of writing, these OCGT peaking plants are clearly operated at a significant loss.

The fuel consumed in heating the expanding gas from a CAES plant forms a major part of the operating costs for a CAES plant. Geschler (2010) notes that operation and maintenance costs for CAES plants are in the range of 20-50 Eur/MWh whereas they are below 25 Eur/MWh for pumped hydro. If properly designed and managed the operating costs are therefore comparable to pumped hydro plants.

Decorso et al (2006) suggest that CAES becomes a more cost effective alternative to conventional gas turbine plant when the price of natural gas exceeds approximately $10/MBtu. Figure 58 shows the steady increase in gas prices in Europe and Japan from 2002 to 2011. Pricing in the US has decreased due to an increased supply of natural gas in recent years (Tverberg, 2012).

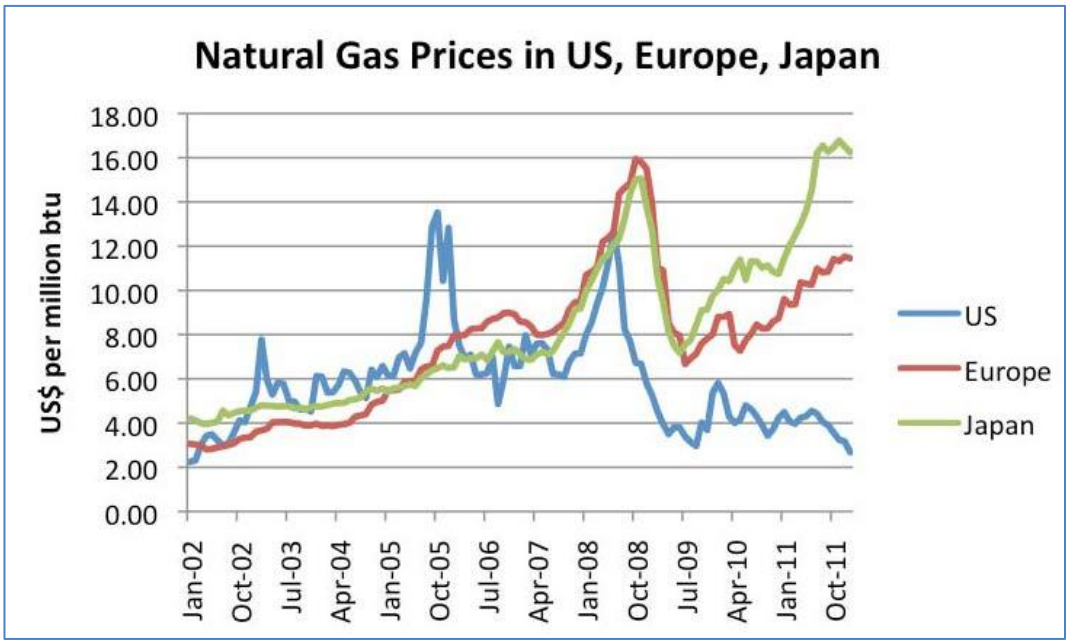


Figure 58 - Natural Gas Price Variation 2002 - 2011 (Tverberg, 2012)

However, whether profitably operating a CAES plant with gas prices at these levels is possible is not confirmed.

Reducing the requirement to heat the expanding air with fossil fuel can further reduce operating costs. The CAES plant recuperator is a heat exchanger that uses waste heat from the turbine outlet to heat the air expanding from the cavern. The use of a recuperator at Macintosh reduced the fuel consumption by approximately 25% (Ter-Gazarian, 1994).

The ADELE project aims to virtually eliminate the need for additional heating of the expanding air and associated costs by storing the thermal energy created during compression of the air and reintroducing it to the air on expansion. Achieving this may increase the overall efficiency of the cycle to approximately 70% (RWE, 2010) which would be comparable to efficiencies of pumped hydro storage plants, refer to Table 36 - Pumped Hydro Storage System Efficiency. Compared with gas turbine plants (particularly open cycle gas turbine plants), CAES plants consume significantly less fuel for a given output making their fuel cost significantly less. The energy required to compress air to drive CAES equipment must be included in input energy costs however.

10 DISCUSSION

10.1 Current State of CAES Technology

CAES cannot be considered a mature technology with only two currently operational plants. However, the Huntorf and McIntosh plants are confirming that CAES technology is safe, reliable and commercially viable. Developments through improved management of waste heat from the process is improving the overall efficiency of CAES, making it comparable to other energy storage types such as Pumped Hydro Storage. The ADELE plant in Germany (refer to Section 4.3 - CAES with Thermal Energy Storage (TES)), represents a significant step forward for CAES technology by significantly increasing the overall system efficiency and lowering operating costs. CAES also has the advantage of providing high efficiencies at partial load as Ter-Gazarian, A. (1994) notes with the plant losing only 15% efficiency when running at 20% rated capacity.

Since CAES utilises equipment based on more mature technologies found in gas turbines, compressors and heat exchangers, many of the challenges associated with designing a CAES plant are diminished. Where CAES is currently pioneering new technology is in the management of large quantities of high temperature thermal energy.

Despite Huntorf and McIntosh both utilising underground caverns solution mined from salt deposits, work by Van der Merwe (1983) suggests that storing compressed air in underground hard rock mines is achievable, though not yet done on a scale required for a CAES plant.

CAES plants currently planned for construction include Norton (USA) and ADELE (Germany) suggesting that CAES will become a more common means of energy storage.

10.2 Bulk Energy Storage

CAES as an energy storage technology is currently comparable only with Pumped Hydro Storage (PHS) as these are the only technologies that are practically implementable on a commercial scale. This is apparent from Chen et al (2009) who describe PHS and CAES as the only technologies currently

available with the output capacity and running duration required to be meaningful on a commercial basis. Chen et al (2009) also highlight the growing need for energy storage globally. Considering these points, it is clear that the need for additional PHS and CAES plants will increase in the immediate future as the demand for electricity increases.

In terms of efficiency, CAES appears to be beginning to approach the efficiencies available from PHS with advanced thermal management systems being developed, though without thermal storage the low efficiency of CAES makes PHS a more economical option.

Eskom releases data annually on the quantity of electricity produced by each of the various generation types. In addition, the amount of electricity consumed is also published which allows the comparison of energy produced and consumed by the PHS schemes, as shown in Table 36:

Table 36 - Pumped Hydro Storage System Efficiency

Pumped Hydro Storage System Efficiency	2007 (GWh)	2008 (GWh)	2009 (GWh)	2010 (GWh)	2011 (GWh)
Pumped Storage Generated	2 947	2 979	2 772	2 742	2 953
Pumped Storage Consumed	3 937	4 136	3 816	3 695	3 962
Net Energy Consumed	**990**	**1 157**	**1 044**	**953**	**1 009**
Overall System Efficiency	**75%**	**72%**	**73%**	**74%**	**75%**

This data indicated that the overall system efficiency of Eskom's PHS system varies from 72% to 75%. The ADELE CAES plant is designing for an efficiency of approximately 70% making it comparable with PHS, assuming the quoted efficiency is correct.

PHS plants potentially have negative impacts on surrounding areas due to the flooding that is required for the water reservoir. CAES can store its medium underground which is an environmental advantage.

The study considers a CAES plant that may be suitable to supply peaking plant capacity in 2018. With increasing scrutiny on the environmental impacts of energy producers and industrial activities in general, it is likely to become increasingly difficult to obtain licenses required for constructing and operating

PHS plants, especially given the scarcity of water in South Africa. Since there are only a finite number of suitable PHS sites, CAES appears to provide an attractive alternative for large scale energy storage.

10.3 CAES in South Africa

There appears to be potential for a CAES plant in South Africa. The report examines the electrical generating capacity of Eskom in 2012 and evaluates this with respect to current demand which showed that there is little reserve capacity available particularly during peak times in winter months when demand is at peak levels. Data compiled from the Eskom website shows that in 2012 South Africa has a total installed capacity of approximately 43 000 MW.

The analysis considers a 2-5% annual increase in the peak demand for electrical power. Including the 15% reserve margin that Eskom is targeting, an annual growth rate greater than 2.7% will result in a shortfall in peak electrical supply by 2018, assuming that the additional capacity provided by the Medupi, Kusile and Ingula plants is commissioned by 2018 as is planned at time of writing. As an annual increase in South Africa's peak electrical demand greater than 3% is a realistic possibility additional peaking plant capacity will be required. The study assumes an average annual increase of 3.7% resulting in an additional generating capacity of 3 500 MW. Therefore a plant similar to that planned at Norton Ohio would be a suitable basis for design.

Having assumed a suitable generating capacity for a potential CAES plant in South Africa to make up the projected shortfall in available power in 2018, the duration for which this plant is to be expected to operate was examined in order to quantify the capacity of the compressed air storage cavern. An assumed capacity to supply air for 8 hours was assumed. The cost per kWh generated by the CAES plant was not determined, but Barrows et al, (2009) suggest that LCOE values may be as low as one tenth the cost of Gas Turbine Peaking Plant. Assuming this to be correct, CAES represents an attractive lifetime cost compared with Gas Turbines currently used for peak load management by Eskom. The actual LCOE would be dependent on the costs for the equipping a storage cavern and require verification.

A future state of Eskom's generating capacity in 2018 that includes the Medupi, Kusile and Ingula plants currently undergoing construction was compared to projected peak demand in 2018 assuming and 2-5% increase in annual peak electrical demand. The comparison revealed that only a 2.7% average annual increase in peak electrical demand can be accommodated by the new generating plant currently being constructed. Additional peak demand would therefore need to be provided by other sources, for which CAES could be considered. It is the opinion of the author that peak electrical demand can be expected to exceed 2.7%, the therefore expects a further need for additional generating capacity.

A CAES plant in South Africa requires a suitable cavern in which to store compressed air. It appears that apart from underground disused mines, there is limited potential for other types of underground storage in South Africa. Due to the limited number of areas in South Africa where salt occurs, locating an underground salt deposit that would be suitable as a CAES storage cavern is unlikely, particularly since most salt occurring in South Africa is very near to surface. Similarly there are a limited number of underground natural gas deposits in South Africa, with most occurring off the coast which would make the process of converting it for compressed air storage all the more challenging and costly. Aquifers have been identified in South Africa thus the possibility of locating a site where aquifers could potentially be used for gas storage exists. However, there are considerable environmental considerations for converting aquifers for any storage purposes particularly in a water scarce country such as South Africa.

The most likely source of a suitable underground storage site exists in the form of a number of disused mines. A disused coal mine close to power stations and the associated distribution network would be ideal for a CAES plant. Unfortunately it appears that South African coal deposits are too shallow to contain the pressure that would be exerted by the underground compressed air. Generally coal mines in South Africa are mining at around 100m and this is too shallow for converting coal mines to CAES storage caverns. Disused hard rock mines therefore appear to offer the only feasible solution to storing compressed air underground in South Africa, though conversion for CAES purposes appear to require significant capital expenditure of the order of 30 times the cost of converting a salt cavern. The site specific challenges and costs associated with sealing cracks and

openings that could allow compressed air to escape within the mine would need to be evaluated on an individual site basis.

10.4 Costs for a South African CAES Plant

A full capital and operating cost estimate for construction and operation of a CAES plant is beyond the scope of this study. However, qualitative comparisons of costs from previous CAES projects and recent construction of Gas Turbine and Pumped Hydro Storage projects in South Africa show that CAES are examined.

The construction costs of CAES plants at R11m/MW appear to be comparative to pumped-hydro storage with the Ingula PHS plant costing R16m/MW to construct, though the construction costs may be largely influenced by the type of storage cavern and the extent of work required to render it suitable for use. Costs for equipping a suitable cavern would need to be evaluated in significant detail for a CAES project to go ahead, considering both technical and environmental aspects.

Findings suggest total costs for a 3 500 MW plant could be approximately R40bn, making this significantly more expensive than a similar Gas Turbine plant that would cost approximately R9.1bn for the same output, though the benefit of CAES is felt through lower operating costs, though TES and the associated increase in efficiency is required. DeCorso et al (2006) suggest that the NRR for CAES plants become comparable to Gas Turbine plants when the natural gas price reaches approximately $10/MBtu. With gas costs in Europe and Japan consistently in excess of this figure since 2010, the economic case for CAES is increasing. The capital costs of a comparative PHS plant are expected to be slightly higher than for a CAES plant, though this is dependent on cavern requirements and additional capital would be required for TES. The ADELE project currently represents the best test case for CAES with TES.

CAES appears to present an attractive option as a replacement for the current Gas Turbine installations currently in service due to the high operating costs. The main cost driver for a CAES plant appears to be cost for cavern conversion, particularly as hard rock mines carry a high conversion cost compared with salt caverns.

10.5 Part Load Benefits of CAES

CAES plants operate efficiently at part loads compared with other generating technology. The McIntosh plant loses 15% efficiency when operated at 20% load whereas a typical coal plant loses around 50% of its efficiency at the same load, making this plant ideal to efficiently regulate power, (Ter-Gazarian A, 1994). The relatively fast ramp up and down rates make this technology suitable as peaking plant, referring to the performance figures quoted for the McIntosh installation in Table 16.

10.6 CAES in renewable energy systems

Energy storage has a critical role with renewable energy sources, as noted by Lund and Salgi (2009). Due to the erratic generation characteristics of renewable sources, storage of energy becomes critical. CAES is receiving focus with regard to the benefit that it could offer to renewable power plants, with particular emphasis on Wind Turbines. Energy storage would provide an improved level of flexibility for renewable energy plants due to the highly variable generation of power. As renewable energy sources become more common on a commercial scale in South Africa (refer to section 5.2.4 Wind Energy (Eskom - RW 0002, 2011), the role of CAES as a storage mechanism is likely to become increasingly important.

10.7 Environmental Impact

A major benefit of CAES when compared with pumped hydro storage is the ability to storage the gas underground out of view, whereas for pumped hydro a significant surface dam is required that is potentially damaging to the immediate environment. With the focus on the availability of fresh water growing, and the potentially limited number of sites that could provide storage for a pumped hydro project, CAES appears to be an attractive alternative with low environmental impact.

11 CONCLUSION

Review of the current state of Compressed Air Energy Storage (CAES) technology reveals it that appears to hold great potential in the future of power generation. South Africa too could benefit both practically and economically from the construction of a CAES plant as a result of diminishing capacity and reserve margin.

Findings suggest that a CAES plant could provide potentially required additional peaking plant capacity in 2018. Beyond 2018 however, CAES is likely to become an important part of energy management in South Africa since CAES and PHS currently represent the only practical solutions to bulk energy storage. With suitable sites for PHS diminishing, CAES currently presents the only suitable alternative.

Costs for CAES, although capital intensive, appear to be favourable when compared with other types of peaking plant, with a LCOE being far less than GT currently in use.

Requirements for a suitable site able to store large volumes of compressed air were quantified. There are no known underground salt deposits in South Africa suitable to construct an underground cavern, similar to those successfully used at Huntorf and McIntosh, but the potential exists for using disused mines as a storage cavern. This is supported by work done in developing underground air receivers in South African hard rock mines.

Results suggest that a plant with 3 500 MW generating capacity may be sufficient to offset a potential shortfall by 2018, and proposes a minimum operating duration of 8 hours based on current Eskom parameters for peaking plant, a total plant capacity of 28 000kWh. The plant should be located near to an existing electrical supply line to reduce costs for distributing the power generated.

Results indicate that costs for building a CAES plant in South Africa are similar to those for PHS (on a per unit basis), though costs would be higher due to lower overall system efficiency. TES with CAES appears to be a minimum requirement

to bring efficiency up to a level than can compete with PHS, though with added capital cost. Operating costs for CAES may be lower than GT peaking plant by as much as a factor of ten, and therefore represent an attractive alternate to GT peaking plant.

CAES appears to be a suitable means of bulk energy storage in South Africa, and the concept warrants further investigation. Recommended areas for further work on the subject should include:

1. Identification of suitable CAES sites in South Africa
2. Detailed process design for the selected capacity plant
3. Plant equipment specification for the process selection
4. Generation of a Levelised Cost of Energy (LCOE) Model for a CAES Plant in the South African context with designed plant parameters.

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14 APPENDICES

Appendix A. Eskom Power Station Locations



Appendix B. Eskom Power Station Plant Summary

EXISTING ESKOM POWER STATIONS	Type	Final Unit Commission date	Quantity of Units	Unit Capacity (MW)	Total Capacity (MW)	Design Efficiency at rated turbine MCR (%)	Ramp Rate (%/hr)	Average availability over last 3 years (%)	Average Production Over Last 3 Years (GWh)
Coal					**37 711**				
Majuba	Coal	2001	3+3	665 & 716	4 143	36.5%	16.7%	97.2%	5 170
Kendal	Coal	1993	6	686	4 116	35.3%	16.7%	93.7%	24 691
Lethabo	Coal	1990	6	618	3 708	37.8%	33.3%	93.1%	21 572
Tutuka	Coal	1990	6	609	3 654	38.0%	33.3%	93.4%	8 962
Duvha	Coal	1984	6	600	3 600	37.6%	40.0%	89.9%	22 798
Matla	Coal	1983	6	600	3 600	37.6%	25.0%	93.8%	25 199
Matimba	Coal	1981	6	665	3 990	35.6%	28.6%	93.7%	23 789
Kriel	Coal	1979	6	500	3 000	36.9%	45.5%	93.4%	17 452
Hendrina	Coal	1976	10	200	2 000	34.2%	33.3%	88.8%	11 718
Arnot	Coal	1975	6	350	2 100	35.6%	34.5%	92.1%	9 675
Camden*	Coal	1967	8	200	1 600	33.4%	-	-	-
Grootvlei*	Coal	1969	6	200	1 200	32.9%	-	-	-
Komati*	Coal	1966	5 + 4	100 & 125	1 000	30.0%	-	-	-
*Return to Service Stations									
Nuclear					**1 800**				
Koeberg	Nuclear	1985	2	900	1800	32.4%	-	83.1%	13 668

Gas/liquid fuel turbine					**2 426**				
Acacia	Gas Turbine	1976	3	57	171	30.3%	-	99.1%	0.15
Port Rex	Gas Turbine	1976	3	57	171	30.3%	-	98.7%	0.48
Ankerlig	Gas Turbine	2007	4 + 5	149.2 & 148.3	1338.3	-	-	-	-
Gourikwa	Gas Turbine	2007	5	149.2	746	-	-	-	-
Hydro Electric					**600**				
Gariep	Hydro Electric	1976	4	90	360	-	-	96.6%	889
Vanderkloof	Hydro Electric	1977	2	120	240	-	-	97.4%	932
Pumped storage schemes					**1 400**				
Drakensberg	Pumped Storage	1982	4	250	1000	-	-	93.9%	2 041
Palmiet	Pumped Storage	1988	2	200	400	-	-	-	-
Wind Farms					**3**				
Klipheuwel	Wind	2003	3	0.660, 1.750 & 0.750	3.16	-	-	93.9%	2 041
Planned Generation					**10 920**				
Medupi	Coal	2017	6	798	4788	-	-	-	-
Kusile	Coal	2018	6	800	4800	-	-	-	-
Ingula	Pumped Storage	2014	4	333	1332	-	-	-	-