COMPRESSED AIR STORAGE

FOR ELECTRICITY GENERATION IN SOUTH AFRICA

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A dissertation submitted to the Faculty of Engineering, University of Cape Town in partial fulfilment of the requirements for the degree of Master in Engineering.

Cape Town 1996

DECLARATION:

I declare that this dissertation is my own, unaided work. It is being submitted, in partial fulfilment of the requirements for the degree of Master in Engineering, to the University of Cape Town. It has not been submitted in this, or any other form, for any degree or examination to any other university.

Signed by candidate

23 day September 1996

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NOMENCLATURE

NAMES

AEC	Alabama Electric Cooperative
CEGB	Central Electricity Generating Board
NASA	National Aeronautics and Space Administration
NWK	Nordwestdeutsche Kraftwerke
VTT	Technical Research Centre of Finland

TECHNICAL NAMES

CAES	Compressed Air Energy Storage
CAESCC	Compressed Air Energy Storage with Combined Cycle
CAESTES	Compressed Air Energy Storage with Thermal energy Storage
CAESSI	Compressed Air Energy Storage with Steam Injection
CAES/PFBC	Compressed Air Energy Storage with Pressurised Fluidised Bed Combustor
HPTES	High Pressure Thermal Energy Storage
HRSG	Heat Recovery Steam Generator
LPTES	Low Pressure Thermal Energy Storage
PFBC	Pressurised Fluidised Bed Combustor
SMES	Superconducting Magnetic Energy Storage
TES	Thermal Energy Storage

C	Compressor
Cl	Clutch
G	Generator
HC	High Pressure Compressor
HP	High Pressure
IC	Intercooler
IP	Intermediate Pressure
LC	Low Pressure Compressor
LP	Low Pressure
LT	Low Pressure Turbine
M	Motor
MG (M/G)	Motor-Generator
REC	Recuperator
T	Turbine

TECHNICAL TERMS

AC	Alternating Current
DC	Direct Current

C	Cost (R)
CEF	Charge Energy Factor
C_{po}	Specific Heat of Air (kJ/kgK)
E	Energy (J)
ϵ_{RC}	Recuperator Effectiveness
FHR	Fuel Heat Rate (kJ/kWh)
h	Enthalpy (kJ/kg)
H	Head (m)
m	Mass (kg)
$\dot{m}$	Mass Flow Rate (kg/s)
N	Number of Intercoolers
η	Thermodynamic Efficiency (%)
P	Pressure (Pa)
Q	Heat (J)
$\dot{Q}$	Rate of Heat Transfer (W)
R	Isentropic Temperature Ratio (kJ/kgK)
S	Capacity (W)
T	Temperature (K)(°C)
V	Volume (m^3)
V_p	Volume of Constant Pressure receiver (m^3)
V_v	Volume of Constant Volume Receiver (m^3)

*	Optimal Value
$_{MAX}$	Maximum Value
$_{INITIAL}$	Initial State
$_{FINAL}$	Final State

MONEY UNITS

DM	Deutsch Mark
R	South African Rand
$	United States of American Dollar

GDP	Gross Domestic Product

Note: The above abbreviations have been used unless otherwise indicated

DEFINITIONS

STATISTICAL MEASURES

Generation capacity

- Net maximum capacity - MW

  This is the maximum power which could be produced, transmitted or distributed continuously throughout a prolonged period of operation. All the equipment is assumed to be fully operational. The power is measured after deducting the power supplies for the power station auxiliaries and allowing for the losses in generator transformers.

- Nominal capacity - MW

  This is the maximum capacity obtainable under continuous operation and is usually determined by the manufacturer's specification and often appears on the "nameplate" of the equipment. It need not relate to any operational reality.

PERFORMANCE INDICATORS

Power generation plant

- Availability - %

  Generation plant availability reflects the proportion of time a unit is capable of providing service and provide a measure of the potential utilisation of the unit.

  Calculated as:

  Available energy generation expressed as a percentage of total installed energy capacity in active state.

- Reliability

  Plant Reliability refers to the probability that a unit will perform as required for a given period of time and gives an indication of the frequency of unexpected failure.

- Load factor

  This is the ratio of the total number of kWh supplied by a generator or generating plant, to the total number of kWh which would have been supplied if the generator or generating plant had been operating continuously at its maximum continuous rating.

  Calculated as:

$$LOAD\ FACTOR = \frac{NET\ kWh\ PRODUCTION\ \ x\ 100}{AVE.\ NET\ MAXIMUM\ CAPACITY\ (kW)\ x\ 8760}$$

Note: 8760 hours in a year

NOTES

All costs given in this thesis were determined as follows. Costs given in foreign currencies were escalated, in the given country's currency, through the gross domestic product (GDP) deflators as given by the *World Tables*(1). The exchange rates of all major currencies, were taken from *Country Profile: South Africa*(2). The foreign currencies were converted into South African Rands. Any further escalation made use of the percentage growth in South Africa's GDP as an escalation factor. All costs are given in 1994 South African Rands.

1994 Exchange Rate: 1 US $ = 3.55 Rand(2)

CHAPTER 1

INTRODUCTION
to
ENERGY STORAGE

1.1) INTRODUCTION

Electricity constitutes 26 percent of the commercial energy in South Africa. Other major contributors are coal, oil and natural gas(1). Figure 1.1 shows the Eskom electricity demand for a winter's week in 1993 where customer demand, in megawatts (MW), is plotted on an hourly basis for an entire week. Fluctuations occur daily as peaks and troughs. Peak demand refers to the shown peaks and off-peak or low demand refers to the troughs and intermediate sections. No matter how demand fluctuates, utilities must supply sufficient electricity to their customers.

Utilities often operate several generating plants on an electricity supply network. A supply network, or grid, connects generating plants to demand centres (e.g. industries, cities and suburbs). To reduce the operating costs of power plants, and thus the price of electricity, utilities determine the most economical mix of generating plant operation. Each power plant has a specific operating cost, consisting of fuel, water and maintenance costs. The cost of electricity produced by a power plant consists of operating costs and capital costs.

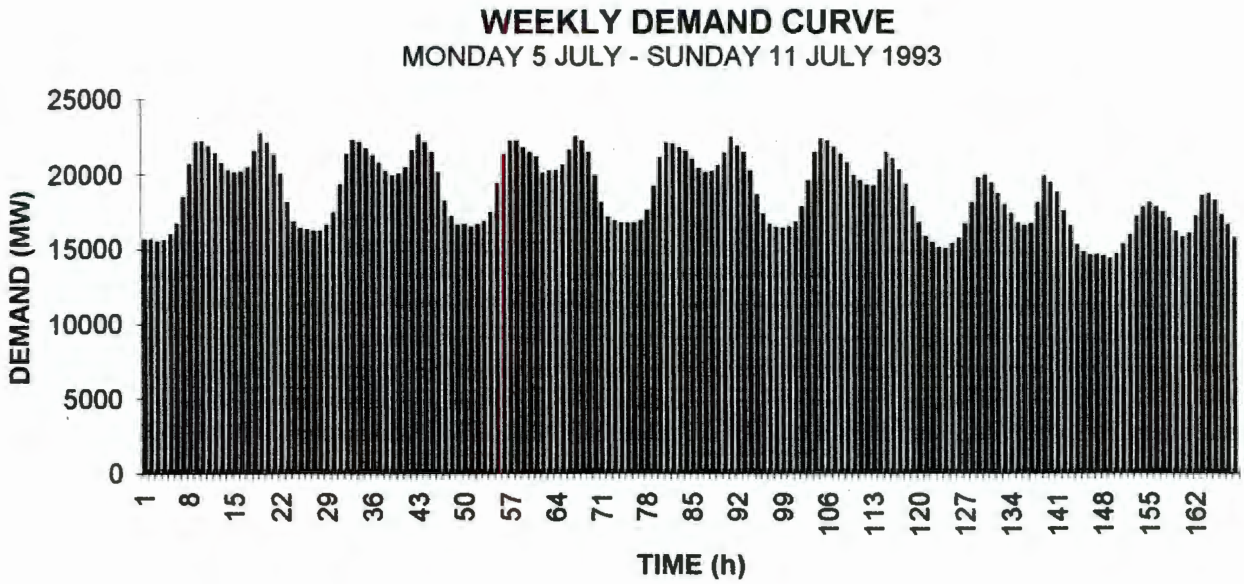


Figure 1.1: South African weekly demand curve for a winter's week in 1993(2)

Each generating plant is specific in its ability to adhere to peak-, intermediate-, and baseload demands. Figure 1.2 shows a typical demand curve of a utility over a one-week period. Different utilities use different plant mix, dependent on the type of plant available. Figure 1.2 shows the typical spread of plant usage during any given week.

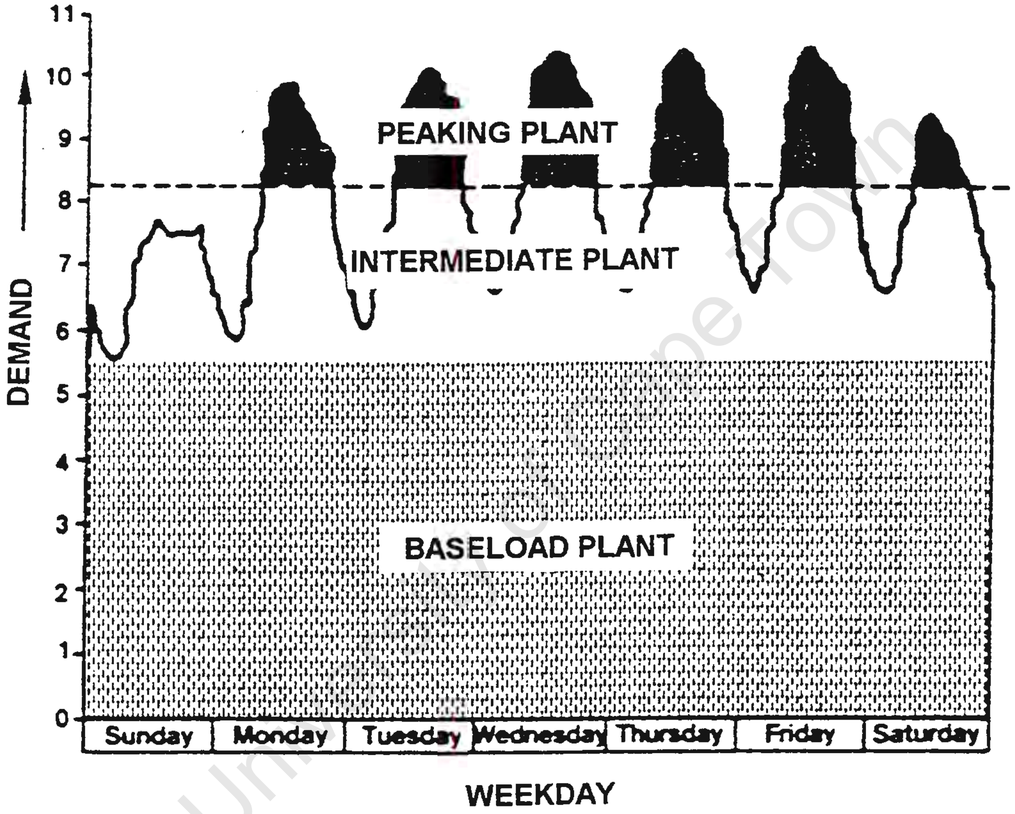


Figure 1.2: Load scheduling on a weekly demand chart(3)

Baseload plants are large fossil-fuelled generating units, which are expensive to build but relatively cheap to run. Nuclear power stations are also high capital cost and low operating cost plants and are incorporated into the baseload bracket. Baseload plants are run continuously and supply a large quantity of energy to meet the customer's demands. They are only taken out of operation for routine maintenance or due to forced outages.

Intermediate plants are also often fossil-fuelled and are generally older baseload plants that have been rescheduled due to lower efficiencies and higher operating costs. Specific intermediate plants can also be constructed. Plants used for intermediate duty, have lower load factors than the baseload plants and must be able to follow load fluctuations.

Peaking plants are often specifically designed for this duty. In view of their demand pattern they are low-capital cost plants with higher operating cost than base or intermediate plants. They use liquid fuels and are designed for quick response to demand. Hydro power is often used for peaking duty. Although operating costs are low they are restricted to a low load factor by water availability considerations.

Figure 1.3 shows Eskom's load duration curve for 1993. By re-arranging the demand values of a weekly demand curve, from maximum to minimum, over a time scale equal to that of one week, a load duration curve is generated. Load duration curves are drawn for individual weeks or for full years. The area under a load duration curve is equal to that of a weekly or yearly demand curve. The energy supply necessary to meet demand is equal to this area. Load scheduling is easier on a load duration curve than on a weekly demand curve.

Load scheduling of power plants is based on the use of the lowest operating plant first, followed by progressively more expensive plants. An utility brings generating plants producing the cheapest electricity online first. Figure 1.4 shows load scheduling on a typical load duration curve. Power plants are thus loaded from the bottom of the load-duration curve in ascending order of unit operating cost.

Baseload generating units are loaded first and are used to generate as much energy as possible. Intermediate plants with higher operating costs will follow, and peaking plants with the most expensive operating cost are loaded last. This method ensures the cheapest supply of electricity at all times. The capital cost of plants already purchased is fixed and cannot be altered by varying the load factor of a plant. Therefore the capital cost of a plant, once it is installed, has no effect on load scheduling.

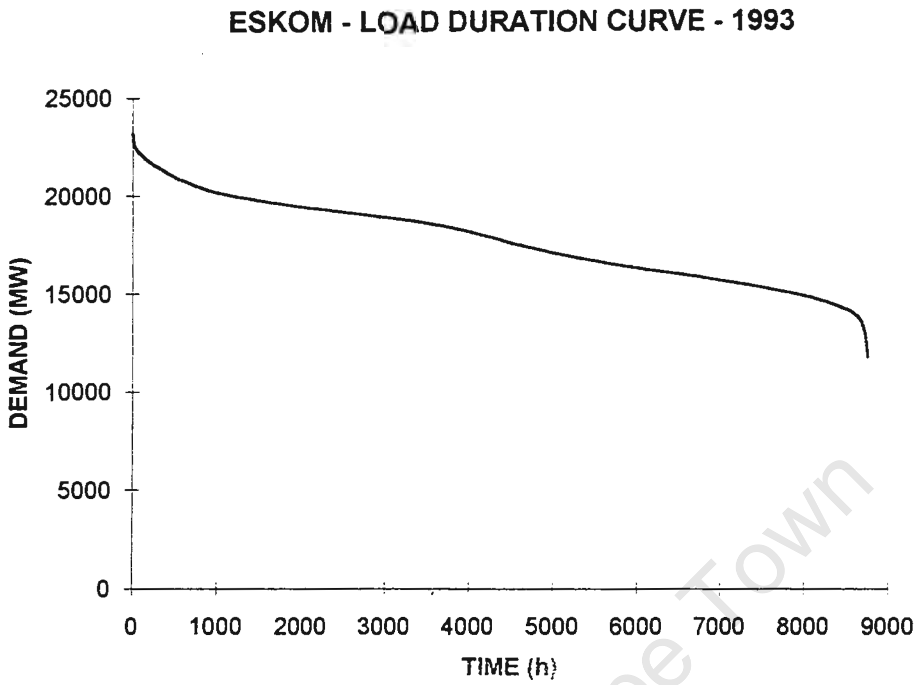


Figure 1.3: Load duration curve: Eskom 1993(2)

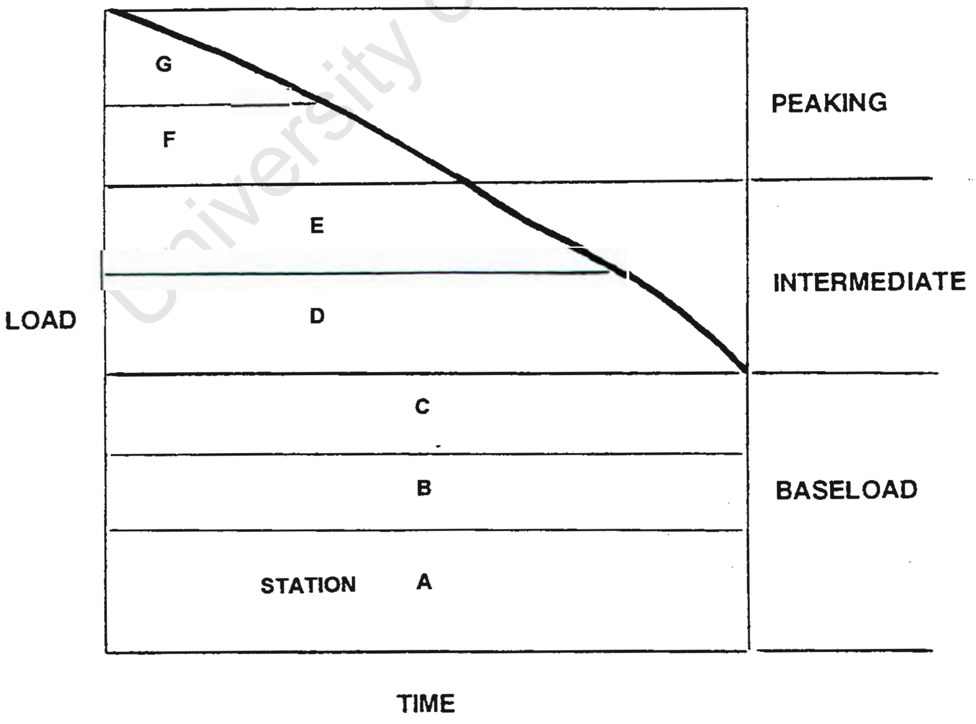


Figure 1.4: Schematic depiction of load scheduling on a load duration curve

When considering the addition of a power plant to a system, the decision must be one that will minimize the cost of power production. Since the capital cost of existing plant is committed, it has no effect on the decision regarding a new plant. The choice of new plant depends on both operating and capital cost components of the new plant, and on the operating costs of the plant already in the system (neglecting the capital cost of the existing plant). The capital cost of a plant is determined by the size of the necessary generating machinery and plant construction. The load factor and future energy production of the plant has no effect on the capital cost.

A new generating plant may be selected from base, intermediate or peaking plant, the choice determined by the need to minimize cost. An additional choice of generating plant is that of an energy storage plant. To justify the choice of an energy storage plant, its capital and operating costs must be competitive when compared with any of the other generating plant options. Energy storage has several characteristics that make its selection attractive, and can be used for:

- Load levelling
- Spinning reserve
- Frequency and voltage control
- Deferred baseload generation capacity construction

The load levelling ability is probably the most important aspect when selecting energy storage over other generating plants. The load levelling ability allows a utility's available energy supplies to be matched to the demand for energy. Energy storage plants store inexpensive energy, and supply it during peak demand periods. During low demand, utilities have generating capacity available which may be used to charge an energy storage unit. During peak demand, when generating capacity may be limited, an energy storage plant can be brought on line, reproducing the stored off-peak energy to meet the peak energy demand. More expensive operating plants are no longer necessary and the cost of energy may become cheaper. Baseload and intermediate load plants may now be operated at a higher loadfactor.

Although the fluctuating customer demand still exists, only the energy storage plant "sees" this with baseload plant supplying a constant capacity, shown as a horizontal line. Figure 1.5 shows the effect of energy storage on a demand curve. The energy below the horizontal line and above the original demand curve is stored by means of an energy storage plant. This energy is later released, for generating capacity, when demand rises above the constant baseload capacity line.

The operating cost of the storage plant is determined by the cost of energy used to charge the system and the efficiency of the system. The efficiency is the ratio of units generated during discharge to the units consumed during charging.

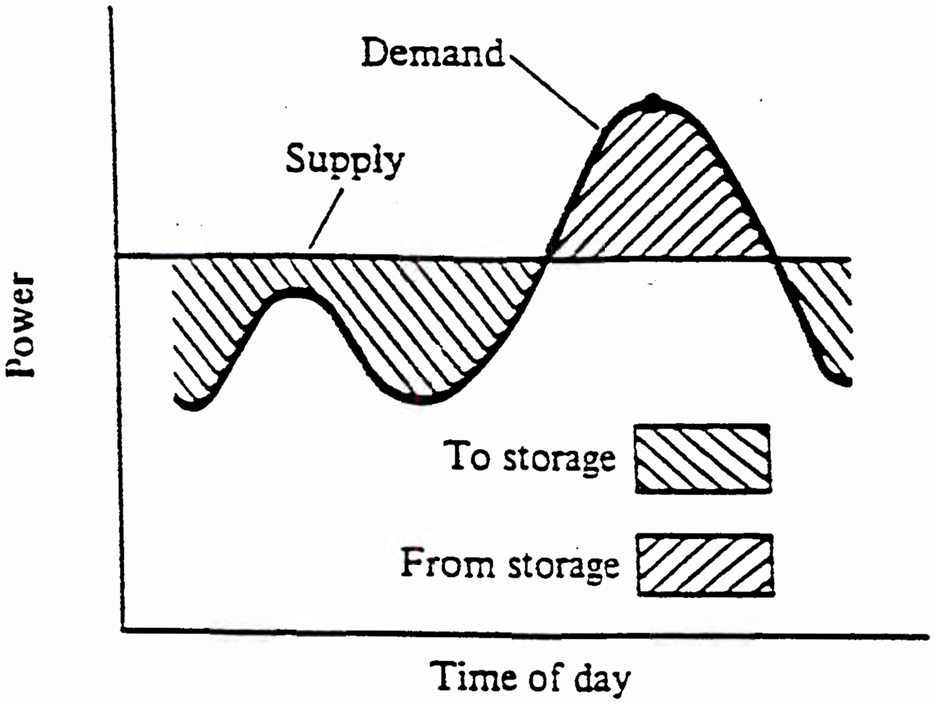


Figure 1.5: The effect of energy storage on a demand curve[4]

1.2) ENERGY STORAGE

It is not possible to store large quantities of electricity because it dissipates as heat in conductor resistance, unless it is converted into another form of energy. Energy can be divided into different forms, namely potential-, kinetic-, chemical-, thermal-, and electromagnetic.

Potential energy is the energy stored by virtue of a body's position. For example the energy available in a body after it has been raised against the force of gravity.

Kinetic energy is the energy available due to a body's motion. The body has the ability to do work by, for example, colliding with another body.

Chemical energy is released or absorbed when atoms form compounds. The energy becomes available when atoms lose or gain electrons. This energy often appears in the form of heat.

Thermal energy is the energy available due to the temperature of a body. The temperature difference between the body and its surroundings allows the heat to be extracted.

Electromagnetic energy is the energy surrounding a current carrying conductor with a potential difference. This energy can be converted into heat or be used to attract and repel other bodies.

It is possible to convert electric energy into any one of these forms and store it over a period of time. When needed, the stored energy can be converted back into electric energy. An energy storage technique, suitable for supplementing generating capacity, has been developed for every one of the above mentioned energy forms. A short description of each technique follows.

1.2.1) Potential Energy Storage

1.2.1 (a) Pumped Hydro Storage

Pumped hydro is probably the most researched and used storage technique available. To date there is over 100 000 MW installed pumped hydro storage world wide(5).

Figure 1.6 shows a schematic layout of a pumped storage plant. As shown, pumped hydro requires an upper and a lower reservoir. These reservoirs may form part of natural water ways or may be artificial. Situated between the two reservoirs lies a powerhouse. The powerhouse is connected, with pipelines to both reservoirs and contains pumping and generating equipment. During periods of low electricity demand, excess generating capacity on the grid is used to pump water from the lower reservoir to the upper reservoir. When additional generating capacity is needed, water is returned to the lower reservoir, through the powerhouse. A surge tank is used to minimize water hammer produced during rapid changes in load.

The elevation between the two reservoirs must be sufficient, to allow for the required potential storage. The loss of energy due to friction in the pipelines is experienced in both the pumping and generating phases. The less the horizontal displacement between the two reservoirs, the less piping is necessary.

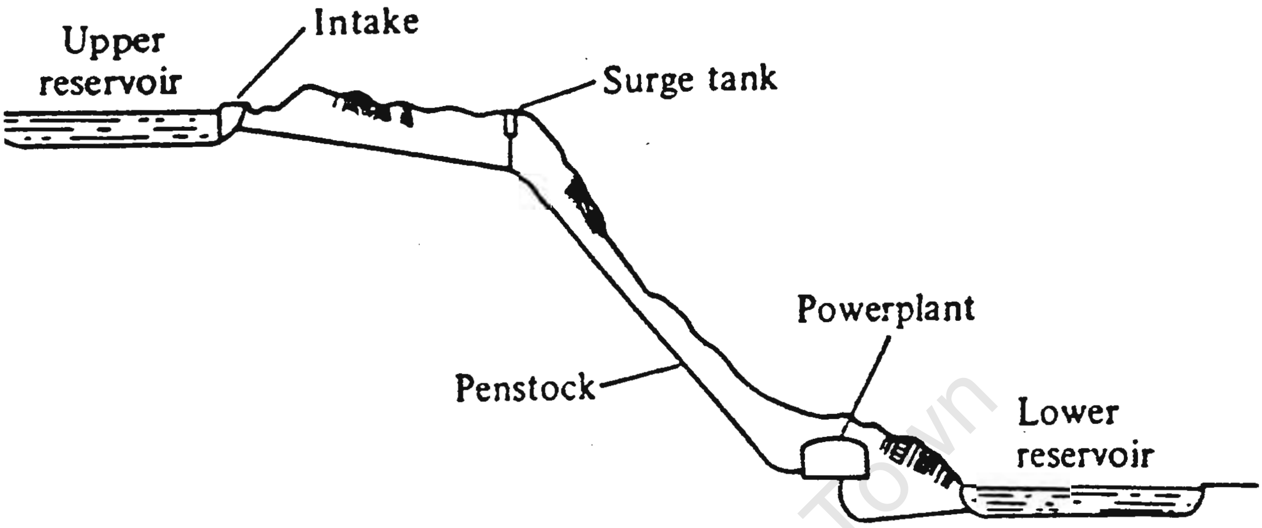


Figure 1.6: Schematic layout of a conventional pumped hydro storage system[(4)]

Suitable topography is not always available, but it is still possible to create a potential difference between two bodies of water by placing the lower reservoir underground. Figure 1.7 shows a layout where the lower reservoir has been placed underground. This reservoir can be developed in natural caverns, disused mines or man made excavations.

Pumped hydro storage requires a lengthy construction time due to the civil works involved. Plant construction may take more than 10 years before operation can commence(6). The efficiency of pumped hydro lies between 65% and 75% and typically has an availability of 85%(6).

South Africa has three pumped hydro plants in operation. The first plant to be built was that of the Cape Town City Council. This is the 80 MW Steenbras power plant. The other two plants, owned and operated by Eskom, are the 1000 MW Drakensberg pumped storage scheme(7) in the Drakensberg, and the 400 MW Palmiet pumped storage scheme(8) near Cape Town.

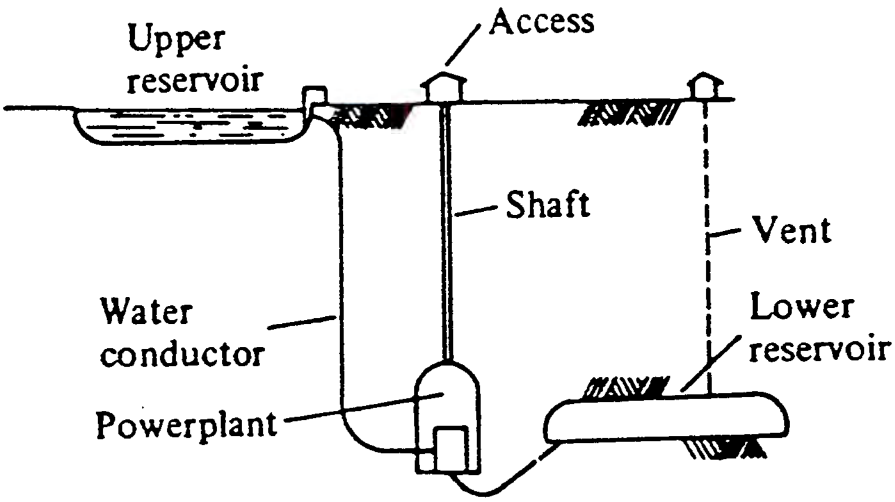


Figure 1.7: Schematic layout of a pumped hydro storage plant with underground storage(4)

1.2.1 (b) Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) is another method of storing potential energy. Figure 1.8 shows a first generation compressed air energy storage plant. During low demand, excess generating capacity is used to compress air into a storage cavern. When increased demand requires extra generation, the air from the cavern is released and used in a turbine-generator combination.

There are many variations possible on a first generation CAES plant. These variations include additions such as a combined motor and generator to minimise capital cost, combustors for fuelling the expansion process, thermal energy storage, pressurised fluidised bed combustors for alternative fuelling, steam injection and recuperators. Each addition or variation is used to increase output and efficiency. Efficiencies of over 80% have been predicted for CAES variants(9).

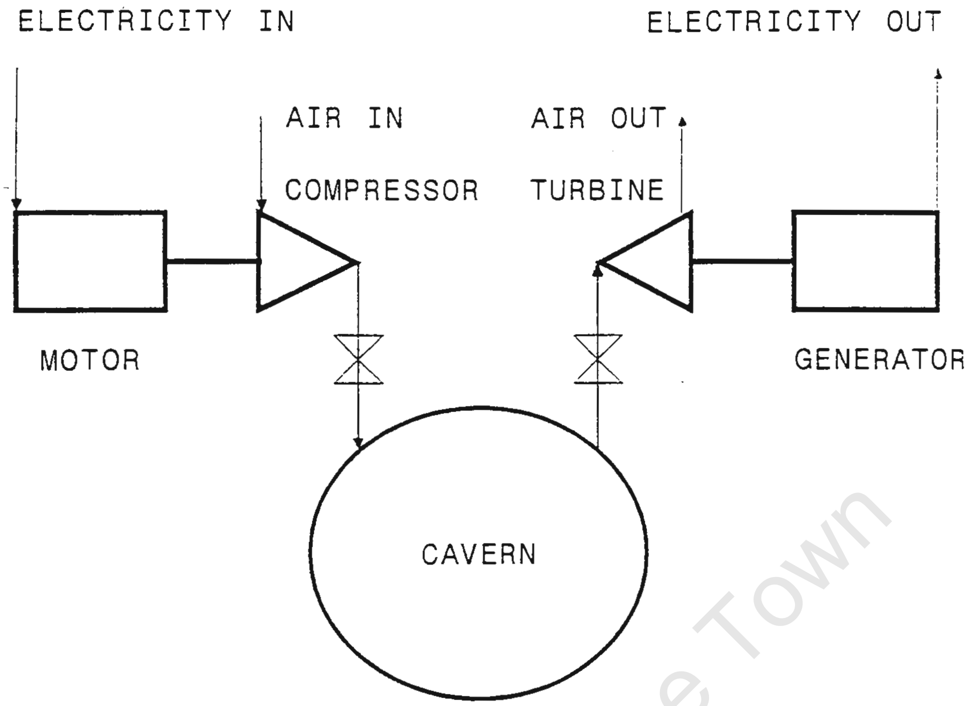


Figure 1.8: Schematic layout of a first generation compressed air energy storage plant

CAES requires large air storage volumes with the ability to support high pressures. Underground storage is the most economical way to provide a large storage volume and at high pressure[10]. Storage can take place in any of the following underground formations: aquifers, salt caverns or hard rock caverns. Air storage may take place under constant volume or constant pressure conditions. Constant pressure storage has the advantage of smaller volumes at high pressure as well as reducing or eliminating throttling before expansion in the turbo-expanders.

CAES has several benefits which include quick response and cycle flexibility, in addition CAES may be used as spinning reserve. Another important benefit of CAES is its short construction time, 2-3 years[9].

There are currently two commercial CAES plants in operation, Huntorf in Germany and Alabama Electric Cooperative's (AEC) plant in Alabama, USA. These plants are discussed in detail in the literature survey.

1.2.2) Chemical Energy

1.2.2 (a) Electrochemical Batteries

Chemical energy is released when atoms lose or gain electrons to form compounds. In a battery the electrodes and electrolyte lose and gain electrons to generate an electric current. Primary batteries have a limited lifespan and supply an electric current and potential for a certain length of time, after which the chemical reaction between electrode and electrolyte is depleted. In secondary batteries the chemical reaction may be reversed by applying an electrical potential to the terminals of the battery. The products formed due to discharge, return to their original state (electrodes and electrolytes), during recharging. Secondary batteries are often known as rechargeable batteries, and are commonly used in automobiles, aircraft, emergency no-fail and standby power sources.

Secondary batteries are characterised by high power densities, flat discharge profiles and good low temperature performance(11). Unfortunately secondary batteries have lower energy densities and poorer charge retention than primary batteries.

As storage devices for electric utilities, secondary batteries are charged during low demand periods and discharged during high demand periods. The requirements for battery storage in electric utility service are, (1) low capital cost, and (2) long cycle life.

The cyclic life of a secondary battery is defined as the number of charge-discharge sequences that can be completed before the capacity of the chemical reaction has depleted to such an extent that little electricity can be produced. A long life battery is associated with shallow cycling, low energy density and high cost.

Battery modules are factory built and can be installed quickly, enabling utilities to match load growth more easily and accurately than large specific and site-specific plants. Batteries also have the attributes of being quiet, compact and non-polluting, and may therefore be sited close to highly populated areas. An example of such a battery storage plant is the 10 MW, 4-hour lead-acid Chino battery storage plant(9,12) situated on the outskirts of Los Angeles. Table 1.1 shows various battery energy storage systems. Energy storage capability in the plants, range from 400 kWh to 40 MWh with battery voltages of over a 1000 volts. Most of these plants run on a daily cycle, and cycle-life times are estimated at 10 years and more. Many of these plants were installed during the 1980's. All of these plants use lead-acid batteries, none of them having ventured into advanced battery technology.

Table 1.1: Several battery energy storage systems throughout the world (Lead-Acid)(12,13)

Company	Size	Start-up	Application
Elektrzitatswerk Hammermuhle Selters, Germany	400 kW 400 kWh	1980	Load levelling Peak shaving
Berliner Kraftund Licht Berlin Germany	17 MW 14 MWh	1986	Frequency regulation Spinning reserve
Kansai Electric Power Company Tatsumi, Japan	1 MW 4 MWh	1986	Multi-purpose Demonstration
Hagen Batterie AG Soest, Germany	500 kW 7 MWh	1986	Load levelling Peak shaving
Vaal Reef Exploration and Mining company, South Africa	4 MW 7 MWh	1989	Peak Shaving Emergency power
Southern California Edison company, Chino Substation, L.A.	10 MW 40 MWh	1988	Economic feasibility Load levelling

Various types of batteries have been developed in addition to the well established lead-acid and nickel-cadmium types. These include the high temperature sodium-sulphur batteries, lithium-chlorine and lithium-telluride batteries, zinc-chlorine batteries and the South African developed Zebra batteries.

Figure 1.9 shows the electric layout necessary between battery and grid. Batteries are DC devices and require AC-DC-AC converters and filtering equipment. The filtering equipment is necessary to protect the batteries and transformer against power surges. With the development of microcircuitry and thyristors efficient conversion is now possible, with the efficiency of battery energy storage plants lying between 70% and 80%(4).

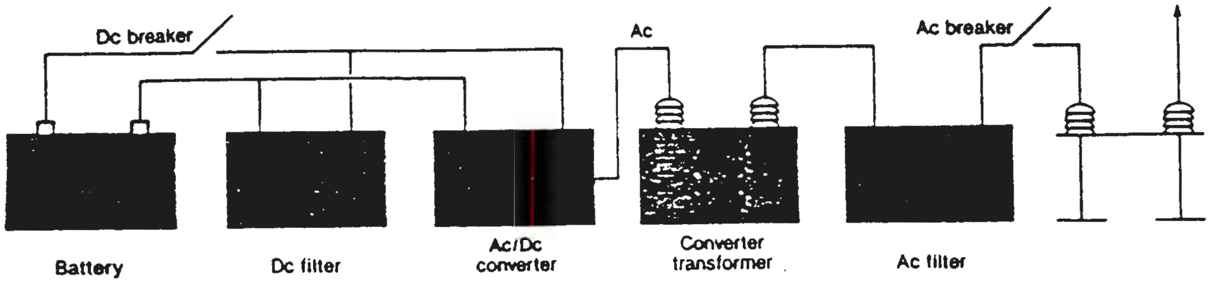


Figure 1.9: Schematic layout of the electric components necessary in a battery storage plant(12)

1.2.2 (b) Hydrogen

The production of hydrogen is another possible method of chemical energy storage. Hydrogen is found in a chemically bonded form such as water or hydrocarbons. When released from this form it may be stored as a pure element. In its pure form, hydrogen is highly combustible and may be used to fuel a generation process.

Hydrogen can be released from its bonded form through the process of electrolysis. Electrolysis is a process where an electric current is supplied to a chemical solution. Through the withdrawal of electrons from a suitable solution, the solution decomposes and hydrogen is released.

Once it is in its pure form, hydrogen has some unusual characteristics. One of these is the ability to diffuse through certain materials and another is the ability to deteriorate certain materials with which it comes in contact. Iron and iron compounds are resistant to these characteristics and are often used to form the walls of hydrogen storage vessels. Hydrogen may also be stored in salt caverns, rock caverns and aquifers.

Hydrogen may be used to fuel the combustion process prior to expansion in the turbine. Pollution is reduced through the combustion of hydrogen since its end product is mainly water although NOx is also formed. Economically, hydrogen combustion is not an attractive energy storage solution, as cheaper fuels may produce a higher output, for the same fuel quantity. It may be more feasible to use the hydrogen, generated off peak, for the production of chemicals such as ammonia and methanol(14).

1.2.3) Kinetic energy

1.2.3 (a) Flywheel

The only effective method of storing kinetic energy is in a rotating mass known as the flywheel. Flywheels have been used for many centuries, mostly to smooth the output of cyclic power sources. Uses have ranged from the potters wheel to the current application in reciprocating motors.

In the electricity grid a flywheel is spun up during low demand periods. Storage takes place through the unassisted rotation of the wheel once it has reached its optimum velocity. When electricity is required, the flywheel would be coupled to a generator.

The amount of energy stored in a flywheel is a function of the moment of inertia of the wheel and its velocity. Thus by increasing the velocity of the wheel the amount of energy stored is increased. Flywheels have high power densities but relatively low energy densities. It is therefore possible to meet the high peaks, but only for a short period. The energy density of a flywheel is limited through friction in bearings and transmission components. The power density on the other hand is limited by the speed of the wheel which is limited by the strength of the material of the wheel. The ideal flywheel must have a high strength:density ratio, high resistance to cyclic crack growth and a high strength:density cost ratio. This has prompted development away from metal flywheels towards composite materials.

The efficiency of flywheels systems is dependent on the period of discharge. The longer the flywheel spins, the more energy is lost in heat due to friction. Friction is largely caused by windage, bearings and seals. To minimise friction, designers place flywheels in evacuated chambers as well as use magnetic bearings.

Few flywheels have been put into operation as electricity energy storage devices. NASA(4) has developed a conceptual design that has nearly zero losses involving many innovative methods to overcome friction, including supporting the rotor with permanent magnets. Researchers at Bradford University(15) in England have been working on a "cycloconverter" to overcome the problems experienced when a flywheel is directly connected to a 50 Hz AC electrical supply. The variable shaft speed experienced produces a variable voltage and current output, that needs to be regulated. Northern Ireland's electricity utility, Northern Ireland Electricity, had planned to install a 1,7 MWh, 25 MW flywheel(16). This flywheel was to be used as a bridging supply between powerplant and emergency generators. A bridging power plant supplies electricity as soon as the main power supply has been terminated and until an emergency supply has been brought online. No progress on the project has been published.

1.2.4) Electromagnetic Energy Storage

1.2.4 (a) Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) is based on storing energy in the magnetic field associated with a DC coil. If a conventional coil is used, the magnetic energy would be dissipated in the wire's resistance as heat. However, if the coil is manufactured as a superconductor, energy could be stored in the magnetic field for an extended period. Superconducting coils can be charged during low demand and discharged during peak demand periods.

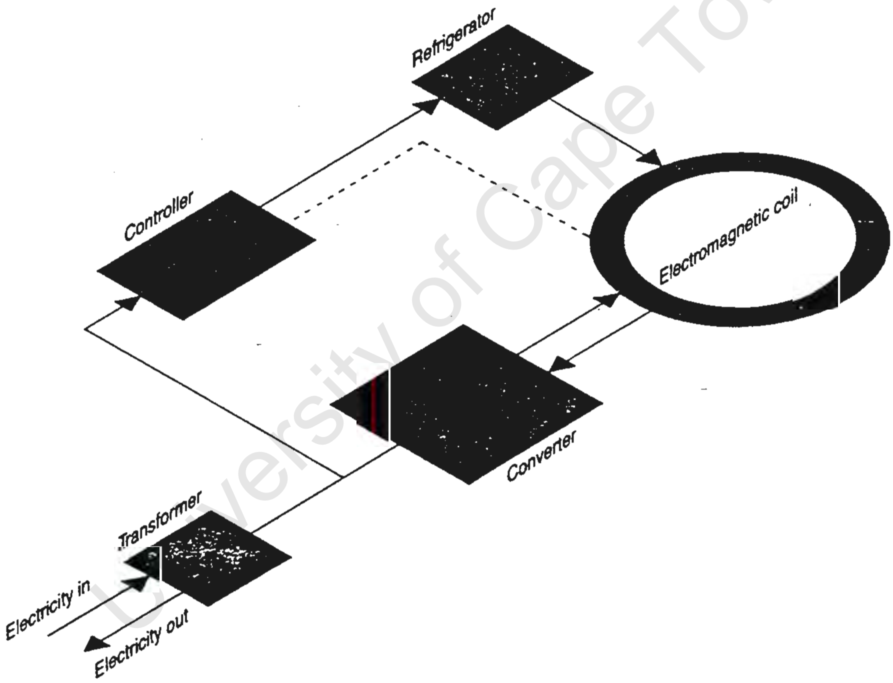


Figure 1.10: Schematic layout of a superconducting magnetic energy storage plant(9)

A superconductor is a conductor that has a very low resistance to electrical current. All conductors have a critical temperature, below which they become super conducting and above which they have a high resistance. Figure 1.10 shows the equipment necessary for a SMES plant. Shown is the coil, converter and refrigeration unit.

The refrigeration unit and controller is used to keep the coil below its critical temperature. Due to the very low temperatures required, a cooling substance such as liquid-nitrogen or liquid-helium is used. Helium is currently the only substance that can maintain a suitably low temperature and still be economically viable(17). The coil also requires insulation from the ambient temperature, which is done by placing the coil in an evacuated chamber.

Only DC coils are suitable to store electromagnetic energy but application is most likely on an AC grid. To overcome this problem an interface (shown as a converter), is required, similar to that used in battery storage. The interface is known as a power conditioning system, containing advanced electronics capable of AC-DC-AC conversion with minimal loss. An extra unit necessary in the converter (one that is not necessary in battery systems) is a connector unit between room temperature and the cold coil. For this, SMES designers have placed the supply leads in a bath of boiling helium.

Two coil shapes have been proposed, the solenoid and the toroid. The coil depicted in Figure 1.10 could be either. Solenoids are conventional coils while the toroid is a doughnut shaped solenoid. The two ends of toroid face each other and are brought into close proximity with each other. A toroid has the advantage of totally containing the magnetic field within the torus, eliminating the end effects of magnetic fields. Associated with superconducting coils are Lorentz forces(17). These forces stem from the interaction between the circulating current and the magnetic field induced by the current. These forces push the coils apart, necessitating a sufficiently strong structure surrounding the coil. It has been proposed that the coil be placed in earth trenches, but recently researches have developed a coil to be self supporting. It is not known how this is achieved. In a toroid Lorentz forces are stronger than in a solenoid, therefore necessitating stronger structural supports.

SMES has one distinct advantage over other storage techniques. Energy is contained in the form of electricity throughout charge and discharge. No conversion to other energy forms takes place (such as mechanical movement), therefore efficiencies as high as 90% may be achieved(17). SMES can respond rapidly to grid fluctuations, being limited only by the switching time of the solid state components doing the AC/DC conversions and coil connection to the grid, allowing full power to be achieved within milliseconds.

SMES also has the following capabilities:

- Increased transmission capacity through enhanced line stability
- Spinning reserve
- Energy storage (load levelling)
- Voltage control
- Frequency control
- Black start capabilities
- Sub-synchronous resonance damping

SMES development has advanced so far that utilities are incorporating them into their systems. Cities such as Anchorage in Alaska have put a proposal forward for the incorporation of a 25 MW SMES plant(18), by 1997, into the city's supply network. The unit is to be incorporated as a backup measure as the city has frequent blackouts. Further development has been carried out by companies such as Superconductivity Inc. of Madison, Wisconsin. This company is making advances in the field of superconductivity and are currently supplying the first SMES unit to South Africa(19). This unit has been bought by Eskom for demonstration purposes at a paper plant, located in a rural area, which frequently suffers from voltage dips.

1.2.5) Thermal Energy Storage (TES)

1.2.5 (a) Sensible Heat Energy Storage

Sensible heat energy storage uses the sensible heat contained in solids and liquids to store energy. Storage is accomplished by raising the temperature of a liquid or a solid and maintaining it at a specified temperature for as long as necessary. Heat may be extracted from the substance when required.

There are various other methods of storing sensible thermal energy:

- pressurised water storage
- organic liquid storage
- packed solid beds
- fluidized solid beds

A working fluid or gas is required to carry the heat to and from these storage systems. Heat may be passed on directly, or indirectly, to the storage substance. Direct heat flow allows the working fluid or gas to flow over the storage substance, whilst in indirect heat flow the working fluid is piped in close proximity to the storage substance.

When energy is required, the working fluid or gas is once again brought into contact with one of the storage substances, and the heat is retrieved.

Thermal systems are often contained in baseload plants. For example, steam may be tapped off a turbine during low demand periods. The steam is brought into contact with the storage substance, and heat is exchanged. An accumulator is the most likely method of storage, where steam is mixed with saturated pressurised water. The accumulator is pressurised to a high temperature and pressure, requiring insulation. It is possible to maintain the stored heat for long periods of time. When additional generating capacity is needed, the accumulator is discharged through a peaking unit. The accumulator may even be discharged into a baseload turbine to increase output.

The system described above, tapping steam off during low demand and operating a peaking turbine, has a very low efficiency, ranging between 20-25%(4). This is due to the low temperature saturated steam that results from the accumulator.

1.2.5 (b) Latent Heat Energy Storage

Latent heat energy storage uses the heat produced or absorbed during the phase change of a substance. Storage takes place by either melting a solid or vaporising a liquid. Once the storage substance has changed phase it must be maintained at a higher temperature. Energy is retrieved from the substances through either solidifying the liquid or condensing the vapour. The storage capacity of latent heat storage is greater than that of sensible heat storage because the latent heat used in a phase change is greater than the specific heat available in a single phase for a given mass of the substance.

A constant temperature as well as small volume changes are possible during a phase change. The system also has the advantage of a wide choice of materials with different fusion or evaporation temperatures. Storage materials must have the correct transition temperature and high latent heat, good thermal conductivity, good containability, high stability and low cost. Several fluoride and eutectic salts meet these characteristics but are very corrosive when in contact with water and air.

In a typical latent thermal energy storage system, steam is tapped off a turbine during periods of low demand. The steam is used, for example, to melt a salt contained in an insulated container. During periods of peak demand the salt is allowed to solidify passing its energy to water, creating steam. This could either be used in a peaking unit or be added to the baseload turbine to increase output. A high efficiency of 90% is achievable(4), as the heat losses per cycle are expected to be small once thermal equilibrium is reached.

1.2.5 (c) Chemical Reaction Storage

Chemical reaction storage utilises the heat of a reversible chemical reaction to store thermal energy. In a typical system, heat is used so that two or more compounds may react with each other. The result of such a reaction may be several products. Heat additions to allow reactions to take place are called endothermic reactions. The products formed from the endothermic reaction may be allowed to react with each other or other compounds in an exothermic fashion, so that heat may be released and energy recovered. Exothermic reactions often occur in the presence of catalysts.

The heat for endothermic reaction can be extracted from steam in baseload plants. The resulting products may be stored and, once needed, they may be reacted with other compounds. The heat produced during the exothermic reaction can be used to generate steam for peaking units. Efficiencies are estimated at 85-90%(4). There are several concerns related to chemical reaction storage including the reactivity of the chemicals, the storage of the original chemical and reaction products, as well as the controllability of reactions. It is important that chemical reactions are controlled so that heat is not lost unnecessarily in either part of the process.

1.3) CONCLUSION

A comparison of the various storage systems has been made by Schainker(6) and a summary of his findings is shown in Table 1.2 and 1.3. For the purpose of comparison his costs (in 1984 US$) have been converted to 1994 S.A. Rand. Two economic terms have been identified namely, the power term (Rands/kilowatt) and the energy term (Rands/kilowatthour), both contributing to the final cost of the energy storage system.

Table 1.2 shows the characteristic efficiency, size and construction schedule for several storage systems. Schainker defines the efficiency of an energy storage plant in two ways: energy conversion efficiency and delivery efficiency. The energy conversion efficiency considers only the storage plant itself (electric energy output / electric energy input). The delivery efficiency considers both baseload plant and storage plant efficiencies.

Thus the delivery efficiency represents the "round-trip" effectiveness of the storage plant's capacity to utilize baseload fuels, store energy, and deliver electricity to the utility transmission grid. The overall delivery efficiency for storing and producing electric energy from a storage plant is the conversion efficiency of the storage plant (e.g. pumped hydro 72%) multiplied by the efficiency of the baseload power plant (e.g. 34%) used to provide the charging energy. The delivery efficiency of pumped hydro is therefore ~24%.

Table 1.2: Storage Technology Comparisons(6)

Technology	Efficiency (%)		Size (MW)	Construction time (yr)
	Conversion (a)	Delivery (b)		
Compressed Air Energy Storage				
Mini	-	-	25-50	2,5
Maxi	-	-	220	4,5
Pumped Hydroelectric				
Conventional	72	24	500-1500	10
Under Ground	72	24	2000	14
Battery	70	24	10	1
Flywheel	70	24	1	1
Superconducting magnet	91	31	1000	8

(a) Conversion efficiency of the energy storage technology only (Electric Energy Out / Electric Energy In).

(b) Delivery efficiency from primary fuel of base-loaded power plant performing the charging (with efficiency of 0,34) and converted through energy storage powerplant.

The efficiencies of compressed air energy storage have deliberately been removed from this table, as it is not possible to compare CAES directly with other storage techniques due to the possible additional fuelling that it may require. The efficiency of CAES is discussed in the literature review.

Table 1.3 shows two costs, an energy-related cost and power-related cost. The power-related cost refers to the size of machinery necessary to produce a certain power. The energy-related cost refers to the storage, and involves the cost of e.g. cavern excavation, dam building, etc. To determine the total cost of a system in Rand per kilowatt, the desired hours of storage are multiplied by the energy term, and the product thereof is added to the power term.

Table 1.3: Cost estimates for Storage Technologies[a]

Technology	Power-Related (R/kW)	Energy-Related (R/kWh)	Period of Storage (hr)	Total cost[b] (R/kW)
Compressed Air				
Mini (25-50 MW)	2190	25	10	2440
Maxi (220 MW)	2750	10	10	2850
Pumped hydroelectric				
Conventional	2950	50	10	3450
Underground	2950	150	10	4450
Battery				
Lead acid	990	770	5	4840
Advanced	590	395	5	2565
Flywheel	690	1475	5	8065
Superconducting Magnet	690	790	5	4640

(a) Costs are given in 1994 Rands converted from 1984 Dollars. They include all engineering, land and material expenses. Allowances for interest and escalation during construction are not included. The costs are estimates based on the megawatt size given in the previous table.

(b) Total cost is equal to the product of the energy related costs and the hours of storage added to the power related costs.

The tables reflect cost and construction as studied by Schainker(6) with application largely aimed at the electricity market of the United States. Although comparisons may be drawn between South Africa and the United States the most noticeable difference would occur in the energy-related cost of CAES. This particular figure is based on the mining costs of constant volume caverns in salt domes. This is difficult to relate to the South African situation where there are no salt domes. South African air reservoirs construction is most likely to take place in hard rock either through new excavation or the conversion of existing mine cavities.

Not included in these tables are hydrogen storage and the various thermal energy storage methods. Schainker's study is aimed at plants that may be economically viable alternatives to other generating plants (baseload, intermediate and peaking plants). Hydrogen storage has been shown to be a non-feasible solution as an energy storage application. It has further been found that producing hydrogen off peak through electrolysis, for use in the production of ammonia and other chemicals, is a more feasible solution(14). Cheaper fuels, such as natural gas, are able to supply a higher output than hydrogen on a equal volumetric basis. The production of hydrogen may still be used to increase power plant load factor through off peak production, a process called valley filling.

Thermal energy storage has largely been used in power stations to supplement generating capacity during peak demand periods. No stand-alone thermal storage plants exist due to the safety factor involved in storing gases, liquids and solids at high temperatures for a large generating capacity. Sufficient thermal storage necessitates large volumes. Large thermal volumes have temperature gradients throughout, that cause stress and possible structural failure. Intricate designs need to be employed to overcome these problems, this adds to the costs involved.

With the most current information available as shown in the above two tables, the following conclusions may be drawn: A technology such as superconducting magnetic energy storage is attractive for short storage periods (i.e. fewer than 5 hours) with high peaks(6). This conclusion may be drawn from its relatively low power-related cost, in comparison to CAES which has an extremely low energy related cost and is therefore more suited to longer storage times. SMES unfortunately has a high energy-related cost compared to other technologies and is therefore more expensive.

The advantage of batteries, SMES and CAES are that they may be rapidly recharged as well as having quick response times, an advantage during emergency situations. Batteries and SMES are however only suitable for smaller energy capacities, as larger designs would increase costs significantly. The increase in energy capacity would involve additional space needed for battery modules as well as extra systems needed for maintaining batteries. Batteries necessitate continuous topping up of water. High temperature batteries need to be maintained consistently at the high temperature. The enlargement of SMES involves the implementation of expensive superconducting material and associated refrigeration. The addition and operation of extra equipment needed to maintain batteries and SMES make operating costs higher than competing energy storage systems.

The only two technologies that are commercially attractive are CAES and pumped hydro. Whilst both have relatively low energy costs and high power costs, the difference is that it takes less energy to run a CAES allowing for larger peak applications or longer duration peak shaving. A CAES increment could, therefore, fit beneath a peak already served by a pumped hydro plant.

CHAPTER 2

LITERATURE SURVEY
on
COMPRESSED AIR ENERGY STORAGE

2.1) INTRODUCTION

The previous chapter covered several energy storage systems suitable for the electricity industry. Electricity utilities and researchers throughout the world have discussed, published and built many variations on these types of storage, all with the aim of cutting costs and enhancing the efficient supply of electricity.

The purpose of this chapter is to review compressed air energy storage and its many variants, with their characteristics, as an alternative generating capacity for electric utilities.

2.2) THE THEORY OF COMPRESSED AIR ENERGY STORAGE

The first concept of Compressed Air Energy Storage (CAES) was patented by Stahl Laval in 1949(1). This system allowed for underground compressed air storage between the compressor stage and expansion stage of a gas turbine. Since then, CAES has been developed into a formidable storage technique. In the previous chapter, an introduction into the operation of a "first generation" CAES plant was given. An illustration hereof, as would be applied on the grid, is shown in Figure 2.1. In the following sections the operation of CAES is discussed in more detail.

2.2.1) Single Stage Compressed Air Energy Storage

CAES is more than just the separation of the various gas turbine sections (Figure 2.1). The compression stage and the expansion stage have been separated to incorporate a motor-generator that replaces a standard generator. Energy storage is achieved through the addition of an air reservoir between the compression and the expansion stages. This allows for the storage of large quantities of air/energy over long periods of time.

Energy storage takes place through the compression of air into a cavern for storage, and released, when required, for electricity generation. Air storage of this type requires large volumes and, ideally, underground storage is most suited. These options involve either storage by constant volume or constant pressure.

Through the control of clutches and valves, the turbo-machinery may be switched from compression (charge) to generation (discharge) in a matter of minutes. During times of low demand, baseload electricity is available for the charging of energy storage systems. Charging CAES takes place by coupling the compressor clutch and thus coupling the compressor to the motor-generator. The valve to the cavern is opened and baseload electricity is used to compress air into the cavern. The generating section of the turbo-machinery train is isolated by closing off the valve in the air pipeline to the turbo-expanders and uncoupling the clutch between the turbine and motor-generator.

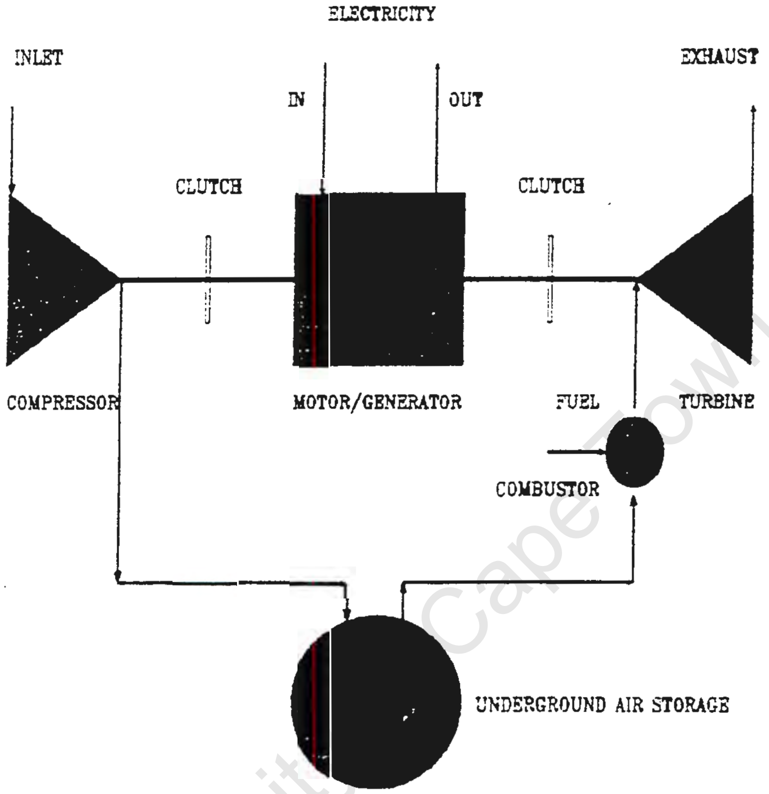


Figure 2.1: Schematic layout of a "first generation" compressed air energy plant

As soon as the need for generation arises, the compression section of the turbo-machinery train is isolated. The clutches are reversed, thus uncoupling the compressors and coupling the turbine to the motor-generator. The air flow valves situated on the air supply pipeline are also reversed, directing the compressed air from the cavern to the turbo-expanders. Simple CAES plants use combustors to heat the air up sufficiently for efficient expansion through the turbines. Once the air enters the turbine, shaft energy is produced, and electricity is generated.

Standard CAES systems use gas turbine fuels, such as fuel oils or natural gas, but there are various other methods of heating the compressed air, resulting in several variations on conventional CAES.

The first question to arise, is that of using CAES rather than a standard gas turbine. In a standard gas turbine, 2/3 of the shaft energy produced is used to drive the compressor, leaving 1/3 for generation purposes (Figure 2.2). The result being that 2/3 of the fuel content is used for compression and 1/3 for generation(2). Using CAES, the separate turbo-machinery allows for the full fuel supply to be used in the turbine and thus the generation of electricity, while the compressors make use of low cost baseload electricity. Internationally the cost of standard turbine fuels are 2 to 3 times that of baseload fuels(2).

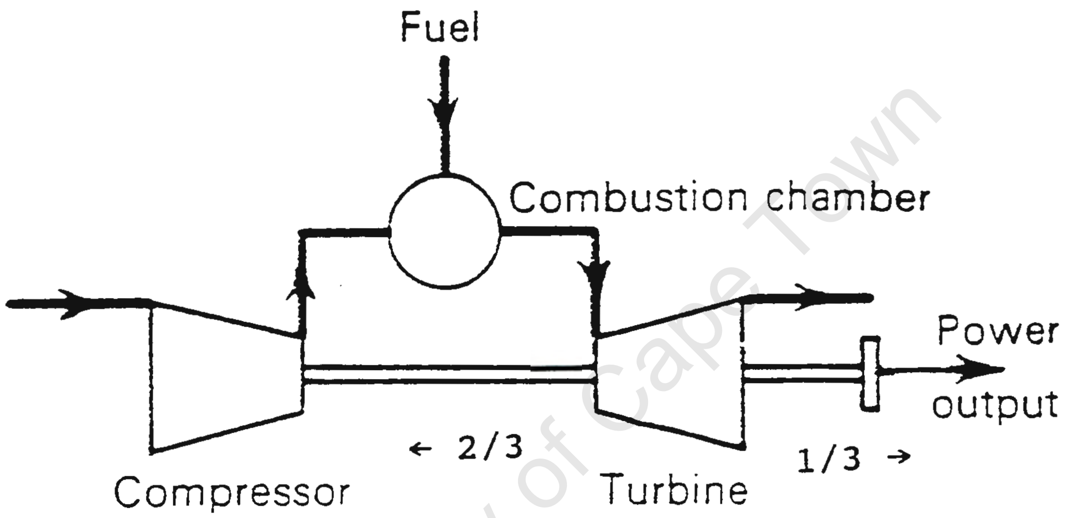


Figure 2.2: Fuel usage in a standard gas turbine(3)

2.2.2) Intercooling, Multi-stage Turbo-machinery and Recuperators

Development of CAES has largely concentrated on simple adaptions and variations on the first generation plant, as discussed in Chapter One. The first major step of advancement was in the field of compression, making use of intercoolers to increase the compression efficiency resulting in isothermal compression. Through intercooling the work input may be reduced and thus operating costs are lowered(4). Other variations include the use of multiple combustors and turbines (turbo-expanders), thus increasing the efficiency of the expansion process (Figure 2.3). Huntorf in Germany has a fully operational plant consisting of multiple compressors and turbo-expanders. This plant is discussed later in this chapter.

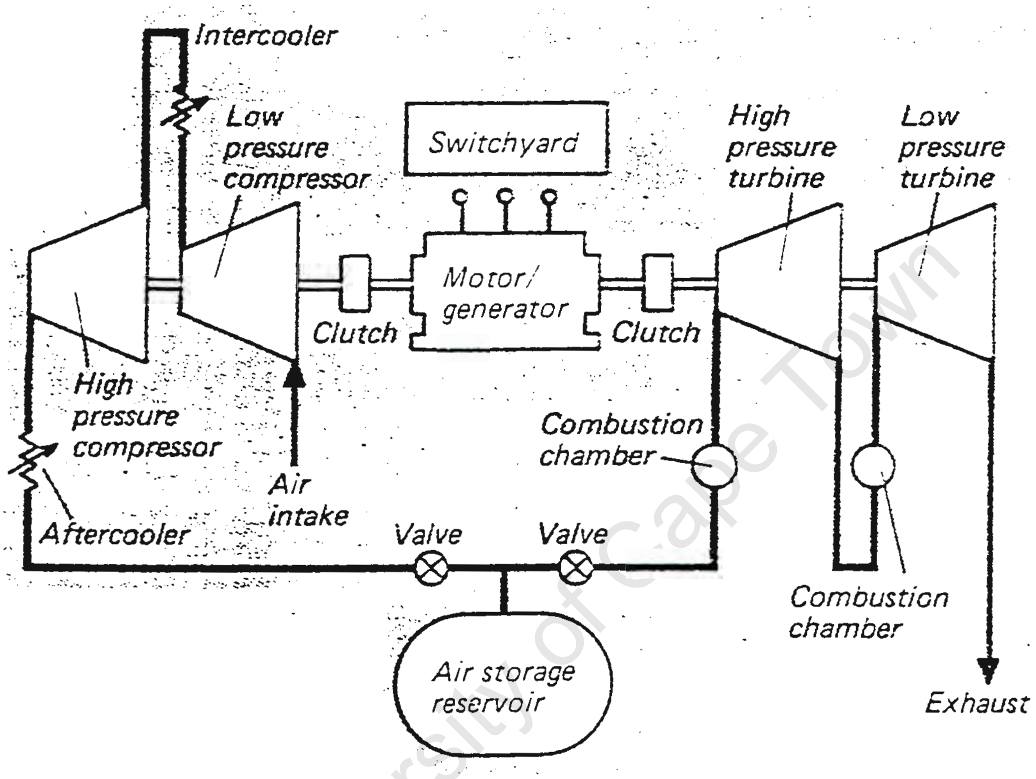


Figure 2.3: Multi-staging compressors and turbines in CAES(5)

Next followed the recuperation of exhaust heat losses. Including a recuperator into the system may reduce the consumption of primary fuels by up to 25%(2). The recuperator is installed between the cavern and the combustor. Air from the turbine exhaust is rerouted through the recuperator so that the exhaust heat may be extracted and used to preheat the air leaving the cavern (Figure 2.4). The best example of the inclusion of a recuperator is the Alabama plant currently in operation in the United States. This plant is also discussed later in this chapter. CAES systems containing multistage turbo-machinery, combustors and recuperators are known as conventional CAES (Figure 2.4).

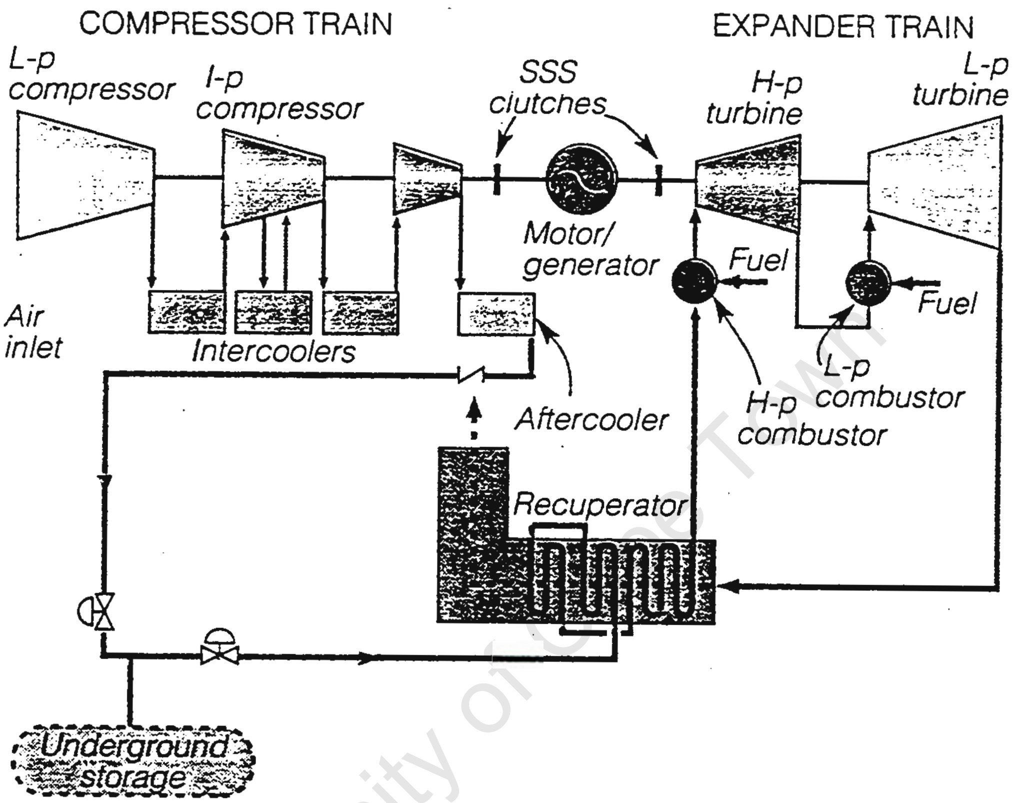
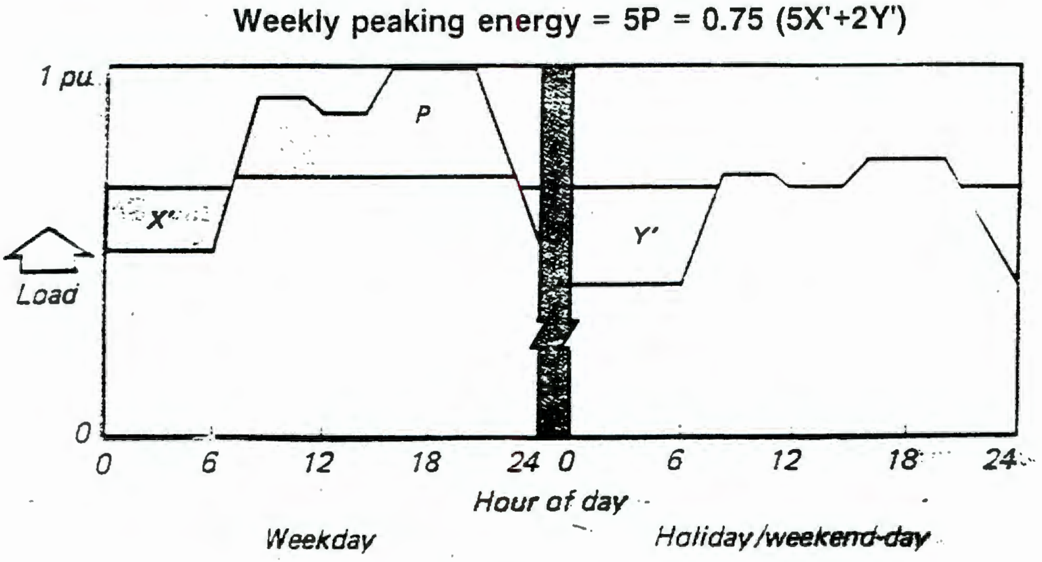


Figure 2.4: The addition of a recuperator into a CAES system (conventional CAES)(6)

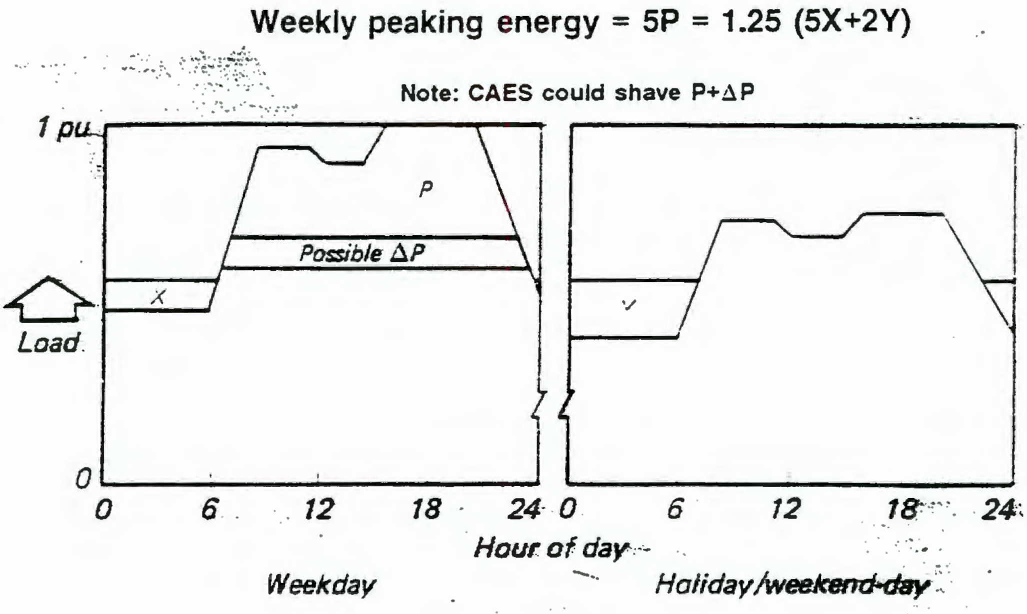
2.2.3) Performance Characteristics of CAES

Due to the fuel added to aid the generation process, conventional CAES has been classified as a hybrid and not as a true storage system. Hybrids have several advantages, one being that they are able to generate more energy than that which has been stored. Simple energy storage systems are only likely to reproduce as much as 75% of the stored energy content for electricity generation(5) (Figure 2.5). Due to the additional fuel, conventional CAES systems are able to produce as much as 125% of the stored energy content(5) (Figure 2.6).



Where: P = Quantity of peaking energy produced per day
5P = Quantity of peaking energy produced during 5 peak weekdays

Figure 2.5: The load levelling ability of standard storage on electricity demand(5)



Where: P = Quantity of peaking energy produced per day
5P = Quantity of peaking energy produced during 5 peak weekdays

Figure 2.6: The load levelling ability of conventional CAES on electricity demand(5)

Due to the addition of fuel, the standard storage efficiency (electrical energy output/ electrical energy input) no longer holds true for a conventional CAES system. An overall thermodynamic efficiency is defined that includes both the fuel input from baseload stations and the additional fuelling in conventional CAES.

The *Thermodynamic Efficiency* $(\eta)^{(2)}$ of a CAES cycle is defined as the output specific work of expansion through the turbine, divided by the heat supplied in the combustor as well as the heat consumed in the baseload power plant to produce the power needed for compression.

Because the storage efficiency no longer holds true for CAES, neither is the overall thermodynamic efficiency very appropriate, Glendenning(1) and the Central Electricity Generating Board U.K.(CEGB) defined the following two performance indicators for any CAES system:

$$\mathit{Charge\ Energy\ Factor}\ (CEF) = \frac{\mathit{Net\ Electrical\ Energy\ Output}}{\mathit{Gross\ Electrical\ Charge\ Energy}} \tag{2.1}$$

which for a pure storage plant is identical to the storage efficiency (typically 0,6-0,75), and

$$\mathit{Fuel\ Heat\ Rate}\ (FHR) = \frac{\mathit{Combustion\ Fuel\ Consumed}}{\mathit{Net\ Electrical\ Output}}\ (kJ/kWh) \tag{2.2}$$

An *Energy Ratio* (7) is defined as the amount of off-peak electrical-energy consumption (kWh) during the compression cycle to generate 1 kWh during generation and equates to 1/CEF. This is easier to interpret than the definition of CEF.

$$\mathit{Energy\ Ratio} = \frac{\mathit{Gross\ Electrical\ Charge\ Energy}}{\mathit{Net\ Electrical\ Energy\ Output}} = \frac{1}{CEF} \tag{2.3}$$

The thermodynamic efficiency (η) affects both the FHR and the CEF and depends on:

- The overall pressure ratio, P_2/P_1
- The number of intercoolers, N
- The effectiveness of the recuperator, ϵ_{RC}
- The pressure losses in the intercoolers, reservoir and other components of the system
- The inlet temperature to the turbo-expander which has the maximum temperature of the cycle.

For a conventional CAES Nakhamkin⁽⁷⁾ has determined CEF = 1,27 and FHR = 4360 kJ/kWh.

2.2.4) Calculated Performance of a CAES system

The performance of a conventional CAES (Figure 2.4) system using a constant pressure air reservoir is shown in Figures 2.7 - 2.11⁽²⁾. The pressure losses assumed are $\Delta P/P = 5\%$ with a conservative value for the firing temperature, i.e. $T_{max} = 870°C$ and a recuperator effectiveness of $\epsilon_{RC} = 0,5$. The value of the inlet temperature of the turbo-expander is constrained for technical reasons and is usually not allowed to increase beyond $T_{in} = 870°C$ ⁽²⁾. Modern gas turbines designers face a challenge to increase the maximum firing temperature.

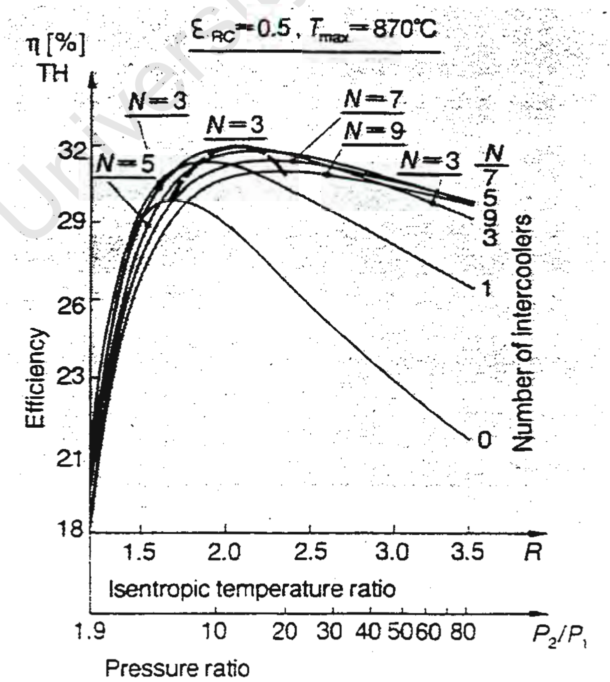


Figure 2.7: Efficiency vs Pressure Ratio for different numbers of intercoolers⁽²⁾

In Figure 2.7 the thermodynamic efficiency, η, is plotted against the isentropic temperature ratio, R, for different values of the number of intercoolers. The maximum values of efficiency for every value of N (number of coolers) have been connected, to give the best design trajectory. From the figure it can be observed that a maximum efficiency of 32% is obtained with three inter-coolers and an optimal temperature ratio of $R^* = 2{,}1$.

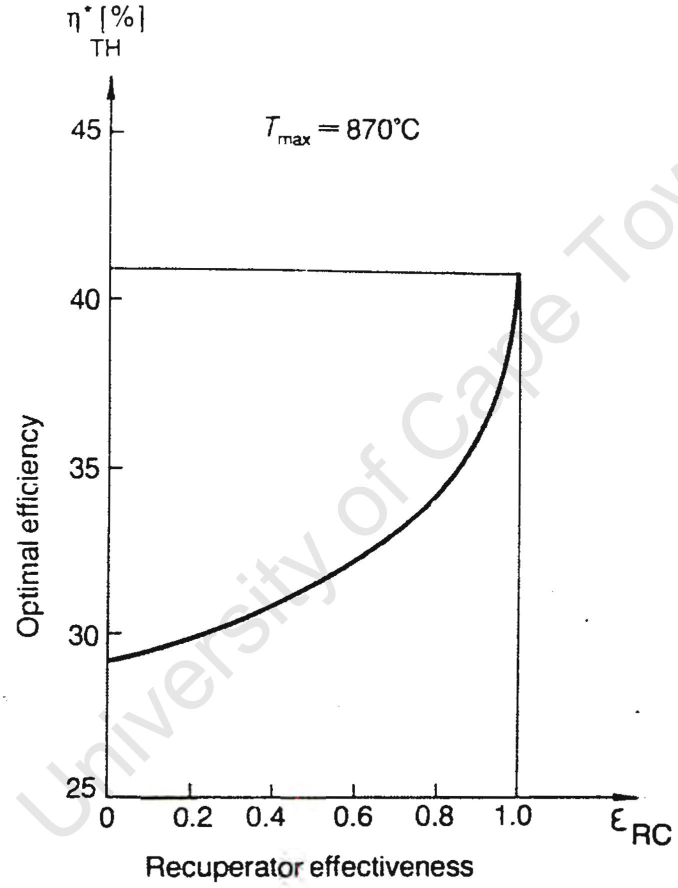


Figure 2.8: Optimal Efficiency vs Recuperator Effectiveness(2)

The variation of optimal thermodynamic efficiency with an increase in recuperator effectiveness is presented in Figure 2.8. From the figure it is concluded that the efficiency can be increased by raising the recuperator effectiveness, but this is limited by the optimal thermodynamic efficiency, $\eta^*_{max} = 41{,}5\%$, corresponding to the ideal case when $\epsilon_{RC} = 1$.

The variation of optimal isentropic temperature ratio, R^*, with the effectiveness ϵ_{RC}, is seen in Figure 2.9, where a decrease of R^* is obtained when ϵ_{RC} increases. This means that the higher the recuperator effectiveness the lower the pressure ratio. The corresponding variation in the optimal number of intercooler appears in Figure 2.10. A similar decrease of the number of intercoolers is obtained when ϵ_{RC} increases.

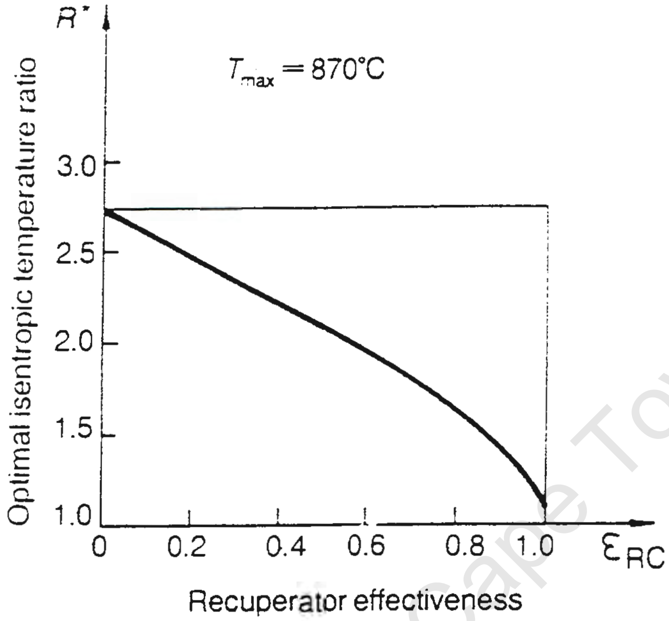


Figure 2.9: Optimal Isentropic Temperature Ratio vs Recuperator Effectiveness(2)

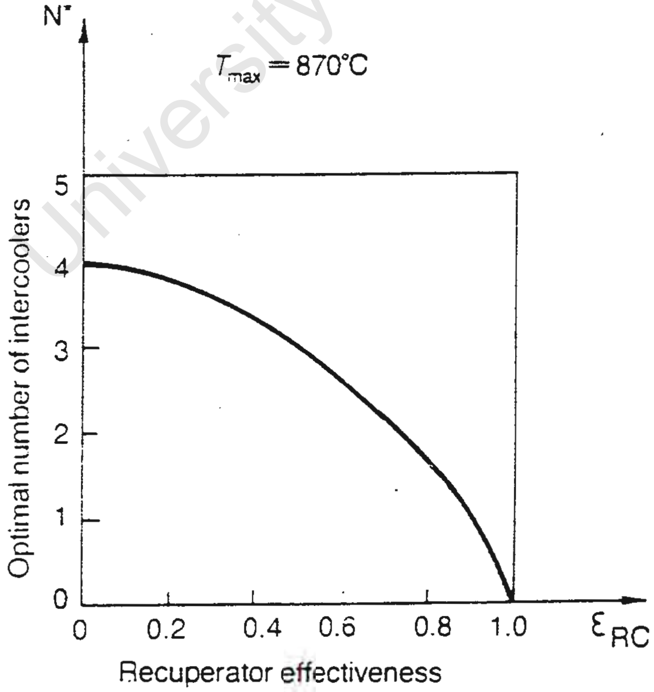


Figure 2.10: Optimal Number of Intercoolers vs Recuperator Effectiveness(2)

The remaining possibility to improve performance is to increase turbine inlet temperatures, since the specific work output from a turbine is proportional to the absolute inlet temperature for a given pressure ratio(1). The optimal efficiency at the optimal value of N^* is plotted in Figure 2.11 against the isentropic temperature ratio for different firing temperatures and for ϵ_{RC} = 0,5. The optimal design trajectory is obtained in this figure by connecting the maximum values of optimal pressure ratios. At a constant pressure ratio, a 3,5% improvement of efficiency is achieved when increasing the temperature from 870°C to 1200°C. The improvement gained by increasing the firing temperatures is associated with significant technical and economical benefits. Since the resulting output power is increased with an insignificant increase in the overall cost of the CAES plant, its specific cost per kilowatt is much lower and hence the specific baseload fuel consumption is reduced.

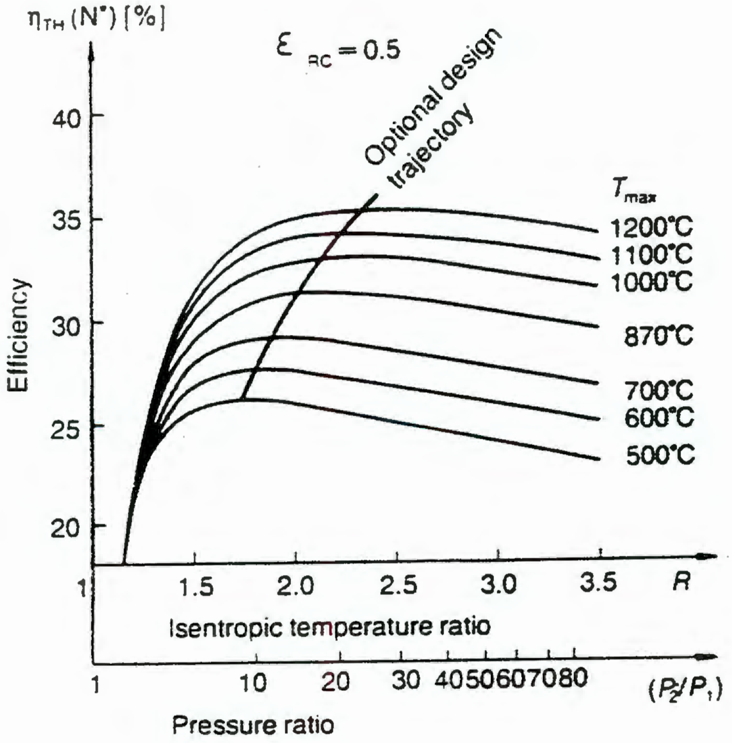


Figure 2.11: Efficiency vs Pressure Ratio for different firing temperatures(2)

In Figure 2.12 the effect of increasing turbine firing temperatures on FHR and CEF is shown for a conventional CAES system with a constant volume reservoir. Two lines are depicted, the first increasing the LP turbine temperature while maintaining the HP turbine temperature at a constant temperature of T_{HP}=550°C. The second graph depicts the increase of both HP and LP turbine temperature with $T_{HP}=T_{LP}$.

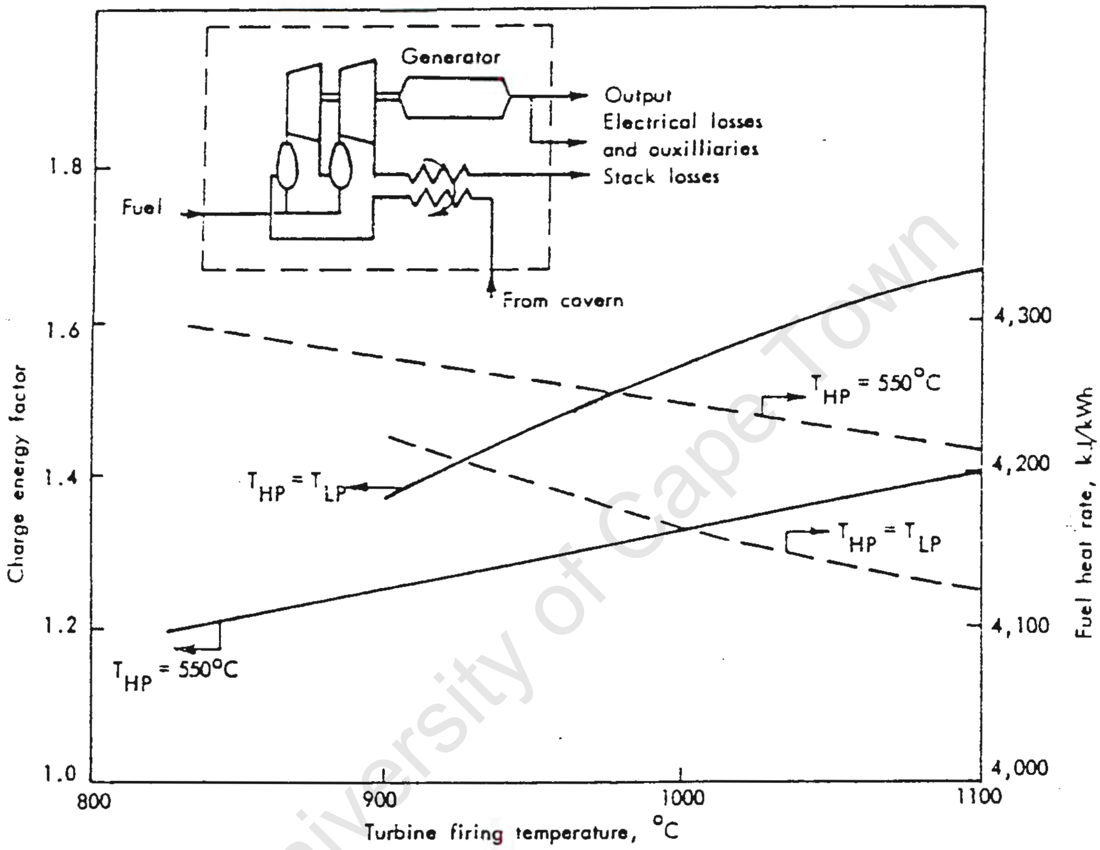


Figure 2.12: The effect of increasing turbine firing temperatures in conventional CAES arrangements(1)

By using a recuperator capable of maintaining a stack temperature of 140°C, in all cases it is seen that a CEF=1,4 is readily achieved and, with developments in the turbine field, the CEF could be increased to 1,6 to 1,7(1). These gains would be accompanied by a small improvement of 5% in fuel consumption but, since only the turbines are changed, a very substantial reduction in capital cost will be achieved(1).

2.3) COMPRESSED AIR ENERGY STORAGE: THE UNDERGROUND PORTION

2.3.1) Introduction

The most important feature of CAES is the air storage reservoir. Due to the large volume of air that needs to be stored for CAES, air storage has to take place underground, as above-ground storage is usually impractical. It is only underground caverns that could support large volumes of air at high pressure, but it is the integrity of the reservoir, or its ability to contain the pressurised air, that governs the efficiency and economics of the CAES operations (8).

Air reservoir site selection requires specific consideration(5):

- Identification of suitable geological formations or depleted hydrocarbon fields in the proximity to an electric utility's load area or transmission grid.
- Structural integrity of caverns in respect to the strength of the caprock and porosity of the cavern.
- Avoidance of liquid and particle contamination during the withdrawal cycle.
- Maintenance of the storage cavern over time.

Three types of underground cavities have been identified as suitable storage for CAES, namely salt caverns, hard rock caverns and aquifer storage (Figure 2.13).

There are conceptually two methods of storage that may be applied to the above techniques(5):

- Constant volume
- Constant pressure

A constant volume cavern is a sealed cavern below the earth's surface with a single pipeline providing the inlet and outlet. Examples are either the conversion or mining of salt caverns in salt domes, or converting unused mines in hard rock.

Constant pressure systems require a method to regulate the air pressure. This is achieved in aquifers through water that occurs naturally, or in caverns making use of an artificial water compensating pressure head.

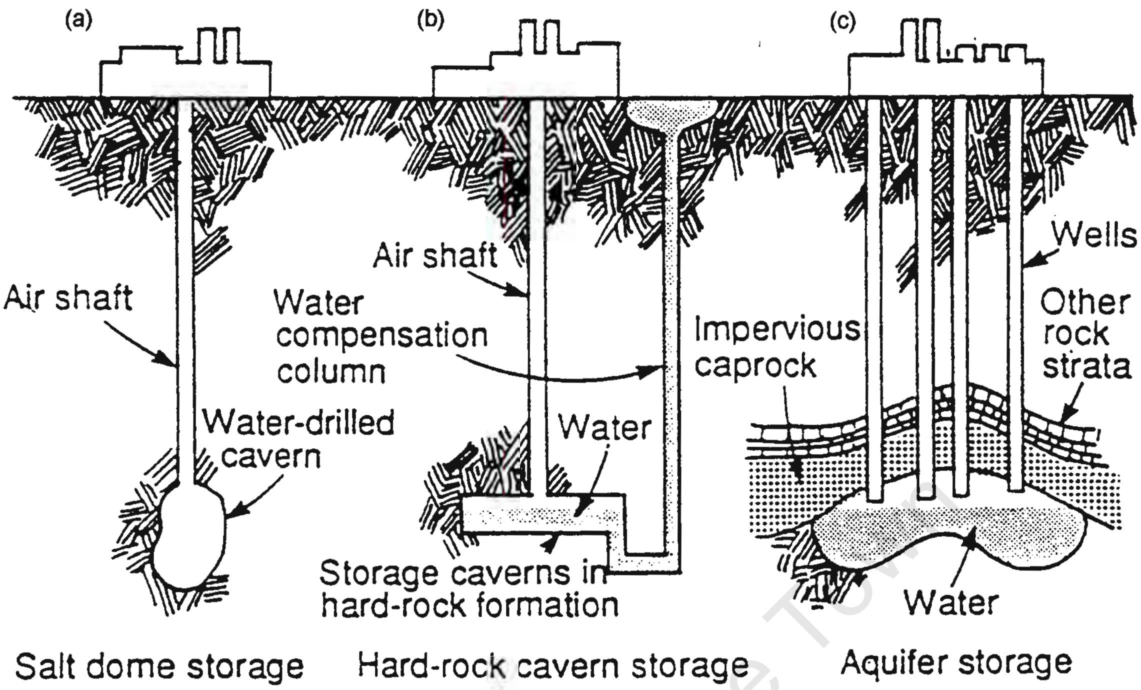


Figure 2.13: Three storage caverns suitable for CAES(9)

2.3.2) Salt Cavern Storage

In the United States, for possibly 40 years or more, salt caverns (Figure 2.13a) have been used extensively to store natural gas, propane and oil. Research so far indicates that they are stable under compressed air storage loads for the duration of plant life. The major concerns are cavern geometry, size and spacings, long term creep and creep rupture of rock salt, and air leakage.

Salt is mined from salt domes through a method of solution mining. Salt caverns are formed through this technique by drilling a narrow well into a suitable salt dome. Fresh water is pumped in and dissolves the salt and the resultant brine is pumped out. This process is continuous until the required volume is reached.

Salt caverns are identified as constant volume storage reservoirs. Salt caverns using water as a compensation medium would continuously grow in volume as the mining process would be continued. If compensation was considered, saturated brine would be required to replace the water in the compensation reservoir.

It is generally accepted that a constant volume cavern is larger than the cavern needed for a constant pressure system. In a constant volume system, air is regulated at the inlet to the turbo-expanders to achieve a constant pressure. This is not necessary in a constant pressure system, as long as the storage pressure is equal to the pressure used in the first stage of expansion. The throttling in constant volume storage systems is approximated as adiabatic and energy loss is minimal and acceptable(10). Both storage systems may be sized to match daily, weekly and seasonal cycles for any utility.

2.3.3) Hard Rock Cavern Storage

In the United States hard rock caverns have been used to store hydrocarbons. These caverns are situated in either depleted gas fields, unused mines or newly excavated caverns.

Excavating a hard rock cavern is considerably more expensive than a salt cavern due to the increased labour and rock breaking equipment costs. The volume of the hard rock cavity can be reduced by changing from a constant volume system to a constant pressure system. It is estimated that the volume of a constant pressure system may be 20% less than that of a constant volume system(10). A constant pressure system requires a column of water maintained by a surface pond connected to the storage cavern (Figure 2.13b). As air is compressed into the cavern, the water passes through a U-bend into a vertical pipe and is forced up to a surface pond. When air is released from the cavern, water runs back through the U-bend and into the bottom of the cavern. This constant head of water pressure maintains a constant air pressure in the cavern during the withdrawal cycle. Air may be fed directly to the turbo-expanders without unnecessary throttling.

A cause for concern is the effect of effervescence of air in the water shaft (called the champagne effect). This allows air to escape from the cavern and reduce the usable volume. This can be counteracted through a suitable U-bend in the compensation shaft.

Caverns can be mined from dense rock beds or converted from existing caverns depending on factors such as rock type, hardness and freedom from fissures, depth of excavation, size of excavation, mine shaft requirements, special sealing techniques required, the need to remove seepage water, and whether water compensation is required. Hard rock air storage is discussed, in more depth, in chapter four.

2.3.4) Aquifer Storage

Aquifers have been used largely for the storage of natural gas, with annual or seasonal storage, rather than for daily cycling. Aquifers are naturally occurring porous sandstone or fractured rock formations under caprock (Figure 2.13c)

Aquifers are utilised through the sinking of numerous wells through the impervious caprock into the porous material (sand, sandstone or gravel) below. Air is compressed into the caprock bulge displacing the water in the porous material. The force of the surrounding water confines the air into the bulge and maintains it at a constant pressure. The air may be extracted at a constant pressure as water replaces the withdrawn air.

The effects of high pressure air storage needs to be evaluated in aquifers. Other concerns include cyclic fatigue of the porous rock, air water interface movement and the generation and transport of fine particulate matter(11).

2.3.5) Conclusion

The cost of developing underground storage is site specific and is governed by local geology, depth of suitable strata, capacity of the CAES facility, and location of the CAES facility with respect to the load area or transmission grid. Consequently the geologic formation existing within the service area will determine the type of underground storage available for consideration. Usually storage selection is limited to one or two options. In ascending order of cost the following volumes are available: Salt cavern (uncompensated), aquifer, salt cavern (compensated), depleted gas field, rock cavern (uncompensated) and rock cavern (compensated)(5).

2.4) COMPRESSED AIR ENERGY STORAGE: RESEARCH AND DEVELOPMENT

Since the implementation of the Huntorf plant in Germany, the level of research and interest into CAES has increased. Alternative turbo-machinery layouts, fuelling, non-fuelling, adiabatic systems, combined cycles and steam injection are all aspects that have been considered by researchers in their effort to cut costs and/or increase output. The following sections outline possible CAES variants.

2.4.1) Variations on the Conventional CAES Turbo-machinery Train

Figure 2.14 shows a CAES variant, as suggested by Lee(12) of the California State University. His design includes matched compressor and turbine airflows, allowing the system to be operated as a conventional turbine in case emergencies occur.

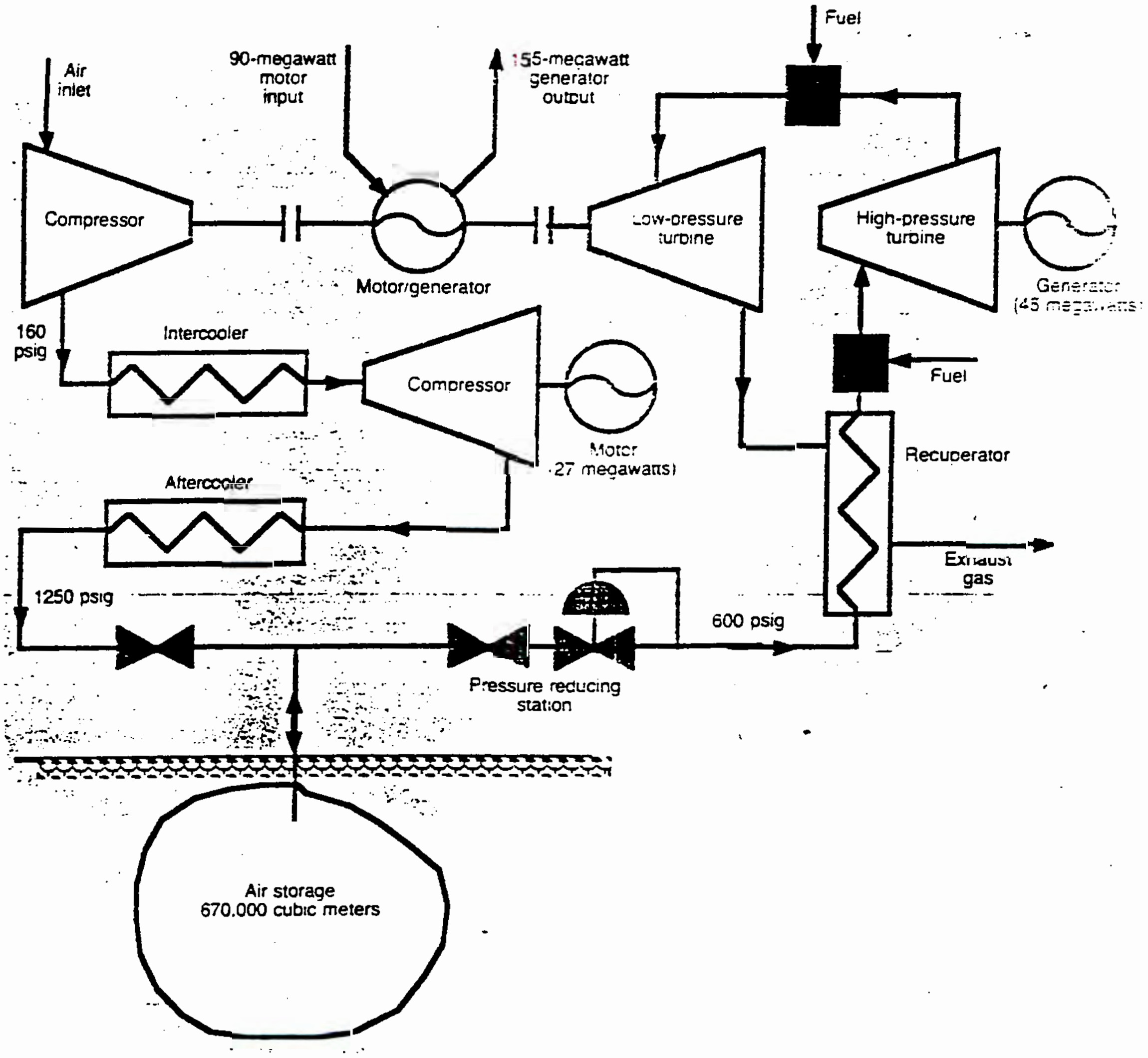


Figure 2.14: Schematic layout of a model 200 MW CAES generating facility^(12)

Lee includes pressures and capacities to his design, as shown. He uses an axial flow compressor in the first stage and a centrifugal compressor in the second. Intercooling takes place between compressor stages, reducing the air's specific volume and temperature. The second stage compressor has been separated from the first stage compressor train and requires a separate motor. An aftercooler has been included, cooling the air down to storage temperature. The design is based on utilising a constant volume salt cavern storage reservoir, operating on a weekly cycle.

During generation, air is withdrawn from the storage cavern and regulated. A recuperator has been included to recover exhaust heat and preheats the air. The air leaving the recuperator is fired with fuel in the high pressure combustor and expanded in the high pressure turbine, which is also a separate unit. Exhaust air from this turbine is reheated in the low pressure combustion chamber to high temperatures. Thus the low pressure turbine requires interstage blade cooling.

This plant would require an input power of 117 MW and would be supplied by a utility's low cost off-peak baseload plant. The plant would be able to produce 200 MW through storage and fuelling to the extent of 4220 kJ/kWh output. This compares favourably with other types of CAES, fuel heat rates.

2.4.2) Adiabatic Compressed Air Energy Storage

In conventional CAES systems heat dissipates in the intercoolers and is replaced by the firing of fuels in the combustors. An adiabatic CAES plant re-uses the heat of compression to reheat the air before expansion in the turbine. In principal adiabatic systems are able to recover approximately 80% of the input energy for the production of electricity(1), closely equivalent to the performance of conventional storage such as pumped hydro.

Figure 2.15 shows how the heat of compression can be stored in thermal energy storage (TES) to be re-used during the generation stage(11). As this heat is either lost in inter- and aftercoolers, storing and re-using it is a suitable solution. It is further not possible to store hot air as this would increase the volume necessary, as well as cause damage, such as cracking and fracture, to cavern walls(4).

The function of the TES is to cool the charging air stream to 30-50°C for the underground storage. Later, during discharge, the TES would reheat the air before expansion in the turbines. Adiabatic systems can achieve a higher overall thermal efficiency than conventional CAES systems.

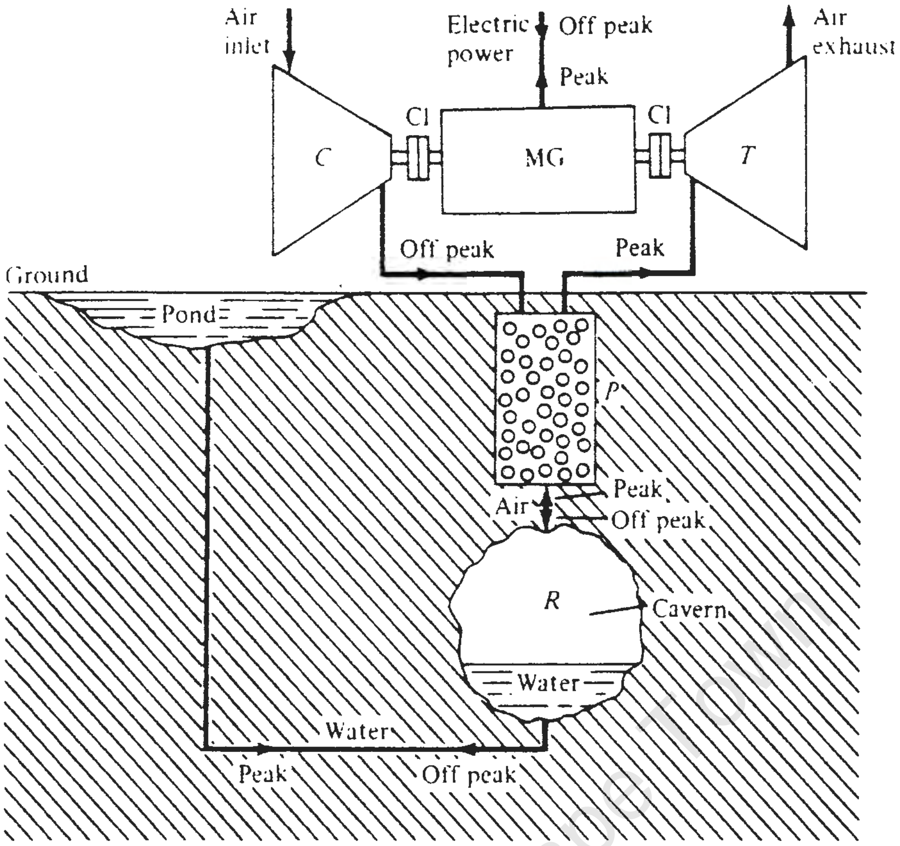


Figure 2.15: Conceptual "No-oil", adiabatic CAES[11]

TES is not new to industry as large TES units have been used successfully in a variety of applications such as preheating air for blast furnaces at steel works, and hypersonic wind tunnels for re-entry vehicle model tests. It is of interest that TES and CAES developments are subject to the same constraints as developments in conventional CAES and should therefore be based on as many standard components as possible.

A suitable thermal energy store would need to meet the following requirements[4]:

- It must be capable of storing all the compression energy.
- The temperature of the air entering the store cavern should be close to the storage temperature.
- The temperature of the air leaving the store during regeneration should be close to the compressor delivery temperature.
- The pressure drop through the store should be small
- It should be simple so as to avoid unnecessary high capital costs.
- It should have no moving parts

Two methods of thermal energy storage have been suggested for CAES applications. The first method of storage is a solid matrix of pebbles or bricks in direct contact with the cycle air and contained in a pressure vessel(1). The second method of storage is storing heat in thermal fluids and insulated storage tanks(7) using a secondary circuit coupled to the cycle air via a heat exchanger. The second method of storage appears to be more feasible(7), although the secondary circuit degrades the thermal performance of the TES and thus direct contact systems would be preferred(1).

A pebble bed with a round trip effectiveness of over 80% would require a matrix materials with a high specific heat and good thermal conductivity properties. It would also need a high surface to volume ratio and a good air to solid heat transfer coefficient. A study conducted by the Central Electricity Generating Board (CEGB)(1) in England, has shown that pebbles, 19-50 mm in diameter, manufactured from a dense fireclay or cast iron would lead to a suitable TES matrix design.

For example, a 300 MW, 8 hour CAES scheme would need a matrix of 22000 tons of cast iron pebbles contained in a pressure vessel 17 m high by 17 m in diameter (internal). This would achieve 93% effectiveness over a full charge-discharge cycle or, on average, result in temperature loss (Compressor delivery to turbine inlet) of less than 20°C (1).

There are several uncertainties regarding the effects of mechanical stress and bed movements produced by successive thermal cycles. Detailed design and development would be required before a large pebble bed TES could be implemented.

Nakhamkin(7) suggests that the heat of compression can be added at various points within the CAES/TES cycle or used externally as follows:

- During power generation, air from the cavern can be heated in the thermal storage system and routed directly to the high pressure (HP) expander (HPTES). The recuperator is used in this cycle to preheat the HP exhaust before the low pressure (LP) combustor.

- The stored heat can be added to the HP exhaust to reduce or eliminate fuel consumption of the low pressure (LP) combustors (LPTES). The recuperator maintains its function as in the conventional cycle.

- If adequate overall pressure exists, a high pressure and low-pressure thermal storage can be utilized to preheat the air upstream of both expanders and eliminate the combustors and fuel consumption completely (Figure 2.15).

- The stored heat can be used for steam generation for use in a separate steam cycle or for injection into the expanders.

The first method suggested above, where the TES is used solely for heating air for the high pressure expander, has been applied by Nakhamkin(7). The second method of TES use, heating air for the LP expander, has been applied by Glendenning(1). Both systems replace the first intercooler in the compressor train with TES with Nakhamkin using an indirect thermal-oil TES system and Glendenning using a direct contact pebble bed TES.

On the turbo-expander side of the TES, there are large differences between the above two concepts. Nakhamkin's TES supplies only the HP turbine with heated air and uses a recuperator to heat HP turbine exhaust gases before combustion in the LP turbine (Figure 2.16). Glendenning's system, on the other hand, uses the recuperator to heat the air for the HP turbine, while the TES is used to heat HP turbine exhaust gases before combustion for the LP turbine (Figure 2.17).

In both systems a redistribution of compressor pressure ratios has been required to raise the first stage discharge air temperature to be thermodynamically effective. In addition to this, both systems are hybrids due to fuel being added in the LP expander.

Through the inclusion of TES into various CAES configurations it has been proved that fuel usage in the generation mode can be reduced. Both the plants described above, with their similarities and differences, have the same fuel heat ratio, achieving FHR = 3000 kJ/kWh. The charge energy factor differs slightly with CEF = 1,11 for Nakhamkin's plant and CEF = 0,96 for Glendenning's system. The aim is to achieve an adiabatic plant that would result in the FHR being equal to zero.

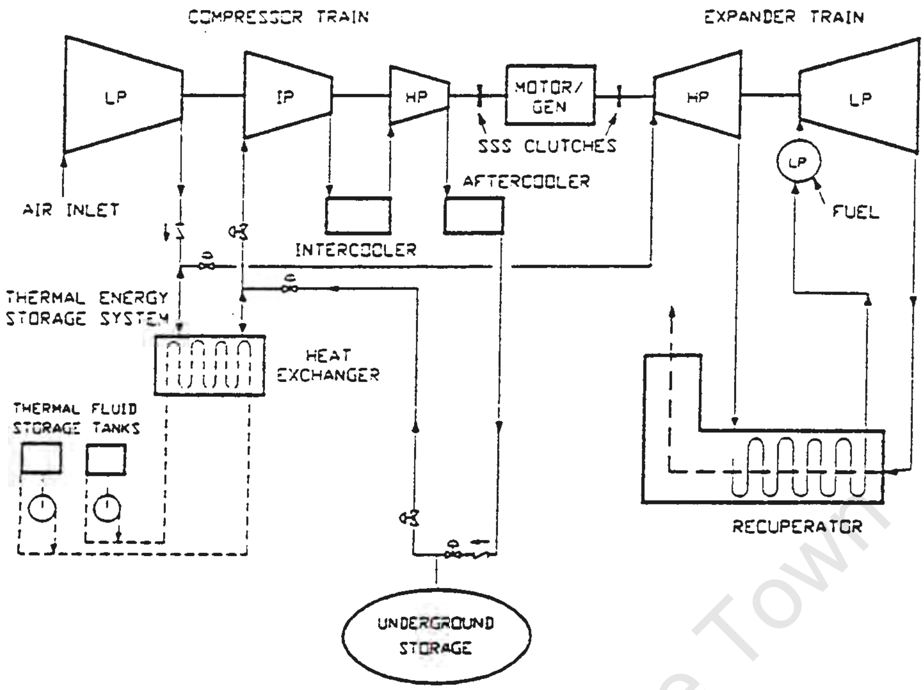


Figure 2.16: Schematic layout of Nakhamkin's[7] CAES with HP thermal energy storage (CAES/HPTES)

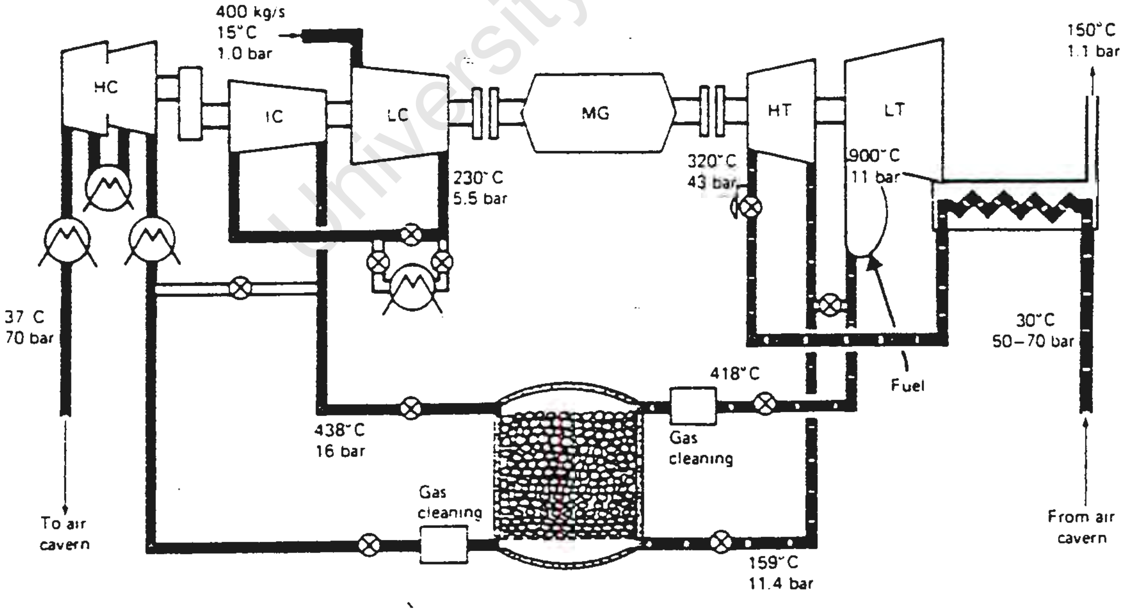


Figure 2.17: Schematic of Glendenning's[1] pebble bed CAES/TES

Capital costs of both plants are expected to be only slightly higher than that of conventional CAES plant, with a significant proportion of TES cost lying in the containment(1,7). This cost is justified since it is off-set by expected savings in the turbo-expanders, due to their lower operating temperatures(7). The capital cost of a CAES/TES is estimated at between 15% and 25% more than that of a conventional CAES plant(1).

CAES with TES will be most attractive to utilities with high fuel costs and low off-peak energy rates and stringent air emissions standards(7). Although fuel consumption and emissions are reduced in all hybrid TES plants, the adiabatic plant eliminates the use of premium fuels and their associated emissions.

Two additional CAES/TES systems were identified in the 1970's incorporating TES, standard fuelling, electric heating and turbo-machinery rearrangement(4).

The first configuration known as the A5(4), is in every sense a hybrid (Figure 2.18). The arrangement avoids conflict between the operation of thermal heat store and the recuperator operation. The heat store is not situated at the inlet/outlet of the cavern, but elsewhere, at a lower pressure than usually expected in CAES storage volumes. Lower pressures are easier to contain in this TES system. The system makes use of low pressure machinery, but a charge energy factor of 0,96 is still possible.

The second configuration (A1)(4) is a proposed adiabatic cycle, eliminating all fuel requirements (Figure 2.19). Despite a very high efficiency, this adiabatic cycle suffers a mismatch between compressor and turbine technology.

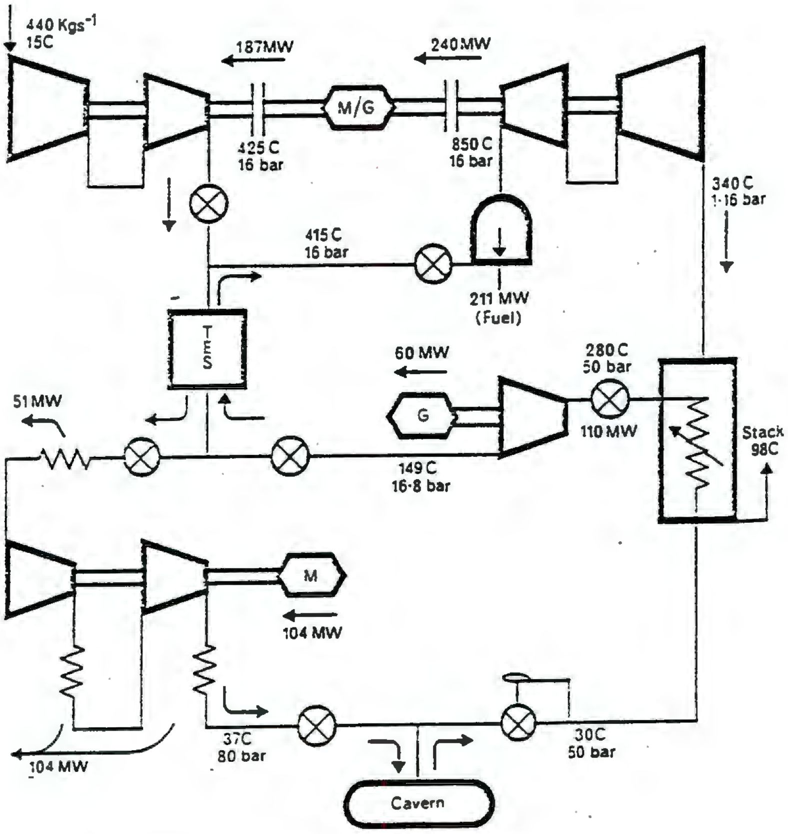


Figure 2.18: The A5 CAES/TES plant(4)

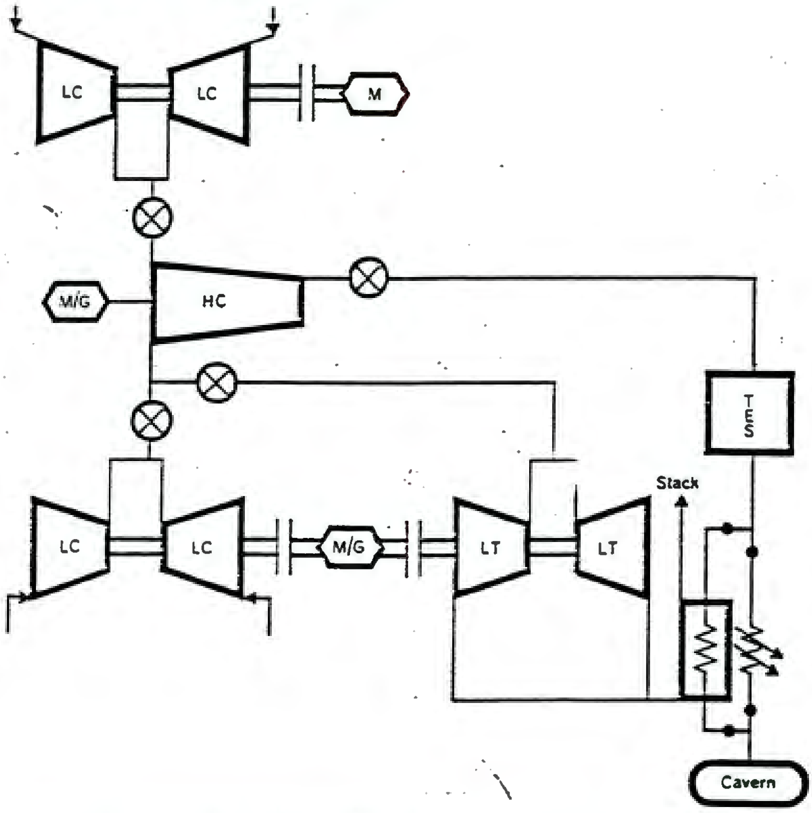


Figure 2.19: The A1 pure adiabatic CAES configuration(4)

2.4.3) Compressed Air Energy Storage with Steam Generation

CAES cycles with steam generation(7) are produced by the replacement of the recuperator in the LP exhaust gas path with a heat recovery steam generator (HRSG). The major motivation for looking at these cycles is as follows:

- Increased plant power output based on a developed or existing turbo-machinery train.
- Potential operation in a co-generation mode.
- Potential improvements in economics.
- Replacement of the recuperator and its potential operating problems.

The first configuration, using steam generation, allows HSRG and CAES to be combined in one layout resulting in CAES Combined Cycle Plant(7) (CAES/CC) (Figure 2.20). In the figure, additional energy is produced by generating steam in a multi-pressure HRSG that drives a condensing steam turbine set. The HRSG surface arrangement and pressure levels have been optimized to provide the most cost effective additional power production.

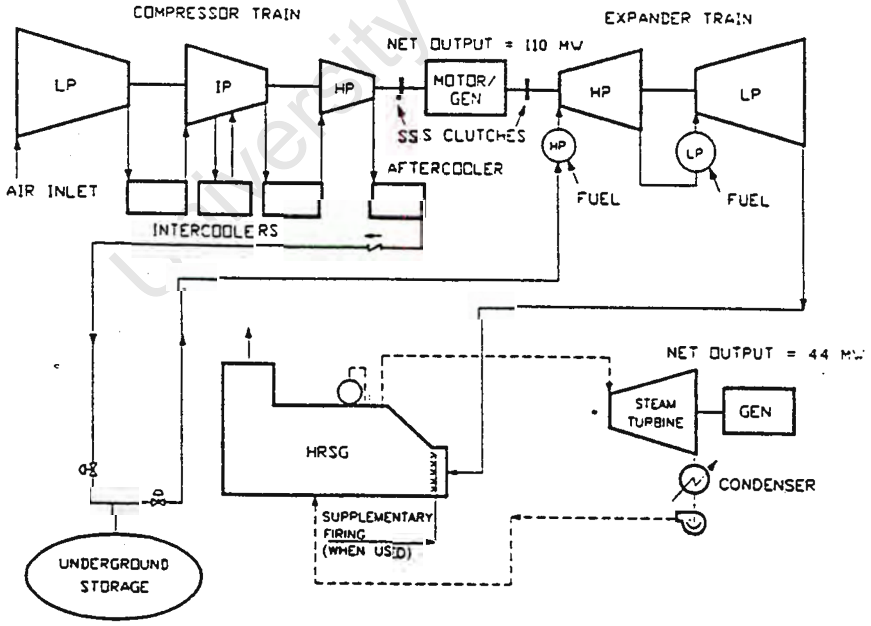


Figure 2.20: Schematic layout of CAES Combined Cycle Plant (CAESCC)(7)

The fuel heat rate of the CAES Combined Cycle plant at 5870 kJ/kWh is greater than that of a conventional plant. The charge energy factor is significantly higher at 1,79, due to the additional power produced with no increase in compressor energy requirements. The specific generating costs of CAESCC are essentially equal to conventional CAES, with specific capital costs R/kW of the plant being slightly greater if no supplemental firing is used. Potentially, capital costs could be decreased at higher firing levels.

The CAESCC plant is the preferred option for the utility with relatively low fuel costs, high off-peak power costs and high capital costs. The combined cycle option offers increased power production without CAES turbo-machinery modifications. It has flexibility in operation, including the potential to operate in a cogeneration mode. The environmental impact of the CAESCC is essentially the same as the conventional CAES plant.

The second method of steam usage in CAES allows steam generated in the HRSG to be injected directly into the HP and LP combustors, increasing the total mass flow and power output of the turbo-expanders(7). Figure 2.21 shows a CAES plant with steam injection (CAESSI). Air flow, the compression cycle and air storage requirements remain the same as in the conventional cycle. With a turbo-expander designed to accommodate the increased flow, power output can be increased.

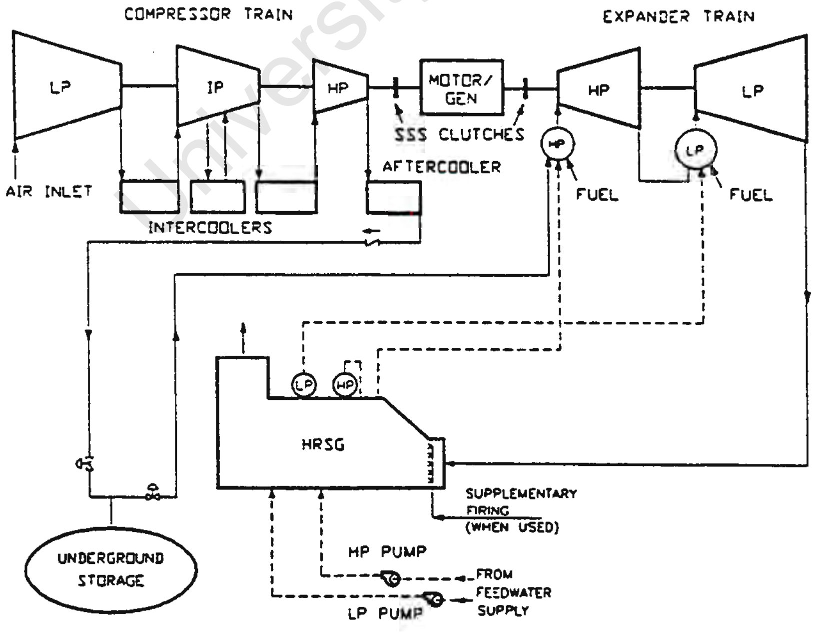


Figure 2.21: Schematic of a CAES Plant with Steam Injection (CAESSI)(7)

CAESSI, like the CAESCC, has a higher fuel heat rate and a higher charge energy factor than conventional CAES. CEASSI achieves a CEF = 1,79 and a FHR = 6410 kJ/kWh. The capital cost of CAESSI is potentially lower than that of CAESCC as it does not require the extra steam turbo-machinery that is required by CAESCC.

Like CAESCC, CAESSI is most beneficial to the utility with low fuel costs, high off-peak energy costs, and high capital costs. An added advantage of steam injection is the reduction of NOx emissions from the turbo-expander. Although not a major additional cost, the steam injection process requires larger amounts of make-up water and a water treatment plant.

2.4.4) Compressed Air Energy Storage and Fluidised Bed Combustors

Development in various countries has shown that the use of coal in pressurised fluidised bed combustors (PFBC) is an efficient method of generating alternative gas. This has reduced the dependence on natural gas and liquid fuels in CAES and promoted the use of coal and lignite as alternative fuels. The air stored underground is used as combustion air in a PFBC boiler to either generate "coal" gas or to indirectly heat the cavern air.

A CAES/PFBC power plant could produce competitive peak- and midrange electrical energy(13). CAES plants employing PFBC appear to have no equipment constraints that would prevent them from being responsive to utility load-following requirements.

Lehmann(14) has suggested two configurations, both with "critical areas" where development has been limited. The first configuration employs a high pressure fluidised bed combustor operating at 40 bar (Figure 2.22). This layout uses the PFBC to generate sufficient high pressure gases for the turbine. The PFBC is situated between the cavern and turbine with cavern air coming into direct contact with the combustion process resulting in a high pressure coal gas. This layout requires a filter to remove any particulate matter before the gas enters the turbine.

The second configuration uses the heating ability of a PFBC to heat cavern air indirectly up to operating temperatures (Figure 2.23). The PFBC incorporates a separate circuit, where air is heated in pipes separated from the main gas stream. This results in high temperature clean air that does not require filtration. The PFBC is self contained, so that the gas produced from the PFBC is used to drive a turbine compressor train that supplies air to the bed.

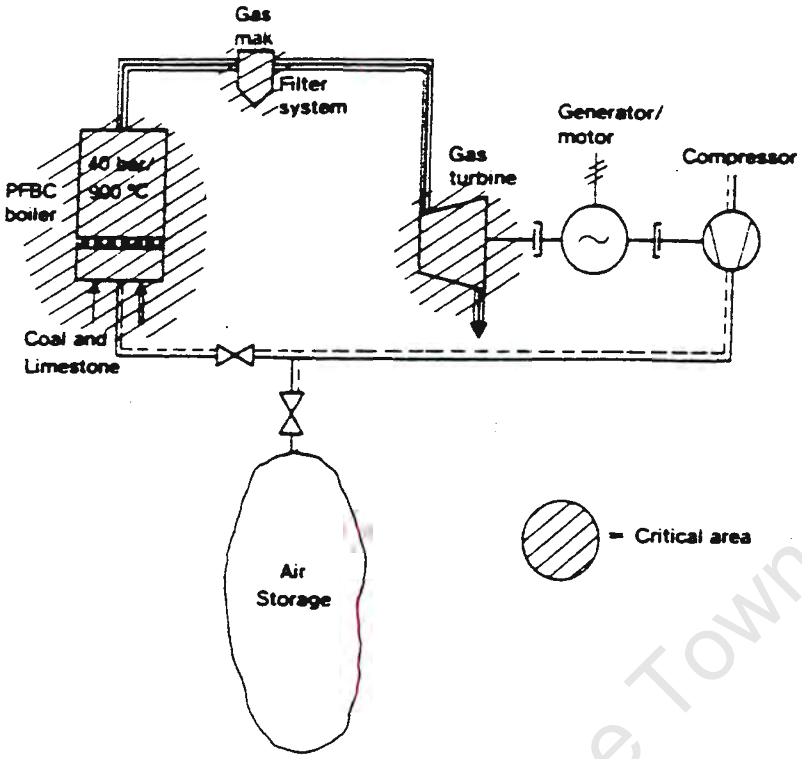


Figure 2.22: CAES with direct air heating with PFBC(14)

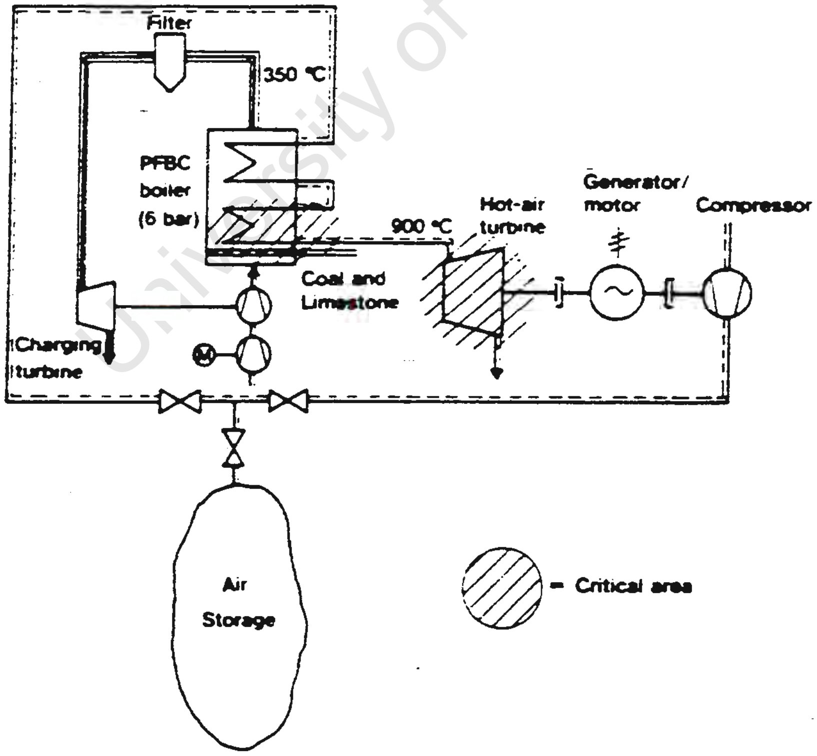


Figure 2.23: CAES with indirect air heating through PFBC(14)

Giramonti(13) has suggested a third configuration for PFBCs in CAES which is shown in Figure 2.24. This configuration employs the PFBC, at an intermediate pressure, between the high pressure and low pressure turbines. The operating conditions are the same as those expected for a conventional system with the recuperator supplying exhaust heat to the high pressure turbine. Giramonti has developed this into a 4 unit plant.

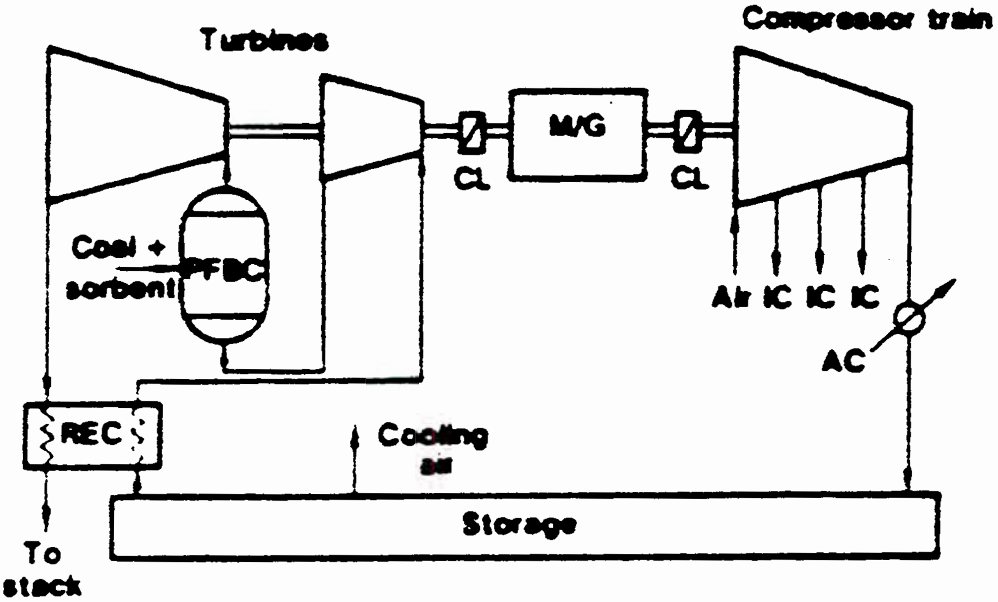


Figure 2.24: Giramonti's CAES with PFBC situated between turbo-expander stages(13)

This design incorporates the maximum utilisation of existing CAES components, including the use of a water compensated hard rock cavern. The design point operating characteristics of the 4 unit plant are summarized in Table 2.1. The turbine train is capable of producing 876,4 MW with a load factor of 25%. The full load performance characteristics are also given in Table 2.1.

Table 2.1: Performance characteristics of Giramonti's CAES/PFBC(13)

Power (4 units)	
Turbine	876,4 MW
Compressor	799,6 MW
Heat Rate	
Generation	4788 kJ/kWh
Compression	9595 kJ/kWh
Round Trip	14383 kJ/kWh
Storage Pressure	72,1 bar
PFBC bed	
Temperature	264,2 °C
Pressure	15,2 bar
Inlet Temperature	
High Pressure Turbine	264,2 °C
Low Pressure Turbine	850 °C
Annual Utilization	2190 h/y
Capacity load factor	25%

The fluidised bed combustor system encompasses the equipment for: coal and dolomite handling, coal and dolomite preparation, coal and dolomite feeding, fluid bed combustion and particulate cleanup, ash and spent dolomite removal, and controls and instrumentation. Separate mills are required to crush the coal and dolomite to the required top size necessary for feeding into the combustor. Coal and dolomite, in the correct ratio are fed in batches to a primary injector system. Fuel from the primary injector system is fed continuously to the combustor.

The fluidised bed combustor pressure vessel contains the bed and the 3-stage cyclone gas cleanup system. The coal-dolomite mixture is injected pneumatically through feed points immediately above the distribution plate. After combustion in the bed, the combustion gases and entrained particles enter the freeboard where most of the particles precipitate out of the gas stream. The remainder of the particles are removed in three high efficiency cyclones used for gas cleanup. Ash and spent dolomite are released through a bed level control system into a pneumatic conveying system. After cooling, the solids are discharged through pressure locks, then conveyed to storage.

During generation the air is heated in the recuperator and expanded through a two-stage turbine. After leaving the expansion turbine, the air travels to and from the PFBC via a co-axial inlet/outlet duct with the cooler, expansion turbine exhaust air on the outside and the hotter products of combustion on the inside. This hot gas is expanded through a four-stage, low pressure turbine which produces most of the output power.

The cost of Giramonti's(13) system was estimated at $458,9 million (1979 dollars) (R3118 million 1994) including all coal handling and processing. The PFBC system, with the coal handling and processing equipment is the most expensive item, accounting for about 43% of the total direct costs.

The performance characteristics of the CAES/PFBC power plant used for this design were based on steady state operation at full load design point. It is of the utmost importance however that the plant has load following abilities and that it can operate at part load. The CAES/PFBC power plant system would achieve part load operation by concurrently and proportionately varying the mass flow of both the air and coal to the PFBC to produce the varying thermal output. During part load operation the following will still be achieved:

- a constant bed temperature and, therefore, a constant low pressure turbine inlet temperature because the air and fuel flow remain proportional;
- a bed pressure that is directly proportional to the flow through the bed because the low pressure turbine nozzle area is fixed, resulting in choked flow;
- a constant superficial velocity in the bed over the entire load range because the flow rates are proportional to pressure and the bed temperature remains constant.

The combustion efficiency is expected to be at least 98,2% over the operational range of 25 to 100% load using the design bed temperature and fluidizing velocity(13). Thus combustion conditions do not represent a limitation to steady state partload operation.

Rapid load-following is an important aspect for an utility. If an utility uses a large percentage of baseload power from units with limited response capability, its remaining units must make up for this by having greater load following capability. Giramonti(13) has determined that CAES/PFBC systems could easily satisfy an utility load following requirement of 5 percent per minute. Using PFBC as an alternative combustion method does not place any constraints on the load following ability of a utility. For this reason the desirability of the system is increased, allowing for cheaper fuels to be used.

2.5) WHAT'S HAPPENING AROUND THE WORLD TODAY?

Compressed Air Energy Storage has made an impression on the electricity industry ever since the installation of the conventional CAES plant at Huntorf, Germany in the late 1970's. This section summarizes the work done in various countries and utilities throughout the world. It also covers proposed, implemented and abandoned projects as well as several feasibility studies into various aspects of CAES.

2.5.1) Luxembourg(14)

The idea behind an air storage scheme in Luxembourg was to combine it with the 1100 MW pumped hydro storage scheme in Vianden, where the upper reservoir would act as a pressure compensating system for the air storage. Feasibility studies for a 285 MW CAES plant have been conducted by the Société Electrique de L'Our (SEO). It is not known what state this scheme has reached.

2.5.2) Yugoslavia(14)

Preliminary ideas for a constant pressure storage system were considered, as only hard rock formations are found in Yugoslavia. The plant would make use of 2 by 130 MW turbine systems using recuperative heat exchanger technology. No further information has been found on this project.

2.5.3) Sweden(14)

It has been reported that authorization has been granted for the construction of a pilot plant. The plant will have a generating capacity of 250 MW and will run on a 1:1 charge ratio. The turbo-machinery train will be constructed so that direct gas turbine operation may take place. No further information has been found on this project.

2.5.4) France(14)

Electricite de France (EDF) has been considering a CAES plant in the Bretagne. The plant would run on a constant pressure system, as good hard rock is found in this area. The project being considered is the construction of a 250-300 MW plant operating for 5-6 hours daily. As in Sweden this plant would be able to run in direct gas turbine mode. No further information has been found on this scheme.

2.5.5) Ukraine(2,15)

A 1050 MW plant was under construction in the Donbass region in the Ukraine under Soviet rule, consisting of 3 by 350 MW units. Due the political situation in the area and the fall of the Soviet regime in the early 90's, it is not known whether this plant will be completed. No further information is available on this plant.

2.5.6) Israel(2,15,16)

For some time the Israel Electric Corporation has been carrying out research on CAES with particular interest in a 300 MW (3 by 100 MW) aquifer type plant. Recent developments have shown that aquifer storage is not as effective as the other methods available.

2.5.7) Japan(16)

Very little information is available on this project, but reports indicate that the project is scheduled to go on line with a 35 MW six hour unit in April 1997.

2.5.8) Tennessee Valley Authority (TVA) - USA(16)

Tennesee Valley Authority (TVA) is considering a 600-1200 MW storage plant. The utility has already spent approximately $1 million on geotechnical studies and has already selected a site in a depleted natural gas field. Core samples were taken in December 1991. If the project proves feasible it is planned to have the first unit running by 1996.

2.5.9) Soyland Power Cooperative - USA(17)

Several studies were conducted on various methods of air storage in the late 1970's. It was just before the completion of these studies that the Soyland Power Cooperative of Decataur, Illinois, committed itself to building the first CAES plant in the United States. A decision was taken to construct a 220 MW CAES plant using a hardrock cavern with a compensating surface water reservoir creating a constant pressure storage system. The plant was to be sited at the Batelle Pacific Northwest

Laboratories using Boveri-Brown electrical equipment. It was determined that a saving of $34 million (1981) could be achieved within the first 16 years of operation. Due to lack of Federal support the project was abandoned.

2.5.10) Technical Research Centre of Finland (VTT)(18)

An economic and technical feasibility study conducted by the Technical Research Centre of Finland (VTT) suggested that the Pyhäsalmi zinc mine in Finland as a compressed air storage cavern should be considered(18).

The mine is situated at Pyhäsalmi in the middle of Finland and is owned by Outokumpu Finnmines Limited. Since its opening in 1962, the mine has yielded approximately 1,4 million tons of ore per year and according to recent calculations of the ore reserve the mine will close in the year 2000. Currently the volume of ore excavated is approximately 1 million cubic meters with the mine reaching a depth of 800 m.

The CAES plant, to be situated above the mine, would be used on a load management basis to cut peak loads and to regulate energy on the electrical network of Revon Säkhö, which is an electrical company owned by 20 Finnish communities. The utility's electricity production is based on its own hydropower plants and partnerships in various fossil and nuclear baseload and intermediate load plants. The consumption of electricity is approximately 600 GWh a year and the maximum demand based on a 3 hour average is 125 MW, with a maximum variation during a day of 30 MW. The utility also buys electricity from the state network when required.

The utility's electricity tariff has three parts with differing prices of energy (base, middle and peak load). The price effect on each part of the tariff is based on negotiated contracts. Prices vary between winter and summer as well as between night and day.

From the study it has been estimated that the lowest parts of the access tunnels are the most applicable spaces to be converted into compressed air storage reservoirs. The other alternative available is to create a new storage cavern where the shafts and tunnels of the mine could serve as access for transport and services. The two different storage volumes were analysed by the researchers with and without a pressurised water curtain system, thereby creating four alternatives. Later these four cases were studied as an uncompensated, constant volume storage and as a compensated constant pressure system.

A water curtain is a method whereby water pressure is maintained around a storage cavern by means of boreholes sunk into the surrounding rock. These boreholes supply water to the rock, minimizing air leakage from the cavern (Figure 2.25).

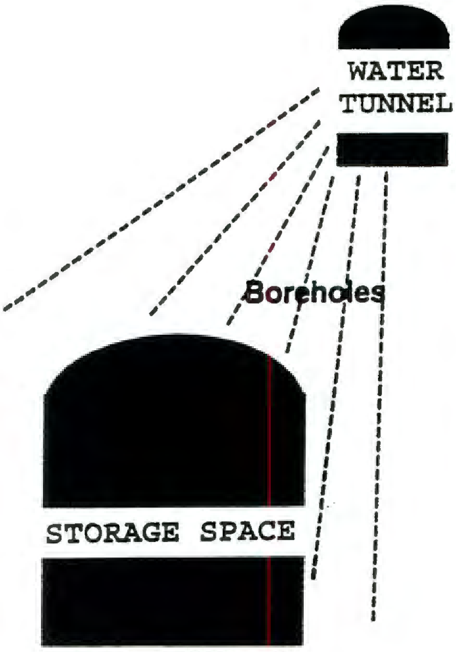


Figure 2.25: The principle of a water curtain system(18)

Costs of construction and conversion (Table 2.2 and Table 2.3) were estimated for: 1) a newly excavated storage space in the neighbourhood of the existing mine with access leading from the mine, and 2) the isolation and conversion of an access tunnel. These costs were adapted from 1994 Finnish Marks (FIM) to 1994 South African Rands.

Table 2.2: Estimated construction/conversion costs of uncompensated, constant volume storage - Cost in million Rands (1994)

VOLUME	CONVERTED SPACE	NEW SPACE
30 000m^3 + watercurtain	14,59 (R486/m^3) 18,52 (R617/m^3)	9,55 (R318/m^3) 13,42 (R447/m^3)
100 000m^3 + watercurtain	24,07 (R241/m^3) 29,5 (R295/m^3)	15,23 (R152/m^3) 20,39 (R204/m^3)

Table 2.3: Estimated construction/conversion costs of compensated, constant pressure storage - Cost in million Rands (1994)

VOLUME	CONVERTED SPACE	NEW SPACE
30 000m^3	17,04 (R568/m^3)	10,97 (R366/m^3)
+ watercurtain	23,04 (R768/m^3)	14,97 (R499/m^3)
100 000m^3	26,27 (R263/m^3)	15,94 (R160/m^3)
+ watercurtain	30,14 (R301/m^3)	19,81 (R198/m^3)

It was found that, from a technical and economical point of view, a new storage space excavated in hard and tight rock far from the mine openings was more economical than converting existing excavations and access tunnels. In addition it was found that a storage cavern would have to be situated at a depth of more than 400 m to maximise the compressed air pressure and to avoid weak rocks in the surface layer, as well as avoiding stability problems occurring in old mine openings.

The estimated price of the compressed air storage system varies from 15 to 50 million FIM (R9 - 32 million 1994) depending on the volume and type of storage. The price of excavating a new space is approximately 30 per cent less than that of storage formed from existing mine cavities(18). Conversion costs are high due to the high quantity of expensive concrete and concrete plugs necessary for isolation and injection.

It was found by the VTT researchers that an optimisation of the CAES plant also requires optimisation of the electricity supply system with specific reference to commercial tariffs and pumped-storage. With short time regulation of power generation it was found that the water resource (hydropower) consumption was decreased by the use of the CAES plant.

The first plant considered in the VTT study had a basic capacity of 210 MWh with a cavern size of 30 000 m^3. For this plant the turbine output was estimated at 34 MW and the input into the compressor at 25 MW. The combustion chamber would be fired with a light oil. The alternative to the above was a 150 MWh unit with a cavern volume of 20 000 m^3 and a turbine generating 41 MW. This option was found to be more economical than the smaller proposal. It was found that a higher peak load could be reduced with the higher power capacity, but a shorter operating period would have had to be maintained.

The VTT study considered CAES operation for the years 1998, 2003 and 2008. In the simulation for 2008 the CAES was used only in winter while the winter tariff prevailed. The water storage would be filled during spring and discharged over the period starting in December.

The revenue from the CAES plant increased as a function of time. The annual revenue was 5,0 to 5,5 million FIM (R3,2 - 3,5 million 1994) in the best year (2008), resulting in a repayment of the investment of 100 million FIM in 20 years at a interest rate of zero percent. Halving the price of fuel in the CAES gas turbine doubled the revenue, and estimated payback time is approximately 16 years at 5% interest. An additional case considered was Revon Säkhö with no hydropower plants.

Table 2.4: Annual revenues when using CAES with an optimised commercial tariff(18) (1994 Rands)

MWh/m^3	MW	1998 Million Rands	2003 Million Rands	2008 Million Rands
210/30 000	34,0	2,0	2,9	3,3
210/30 000	40,8	2,0	2,8	3,6
150/20 000	40,8	-	-	3,5
½ **Fuel Price** 210/30 000	40,8	-	-	6

It was found that the investment costs were too high for the Finnish electricity tariff system and it was determined that the CAES plant could be simplified by using existing commercially manufactured components. It was also suggested that the plant be operated as a normal gas turbine plant for regulation on the grid. The use of natural gas was also suggested as this is a cleaner and cheaper fuel than oil.

It was determined that almost all the available water power resources had been utilised in Finland allowing CAES to be a good source of power in the future, when the relative contribution by hydropower to total energy supply would have decreased. Due to the predicted increase in peak demands it will become necessary to increase the capacity of the regulating supply.

The next step in the VTT research was to include a process simulation model of the CAES plant as well as undertaking a study of rock properties including pressuring tests on boreholes, mechanical and thermal simulation and laboratory tests on rock mass under cyclical pressure and temperature load conditions.

The last step before the complete project was to be initialised was to be a pilot project using a test capacity on the scale of 1:10. A proposal put forward by the VTT involved the isolation of one of the mine's tunnels into a storage cavern of 3000 m^3.

2.5.11) Sesta - Italy(2,12,15,16,17)

A pilot CAES plant has been running in Sesta, Italy since 1987. The plant is small, generating only 25 MW and uses an aquifer storage system situated in porous rock. In December 1991 the project came to an end and the plant was taken out of operation. No further information is available on this project.

2.5.12) Nordwestdeutsch Kraftwerke - Germany (NWK)(1,2,11,19)

The NWK was the first electricity utility to introduce compressed air energy storage into its network. The Huntorf plant(1,11) was designed and engineered by Boveri-Brown & Sultzer becoming the prototype for all CAES projects to follow. This plant came into operation in December 1978 generating up to 290 MW. It has a charging ratio of 1:4, running on a daily cycle consisting of storing air for 8 hours and generating electricity for a maximum of 2 hours.

The plant is situated above a salt-dome in which two caverns were solution mined. Each cavern is situated between 650 and 800 m underground with a combined volume of approximately 300 000m^3. Air is stored at a pressure of between 50 to 70 bar. A pressure drop below this could result in the cavern collapsing.

Electricity is used during off peak hours to operate the 60 MW motor section of the motor-generator. This in turn produces shaft power through two clutches situated on either side of the motor-generator. In this state the compressor clutch is coupled while the turbine clutch remains open. The coupled clutch connects the compressor train consisting of several stages, the first being a low pressure compressor that rotates at 3000 rpm to increase the pressure of the incoming ambient air at a ratio of 5,5:1. After this compressor the rotational shaft speed is stepped up, via a 45 MW gear box, to 7626 rpm, allowing for the use of a high pressure compressor that delivers air to the cavern at between 50-70 bar, thus creating a pressure step-up ratio of approximately 68:1 from ambient. Both these compressors are off-the-shelf industrial designs with the low pressure compressor being of axial design and the high pressure compressor consisting of six radial stages(1). With such a high outlet pressure it was found that the outlet temperature would approach 820° C and the specific work input some 865 kJ/kg, all of which would have to be dissipated in the aftercooler(1). Making use of several intercoolers the Huntorf designers have achieved operating conditions such that no gas temperature exceeds 230° C. In addition to this the specific work has been reduced to 550 kJ/kg resulting in a saving of 37%(1). Huntorf makes use of three inter-coolers and one after-cooler (Figure 2.26).

After the required pressure in the cavern has been achieved, the cavern is closed off by a valve. Once the demand for electricity peaks, air is released via a pipeline and valve and fed into the turbine train. At this stage, the clutch couplings have been reversed and the compressor clutch is uncoupled while the turbine clutch reconnects the turbine. The Huntorf plant makes use of two turbines, the first being a high pressure turbine running at an inlet temperature of 550° C and pressure of 43 bar and the second being a low pressure turbine with an inlet temperature of 825° C and a pressure of 11 bar(1). The choice of these temperatures was decided upon by Boveri-Brown, the designers of the plant, for practical reasons, making use of standard off-the-shelf equipment. The low pressure turbine with combustion chamber is a standard industrial gas turbine with a pressure drop of 11:1 while the high pressure turbine makes use of an inlet pressure of 43 bar which has been chosen in conjunction with the minimum cavern pressure. This turbine is a small intermediate pressure steam turbine. The turbines use natural gas that is stored in the same saltdome but in separate caverns.

Construction was started on the site in May 1975, with equipment installation taking place from July 1976 to Sept 1977. Due to several commissioning delays resulting in several equipment rebuilds, the plant was finally commissioned in December 1978.

Huntorf has an impressive track record with an availability of 90% and a reliability of 99%(2,19). The plant has also achieved a Charge Energy Factor (CEF) of 1,2 and a Fuel Heat Rate (FHR) of 5800 kJ/kWh(1). The plant is cheaper to run than a conventional gas turbine plant, and in 1978 the full project cost of DM110 million (1978 DM) was less than the equivalent gas turbines cost(1). This cost, is equivalent to R 400 million (1994 Rands), or approximately R1380 /kW.

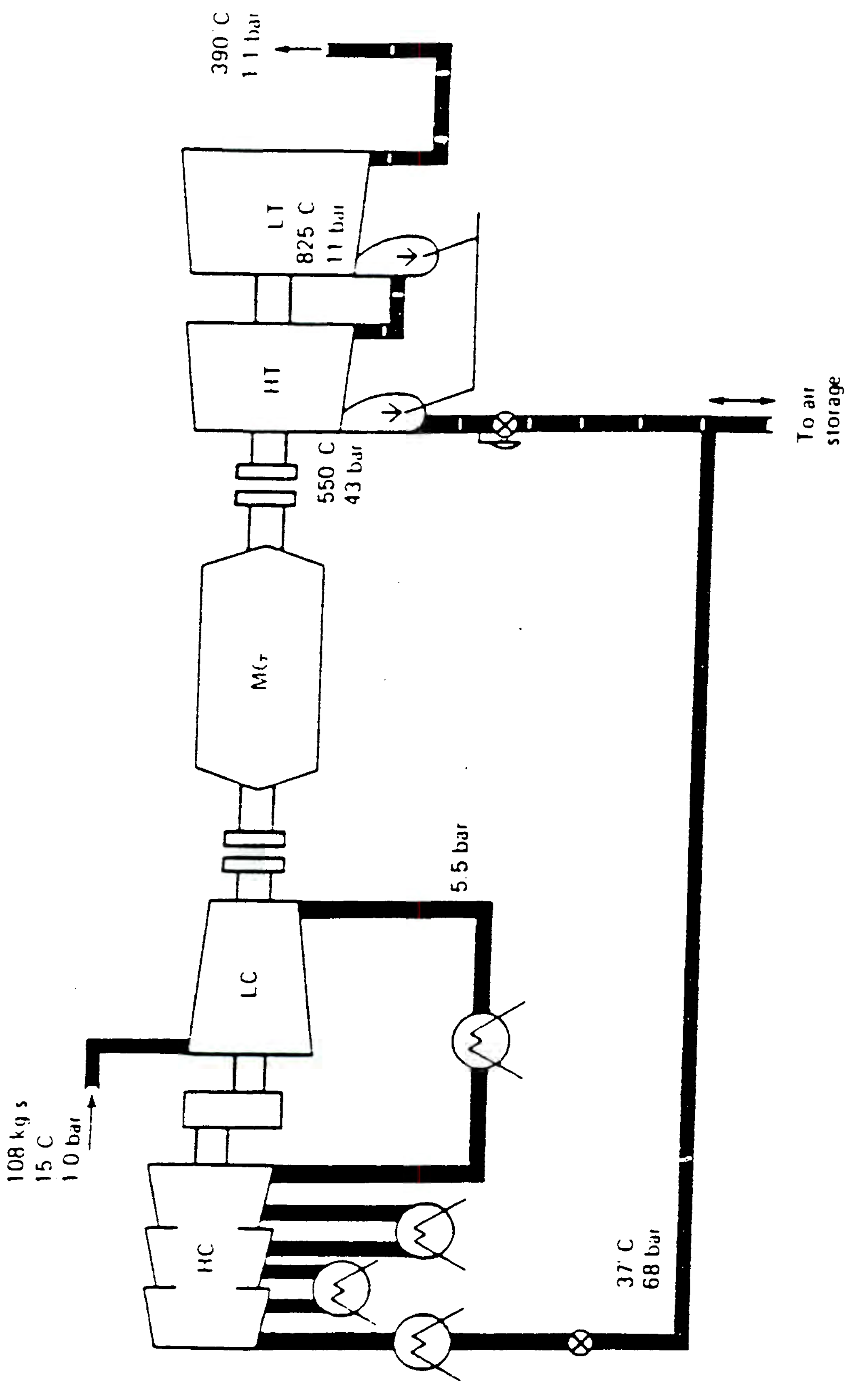


Figure 2.26: Schematic layout of the 290 MW CAES plant at Huntorf Germany(1)

2.5.13) Alabama Electric Cooperative - United States(6,9,16,19,20)

In May 1991 the first compressed air energy storage plant in the United States came into operation, 13 years after Huntorf was officially opened. Although not being first in the field of CAES, the Alabama plant situated near McIntosh, is the first CAES plant to make use of recuperator technology, resulting in a 25% more fuel efficient plant(16,19). The plant went into continuous operation on 31 May 1991 and became one of the six winners of POWER magazine's 1992 Powerplant Award(6).

Alabama Electric Cooperative (AEC) was faced with a load growth of between 3 to 5 percent over 10 years from the mid 1980s(19). It was found, after a feasibility study by AEC, that CAES could increase the load factor on AEC's coalfired baseload Loman Powerplant (600 MW). The most technical and economical solution to achieve this was to develop a 200 MW CAES plant to operate on a weekly cycle, with phased construction of 4 by 50 MW units from 1989 to 1993(19). Storage time of 26 hours was determined from the load curve shape, with weekly charge and discharge cycles, with charging taking place largely over weekends due to cheaper electricity available.

Four powerplant firms submitted bids on a turnkey basis using turbo-machinery from ABB and Dresser Rand. After receiving these bids it was found that the four 50 MW units were less attractive than a more recent proposed 110 MW unit, and on a cost per kilowatt basis it was found that the 110 MW unit was more viable(19). The plant is situated on approximately 16 ha of ground which allows for a possible second 110 MW unit. In 1988 the contract was awarded, as a joint venture, to Gibbs & Hill and Harbert International, utilising Dresser Rand turbo-machinery and controllers. Fenis & Scisson solution mined the cavern and owner's engineer on the project was Burns & McDonnell Engineering Co. of Kansas City.

The plant was built over a period of 2 years and 9 months. AEC never expected to be the first to implement CAES in the USA, it was just coincidence that the cost was more favourable in comparison to the two other options being considered at the time, namely simple-cycle combustion turbines and combined-cycle fossil plants(16). The Alabama plant represents about 14% of AEC's generating capacity and the utility had planned to run the plant for approximately 1700 hours per year(16).

The total cost of the contract was \$65 million (1988 dollars)(R281,5 million - 1994 Rands) (R2560/kW). This was partially funded by the Electric Power Research Institute (EPRI) (\$8 million) and the National Rural Electric Cooperative Association (\$660 000)(6) (1988 dollars).

Similar in design to the Huntorf plant, the Alabama plant is situated on a salt-dome with a solution mined cavern of approximately 0,53 million m^3, situated at a depth of between 450 m and 760 m. The cavern walls can withstand pressures of about 138 bar which is almost twice the operating pressure. The choice of a salt cavern was based on the geological situation in Alabama, as suitable geological formations can be found in approximately 75% of the United States. The cavern was solution mined with water, creating brine. This was then discharged via pipeline to the nearby Olin chemical plant, which owns the mineral rights to the entire saltdome, and makes use of the brine in their chemical processes. A weak brine solution with a quantity of diesel fuel is returned to the cavern. As the mixture is pumped in, the diesel separates from the water and rises to the top. This forms a seal at the roof of the cavern preventing air loss(9). Once this is done the brine is once again pumped out of the cavern leaving an air tight volume.

The cavern volume allows 26 consecutive hours of generation at 100 MW net(6). A second cavern is to be mined once the demand has risen, allowing a second unit to be installed. The compression cycle of the Alabama plant has a ratio of 1,7 hours of pumping for every hour of generation(19), where the Huntorf plant needs 4 hours of compression for a single hour of generation. The plant is run on a weekly basis, with intermediate charging taking place on a daily basis and complete recharging over weekends.

The Alabama plant is the first CAES plant in the world to make use of a recuperator, allowing exhaust gas leaving the turbines to preheat the air from the cavern before it enters the combustors (Figure 2.27). Preheating increases the air temperature leaving the cavern to 290°C to 340°C, depending on the load on the system(19). After the air has left the recuperator it flows through a combustor and is expanded in the high pressure turbine, then the gas is reheated in the low pressure combustor and expanded in the low pressure turbine. The exhaust gases are directed through the recuperator and released to the atmosphere at temperatures between 125°C and 145°C. The recuperator reduces fuel consumption by approximately 25%(6,16,19).

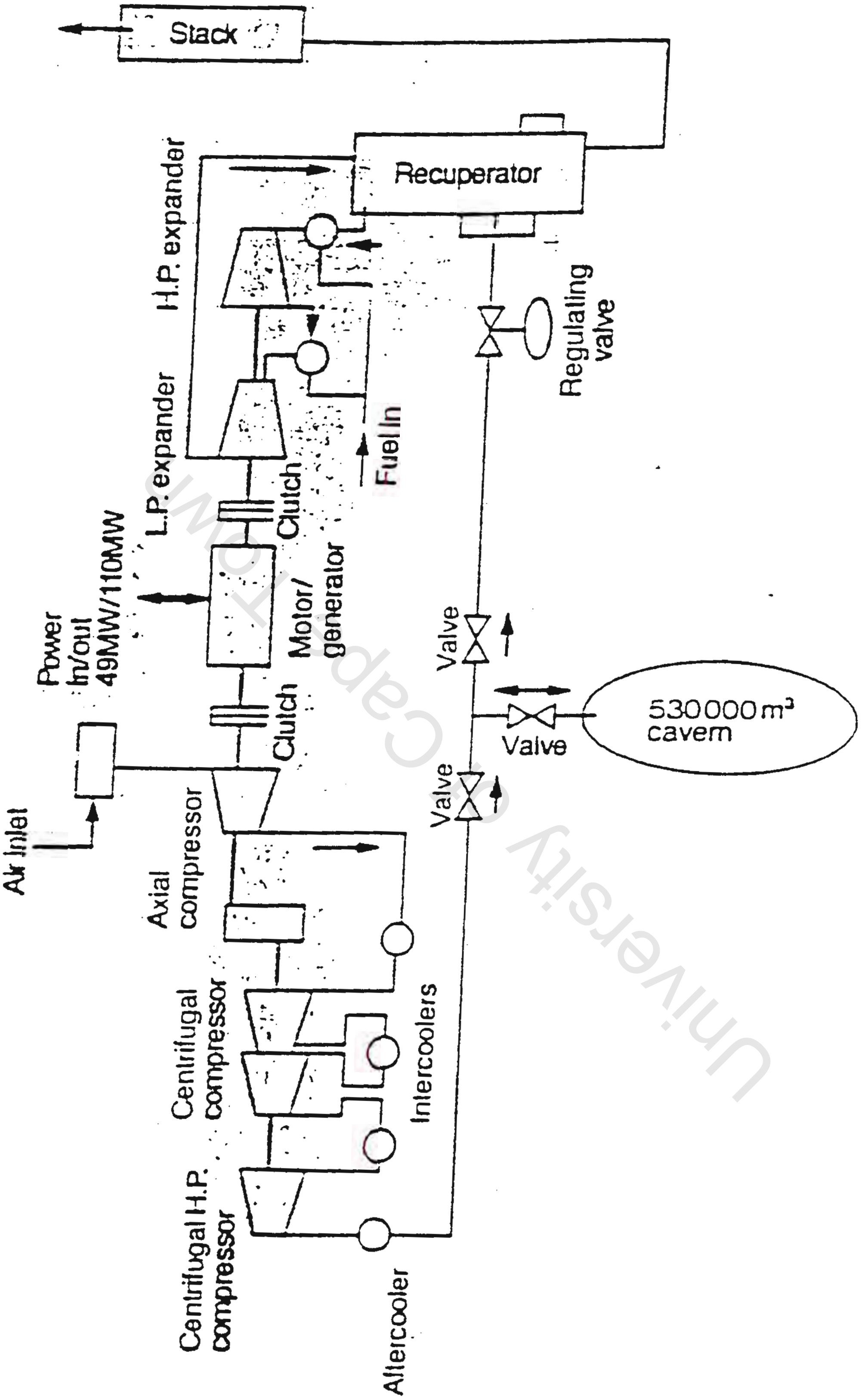


Figure 2.27: Schematic layout of AEC's 110 MW CAES plant in Alabama, USA(19)

The recuperator was designed by EPRI and Energy Storage and Power Consultants Inc., with care being taken to minimize cycling fatigue and corrosion. Corrosion of the recuperator's carbon steel tubes is a major concern when oil is fired(6). The tubes are arranged and the air flow directed in such a manner that the tube temperature always remains above the dewpoint of sulphuric acid. A co-current section separates two counter-current sections (Figure 2.28). Cold air from the cavern enters the recuperator's co-current section and is heated by hot exhaust gases at a temperature that results in an outside tube metal temperature being maintained above the dewpoint. A further precaution against corrosion was to equip the exhaust stack with a damper that is closed whenever the plant is shut down.

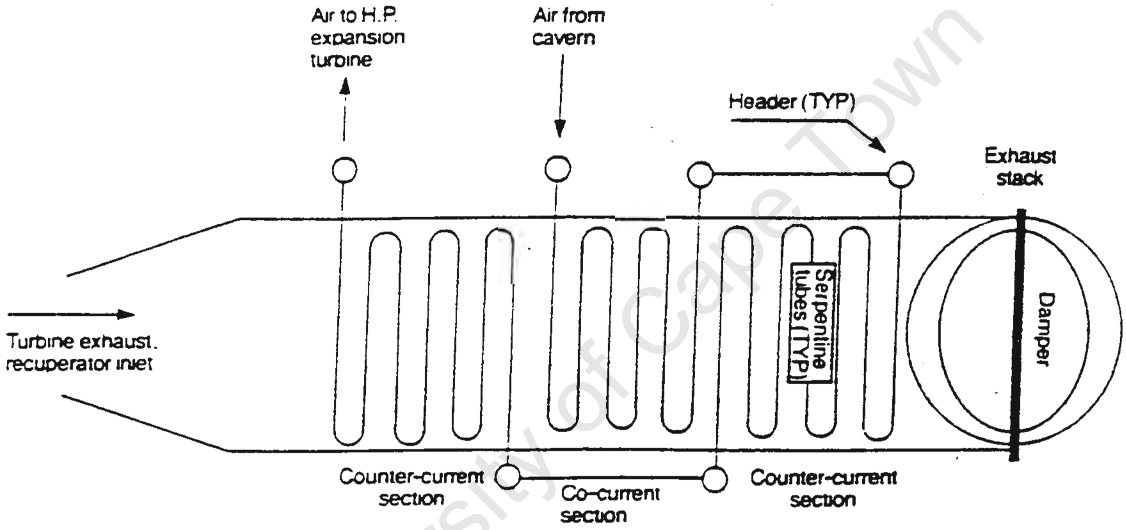


Figure 2.28: Schematic diagram of the CAES recuperator(19)

The compressor train requires a minimum of 30 MW and a maximum of 55 MW to compress the more than 2800 MWh of energy, that can be stored for later use(20). The first compressor in the train is a low pressure axial compressor run at 3600 rpm. A step-up gearbox allows the rest of the stages to turn at 6024 rpm. The second compressor in the train is an intermediate pressure compound centrifugal compressor and the last compressor is a high pressure barrel compressor. There are 3 intercoolers in the train, placed between compressor stages (after the axial compressor, between the first and second stages of the compound centrifugal compressors, and between the intermediate pressure and the high pressure compressors). Lastly, before the air is compressed into the cavern, there is an aftercooler that cools the air down to 43° C.

When the electricity demand rises to such an extent that the plant needs to be employed, air is released from the cavern through a pressure regulator, through the recuperator to the high pressure combustor. Air enters the recuperator at approximately 35° C to be released at between 290° C and 340° C. The high pressure combustor elevates the temperature of this gas to 540° C before it is released into the expander. After this stage the gas is reheated in a low pressure combustor and enters the low pressure expander at 870° C. The high pressure expander generates 23 MW while the low pressure expander generates 87 MW. From the low pressure expander the gas is directed through the recuperator and to the atmosphere. The complete unit generates 110 MW while operating on natural gas with a fuel heat rate of 4820 kJ/kWh, and a charge energy factor of 1,22(6).

The switch over between charging and generating from a 55 MW load on the motor to a 110 MW generating mode takes between 30 and 40 minutes. Once the storage cavern is completely charged the CAES unit may be brought from cold standby to fully loaded (110 MW) within 10 minutes for an emergency and 12 minutes under normal starting conditions(20). This allows AEC the capability of covering sudden generation losses. By comparison, gas turbines take between 20 and 30 minutes for normal start-up. CAES has black starting capability that allows it to be brought on line with no additional external electricity source. Once the unit is running, it can provide power to nearby generating plants for start-up.

When AEC first investigated the potential for CAES in 1977 the only system on the market was the one supplied by Boveri-Brown which was too large and costly for AEC's needs. EPRI carried out several technical and economic feasibility studies and found several utilities interested in CAES but none interested in such a large unit. Schainker(16), energy storage program manager for EPRI, discovered that all the components necessary for a smaller unit were available off-the-shelf, due to their use in various other industries.

The turbo-machinery train at the Alabama plant is 38 m long and is separated into three equipment modules; motor-generator, the compressor train and the generation train. Alignment of the train could have proved difficult, resulting in some excessive vibration occurring between clutch and generator, but was solved with conventional balancing methods (Figure 2.29).

The compressor train consists of three compressors(19). The first being a Model MGA4015 axial compressor which operates at 3600 rpm. This compressor incorporates 15 stages of axial blading in a horizontally split cast iron case. The first seven stages of stator blading as well as the guide vanes are continuously variable by means of a pneumatic actuator. The second compressor in the train is a Model 4M7-5 compound centrifugal compressor that operates at 6024 rpm, which is achieved by using a speed increasing gear box. This compressor is a horizontally split compound type with two stages of compression achieved through the use of compound inlet and discharge nozzles. Two impellers are located in the first stage and three in the second. Between stages the air is cooled via a water-to-air intercooler. The last compressor in the train is a Model 553B7 barrel type centrifugal compressor. This compressor operates at the same speed as the intermediate compressor to which it is linked via a shaft. This compressor utilizes a vertically split type casing with tilt pad thrust and journal bearings. It has seven welded stainless steel radial impellers on an integral stainless steel shaft. The compressor train is separated from the motor/generator by means of a clutch, and the motor/generator is rated at 131 MVA.

The power section of the turbo-machinery train consists of two expanders(19). The first expander is a high pressure turbine utilising steam turbine technology (Figure 2.30), similar to that of the Huntorf plant. This expander is actually a back pressure steam turbine with six impulse stages. The design incorporates a cast low alloy steel horizontally split casing with tilting pad thrust, journal bearings and standard steam turbine bearing cases. The rotor consists of a solid low alloy forging (ASTM A470) with integral turbine discs and 400 series stainless steel turbine buckets. The interstage and end gland labyrinth seal stationary points are made of Type 3 Ni-Resist ductile iron. The impulse design of the high pressure expander allows the flow path to be reasonably insensitive to clearance variations(19). For this reason blade tip seals are unnecessary and there is ample clearance between moving and static parts. This is particularly important for CAES plants that are continuously cycling.

EPRI, in conjunction with the Turbodyne Division of Dresser-Rand(19) on a cost sharing basis, developed a low-pressure single flow expander specifically for CAES, resulting in a more efficient expander at higher rating than the double flow hot-gas expanders available at the time (Figure 2.31).

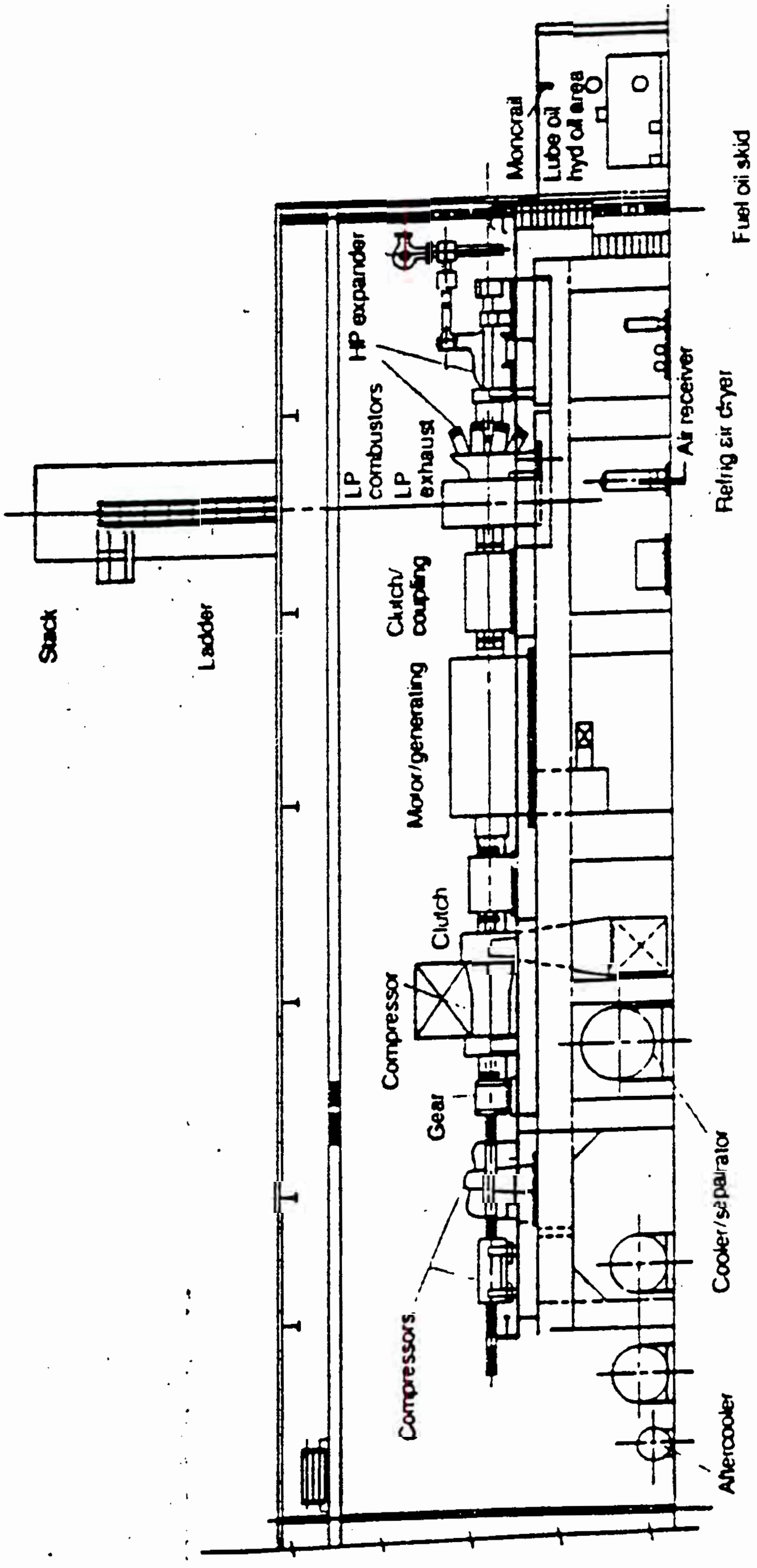


Figure 2.29: The CAES power train(1.9)

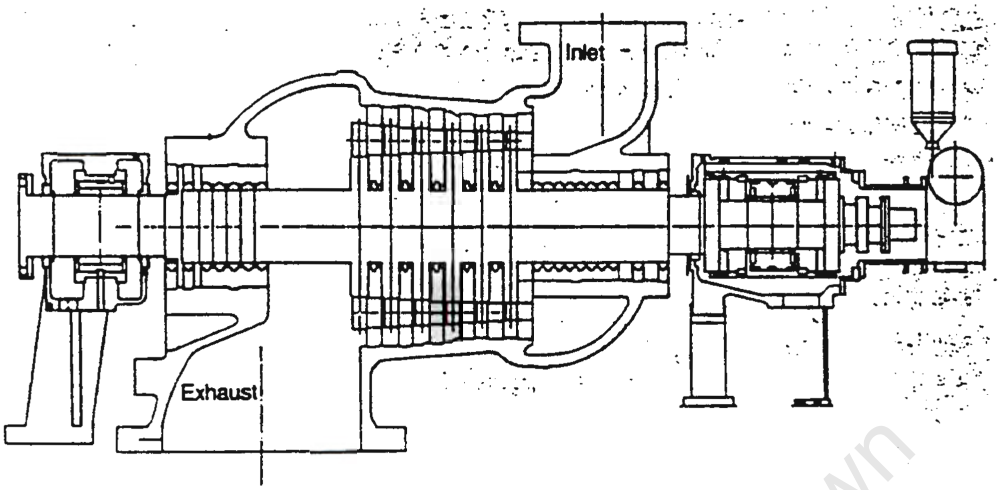


Figure 2.30: The Dresser-Rand high pressure expander(19)

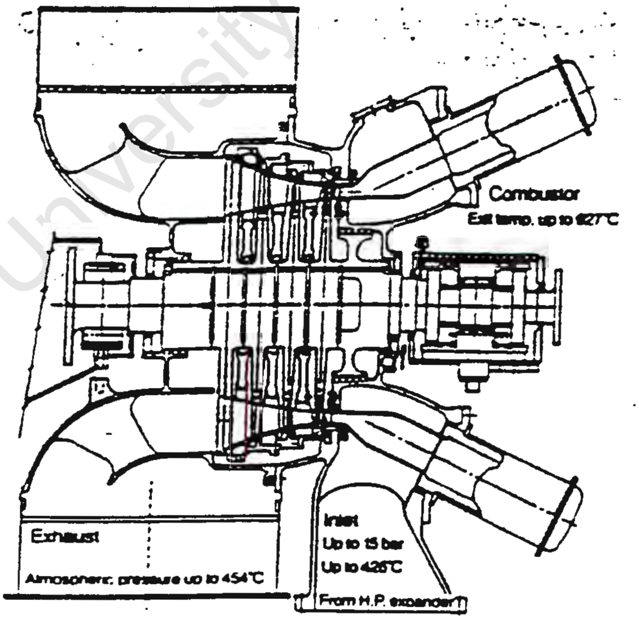


Figure 2.31: The low pressure expander(19)

The high pressure and low pressure combustors were designed, tested and manufactured by Lucas Aerospace(19). The high pressure expander is equipped with two vertical casings which are 0,48 m in diameter and 1,07 m long. Gas enters the low pressure expander at the bottom centre of the inlet casing and is distributed to eight combustors, 0,43 m in diameter, and of the same length of those of the high-pressure expander. Each combustor contains sheet metal combustion, dilution and cooling of the outer casing. Here, the gases pass through an annular space formed by the combustor casing and the combustor liner. The hot combustion gas then flows through transition ducts towards the expander casing. The fuel nozzle assembly is equipped for dual fuel operation on natural gas and No.2 fuel distillate(19).

The plant has not been without teething problems, resulting in several hours down-time. The first occurred in August 1991, when the two metal linings inside the plant's two high pressure combustors cracked(6). This occurred after some 850 starts. Failures were attributed to low cycle fatigue stress near the ring of holes that admits the combustion and cooling air. Shortly after the incident, redesigned test liners were installed and have been examined on a frequent basis. These were to be replaced by permanent linings at a later stage. The fuel injectors have exhibited some failures of brazed joints due to the manufacturing process(6). This allowed leakage to occur between the concentric fluid passageways - these separately handle water for NO_X injection, oil, fuel gas, and air allowing oil to enter the natural-gas passageway. When the oil "cokes," the gas passageway is obstructed and gas flow is reduced. A new design has already been implemented on several of the nozzles using more electron-beam welding and less brazing.

Plant engineers have been studying condensation in the intercoolers, to prevent higher-than-desirable concentration of moisture droplets impacting on the first stage of the high pressure compressor. Compression heat is rejected through a conventional cooling tower.

Additional concerns were thermal stresses that developed in the high pressure combustor. These stresses have been overcome by supplying a standby combustor(6), which lights up when either expander's temperature drops below 260° C, returning the temperature to 370° C.

The Digital Control System (DCS) has been debugged in the process to curb unnecessary problems. Operators have concluded that there are over 270 possible conditions which could trip the unit(6). The 16-inch ball valve that regulates cavern air pressure is mentioned as particularly problematic. This is not surprising as this valve regularly has to operate down to 4-6% of its full-load duty.

EPRI has provided engineering support throughout the project by gathering and analysing information(16). The Institute is working on additional methods of improving CAES, one possibility being the inclusion of a humidifier. The humidifier will use both waste heat and water to increase the energy content of the mass flowing through the turbine, providing additional power without requiring an increase in unit size. EPRI is also investigating the use of high-temperature turbine technology that would lead to a reduction of nitrogen-oxide emissions.

Operating the plant for significant periods below full load results in a decreased efficiency and excessive fuel usage. Below 50 MW, for example, the fuel heat rate and charge energy factor deviate from the optimum. At 110 MW, the figures are FHR = 4820 kJ/kWh and CEF = 1,22 respectively, whereas at 25 MW these figures become 5542 kJ/kWh and 0,75(6). Even at 25% load, the fuel heat rate of the Alabama plant is much better than that of most utility generating plants(6).

By employing CAES as an energy management tool on their electricity network, AEC system controllers can shed up to as much as 55 MW of load by simply dropping the unit's motoring supply(20). This becomes particularly useful when other generating units have forced outages. During summer months the plant is used to supply capacity while the utility's baseload coal-fired units are down for maintenance. The Alabama plant can also respond swiftly to fluctuations in load, following load demand to supplement supply as needed, with minimal change in generating efficiency. The plant may also be remotely controlled with minimal staff on site.

2.6) CONCLUSION

The ability of a CAES variant is reflected in the charge energy factor and the fuel heat rate. Although the capital- and running costs are important factors, and naturally the first aspect, in the selection of a suitable CAES configuration, it has not been possible to gather this information, as many of the CAES variants are concepts that have not been costed. Following is a summary of the performance characteristics of the various CAES configurations (Table 2.5).

Table 2.5: Performance characteristics of various CAES configurations

CAES Configuration	Charge Energy Factor	Fuel Heat Rate (kJ/kWh)	Energy Ratio	Figure
-Conventional	1,27	4360	0,79	2.4
-Lee's Turbomachinery variation	--	4220	--	2.14
-Pure Adiabatic	Aim 0,71	0	1,41	2.15
-Nakhamkin's indirect CAES/TES	1,11	3000	0,90	2.16
-Glendenning Pebble Bed CAES/TES	0,96	3000	1,04	2.17
-A5	0,96	--	1,04	2.18
-A1	--	0	--	2.19
-CAESCC	1,79	5870	0,56	2.20
-CAESSI	1,79	6410	0,56	2.21
-CAES/PFBC direct gas supply	--	--	--	2.22
-CAES/PFBC indirect heating	--	--	--	2.23
-Giramonti's CAES/PFBC	--	--	--	2.24
-Huntorf	1,2	5800	0,83	2.26
-Alabama	1,22	4820	0,82	2.27

where

$$\textit{Charge Energy Factor (CEF)} = \frac{\textit{Net Electrical Energy Output}}{\textit{Gross Electrical Charge Energy}}$$

$$\textit{Fuel Heat Rate (FHR)} = \frac{\textit{Combustion Fuel Consumed}}{\textit{Net Electrical Output}} \; (kJ/kWh)$$

Energy Ratio: The amount of off-peak electrical-energy consumption (kWh) during the compression cycle to generate 1 kWh during generation and equates to 1/CEF.

A summary of the projects and studies into the application of CAES in various utilities and countries electricity networks is given in Table 2.6. It is interesting to note that all the projects, feasibility studies and plants are based on the conventional CAES layout, only differing in the method of air storage. They use either natural gas or fuel oil for combustion.

Table 2.6: Status of Compressed Air Energy Storage throughout the world

Utility	Output MW	Charging Ratio	Cycle	State of development	Type of reservoir
Luxembourg	285	?	Daily	Feasibility study	Rock
Yugoslavia	2 x 130	1:2	Daily	Feasibility study	Rock
Sweden	250	1:1	?	Authorised construction	Rock
France	250-300	1:1	Daily	Considering	Rock
Ukraine	1050	?	?	Construction unknown	?
Israel	3x100	?	?	Feasibility study	Aquifer
Japan	35	?	?	Status unknown	?
TVA-USA	600-1200	?	?	Feasibility study	Worked out Gas Field
Soyland-USA	220	?	?	Aborted study	Salt Cavern
VTT-Finland	34-41	?	Weekly	Feasibility study	Rock
Sesta-Italy	30	?	?	Pilot study completed	Aquifer
Huntorf-Germany	290	1:4	Daily	Fully operational	Salt Cavern
Alabama-USA	110	1:1.7	Weekly	Fully operational	Salt Cavern

CHAPTER 3

ANALYSIS

of

ESKOM DEMAND

3.1) INTRODUCTION

The cost of not meeting customer electricity demand has a deleterious effect on the country's economy(1). Electricity demand needs to be forecast well in advance, as the construction of a generating plant can take as long as 12 years(2). Planning to meet demand necessitates not only installing the correct amount of supply but adding a percentage of reserve capacity to accommodate unexpected high demands and unforseen outages of the standard generating equipment. The purpose of this chapter is, firstly, to evaluate Eskom load demand curves, secondly, forecast customer demand and the need for additional generating capacity and, thirdly, size a CAES plant suitable to meet future electricity demands.

3.2) THE THEORY OF DEMAND FORECASTING

To predict the South African electricity demand, it is necessary to consider where electricity lies within the country's energy sector. It has been well documented that there is a link between energy consumption and economic growth of a country(3). This relation is expressed as the energy intensity index, which is the ratio of energy consumption to gross domestic product (GDP) and may be expressed as kilograms of oil equivalent per Rand of GDP. This is an important relationship, as the energy intensity index of South Africa is expected to follow the pattern set by those of developed countries. Energy consumption is also a function of sectoral economic activity(3). For example, primary industry is more energy intensive than agriculture or mining. As primary industrial activity increases so does the energy intensity.

Electricity is well established within the commercial energy sector of South Africa. The three major forms of commercial energy are coal, oil and electricity. Gas has only a small contribution at present, but will become a role player as the Pande and Kudu gas fields are exploited in Mozambique and Namibia respectively. The sectoral mix of the various energy carriers from 1933 to 1988 is shown in Figure 3.1. As shown, there has been a distinct move from solid fuels towards liquid fuels and electricity. This is likely to continue and it is estimated that there will be a final percentage market saturation. Table 3.1 shows the expected saturation for the various forms of commercial energy. Electricity is expected to contribute approximately one third of the country's commercial energy needs(1,3). Saturation is determined by the fact that certain applications will, for the foreseeable future, be supplied by energy forms other than electricity. For instance, the use of process heat in industrial applications might be better served by coal boilers than by electricity. Similarly, it is unlikely that electricity would make more than a small contribution to road transport.

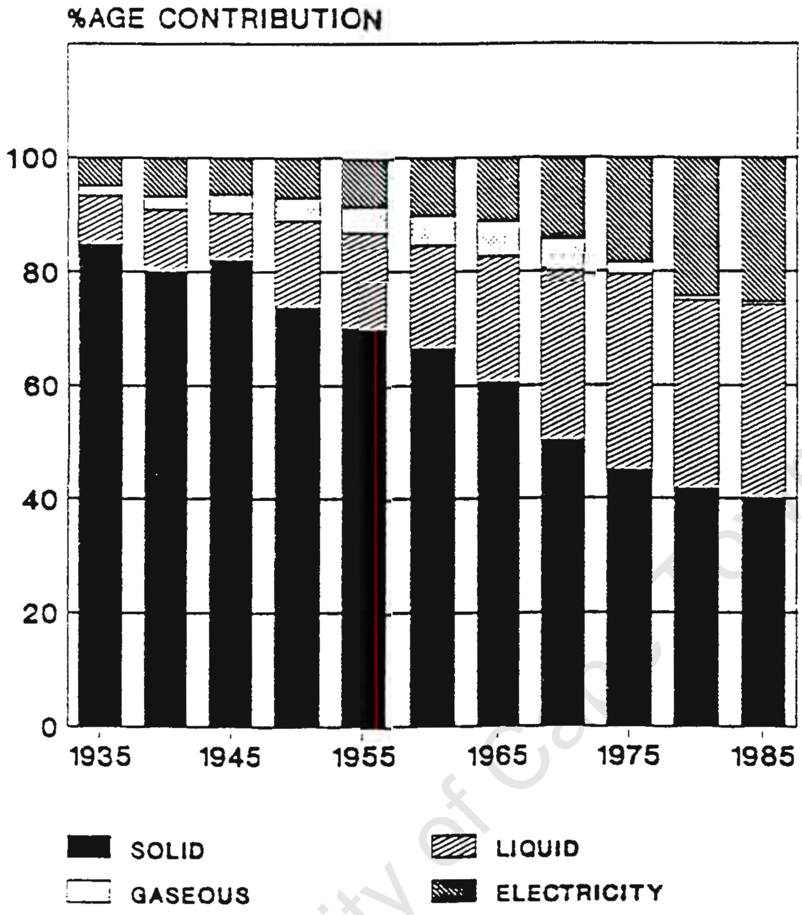


Figure 3.1: Contribution of energy sources to final energy demand in South Africa (1933 to 1988)[3]

Table 3.1: Total commercial final energy - values from saturation curves[3]

COMPONENT	FINAL CONTRIBUTION	YEAR FOR 99% OF FINAL	YEAR FOR INFLEXION
Coal + Gas	34,0 %	2000	1972
Oil	33,0 %	1984	1964
Electricity	33,0 %	2002	1980

The economic growth of a country is difficult to predict, forecasters make use of a variety of scenarios to determine the growth in GDP(4). Estimating an energy intensity index from the information available on developed countries and applying this to various GDP scenarios it is possible to make a prediction of energy consumption. To determine the electricity consumption expected, the sectoral energy mix needs to be determined.

Table 3.2 shows several electricity consumption forecasts, over the last 20 years, for the year 2000(5). The higher economic optimism in the 1970's is reflected in the demand forecasts, being much higher than those forecast during the 80's. The values forecast are for the actual South African demand, excluding internal use in power stations.

Table 3.2: Electricity demand forecasts for the year 2000(5)

YEAR OF FORECAST	AUTHOR	CONSUMPTION (GWh) (Low Scenario)	GDP GROWTH (% ANNUM) to 2000
1974	D.P&E	289513	5
1976	du Toit	290952	5
1977	D.P&E	280901	4,4
1978	Norman	345000	5
1985	Kotze	185413	2
1988	v.d.Dussen	187000	3
1989	Davison(1,3,4)	210000	2,5
1989	Davison(2)	230000	1,6
	SOURCE(6)	**1994 CONSUMPTION (GWh)**	**GDP GROWTH 1993-1994**
	ESKOM statistics	167609	2,1%

Note: D.P&E - Department of Planning and the Environment
Davison - See Table 3.3

The forecasts in Table 3.2, made by Davison(4,5), were made on the basis of four different economic scenarios. These scenarios were developed from a range of overall economic world views developed by the Economic Analysis Unit of Eskom's finance group(4). The scenarios were drawn up by anticipating South Africa's response to the world environment.

Davison discusses her scenarios in depth and brings attention to the high impact issues that influence scenario development. These issues are as follows:

- Economic
- Political
- Legal / Institutional
- Social
- Physical
- Technological

What is important is that many of these factors are interdependent and may influence each other in both a positive and negative manner. The category carrying the most weight is that of economic issues and may influence any or all of the other issues listed. Davison's(4,5) four scenarios are shown in Table 3.3. She has developed her scenarios until 2008, from which she has been able to determine an electricity growth rate for each scenario.

Table 3.3: Davison's demand scenarios(4,5)

RSA **WORLD**	**INWARD FOCUS**	**OUTWARD FOCUS**
HAPPY DAYS	**(1)** GDP = 2,5% to 2000 = 5,4% 2000 to 2008 **ELEC = 4,6%**	**(2)** GDP = 2,5% to 2000 = 7,6% 2000 to 2008 **ELEC = 6,3%**
HARD TIMES	**(3)** GDP = 0,5% to 2000 = 2,4% 2000 to 2008 **ELEC = 3,3%**	**(4)** GDP = 2,5% to 2000 = 4,1% 2000 to 2008 **ELEC = 4,0%**

3.3) FORECASTING MAXIMUM DEMAND

Electricity sales in South Africa, supplied by Eskom generating plants, increased from 15969 GWh in 1960 to 149443 GWh in 1994(6). The growth in sales from 1960 to 1982 showed an annual increase in sales of 8,5% (15969 to 96136 GWh). Between 1981 and 1982 a remarkable drop in growth was experienced. The annual growth from 1982 to 1994 was determined at 3,74% (96136 to 149443 GWh), substantially lower than the growth between 1960 and 1982.

Figure 3.2 shows the electricity sales since 1955(6), and Figure 3.3 shows the percentage growth rate(6). The most remarkable changes took place in the early 1980's when the economic growth of the country slowed down dramatically(7). Recovery has been slow with the highest increase in sales, since 1988, occurring in 1993 (4,1%)(6). The increase in 1988 was short lived and not attributable to any particular circumstance. However, the increase in 1994 has been attributable to the new political dispensation, the business cycle gaining momentum, an upturn in the agricultural sector, as well as a recovery of prices and increased activity in the metal sector(8). The growth in world economy is expected to continue having a positive impact on the demand for raw materials and commodities as well as enhancing optimism in the business sector and inspiring confidence(8). Higher economic growth rates are predicted and the high growth rate in electricity sales is therefore expected to continue(8).

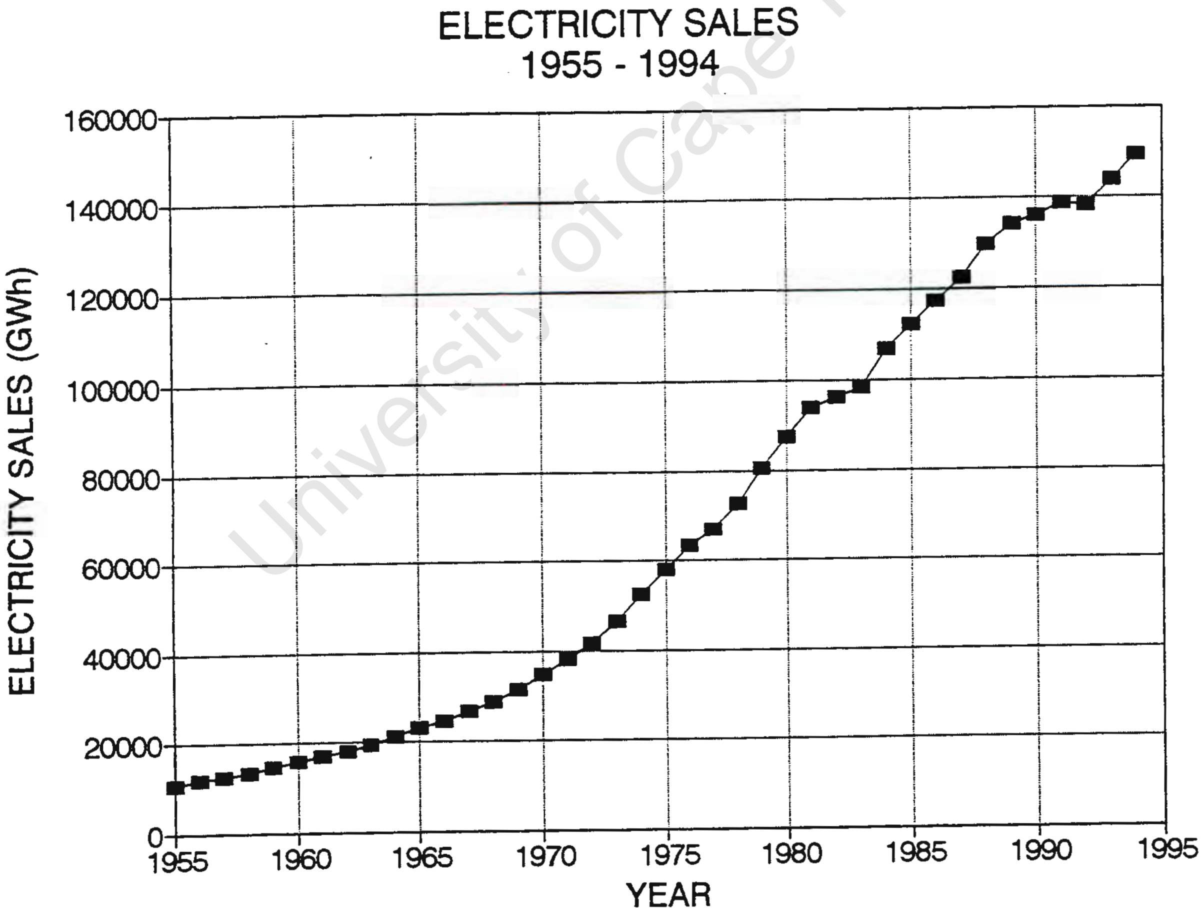


Figure 3.2: Eskom electricity sales: 1955 to 1994

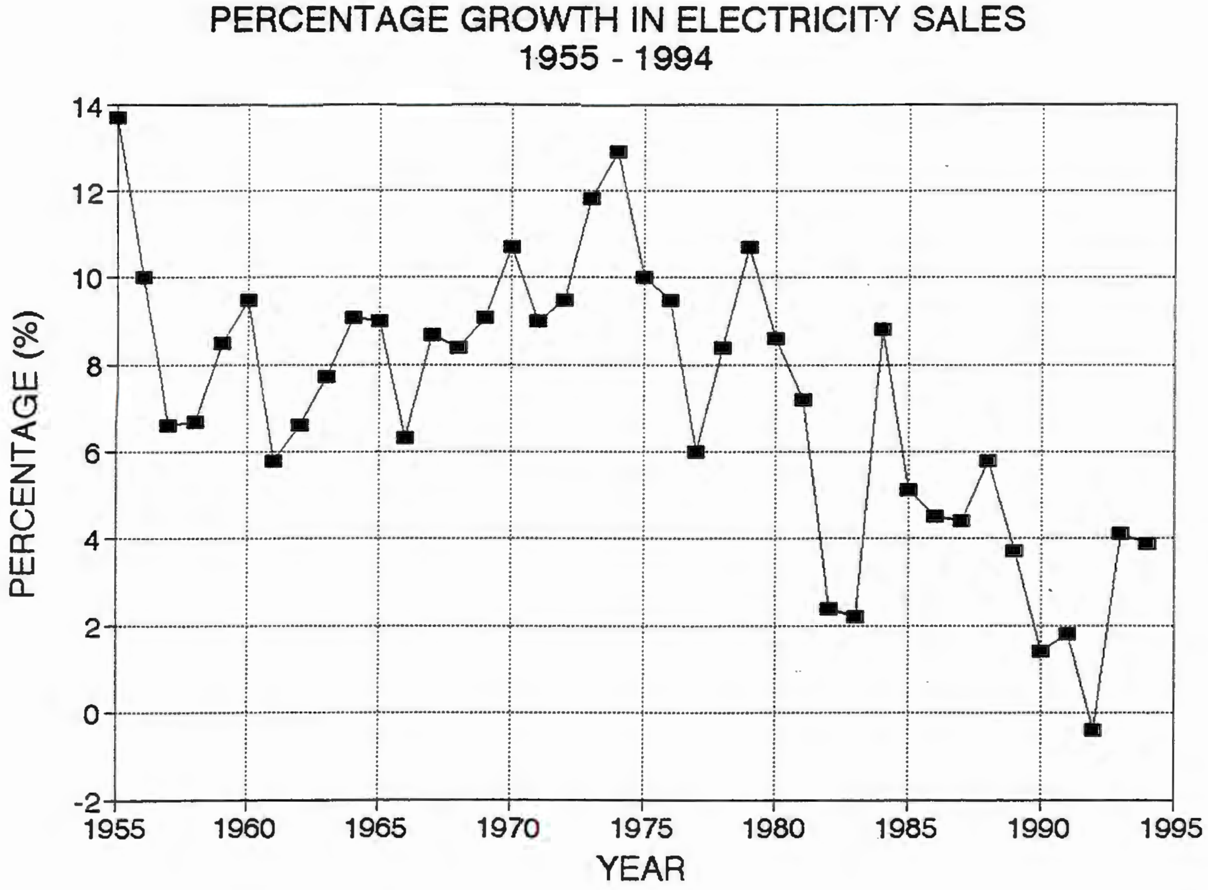


Figure 3.3: Percentage growth in electricity sales

Figure 3.4 shows the various growth rate scenarios and the effect on future electricity sales. The growth rates used are the values determined by Davison(4,5) from the varying economic scenarios. Although Davison made her predictions in 1989, they are still suitable for current day forecasting and are applied until 2020 in this analysis. Although the highest forecast of 6.3 percent may seem high, it is not unlikely, as growth rates of this magnitude have been exceeded in the past.

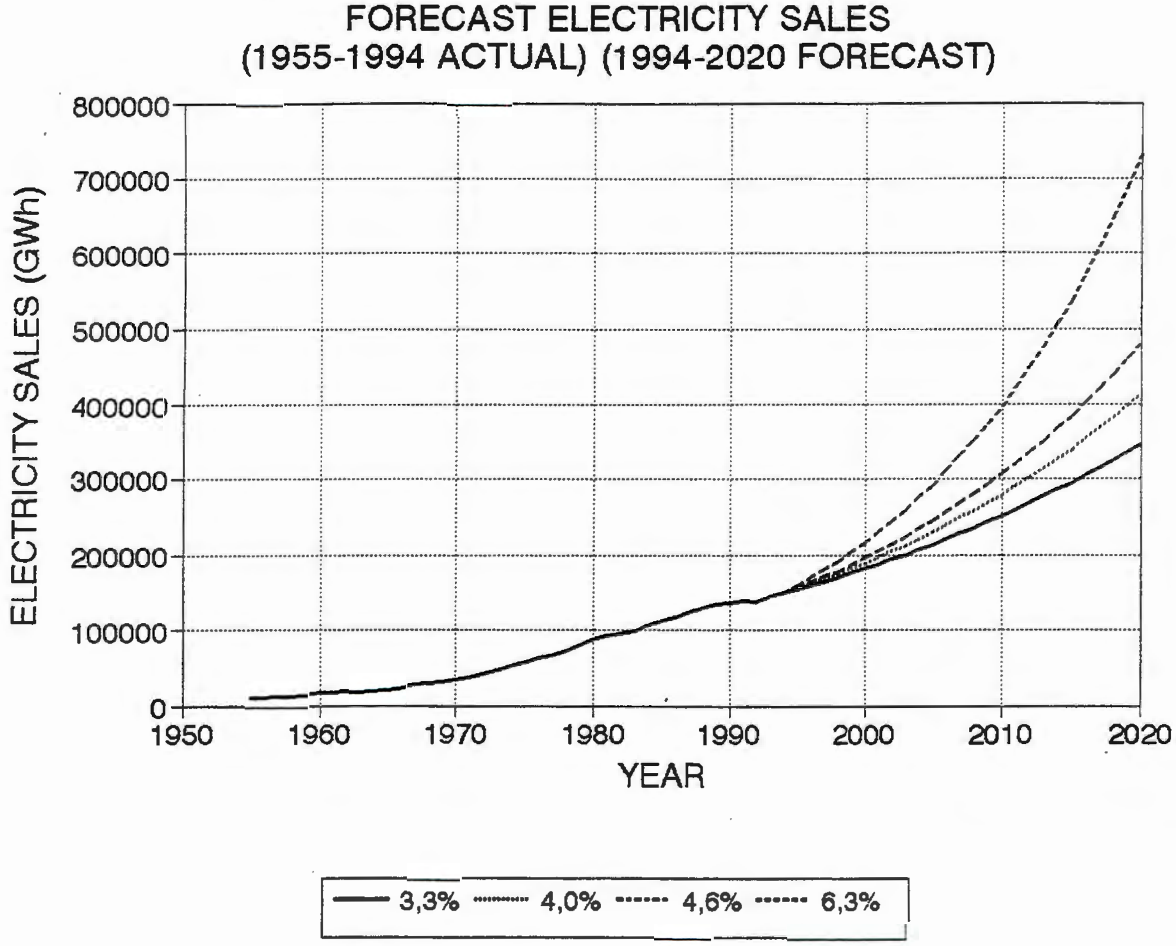


Figure 3.4: Forecast electricity sales until 2020

From the electricity sales forecasts, it is now possible to determine the maximum demand for the future. This is achieved through the system load factor. Figure 3.5 shows the system load factor since 1955^(6). From this figure, it is seen that the load factor has dropped, on average, by less than 2% over 39 years. It is not expected to change over the following years, even with the substantial domestic electrification program in progress. The system load factor is taken to be constant, at 72,8%^(6), from 1994 onwards for this analysis.

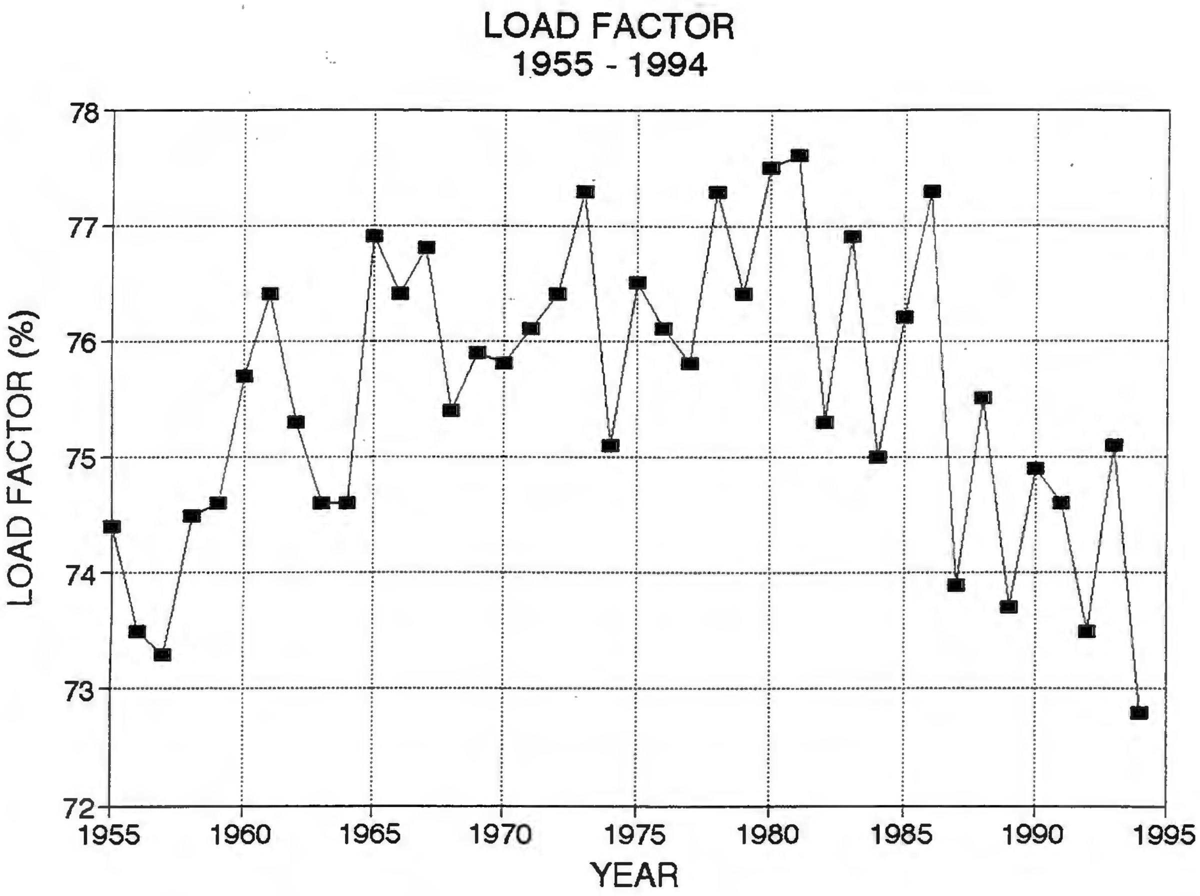


Figure 3.5: Eskom's load factor history

The system load factor[6] is determined from the following equation:

$$\text{System load factor \%} = \frac{\text{kWh available for distribution} \times 100}{\text{Peak maximum demand (kW)} \times 8760} \tag{3.1}$$

Note: 8760 is the amount of hours in a year.

This equation may be rewritten as:

$$\text{Peak maximum demand (kW)} = \frac{\text{kWh available for distribution} \times 100}{\text{System load factor \%} \times 8760} \tag{3.2}$$

The net average maximum demand can be determined for the years for which the forecast has been developed. The equation uses electricity available for distribution, and not electricity sales. The difference between electricity available for distribution and electricity sales is an amount lost during transmission⁽⁶⁾. This is approximately 5,5%⁽⁶⁾. By adding 6% to the forecast sales figures, a reasonable estimation is achieved. The electricity available for distribution is shown in Figure 3.6 for the same scenarios as for the electricity sales. Using equation 3.2. the maximum demand is determined for every point in every scenario. Figure 3.7 shows the maximum demand for all 4 scenarios. Included in this figure is Eskom's full generating capacity (base and peaking plants).

In 1994, Eskom's full generating capacity was 35926 MW, by 2001 Eskom will have added another 3843 MW to this amount. Eskom will have approximately 39769 MW generating capacity by 2001. This amount includes reserve capacity. This amount is considered to stay constant until 2020. Ignoring the most extreme forecast, Eskom may run out of capacity sometime between 2004 and 2008.

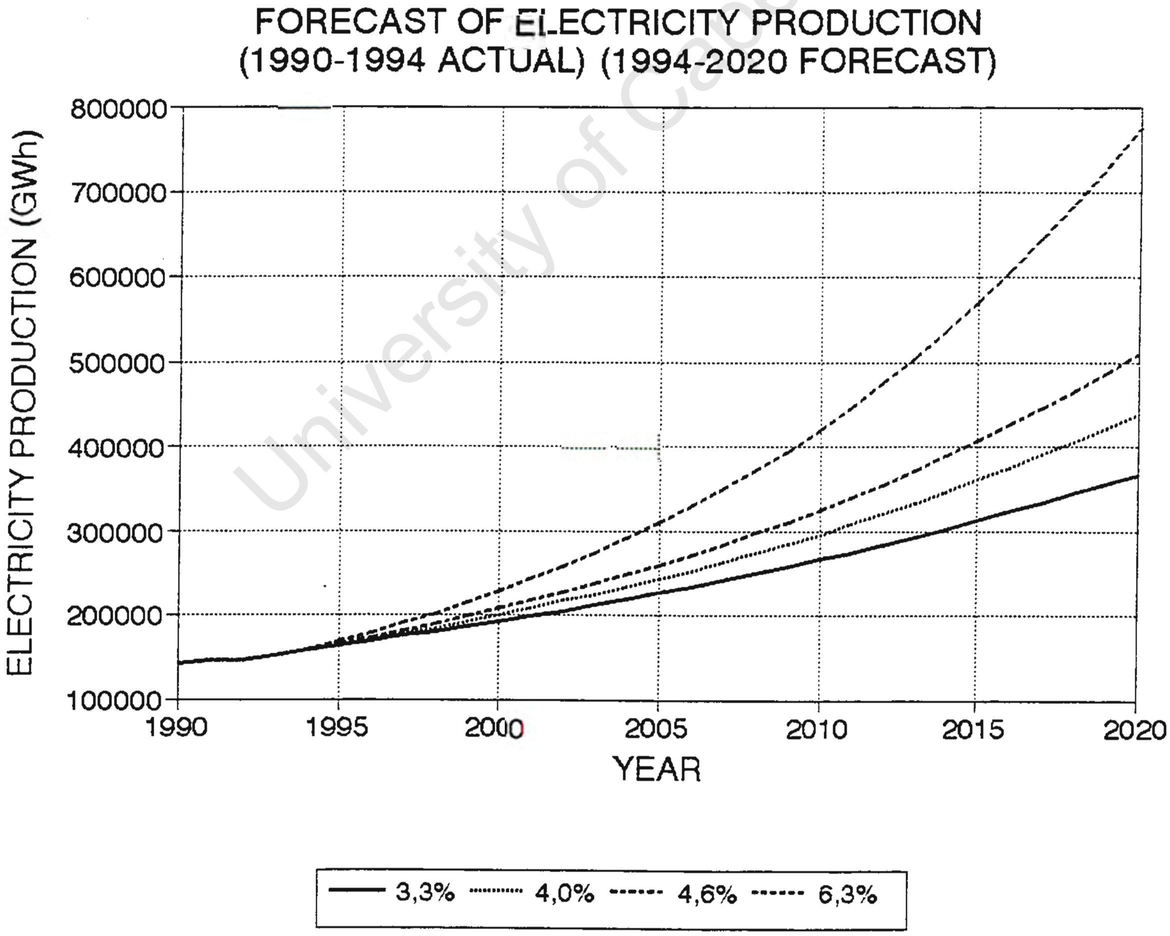


Figure 3.6: Electricity available for distribution forecast

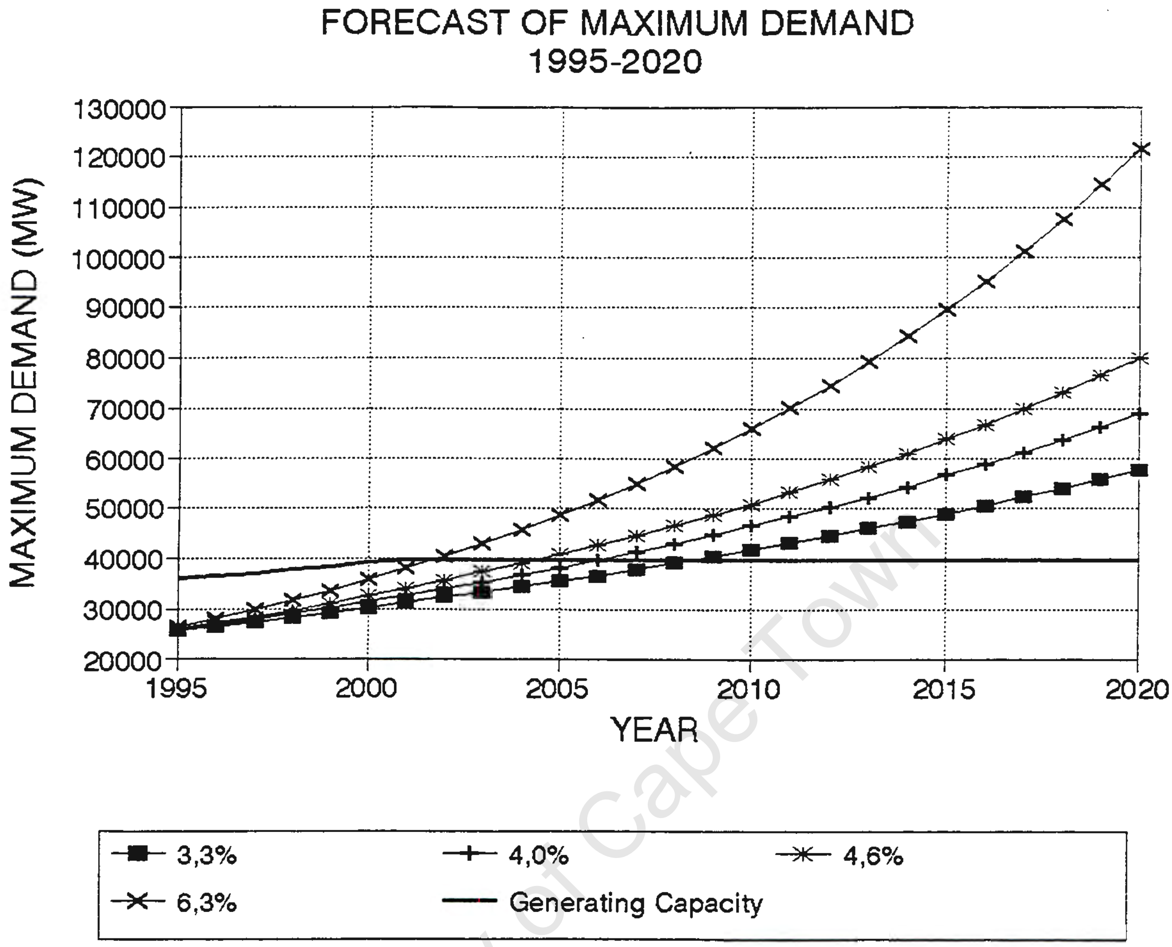


Figure 3.7: Maximum demand forecast and generating capacity

The maximum demand for the years 2000, 2010 and 2020 for the 4 scenarios are listed in Table 3.4.

Table 3.4: Forecast maximum demand

YEAR GROWTH SCENARIOS	2000	2010	2020
1) 3,3%	30182 MW	41759 MW	57777 MW
2) 4,0%	31430 MW	46524 MW	68867 MW
3) 4,6%	32534 MW	51010 MW	79978 MW
4) 6,3%	35838 MW	66021 MW	121622 MW

3.4) SIZING CAES ON SYSTEM DEMAND

Figure 3.8 shows the Eskom demand during an average winter's week in 1994(9). The week is taken from Sunday 3 July until Saturday 9 July. The week with the day of maximum demand was not selected, due to the extraordinary high usage of electricity throughout the day of maximum demand and the deviation from the general demand trend. The demand depicted in the graph is the net system demand and excludes the pumped storage load.

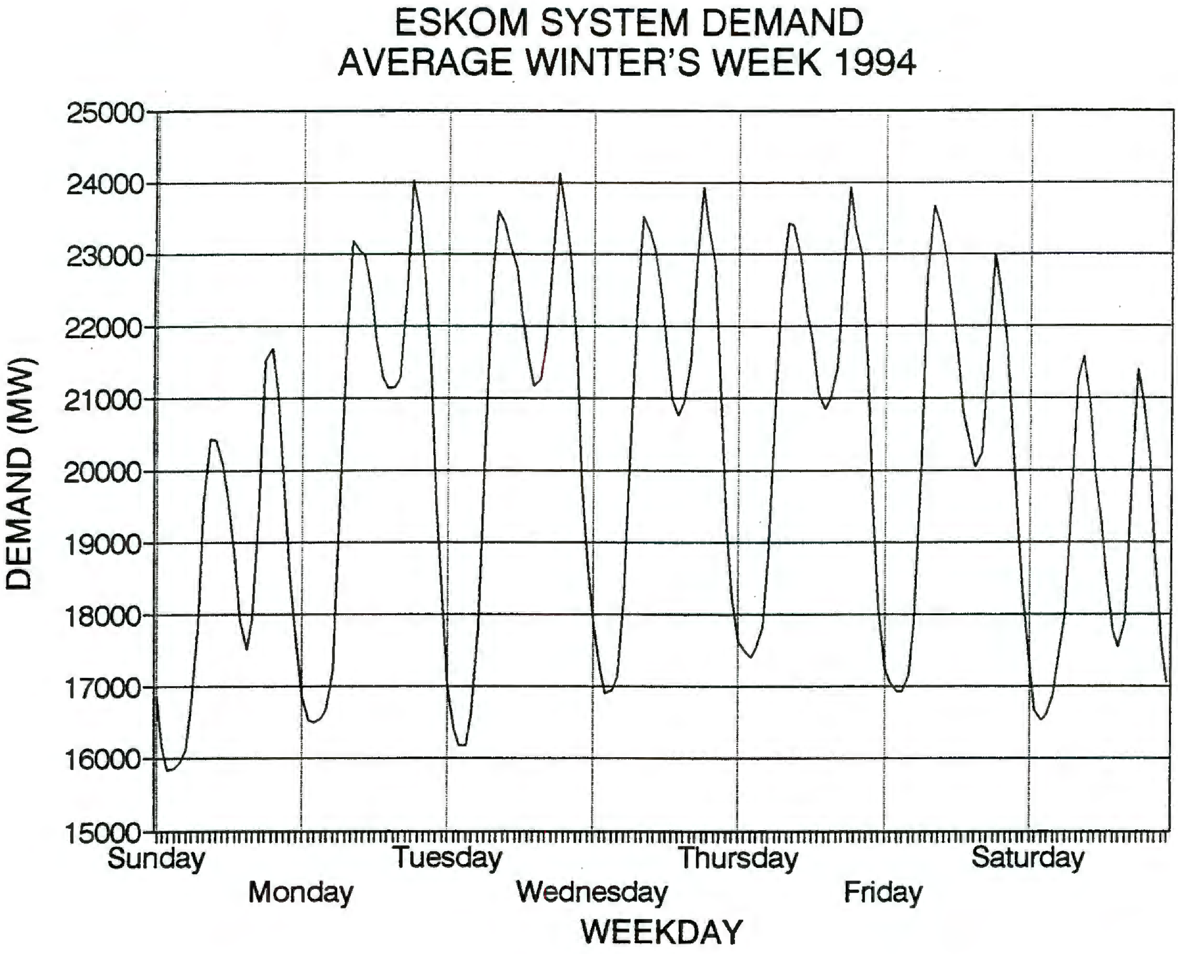


Figure 3.8: Eskom system demand(9) - An average winter's week

In the future, the average weekly demand is expected to be similar to the week depicted in Figure 3.8. It is possible to redraw the weekly demand curve as a load duration curve, by restructuring the demand from maximum to minimum(10). This is shown in Figure 3.9. A load duration curve is a simplified version of the weekly demand curve. The energy demand is the area under the weekly demand curve and is equal to the area under a load duration curve.

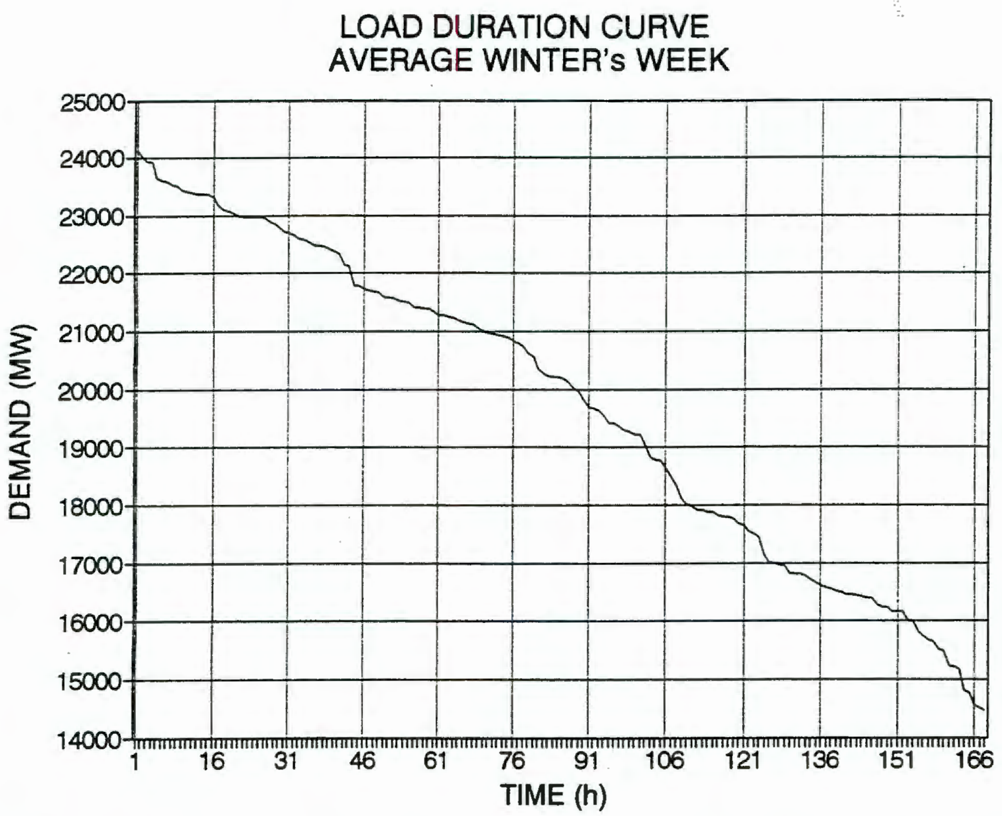


Figure 3.9: Eskom's load duration curve

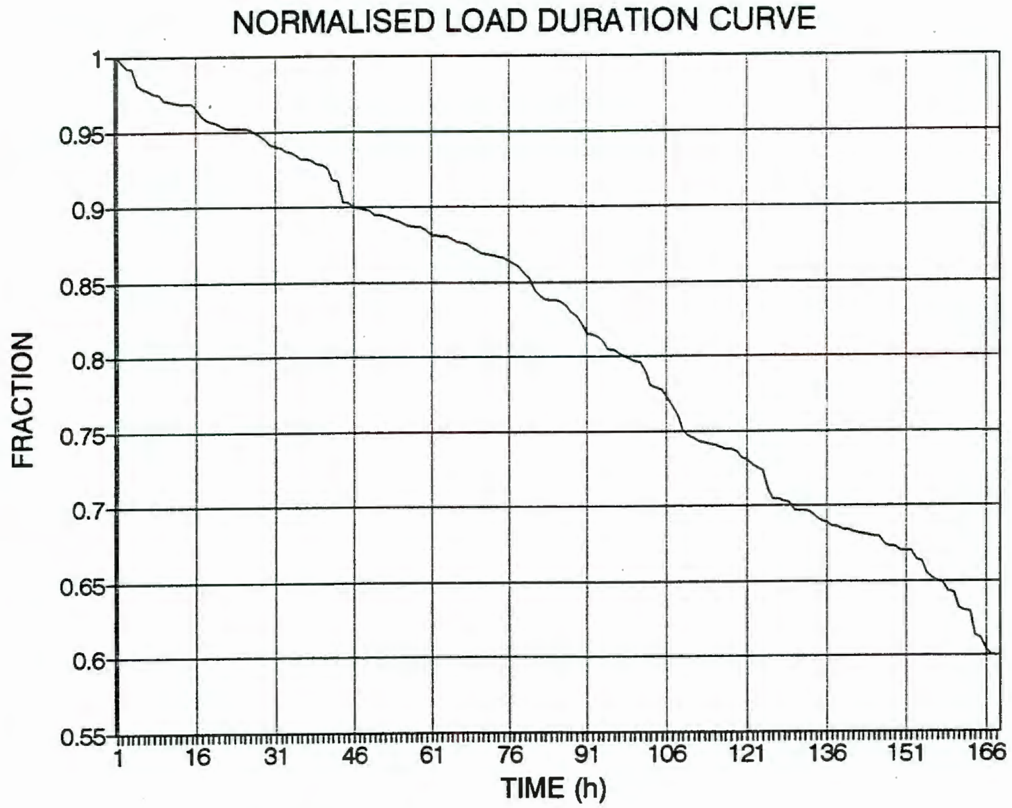


Figure 3.10: Normalised load duration curve

By normalising the load duration curve (Figure 3.10) and applying it to the maximum demand forecasts derived in Figure 3.7 and listed in Table 3.4, it is possible to determine the size of compressed air energy storage plant that may be best suited for future demand. It is assumed that the compressed air energy storage plant is run on a weekly cycle, with full recharging taking place over weekends. The load duration curves for each forecast year are shown in Figure 3.11.

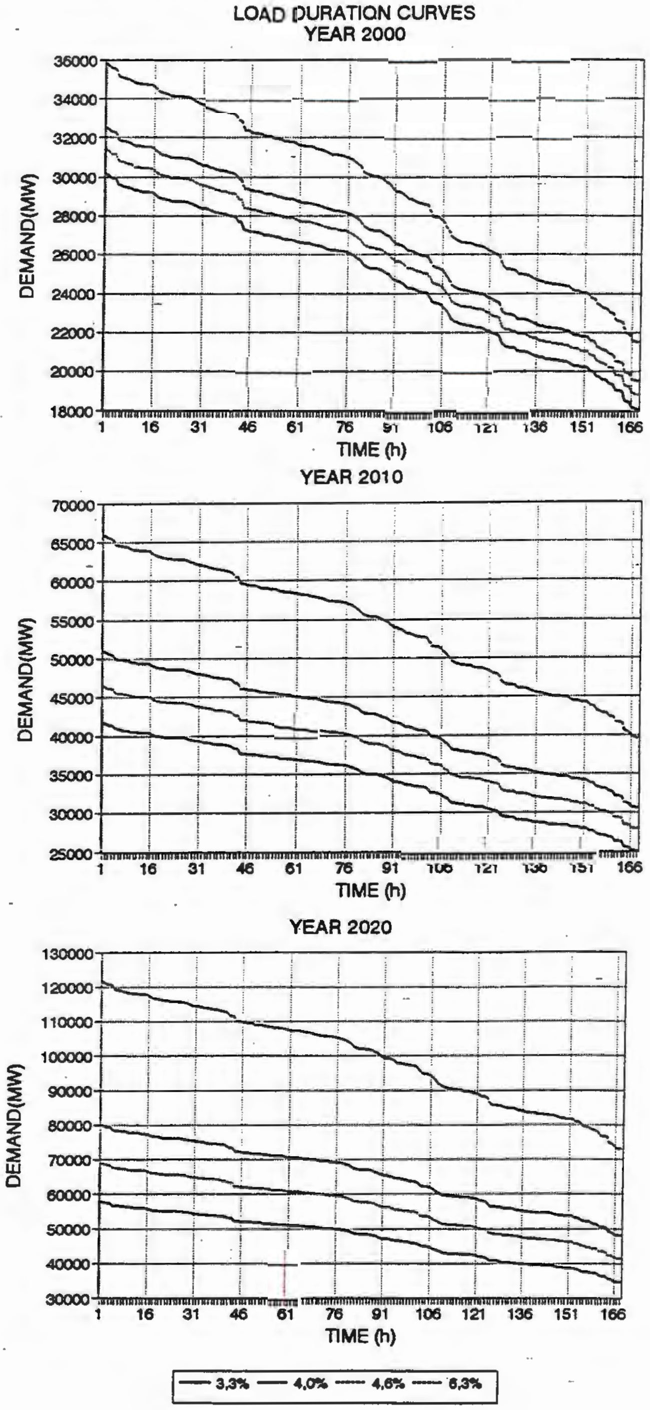


Figure 3.11: Load duration curves for the forecast years

For every curve, an amount of energy is supplied by the baseload plant, as shown in Figure 3.12, which is the load duration curve of the winter's week in 1994. The energy demand above the baseload cut, must be supplied by a peaking plant or alternative by storage plants. When using storage plants the following occurs, the baseload supply is increased to a level as shown in Figure 3.13. The storage plant must be able to store the excess energy produced by baseload plants during low demand and reproduce it at a later stage to meet peak demands.

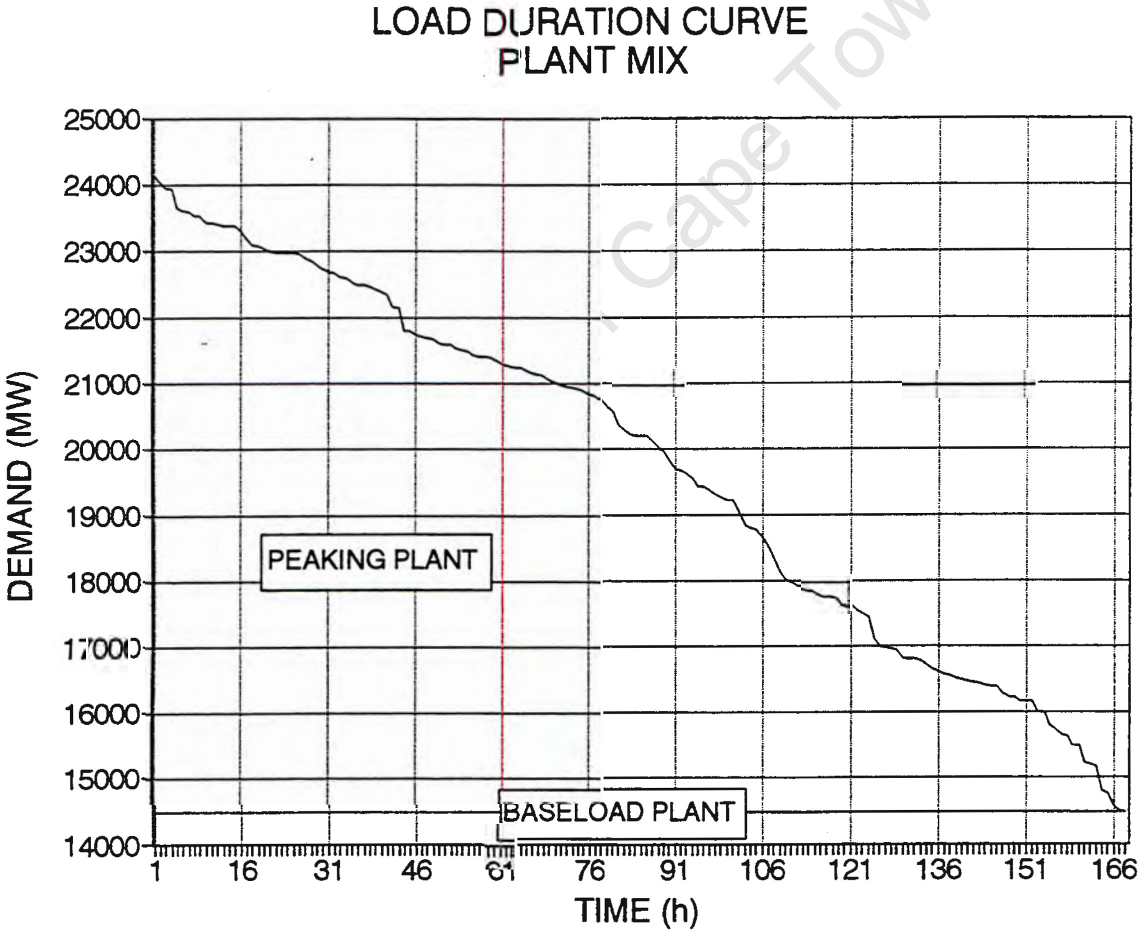


Figure 3.12: Plant mix on a load curation curve

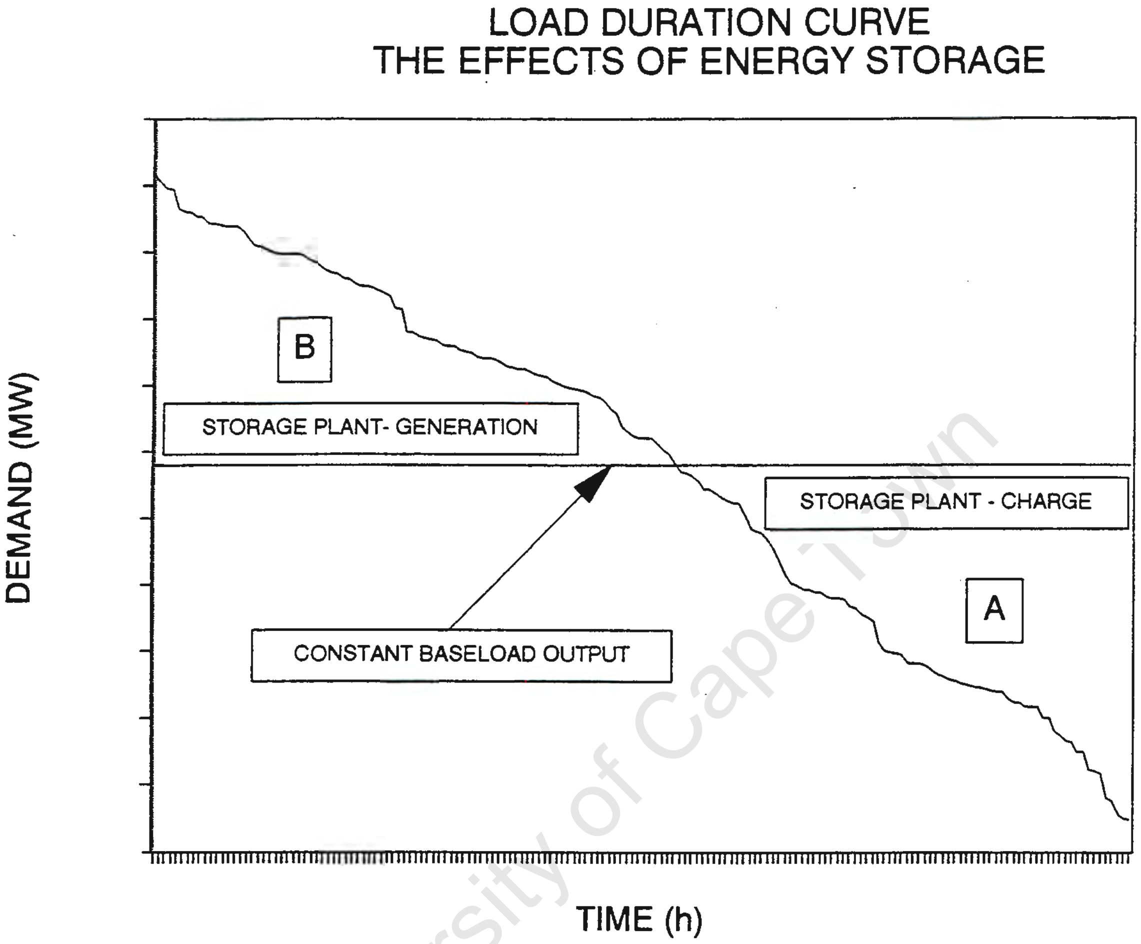


Figure 3.13: The effects of energy storage on a load duration curve

As seen in Figure 3.13, the area (A) below the constant baseload output and above the curve is the excess energy produced by baseload units. This energy is shifted, through storage, to the area (B) above the constant baseload and below the curve. The efficiency of the storage plant determines how much energy may be moved from A to B. A pumped storage plant's efficiency is approximately 75%. The generation energy capability would be: B = 0,75 x A (GWh). By moving the constant baseload output, up or down, the correct ratio between A and B may be achieved and thus the plant size may be determined. This method does not take baseload plant availability into account and therefore a percentage of error exists in the size of the storage plant.

Applying the above argument to CAES, a charge energy factor is defined (Chapter 2), which includes an increased output due to additional fuelling(11).

$$\text{Charge Energy Factor } (CEF) = \frac{\text{Net Electricial Energy Output}}{\text{Gross Electrical Charge Energy}} \tag{3.3}$$

From the literature a conventional CAES plant has a CEF = 1,27(12), Alabama has a CEF=1,22(12) and Huntorf has a CEF = 1,2(11). It can be accepted that any CAES plant that may be installed in future would be based on the conventional plant and require the additional fuelling. For the sizing of the CAES plant it is assumed that the CEF would lie between 1,2 and 1,3. A CEF of 1,25 is used in this analysis.

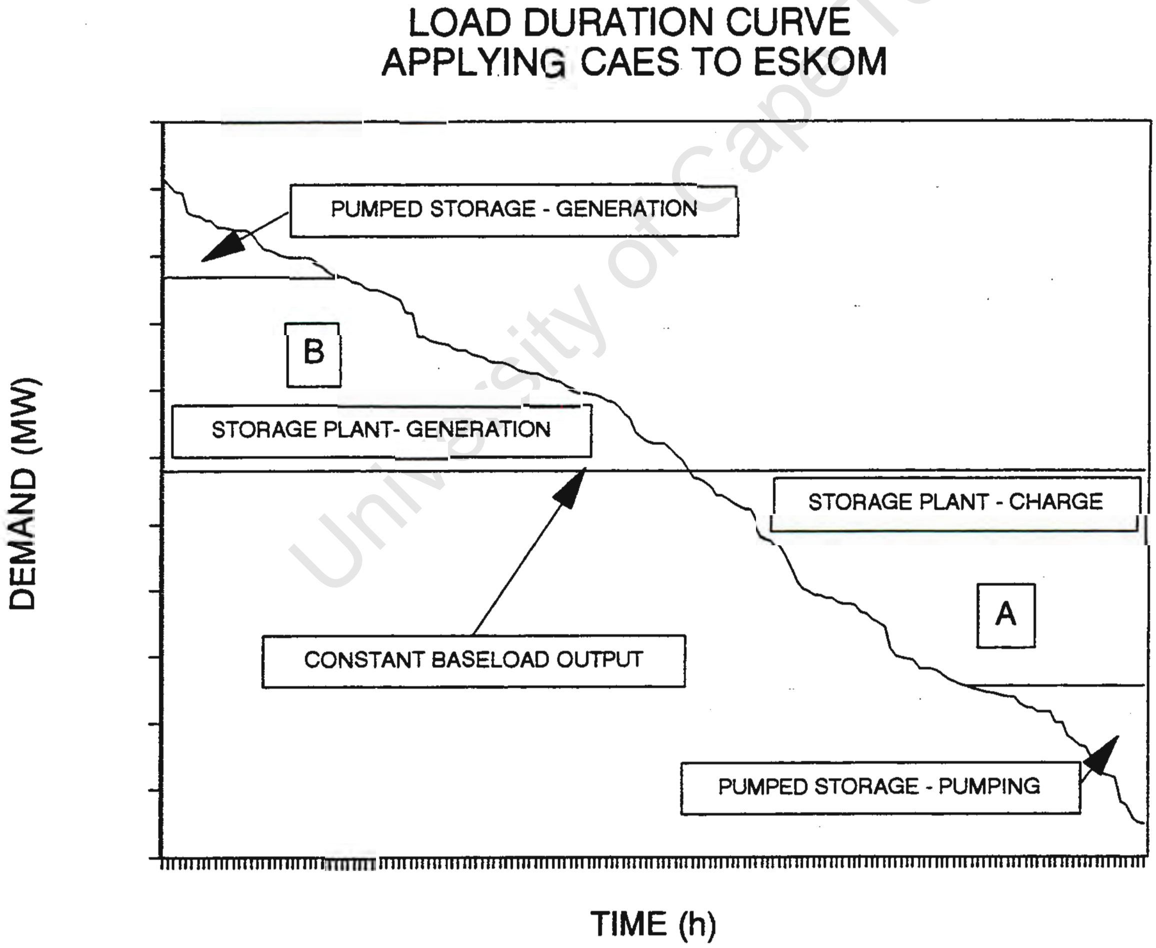


Figure 3.14: The effects of pumped storage and CAES on Eskom's load duration curve

In South Africa a section of the peak demand is already met by pumped storage (Figure 3.14)$^{(6)}$. In this analysis it is assumed that all current pumped storage will still be in operation in 2020. Figure 3.15 shows how any additional storage plant (e.g. CAES) is sized to suit Eskom, as a generating alternative. To determine the size of the CAES plant capacity in South Africa, the following formula is applied, on the basis of the forecast maximum demand load duration curves of the various scenarios:

$$B = CEF \times A \text{ (GWh)} \tag{3.4}$$

Eskom has two pumped storage plants operating on its network. The first is Drakensberg$^{(13)}$, rated at 1000 MW with a capacity of 27,6 GWh and the second is Palmiet$^{(14)}$, rated at 400 MW with a capacity of 10 GWh. Drakensberg has 4 x 250 MW and Palmiet has 2 x 200 MW generating sets. The loading of pumped storage is determined on an efficiency basis$^{(15)}$. The plant with the highest efficiency will be loaded first, because it will be used for a longer time period and be cheaper to operate. The reservoir of the Drakensberg scheme is big enough to operate the scheme in the generation mode with a weekly load factor of 30%$^{(13)}$. The reason for this is that the scheme also supplements water supplies to the Highveld. Palmiet supplements water supplies to Cape Town. For this analysis it is assumed that both schemes will be run on a weekly load factor of 30%. Therefore, on a weekly basis, Drakensberg$^{(13)}$ is able to supply 50,4 GWh to the grid, and Palmiet$^{(14)}$ 20,16 GWh. It is also assumed that pumped storage would be loaded last after the CAES plant, and appears at the top of the load duration curve for the forecasts, similar to that shown in Figure 3.14. Drakensberg$^{(13)}$ has an efficiency of 73,7% and Palmiet$^{(14)}$ an efficiency of 77,9%. In practice, Palmiet would be loaded before Drakensberg.

For this analysis it is assumed that Palmiet and Drakensberg are combined as a single 1400 MW plant with a 30% load factor and a combined efficiency of 75%. The combined plant is thus able to supply 70,56 GWh at no more than 1400 MW. Applying the pumped storage to the load duration curves of the various scenarios, the graphs in Appendix A are generated. The peaks and troughs are slightly levelled off through pumped storage. Using the remaining area under the curve and above the original baseload plant it is now possible to determine the size of CAES using a CEF of 1,25.

The graphs in Appendix B show the constant baseload power output as a straight line for the various forecasts, 125% of the excess baseload generating capacity is used to meet the peak demands.

3.5) CONCLUSION

As mentioned, plant availability was not taken into account for this analysis and a percentage of error exists in the results obtained for the CAES capacity. Using the graphs generated in Appendix B it is possible to determine suitable CAES storage and generating capacities for the CAES sizes. The horizontal line is the constant baseload output for CAES plants with a CEF =1,25. Table 3.5 shows the resulting sizes for CAES plants for the forecast years for an average week. It is assumed that the CAES plant would be situated close to load centres and no transmission losses are taken into account.

Table 3.6 shows the constant baseload power demand needed throughout the week. By adding 6% to the values in Table 3.6 for transmission losses the constant baseload output is shown in Table 3.7. By adding a further 20% for reserve capacity, the forecast size of installed capacity necessary to meet these peak demands, is determined and shown in Table 3.8.

Table 3.5: Size of CAES plant generating capability for the forecast years.

Forecast Growth Rate	2000	2010	2020
3,3 %	272802 MWh 4732 MW	381541 MWh 6829 MW	530672 MWh 9787 MW
4,0 %	284312 MWh 4950 MW	426059 MWh 7724 MW	633540 MWh 11867 MW
4,6 %	295005 MWh 5155 MW	468230 MWh 8560 MW	738127 MWh 14018 MW
6,3 %	325886 MWh 5748 MW	608144 MWh 11341 MW	1125577 MWh 22032 MW

Table 3.6: Constant baseload power demand by a CAES plant, for a week in the forecast years

Forecast Growth Rate	2000	2010	2020
3,3 %	24390 MW	33740 MW	46680 MW
4,0 %	25400 MW	37590 MW	55640 MW
4,6 %	26290 MW	41210 MW	64600 MW
6,3 %	28960 MW	53330 MW	98230 MW

Table 3.7: Constant baseload generating capacity required for a week in the forecast years (+6% transmission losses)

Forecast Growth Rate	2000	2010	2020
3,3 %	25853 MW	35764 MW	49480 MW
4,0 %	26924 MW	39845 MW	58978 MW
4,6 %	27867 MW	43683 MW	68476 MW
6,3 %	30698 MW	56530 MW	104124 MW

Table 3.8: Installed capacity necessary to meet peak demands in the forecast years (+20% reserve capacity)

Forecast Growth Rate	2000	2010	2020
3,3 %	31024 MW	42917 MW	59337 MW
4,0 %	32309 MW	47814 MW	70774 MW
4,6 %	33441 MW	52419 MW	82171 MW
6,3 %	36837 MW	67836 MW	124949 MW

These figures quoted in Table 3.7, for the all 4 scenarios for the years 2010 and 2020, are above the forecast generating capacity of Eskom (39769 MW). Because CAES has short construction lead times, it may tie Eskom over during a period of possible electricity shortage during the lengthy construction phase of a fossil fuelled plant. A CAES plant may take approximately 3 years(16) to construct while a fossil fuelled plant may take between 8 and 12 years(2).

With the introduction of the Southern African power pool, CAES may be a suitable generating system. Power imported from the North may act as reserve capacity or additional baseload capacity and Eskom's current generating capacity plus a CAES plant will be able to meet the customers demands. The question that remains is whether CAES is competitive on a capital cost basis with other generating plant.

CHAPTER 4

UNDERGROUND AIR STORAGE RESERVOIRS

in

SOUTH AFRICA

4.1) INTRODUCTION

The purpose of this chapter is to investigate underground compressed air storage in South Africa. A brief introduction to underground storage reservoirs was given in the literature survey. The only suitable storage capacity meeting the CAES criteria of a large volume at high pressure, is underground storage. Storage volumes are created by excavating or converting one of the following: hard rock caverns, salt caverns or aquifers(1). In these storage systems, air may be either stored and extracted from a constant pressure or a constant volume system.

4.2) UNDERGROUND AIR STORAGE OPTIONS IN SOUTH AFRICA

There are no significant saltdomes in South Africa and thus salt cavern air reservoirs may be excluded from any South African CAES system consideration.

Natural gas is often found underground in aquifers(2). These aquifers have stored gas for millions of years. Once all the gas has been extracted from the aquifer it may be used to store air(1,3). These systems are highly recommended as they have a proven record of storing gas over, possibly, millions of years. Many gas utilities use old gas fields for seasonal gas storage(1,3). In South Africa the availability of such aquifers is unknown. Usable aquifers may exist off-shore in the Mosselbay region, where numerous small discoveries of gas and oil have been found(4). To utilise aquifers with an "unproven" record is highly risky, as geological surveys do not always show the full extent of fractures and leakage points in the caprock or indicate the response of the porous rock to pressurised air.

A storage capacity in hard rock is the most likely possibility. Underground hard rock formations are abundant in South Africa, but due to the technology and labour necessary, excavations are expensive. Currently, South Africa has large underground excavations, left over from extensive mining operations(5,6). The conversion of underground workings into CAES storage caverns is a possibility(7), as similar conversions have been implemented before(8,9,10). These storage devices have been used to store compressed air in order to supplement mining compressed air needs. Underground air storage chambers are referred to as "underground air-receivers" in the mining industry.

4.3) COMPRESSED AIR AND THE MINING INDUSTRY

The compressed air demand peaks that are experienced in the mining industry are similar to the electricity peak demands experienced by electricity utilities. As mining operations, and specifically rock drilling operations, experience a peak during the day, a loss of pressure is experienced by the drilling teams. This occurs when too many drills are brought on line. This requires that either less drills are operated during this time, thus decreasing output, or alternatively an additional compressor has to be brought online, resulting in high energy costs.

By adding an air receiver into the compressed air system, compressed air may be stored during low demand periods to boost the air supply during high demand periods, meeting both peak demand and saving on electricity costs(5). The receivers are then recharged during off-peak periods making use of a low electricity tariff. Due to the high costs of above-ground storage installations, unused underground excavations have been sealed off, and used as air receivers. In South African mines, air has been stored in both constant volume and constant pressure underground receivers(8,9,10,11). Both types of systems have been used successfully to supplement compressed air demands. The use of an air receiver for a CAES plant is therefore a possibility. The following is a description of several air receivers implemented in the mining industry.

The first documented South African underground air receiver was implemented in the 1930's at West Springs mine(8). This receiver was developed by isolating an unused haulage with concrete plugs at both ends, and converting it into an air storage device. During low demand the volume was pressurised. Once demand had risen to above the compressor supply, air was released from the receiver, through a regulating valve, and into the air mains.

Since the implementation of the receiver at West Springs, many receivers have been developed, both constant pressure and constant volume systems. In a constant volume system the volume remains constant during charge and discharge(8), charging taking place by compressing air into the receiver until the desired pressure is attained. Discharge is normally controlled via a regulating valve at the outlet. Air is released from the receiver at the required pressure, while the pressure within the receiver simultaneously drops from fully charged to the regulated pressure. Once the pressure within the receiver is equal to the regulated pressure the additional air supply ceases.

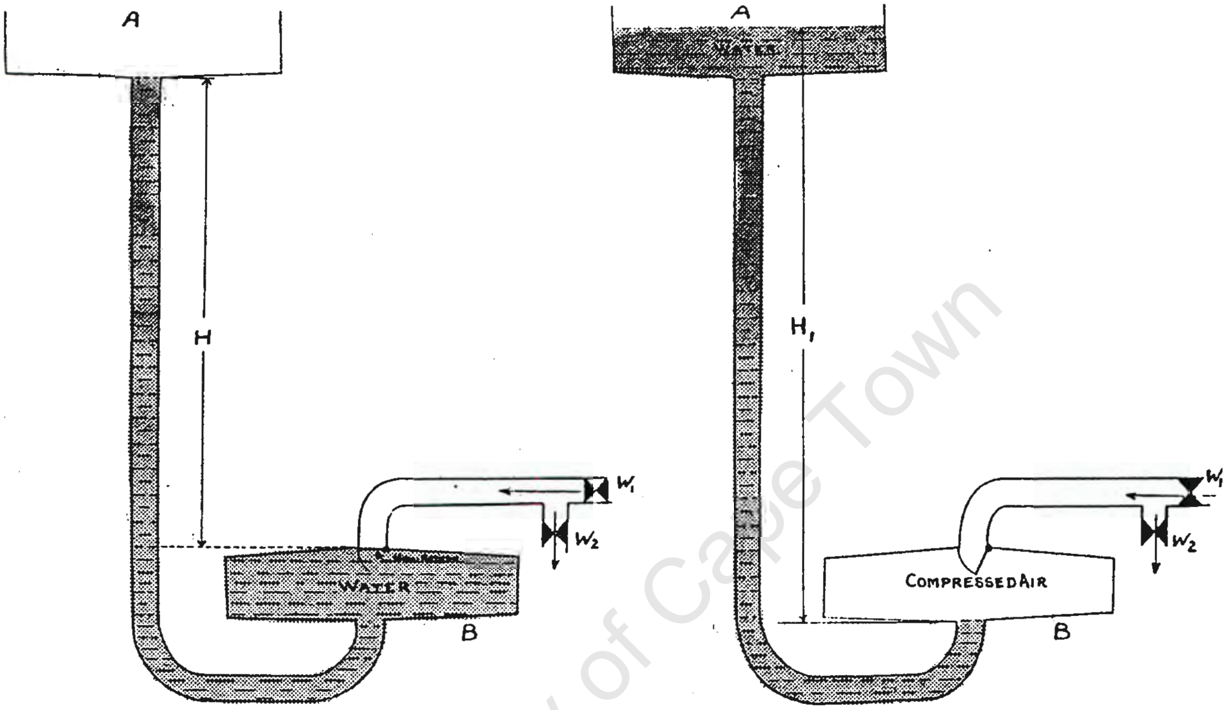


Figure 4.1: Schematic diagram of a constant pressure receiver(9)

In a constant pressure receiver (Figure 4.1) air is supplied from the receiver at a constant pressure while the volume changes(9). To achieve this, water compensation is necessary, as shown in the figure. Water compensation is achieved through a U-tube, with two volumes at either end. The bottom reservoir is totally enclosed, while the top is open to the atmosphere. If the bottom chamber and connecting tube are filled with water, and compressed air, at a pressure slightly higher than that corresponding to the head H, is let into the lower reservoir, the water will be forced up the U-tube into the upper reservoir. The bottom chamber will be filled with air at a pressure corresponding to the head H_1. If the supply of compressed air is reversed and air is drawn from the lower chamber, it will escape at a practically constant pressure until the original state is restored.

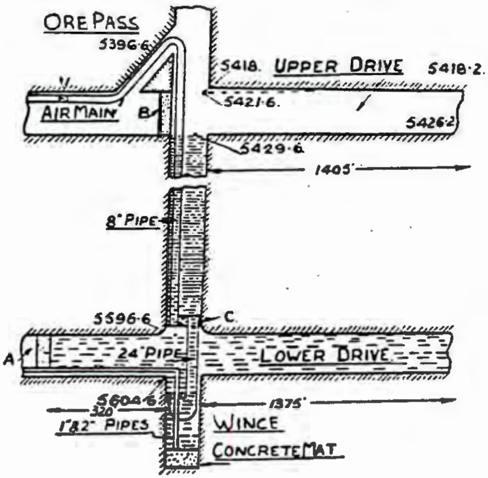
The variation in air pressure is dependent on the water pressure head. In order to operate at a constant pressure both reservoirs should be made as shallow as possible. For efficient utilisation of space, no air locks should be allowed to form, and the lower reservoir should be inclined to the connecting U-tube inlet. The roof of the lower reservoir should also be inclined, allowing air to escape freely. The resulting air pressure is equivalent to the water head.

For mining operations it has been estimated that approximately 10 per cent of the air stored in a constant volume receiver may be utilised(12). Constant pressure air receivers have been developed and used with great success, where practically the full volume of air may be extracted(9).

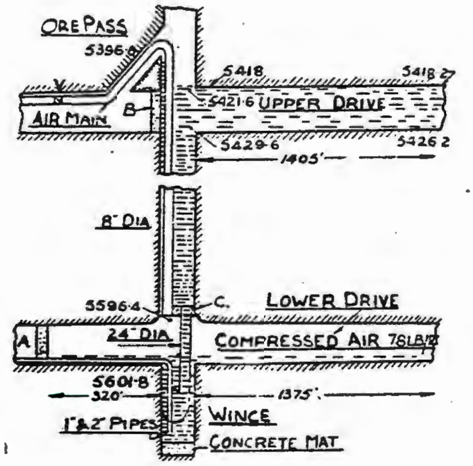
Every individual underground air receiver implemented in South African mines is unique. This is because they are developed in cavities and excavations that are available and unused at the time. The most common layout of an underground receiver is that not only is the air reservoir underground but so also is the compensation water reservoir. This avoids extensive aboveground civil works and also minimizes capital costs.

Figure 4.2 shows the layout of the constant pressure receiver installed at the Randfontein Estates goldmine on the Witwatersrand in the 1930's(9). Two drives on adjacent levels connected by a raise were used. The bottom of the raise was sealed off, shown as wall C, forming the bottom of the water reservoir. Two pipes are situated within this wall. The first runs from the wall down into a vertical wince below the raise forming the U-section of the water head by filling up the wince. The second pipe runs up the raise, this being the compressed air supply pipe. This pipe runs through the water reservoir, to above the main body of water. Here it is directed down a convenient ore pass to the air mains. The water reservoir plug (B) is situated between the raise and the outlet of the ore pass. The ore pass has a multi-purpose function. Once the water has reached the top of the reservoir it fills up the upper raise towards the inlet of the ore pass. The pressure head is controlled in this manner, as any excess water spills over the top and down the ore pass. Thus the air pressure in the lower reservoir cannot exceed this water pressure head. This arrangement also prevents water from passing into the air mains. Water flowing up the air pipe is unable to pass the highest point of the compensation water, and is thus unable to flow over the ore pass into the air mains.

(a) Completely discharged



(b) Intermediate



(c) Totally charged

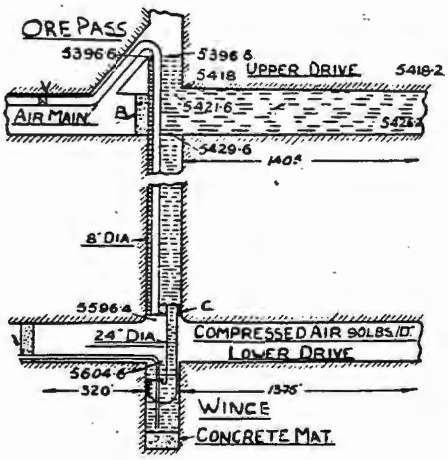


Figure 4.2: Schematic layout of a constant pressure air receiver installed at Randfontein Estates mine[9]

For this design, the lower chamber had a larger volume than the upper reservoir. If the compressed air pressure is exceeded the water would have to fill the top drive and raise before air escapes through the U-tube. Water spilling over the top of the ore pass was a good indication of air pressure exceeding the set limits.

Figure 4.2 shows the receiver in (a) a totally discharged state, (b) an intermediate state and (c) a totally charged state. To charge the receiver, air is compressed into the chamber via the air pipe that leads past the ore pass and down to wall C. The compressed air lowers the level of the water. As the pressure increases the water level drops into the wince and the lowest part of the cavern where the U-tube is situated. During compression water is pushed down the tube, and up to wall C. Above wall C the water reservoir fills up. In the fully charged state the water level in the bottom reservoir is just above the entrance to the U-tube and the upper level, at the same height as the ore-pass.

The air may now be retrieved by reversing the air flow. The water flows down the raise into the lower chamber. The air flows back into the air mains at an almost constant pressure. The fully charged state is shown in Figure 4.2(c).

A drainage valve is situated in plug A and leads to the bottom of the wince since natural water from fissures is continuously added to the system. Once the water spills down the ore pass the drainage valve may be opened and extra water will be removed from the system, and any sludge that may have accumulated.

Most receivers are based on a similar system as the system described above. Figure 4.3 shows the receiver installed at the Welkom No2. shaft in the 1970's(10). Two unused ventilation air ways were used in close proximity to a inclined shaft system. Figure 4.3 (a) shows the underground plan of the receiver and compensation reservoir. The two air ways were connected by a ventilation raise. Figure 4.3 (b) shows the piping and supplementary machinery of the receiver. In this system air is retrieved directly from the highest point of the lower reservoir, and a float valve is used to ensure that no water enters the air mains. This system also incorporates two pumps to assist the compressors in displacing the water to the upper reservoir.

The receiver installed at Welkom No3. shaft(10) is shown in Figure 4.4. This design necessitates a booster compressor to assist in returning the water back to the upper level, due to the high pressure head.

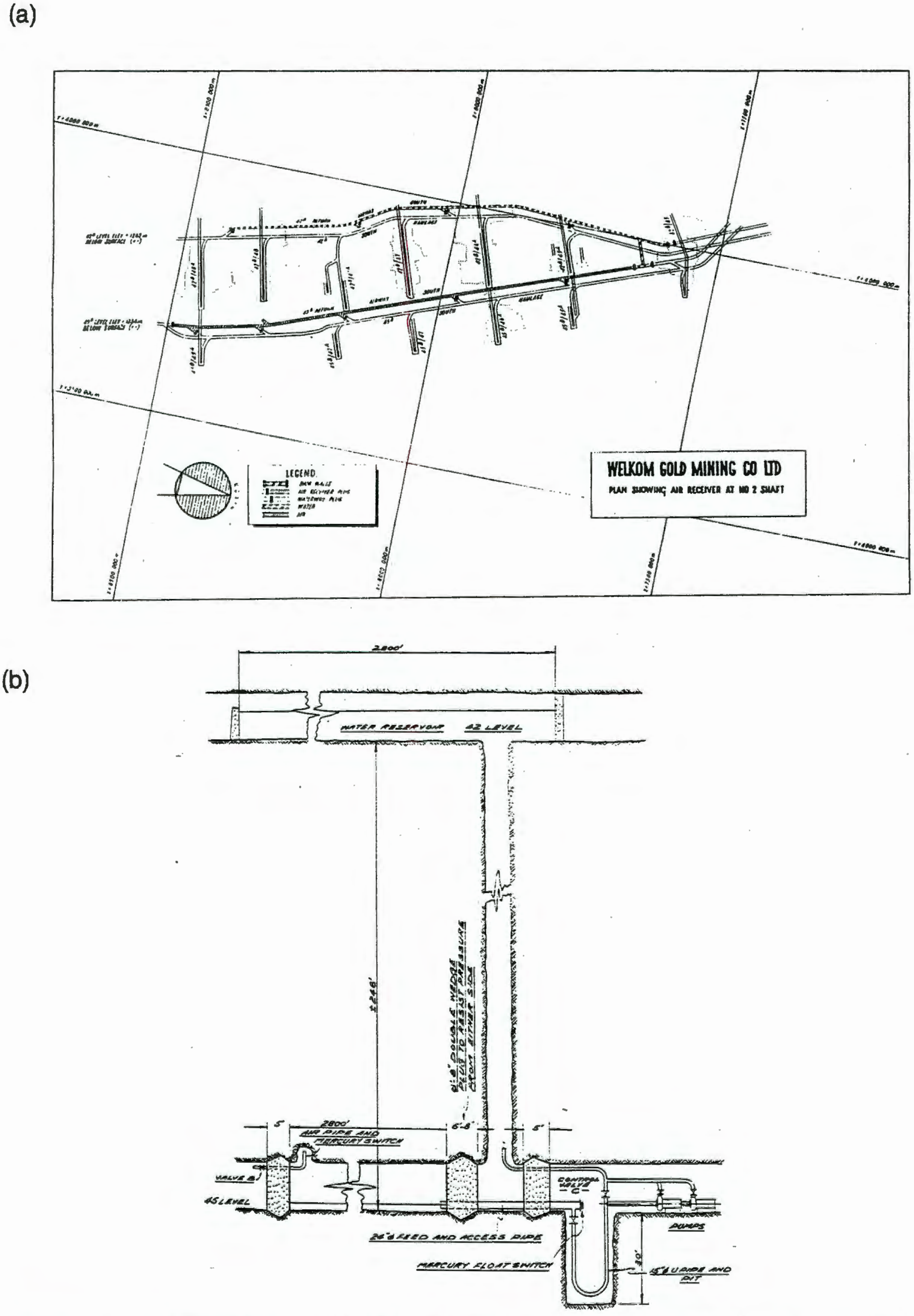


Figure 4.3: Air receiver installed at Welkom No.2 shaft using additional pumps(10)

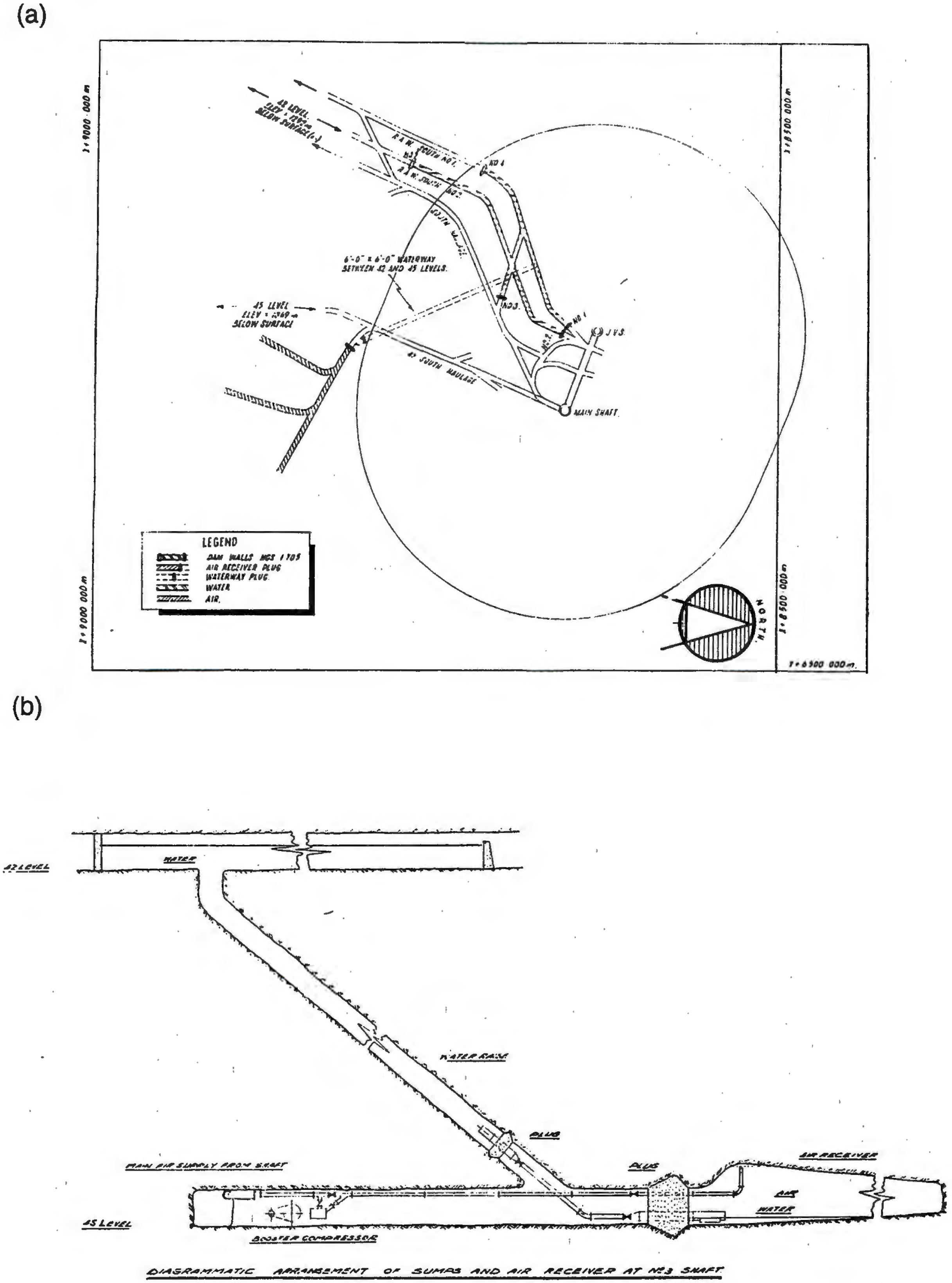


Figure 4.4: Air receiver installed at Welkom No.3 shaft using booster compressors[10]

Booster compressors may also be used in situations where the available head is small, as this would seriously affect the total quantity of air available. The booster compressor is used to increase the pressure of the air leaving the receiver.

Blyvooruitzicht goldmine(10) converted an abandoned twin cross cut system into air storage. Unlike the systems at Welkom no water was used to maintain pressures, and a constant volume receiver was developed.

4.4) SEALING UNDERGROUND RECEIVERS AND CONCRETE PLUGGING

Creating underground storage necessitates isolating existing excavations with concrete plugs and sealing all other possible places of leakage(11,13,14).

Due to the safety measures required in using air receivers and high pressure systems, a code of practice has been developed for the construction of underground plugs required to retain water under pressure(15). The code is also used for the development of concrete plugs used in retaining compressed air. The code covers the full design of underground plugs, including the process, requirements, process control, site selection, site preparation and equipment necessary for plug development. It continues with the placement and design of plugs, shuttering, aggregate placing, grout preparation, grout intrusion, stoppages during intrusion, strength requirements and sealing of the rock-plug interface and surrounding rock. Lastly the code has several notes on additives, concrete preparation machinery, calculations on plug length, and sand-cement ratio required. The design of all concrete plugs, used to contain pressurised volumes, need to be passed by the Government Mining Engineer.

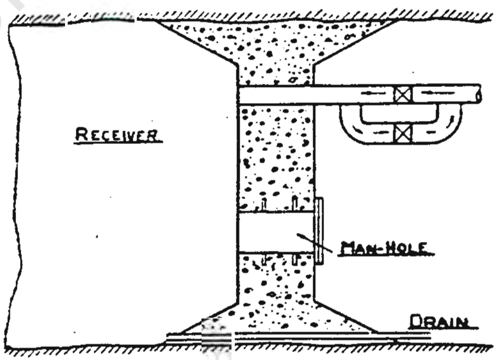


Figure 4.5: Standard friction concrete plug(12)

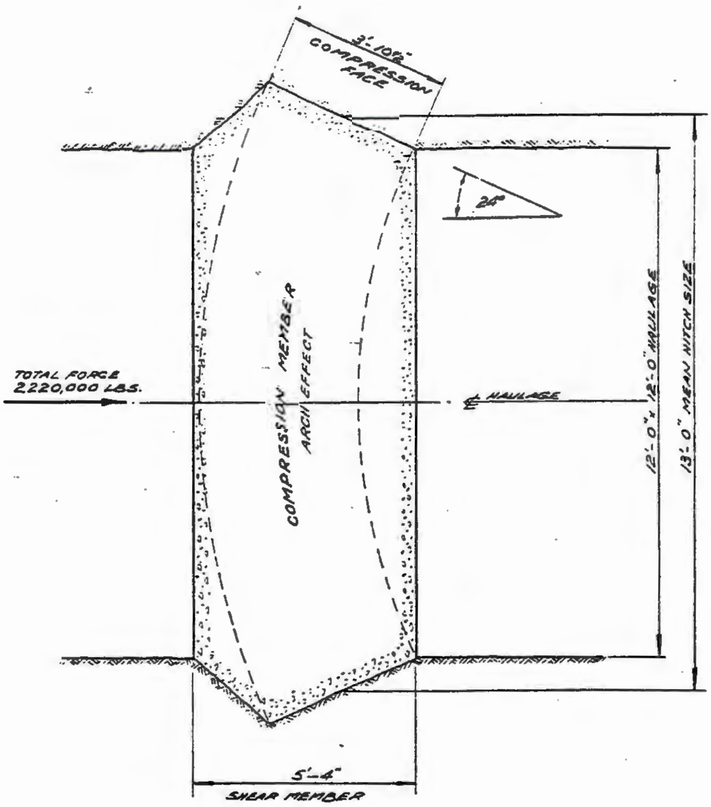


Figure 4.6: Semi-arch concrete plug(10)

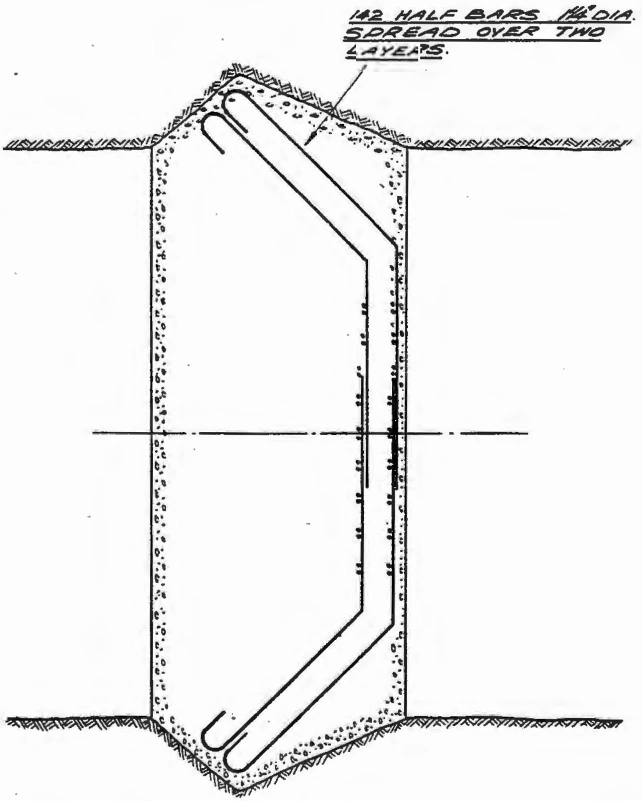


Figure 4.7: Steel reinforcement in a semi-arch concrete plug(10)

Plug design may vary from a standard friction type plug (Figure 4.5) to a semi-arch type (Figure 4.6). The following is a discussion of the semi-arch type plugs installed at the Welkom No.2 shaft underground air receiver(10). The plugs are depicted in Figure 4.6 and Figure 4.7. The plugs are a reinforced concrete wedge (semi-arch) designed to tighten under pressure, eliminating scaling of the sidewalls.

The design is such that all the retaining forces are directed in a wedge action against the rock face. Sufficient reinforcing steel was installed to take the entire shear force load while the concrete only acts as a compression member. The resultant of the forces imposed upon the plugs is at an angle of ± 66° to the polar axis of the drive. The walls are approximately 1,5 m thick and about 3,0 x 3,66 m maximum cross section. The calculations for the plug have been determined by Leimer(10) for a receiver pressure of 7,4 bar. Due to the weakening effect of the piping that may run through the plug it is assumed that the forces are only resisted by the wedge action on only two of the sides. The thickness is approximately half that of a friction type plug under the same load.

Diamond drill cores were taken of the rock and examined to determine the extent of rock fracturing before plug site finalisation could take place. Once site selection had taken place, it was prepared by barring down as much loose rock as possible. Next the wedging hitches were cut by blasting. The final size was achieved with smooth wall blasting. No pinning steel was installed due to the wedging action of this type of plug.

The installation of the plugs took place as follows:

- A mild steel frame was fabricated as an initial support for the reinforcing steel.
- All wall pipes were placed in position.
- The reinforcing steel was welded into position and the entire assembly painted.
- Shuttering was erected leaving an opening at the highest point for a concrete blower pipe to be fitted. The upper section on the one side was left open to enable concrete to be placed by means of a mini conveyor, final concrete placing being done by blower and by hand.
- The placing of concrete was completed in a non-stop shift.
- Shuttering was removed three days afterwards and the waterface of the plug was painted.

Cementation plugs were cast into the concrete, so that after curing of the concrete the plugs could be drilled to the concrete-rock interface and injected with a thick cement-sand grout. When this had set the pipes were re-drilled to a depth of 3 m into the rock, and injected with a cement slurry at a pressure of 68 bar. This was done to seal any cavities between the rock and plug and any cavities within the load zone of the plug. The results were successful with minimal losses. Slight leaks appeared at pressures of 1 MPa (10 bar) which required re-cementation.

A receiver installed at Western Deep Levels Limited(10) utilized standard friction type concrete plug. The formula(15) used for friction type plugs, as stipulated by the Government Mining Engineer is as follows:

$$\text{Plug Length} = \frac{\text{Area of plug x pressure}}{\text{Perimeter x shear stress}} \qquad (4.1)$$

The calculated length, at Western Deep, amounted to 0,762 m for a pressure of 8,3 bar, but a length of 3 m was installed to coincide with the maximum cross sectional dimension of the haulages as recommended by the Government Mining Engineer. This is standard practice for normal friction type plugs.

Harmony Goldmine(11) stipulates that the plugs must be situated in sound quartzite formations with a distance of at least 15 m around the plug be free of structural weaknesses such as faults and fissures. Further, the rock surfaces upon and adjacent to which the aggregate is to be packed must be:

- solid, free from any foreign material and standing water
- sufficiently rough to ensure a satisfactory bond with the concrete.

Rock surfaces in underground excavations are often cracked due to the powerful explosives used to break the very hard quartzitic rock. Rock bolts are frequently used in mine tunnels to hold small and large chunks of rock together(14).

Sealing does not only include the plugging of cross sections to isolate the area. Rock fracture and fissures require sealing to prevent losses from the receiver. Sections of receiver surfaces are often grouted with cement to prevent any leakage that may occur(13). Some mines grout approximately 15 m from the plug into the receiver. Fissures are problems, as they produce water sometimes at a considerable rate. To remove this water it is often necessary to drain large quantities of water from the receivers and drain pipes and pumps are required. Any area with fissures producing large amounts of water should be avoided. Any shale formations should also be avoided as they may be eroded through the movement of water in and out of the receiver(8).

It was suggested by Steed(14) that a volume be made airtight by covering some rock surfaces with plastic sheeting, held in position by adhesives. Adhesives are currently being used on damp rock surfaces with success.

An aspect to note is that, although leaks occur and decrease the amount of available air, in a constant pressure receiver the leaks do not allow for pressure loss as pressure is maintained by the water head(16). In a constant volume system the leaks cause both loss of available air and pressure.

4.5) IMPLEMENTED SIZES OF UNDERGROUND AIR RECEIVERS

The underground air receivers built in South Africa have been used at relatively low pressures, and the volumes have been adapted to the available space requiring the minimal amount of plugs and sealing. Table 4.1 gives a list of the volume and operating pressures of several South African air receivers.

Table 4.1: Air receivers operating pressure and volume

MINE & RECEIVER	TYPE	MAXIMUM OPERATING PRESSURE	AIR RECEIVER VOLUME
West Springs Ltd.(8)	Constant volume	5,2 bar	8950 m^3
Randfontein Estates(9)	Constant pressure	5,86 bar	6145 m^3
Welkom No.2 shaft(10)	Constant pressure	7,4 bar	9510 m^3
Welkom No.3 shaft(10)	Constant pressure	13,7 bar	2832 m^3
Western Deep Levels Ltd.(10)	Constant volume	8,27 bar	42957 m^3
Blyvooruitzicht(10)	Constant volume	7,7 bar	62300 m^3
Harmony Sub Vertical +14 level(11)	Constant volume	13,5 bar	45000 m^3

4.6) THE COST OF UNDERGROUND AIR RECEIVERS

The costs of underground receivers depend largely on seals and plugs used in isolating the required volume. Further costs include piping and valves connecting the receiver to the air mains, monitoring equipment and labour costs. A few costs are available and have been escalated to 1994 S.A.Rands. As mentioned, the Government Engineer requires that the plug length to be no shorter than maximum cross sectional dimension of the plug, resulting in large plug volumes.

The Welkom No.2(10) shaft receiver required the construction of seven concrete plugs in cross cuts and connections. The compensation water dam required four ordinary dam walls. The cost of installation was R48 000 (1971 Rands) (R900 000 in 1994 Rands), which excludes development costs as all the necessary excavations were available.

The cost of installation of the constant volume receiver at Western Deep Levels Ltd.(10) was considerably cheaper and is given in Table 4.2.

Table 4.2: Cost of air receiver at Western Deep Levels Ltd.(10)

Labour Costs	R 980
Sand & Cement	R 650
Gunniting & Pressurising	R 1900
Total (1971 Rands)	**R 3530**
Total (1994 Rands)	**R66 000**

Table 4.3: Construction cost of air receiver at Harmony Goldmine 14 level(11)

	Volume (m3)	**Cost (R/m3)**	**Total Cost (Rands)**
Plug 1 ex 14 level	77,76	700	54 432
Plug 2 ex 14 level	77,76	700	54 432
Plug 3 ex 6 level	77,76	700	54 432
Shaft plug below 31 level	178,03	700	124624
Total (1985 Rands)			**R 287 920**
Total (1994 Rands)			**R 920 000**

Table 4.4: Piping and monitoring equipment costs at Harmony

	Cost
660 m x 356 mm diameter piping at R52,08/m	R34373
1700 m x 50 mm diameter piping at R 4,50/m (Plastic)	R7858
650 m x 152 mm diameter piping at R36,00/m	R23400
2 x Ecolyser series 4000 CO monitors at R 3000 each	R6000
2 x centre flow recorders at R 2856 each	R5730
2 x flow/pressure recorders at R2856 each	R5730
2 x pressure recorders at R1427 each	R2854
Total (1985 Rands)	**R85 945**
Total (1994 Rands)	**R275 000**

The cost of the installation of the receiver at Harmony goldmine 14 level(11) is the most recent, quoted in 1985. The costs are given in Table 4.3 and 4.4. The concrete cost per/m^3 ex Rodio SA Pty Ltd = R700 / m^3 (1985 Rands). Table 4.3 shows the breakdown of the plug costs for the receiver. Table 4.4 is a breakdown of all the additional costs necessary for pipe connections into the system and monitoring equipment.

The total cost installation of the 45000 m^3 receiver at Harmony was R373 865 (1985 Rands) (R1,2 million in 1994 Rands), resulting in a conversion cost of approximately R 26,7/m^3 (1994 Rands) for a constant volume receiver at low pressure.

If the pressure in the receiver was to be increased, the concrete plug sizes would increase proportionally and hence also the costs. If the above receiver was to store air at 70 bar the construction costs would increase to approximately R1,4 million (1994 Rands). The piping and monitoring equipment costs would also increase but not as severely as the construction costs. For this analysis it is assumed that the piping and monitoring costs stay the same. The total cost of a high pressure receiver, the same size as the Harmony 14 level receiver, would be approximately R1,68 million(1994 Rands) approximately R 37,2/m^3 (1994 Rands).

4.7) CONSTANT VOLUME vs CONSTANT PRESSURE

It is generally accepted that the volume necessary for a constant pressure air receiver is smaller than that for a constant volume air receiver. It is possible to use the equations of state of a simple compressible substance(17) to determine the volume difference between a constant volume and constant pressure air receiver. By equating the amount of energy that has been extracted from the constant volume and constant pressure receiver the following result is obtained (See Appendix C):

$$\frac{V_p}{V_v} = \left(\frac{P_1}{P_2} - 1\right) \tag{4.2}$$

Where: P_1 = Fully charged pressure of constant volume receiver

P_2 = Completely discharged pressure of constant volume receiver
= Pressure of constant pressure receiver

V_v = Volume of constant volume receiver

V_p = Starting volume of constant pressure receiver

For:

$$P_2 < P_1 < 2P_2$$

$$V_v > V_p$$

(4.3)

For:

$$P_1 = 2P_2$$

$$V_p = V_v$$

(4.4)

For:

$$P_1 > 2P_2$$

$$V_v < V_p$$

(4.5)

From the above results the following may be determined for two ideal receivers. If the fully charged pressure, P_1, of the constant volume receiver is less than twice the extraction pressure, P_2, the constant pressure receiver will require a smaller volume than the constant volume receiver. Once the fully charged pressure, P_1, of the constant volume receiver is larger than twice the extraction pressure, P_2, the volume of the constant volume receiver required is less than the volume of the constant pressure receiver.

Applying the above deductions to the CAES plant at Alabama the following is determined. Alabama makes use of a constant volume underground air receiver, with a constant volume $V_v = 530\ 000\ m^3$, at a fully charged pressure $P_1 = 73$ bar. Air is withdrawn from the receiver at a pressure $P_2 = 45$ bar[(18)]. Applying formula (4.2), the volume of a constant pressure receiver, to supply the same amount of air at the same pressure, is

$$V_p = 0{,}623 \times V_v = 330\ 230\ m^3.$$

The Alabama CAES plant has an electric generating capability of approximately 2600 MWh. For the constant volume receiver the energy capacity of the air is approximately 4,9 kWh/m^3. If a constant pressure receiver was used with an underground water reservoir, approximately 660 460 m^3 would have to be converted or excavated underground. The usage of an underground water reservoir eliminates the development of a dam on ground level, therefore minimising costs. For a constant pressure receiver with a water reservoir the energy capacity of the air is 3,9 kWh/m^3.

Reverting to the South African situation, and using the underground excavation conversion costs, determined for the "high pressure Harmony receiver" (R37,2/m^3), the following results are obtained. The conversion cost of existing caverns for a constant volume air receiver is approximately R7,6/kWh. The conversion cost of existing caverns for a constant pressure receiver and underground water reservoir is approximately R9,5/kWh.

4.8) CONCLUSION

The best site for an air receiver is where the minimum number of seals is required, in an excavation that is no longer used. The plugs and seals must be passed by the Government engineer to meet the air receiver pressure criteria. The area must be accessable, and in the case of CAES must be connected with the turbo-machinery train through the shortest possible distance. The rock in which the receiver should be developed must be non-porous with no faults, slips or dykes, where leakage may occur. Seismicity poses a problem to the stability of underground workings and concrete plugging. It may counteracted by grouting and wire meshing any excavations.

Fissures are a common problem, releasing water that would effectively minimize the usable volume of the receiver. Unless the water pressure of the fissures can be counteracted through the air pressure, without air loss, fissures should be avoided. Drainage is important and needs to be included in air receivers, both for the drainage of fissure water and sludge.

A problem in mines is the production of noxious and explosive gases such as methane. Such areas should be avoided and internal gas monitoring devices need to be installed, e.g. for CO, CO_2 and CH_4.

Maintenance of constant volume receivers may take place during periods when the receiver is in a discharged state. Access doors may be situated in the concrete plugs, and should pose few problems as they have been used in receivers for many years. Constant pressure systems are a problem as, at the discharged state, the air receiver is full of water and maintenance is impossible.

According to Carr(5) and Steed(14) the most suitable depth for an air receiver is 1000 m below the surface. Other sources(13) suggest a depth of 2000 to 3000 m, as a lot of mining has taken place on these levels leaving large excavated volumes. The suggested depth of approximately a 1000 m is largely due to less rock stress and the closing down of workings. The receiver should be situated in excavations that are isolated and less likely to be subjected to high rock stresses by mining operations. The installation of a high pressure receiver similar to that of Alabama requires development. According to Roux(11) and Jenner(13), the development of a high pressure receiver should pose no problem, as it is expected that the rock will easily be able to withstand high air pressures. The limiting factor on the receiver is the concrete plug design and cost.

In South Africa air storage volumes of 530 000 m^3 and 330 000 m^3 need not only be developed in cross cuts. These volumes could include excavations around the reef area, inter-connected haulage tunnels, steeply dipping ore-passes and partly stoped-out areas. The standard dimensions of underground tunnels is 3 m x 3 m. For a constant volume receiver with a volume of 530 000 m^3, approximately 59 km of cross cut is necessary. For a constant pressure receiver 37 km is necessary for the air receiver of 330 230 m^3 and approximately the same for the underground water reservoir. Resulting in a volume of 660 460 m^3 underground.

There are many closed mines(6) in the immediate Johannesburg area and the Gauteng province which are potentially suitable for conversion. Most of the mining in Gauteng takes place in hard quartzitic rock, that would be suitable for a high pressure air receiver. Access to the reef is shown in Figure 4.8, through combinations of inclined shafts, vertical shafts and crosscuts, leaving large excavated area available for conversion. Both constant volume and constant pressure systems may be considered, as these reef mines have many crosscuts and ventilation ducts allowing scope for selecting the most suitable system.

Appendix D contains a list of worked-out goldmines around the country. Extensive research needs to be done to find a suitable mine with sufficient excavated volume needing the minimal amount of sealing and concrete plugs. Many mines are currently not being worked rather than abandoned. A rise in the gold price could result in the mines being reopened. Cavities of the order of 1 million m^3 are expected in some of these mines.

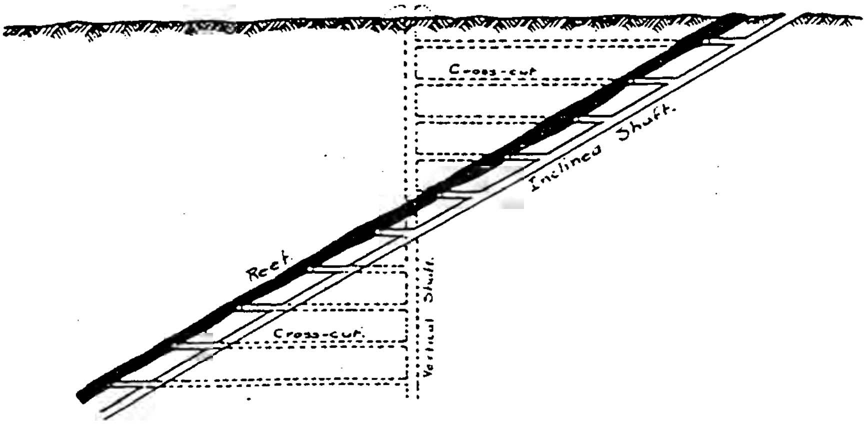


Figure 4.8: Mining in Gauteng(19)

Using the conversion costs of underground excavations derived from the "high pressure Harmony air receiver" of R37,2 /m^3, a 530 000 m^3 receiver would cost approximately R20 million (1994). The same analysis used in the constant pressure receiver results in a cost of R12,3 million (1994). This cost will double with the addition of a compensation water reservoir, resulting in a total cost of R24,6 million (1994). Comparing these costs to mine excavation costs of approximately R170/m^3 (1994)(11), the conversion of existing mine cavities is economically attractive.

With the inclusion of the water reservoir volume underground, as done in many mines, for a constant pressure system, the conversion cost is R9,5/kWh whereas the conversion cost of a constant volume receiver is approximately R7,6/kWh. Unless the water reservoir already exists, it would be more feasible to construct a constant volume receiver than a constant pressure receiver.

Not one of the receivers discussed in this chapter is still in operation, and it is not known if any receivers are still in use in the country(5,11,12,13,14). Problems occurring with leakages, seismicity and explosive gases have resulted in the decommissioning of the receivers.

CHAPTER 5

CONCEPTUAL DESIGNS

and

COST ANALYSIS

5.1) INTRODUCTION

The purpose of this chapter is to identify and cost CAES turbo-machinery configurations suitable for South Africa.

Several of the compressed air energy storage system configurations discussed in the literature review are suitable for South Africa. It is assumed that a CAES plant implemented in South Africa would consist of tried and tested technology combinations. Systems involving large thermal storage and steam injection systems have been rejected due to the additional research necessary before possible implementation could take place. Currently, conventional CAES and CAES with pressurised fluidised beds (CAES/PFBC) are the only viable systems. In South Africa the choice of fuelling is largely dependent on the availability of fuels in close proximity to the plant. The plant on the other hand is site specific, dependent on the location of the air reservoir.

5.2) CAES TURBO-MACHINERY SUPPLIERS

There are several CAES turbo-machinery suppliers around the world. Brown Boveri, the manufacturers of the turbo-expander train and motor-generator of Huntorf, have since become Asea Brown Boveri (ABB). Sultzer, suppliers of the Huntorf plant compressors, have passed their systems onto ABB. Reports indicate that the 290 MW conventional system, now with recuperator, is still available from ABB(1). It is assumed that a certain degree of development would be necessary.

Dresser-Rand, turbo-machinery supplier to the Alabama plant, still offers the same conventional CAES system(2). The system has a generating capability of 110 MW and uses 49 MW for compression. The charging ratio is 1:1,7, thus for every hour of generation, 1,7 hours is needed for compression.

There are reports that manufacturers such as General Electric and Westinghouse may offer designs similar to both Huntorf and Alabama(1).

The Alabama plant is the most modern CAES plant and is still fully operational. The Alabama plant is used as a benchmark for this analysis. All turbo-machinery costs in this analysis have been escalated from the Alabama plant and supplemented from other sources where necessary.

5.3) CONCEPTUAL DESIGNS

5.3.1) Conventional CAES

The Alabama turbo-machinery train is shown in Figure 5.1. This is the system still available from Dresser-Rand. The complete cost of the Alabama plant(3) was \$65 million or \$591/kW (1988 dollars) (R2560/kW 1994). Excavation costs of salt caverns were estimated at \$55/kW (1985 dollars) (R260/kW 1994) for a 2200 MWh plant by Nakhamkin and Schainker(4). The cost of a full 110 MW plant (turbo-machinery, engineering and infrastructure) excluding the air storage reservoir amounts to approximately R2300/kW (1994 Rands)(R253 million). This plant may be fuelled with natural gas or fuel oil.

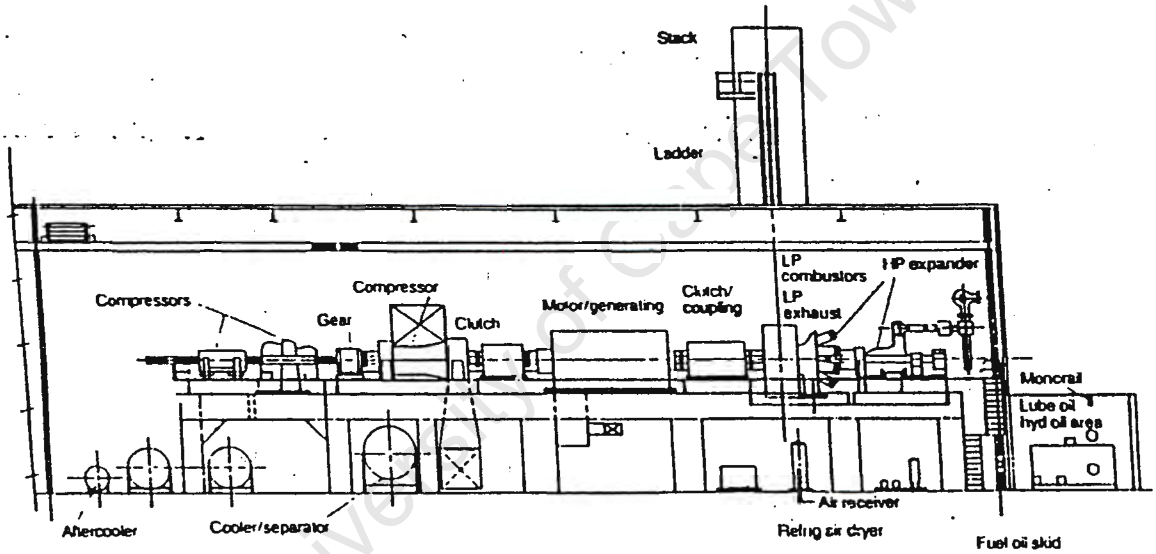


Figure 5.1: Dresser-Rand's CAES turbo-machinery train(5)

The turbo-machinery train consists of multistage compressors with intercoolers, clutches, a combined motor-generator and high and low pressure turbo-expanders(5). Fuel is added before both expansion stages. The addition of fuel before the high pressure expander is not always necessary as hot air may be received directly from the recuperator. The cost of removing the high pressure combustor may be justified, as this combustor experienced several problems in the Alabama plant(6).

Other layouts may split the motor/generator into separate units. The separation of the motor and the generator has added advantages of flexibility and immediate response without the time delays involved with clutch coupling. It would be necessary to justify the costs of an extra unit when reversible units are highly efficient.

Natural gas may be obtained from three possible gas fields in close proximity to South Africa(7). The first field, is situated offshore from Mosselbay supplying largely the Mossgas synfuel plant. The second gas field is the Pande gas field in Mozambique. Through the involvement of ENRON, IDC, Empresa Nacional de Hidrocarbonetos and the World Bank it is expected that the Pande fields will begin supplying gas to Gauteng and Natal by 1997. The last gas fields, are the Kudu gas fields in Namibia. These fields could possibly supply a power plant in the Northern Cape. It is expected that gas from Pande would be cheaper than gas from Kudu or Mosselbay, but still more expensive than coal(8). The price for gas in Gauteng ranges from 1353 c/GJ to 3507 c/GJ (1994) depending on the load factor of the gas utilising plant(9).

5.3.2) CAES with fluidised bed combustors

Approximately 3500 million tonnes of coal will be mined in South Africa by the year 2000(7). This will add approximately 800 million tonnes to the 500 million tonnes that already exists. The upgrading of coal to export quality remains the main reason for the generation of discard coal. Using good quality coal is an unnecessary expense when discard coal may be combusted in a fluidised bed combustor. The combustion gases can be used to drive a turbine.

In the literature survey several layouts using pressurised fluidised beds (PFBCs) were discussed(10,11). Using PFBCs, the turbo-machinery layout could be the same as that shown in Figure 5.1. The combustors are simply replaced with PFBCs in two possible configurations shown in Figures 5.2 and 5.3. The configuration shown in Figure 5.2 uses the cavern air to fluidise the bed(11). Coal combustion takes place directly in the cavern air stream and is piped through a filter system to the turbines. This is the conventional way that PFBCs are used in industry for heating purposes, but to date no high pressure (40+ bar) system has been built in South Africa(12). The configuration in Figure 5.3 heats the cavern air indirectly(11). The PFBC is self-contained so that the combustion gases of the PFBC are used to drive a turbine and compressor that pressurises the ambient air and maintains the pressure within the bed. An additional compressor may be used, to achieve the correct pressure and volume flowrate. In this system the cavern air is heated indirectly having the advantage of not requiring filtering. Pressurised fluidised beds using pressures of 6 bar are acceptable and have been constructed and may be implemented in this type of arrangement(10,11).

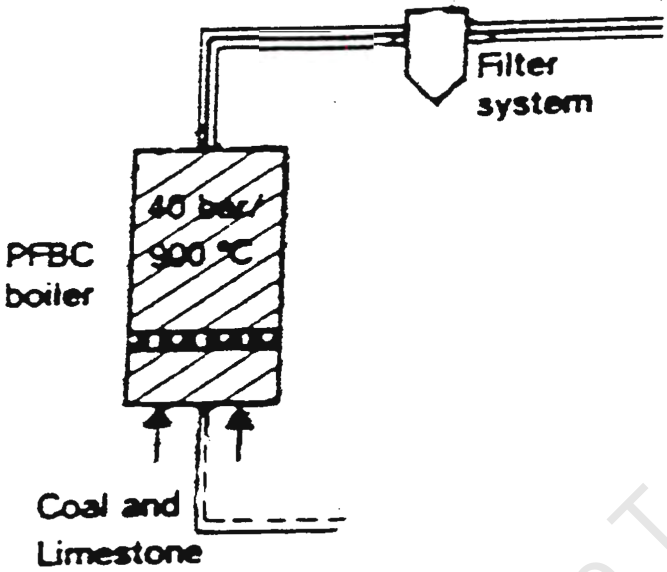


Figure 5.2: Direct air heating with a pressurised fluidised bed combustor(11)

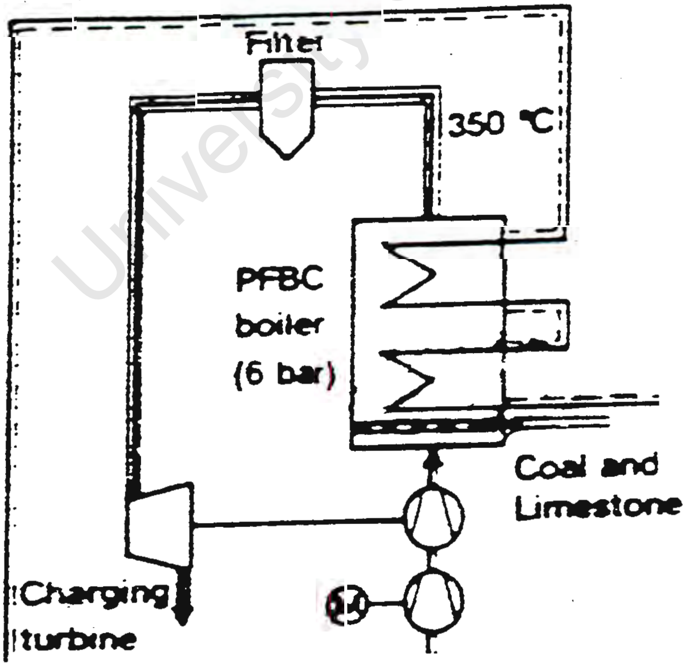


Figure 5.3: Indirect air heating with a pressurised fluidised bed combustor(11)

To determine the size of the PFBCs necessary to replace the standard combustors on the Alabama plant the heat input to the cavern air is approximated by assuming an ideal gas relation and applying the following equation(13):

$$Q = E_{final} - E_{initial} + W \tag{5.1}$$

Where
Q = Heat transfer (J)
$E_{initial}$ = Initial energy of the system (J)
E_{final} = Final energy of the system (J)
W = Work done by the system = 0

This equation may be rewritten as follows:

$$\dot{Q} = \dot{m}\,(h_{final} - h_{initial}) \tag{5.2}$$

Where
$\dot{Q}$ = Rate of heat transfer (W)
$\dot{m}$ = mass flow rate (kg/s)
h = enthalpy (kJ/kg)

Thus

$$\dot{Q} = \dot{m}C_{po}\,(T_{final} - T_{initial}) \tag{5.3}$$

Where
C_{po} = Specific heat of air at constant pressure = 1,0035 kJ/kgK
T = Temperature (K)

The high pressure combustor at Alabama increases the air temperature from 290°C to 540°C at a mass flowrate of 155 kg/s(5). The heat input is thus $\dot{Q}$ = 39 MW. The low pressure combustor increases the air temperature from 381°C to 870°C at the same mass flowrate as above resulting in a heat input of $\dot{Q}$ = 76 MW. The two PFBCs replacing the standard combustors would require capacities of 39 MW and 76 MW respectively. It is assumed that the combustion efficiency is 100% resulting in slightly smaller PFBC capacities than actually required.

Recently (1994/1995), a 4600 kW PFBC hot-gas generator plant was commissioned by the Hartley platinum mine in Zimbabwe from John Thompson Africa at a cost of R1,3 million(14). This cost may be escalated for an estimation on the suitable PFBCs for a CAES system through a cost-capacity relationship(15).

$$C_B = C_A \times \left(\frac{S_B}{S_A}\right)^x \tag{5.4}$$

Where C_B = Cost at capacity B
C_A = Cost at capacity A
S_B = Capacity B
S_A = Capacity A
x = Cost-capacity factor
= 0,75 (An acceptable factor in the absence of sufficient information)

The cost of a 39 MW PFBC plant would be R6,5 million and the cost for the 76 MW PFBC plant would be R11 million, a combined cost of R17,5 million (R160/kW 1994). An estimate for a CAES plant such as Alabama with PFBC would be to add these PFBCs costs to that of the normal plant. A PFBC/CAES with a turbo-machinery layout such as Alabama, excluding the cavern, would cost approximately R2460/kW (1994)(R270,5 million 1994).

Discard coal may be utilised as the standard fuel for a CAES/PFBC plant(16). South Africa's coal reserves are located in Mpumalanga, the Waterberg, the northern Orange Free State and Northern Natal(7). These deposits are mostly in thick, easily worked seams near the surface which allows mining at low cost. The cost of discard coal is made up largely of transport costs, as mining and benefication (the process of separating coal grades) costs are currently added onto the price of export coal. There are very few uses for discard coal and CAES/PFBC systems will lessen the stockpile. The cost of grade D coal is 204,73 c/GJ (1994)(9). It is expected that discard coal will be even cheaper than this figure. From the figures available(9), it is estimated that the cost of transport would be less than 7200c/GJ.

5.4) FUTURE DEVELOPMENTS

CAES is not limited through turbo-machinery development. In both the Huntorf and the Alabama plant the high pressure expander is an adapted steam turbine. Currently there are stand-alone steam units producing 1500 MW electricity, such as the Arabelle steam turbine unit installed at the Chooz B nuclear power station in France(17). Gas turbine technology has allowed for units as large as 240 MW to be developed, e.g. Siemens V94.3A(18). Removing the compressor unit of this gas turbine, as in the CAES layout, the 2/3 of power that would have been lost, may now be used to produce an extra 480 MW, resulting in a turbine capable of generating 720 MW of electricity. The future generating capability of CAES may easily be over 1000 MW, as long as a balanced system may be developed. Higher pressures may be needed, but the compressor technology, with suitable intercoolers, already exists.

Pressurised fluidised bed combustors may also be used, as their development is also still ongoing. Recently a 360 MW electric PFBC combined cycle plant has been commissioned at the Karita site in Japan(19).

Making the assumption that a single CAES turbo-machinery train may be developed delivering a 1000 MW, equation 5.1 is used to estimate costs. Using the same cost-capacity factor of 0,75, a cost of R1325 /kW (1994)(R1325 million 1994) is obtained for the conventional CAES plant with natural gas combustors and R1416/kW (1994)(R1416 million 1994) for the CAES/PFBC plant (no cavern).

5.5) CONCLUSION

Table 5.1 shows comparative costs for the type of plant likely to be implemented in South Africa. To achieve the criteria laid out in the previous chapters of load demand and cavern volume, several turbo-machinery trains may be implemented. Multiples of the costs indicated may be used to achieve the correct generating capacity. The costs produced in this table are for the full plant (engineering, equipment, infrastructure etc.) excluding the cavern.

CAES plants in Gauteng could use natural gas from Pande, as this field is situated on-shore and will be cheaper to exploit than other fields situated off-shore. Pande gas should be supplied to Gauteng by 1997. A second source of gas exists through GASKOR, who supply SASOL-gas through an established distribution network. Discard coal may also be used in Gauteng as it is in clear abundance and at low cost. Coal in Gauteng is substantially cheaper than natural gas.

Table 5.1: Comparative capital costs of CAES units, excluding cavern costs

CAES CONFIGURATION	COST	FUEL
Conventional CAES		
▪110 MW	R2300 /kW	Natural Gas
▪1000 MW	R1325 /kW	Natural Gas
CAES/PFBC		
▪110 MW	R2460 /kW	Discard Coal
▪1000 MW	R1416 /kW	Discard Coal

A CAES plant in the Mosselbay area using a depleted natural gas aquifer as an air storage reservoir would use the natural gas available from these fields. A conventional system would be best suited for this area.

The CAES configuration of a plant anywhere else in the country would be determined by the availability of fuels in these areas.

CHAPTER 6

CONCLUSION

The objective of this dissertation was to investigate compressed air energy storage as an alternative generation capacity for the South African electricity industry.

In chapter one, *an introduction to energy storage*, electrical energy storage was introduced as an alternative generation option. Various energy storage technologies were discussed with their characteristics and applications. Compressed air energy storage was identified as a competitive energy storage option to pumped hydro in particular, and a suitable contender for the South African electricity market.

In chapter two, *the literature review*, an in-depth study into compressed air energy storage was conducted. Many aspects of CAES were covered including CAES variants, underground pressurised air storage, projects and pre-feasibility studies, and operational plants. Due to the additional fuelling that certain CAES variants require, a Charge Energy Factor and a Fuel Heat Rate were defined. From the literature review it was seen that to date, only two CAES plants are still in operation. They are both of the conventional CAES type and use fuel-oil or alternatively natural gas for combustion

In chapter three, *an analysis of Eskom's demand*, Eskom's future demand growth was analysed. A prediction in load growth, based on several economic scenarios, was made and the capacity of a suitable CAES plant, to meet this future demand, was determined.

Chapter four, *underground air storage reservoirs*, focused on the aspects and prospects of storing compressed air underground in South Africa. Past underground air storage in South Africa was discussed and unused goldmines were identified as the most convenient and cost effective storage volumes available. The uniqueness of individual underground air storage volumes in mines were discussed as well as techniques necessary for the conversion of existing cavities. Both constant volume and constant pressure systems were investigated and mine cavern conversion costs where estimated per electric energy generated (R/kWh).

Two of the most likely CAES turbo-machinery configurations suitable for South Africa were evaluated in chapter five, *conceptual designs and cost analysis*. The two types of CAES were conventional CAES and CAES with pressurised fluidised bed combustors (CAES/PFBC). Available plant was discussed and future generating capacities of individual CAES turbo-machinery trains were predicted. Costs per kW for CAES plants, excluding the cavern, were estimated through the escalation of costs from other plants and sources.

The results of this dissertation are summarised in Table 6.1.

Table 6.1: The capital costs of CAES plants in South Africa

CAES CAPACITY	PLANT COST (CAVERN EXCLUDED)	HOURS OF GENERATION	STORAGE VOLUME	TYPE OF STORAGE	COST OF STORAGE (CAVERN COST)	PLANT COST
	POWER TERM				ENERGY TERM	
			CONVENTIONAL CAES			
1000 MW 54000MWh	R 1325/kW	54 h	11 million m^3	Constant Volume	R 7,6/kWh	R1735 mill R1735/kW
220 MW 4900 MWh	R 2300/kW	22 h	1 million m^3	Constant Volume	R 7,6/kWh	R542,8 mill R2467/kW
1000 MW 54000MWh	R 1325/kW	54 h	14 million m^3	Constant Pressure	R 9,5/kWh	R1838 mill R1838/kW
220 MW 3900 MWh	R 2300/kW	18 h	1 million m^3	Constant Pressure	R 9,5/kWh	R543,6 mill R2471/kW
			CAES / PFBC			
1000 MW 54000MWh	R 1416/kW	54 h	11 million m^3	Constant Volume	R 7,6/kWh	R1826 mill R1826/kW
220 MW 4900 MWh	R 2460/kW	22 h	1 million m^3	Constant Volume	R 7,6/kWh	R578 mill R2627/kW
1000 MW 54000MWh	R 1416/kW	54 h	14 million m^3	Constant Pressure	R 9,5/kWh	R1929 mill R1929/kW
220 MW 3900 MWh	R 2460/kW	18 h	1 million m^3	Constant Pressure	R 9,5/kWh	R578,8 mill R2631/kW

In the above table a breakdown is given of the capital costs of two types of CAES plant in South Africa. The two types of plant are, firstly conventional CAES and secondly, CAES/PFBC. Both these types of plants are suitable for South African circumstances, where conventional CAES would use natural gas for combustion purposes and CAES/PFBC would use discard coal. Both CAES variants are based on the Alabama turbo-machinery layout.

Two sizes of power generating capacity are shown for the different CAES variants, firstly a 1000 MW plant and secondly, a 220 MW plant. The 1000 MW plant is based on the information supplied in chapter five. In chapter five it is established that a plant of 1000 MW could exist with current technology. The 220 MW CAES plant is defined on the assumption that one mine of 1 million cubic meters may be used as an air storage reservoir. The capacity of 220 MW has been escalated from the 110 MW Alabama plant which has an air storage reservoir of 530 000 m^3.

Two storage costs have been defined as determined in chapter four. A constant volume reservoir cost and a constant pressure reservoir cost. For this analysis it was assumed that no surface water reservoir already exists. Therefore the volume of the constant pressure reservoir includes the water reservoir underground, such as many mines have implemented in the past, resulting in the higher cost. If a surface reservoir existed the costs of the receiver for a constant pressure system would be the same as for a constant volume system. Further, all storage takes place underground to be converted from existing mining cavities, as this has proven cheaper than excavating new caverns.

Approximately 8000 MW of CAES capacity is necessary to meet future demand in addition to a constant baseload supply. In chapter three it was determined that a CAES plant with a generating capacity of 7724 MW supplying 426059 MWh of energy would meet the customers demands in the year 2010, as long as a constant 39845 MW was generated by baseload plant. This was based on a load growth of 4,0% and the plant would need to be implemented before 2006. In approximately 2006, Eskom's maximum demand is going to exceed its total installed capacity of 39769 MW. By installing a CAES plant of 7724 MW (≈8000 MW) supplying 426059 MWh (≈432000 MWh) before 2006, no further baseload plants would need to be implemented before 2010 or possibly later. It is in 2010 when the constant baseload demand of a CAES system of 7724 MW exceeds the installed capacity of Eskom, that additional power suppliers need to be sought. The Southern African power pool could provide a constant baseload supply, while a CAES system meets the peak demands.

A CAES capacity of 8000 MW would consist of eight 1000 MW units. A CAES capacity of 8000 MW supplying 432000 MWh would require either a constant volume air storage system of 88 million cubic meters capacity or a constant pressure system of 111 million cubic meters capacity.

On the assumption that a single unworked mine could have 1 million cubic meters of volume available(1), between 88 and 111 mines would be necessary for a 432000 MWh / 8000 MW CAES system. The development of air storage cavities of this capacity is extensive, and will be the limiting factor on any large CAES system.

As shown in Table 6.1, the choice of CAES variant and air storage combination from the cheapest to most expensive is as follows:

- Conventional CAES with constant volume storage
- CAES/PFBC with constant volume storage
- Conventional CAES with constant pressure storage
- CAES/PFBC with constant pressure storage

The capital costs for a CAES capacity of 1000 MW is competitive to that of a fossil fuelled plant. The capital cost of a six unit coal fired plant is approximately R3000/kW(2). All the 8000 MW systems' capital costs are less than two-thirds the capital costs of a coal fired plant. A single 1000 MW unit could be competitive with pumped hydro as the capital costs of a pumped hydro scheme are approximately R1800/kW(3). The storage volume is the limiting factor in both systems.

For both the 220 MW conventional CAES and the CAES/PFBC systems, the systems using constant volume air reservoirs are slightly cheaper than the constant pressure systems. In the situation of a water reservoir already existing the result would be reversed.

Due to the limited underground storage available in South Africa, without unnecessary excavations, the most suitable CAES installation would be the 220 MW system. Two CAES turbo-machinery plants the size of Alabama could be implemented. The likelihood of applying this system to an underground storage cavern, converted from a mine, in the Gauteng area is greater than anywhere else in the country. The reason for this is the large amount of mining that has commenced in the area in the past, and the close proximity to a major load centre.

In Gauteng water usage is already limited and the existence of "ready to use" compensation reservoirs are unlikely. Constant pressure underground air storage systems would need to have their compensation water reservoirs situated underground, diminishing the available volume, and thus the available energy. The result of this is shown in Table 6.1. The most suitable solution, where underground storage is limited, is that of a constant volume air storage cavern. The full cavity may be utilised, although less efficiently than a constant pressure system. As shown in Table 6.1 more energy is stored through a constant volume system than through constant pressure storage system.

It would be difficult to justify the use of a CAES/PFBC plant above that of a conventional CAES plant on a capital cost basis. As shown in Table 6.1 both 220 MW CAES/PFBC plants are more expensive than the conventional 220 MW CAES plants. Taking generating costs into consideration, the cost of discard coal per gigajoule is less than that of natural gas and may justify the choice of CAES/PFBC over conventional CAES. The maintenance of a CAES/PFBC plant would be greater than that of a conventional CAES plant due to coal handling, combustion and the air filtering aspects of a fluidised bed combustor.

A conventional CAES plant with a constant volume air receiver would be the most suitable CAES system for South Africa.

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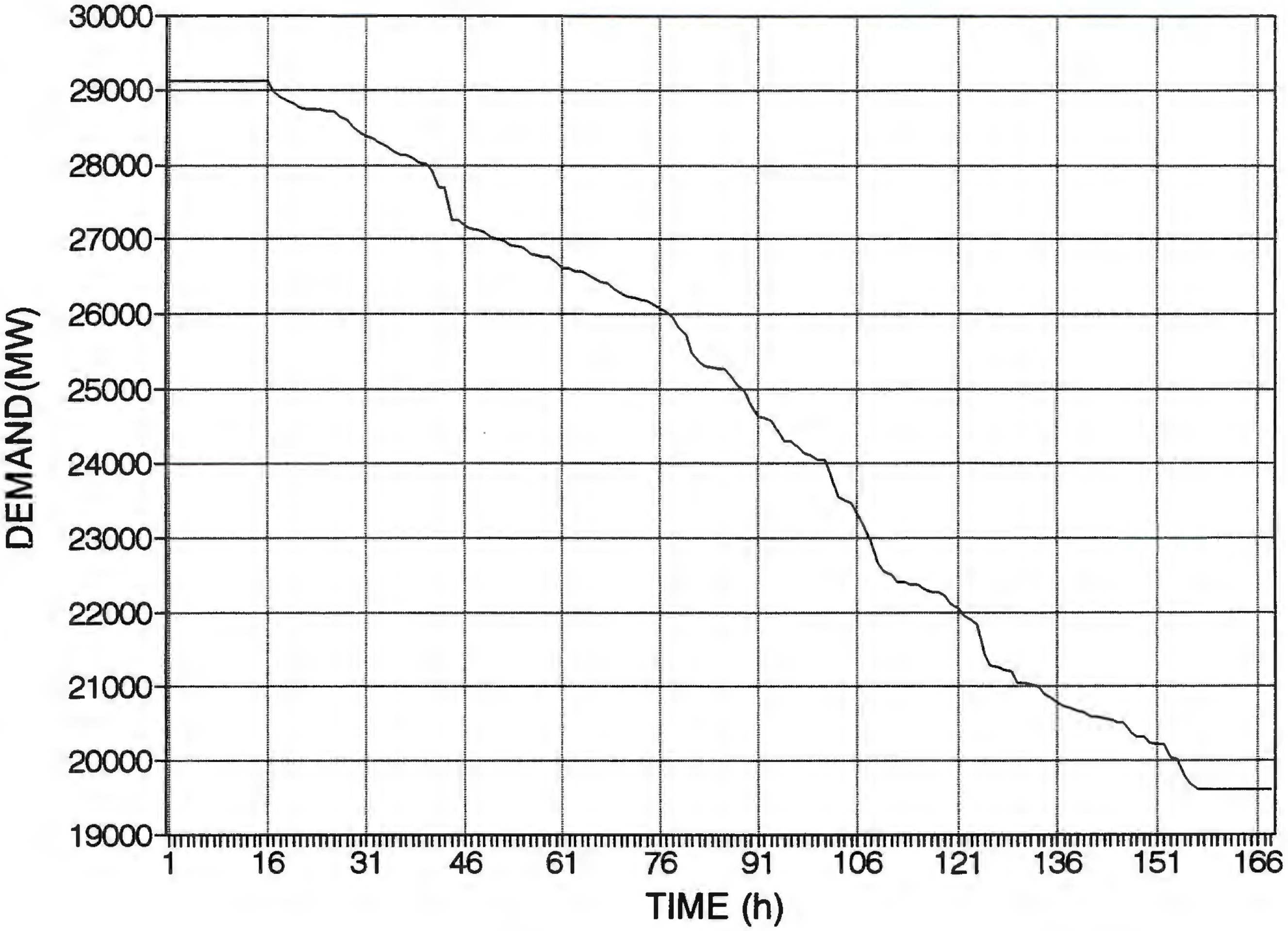
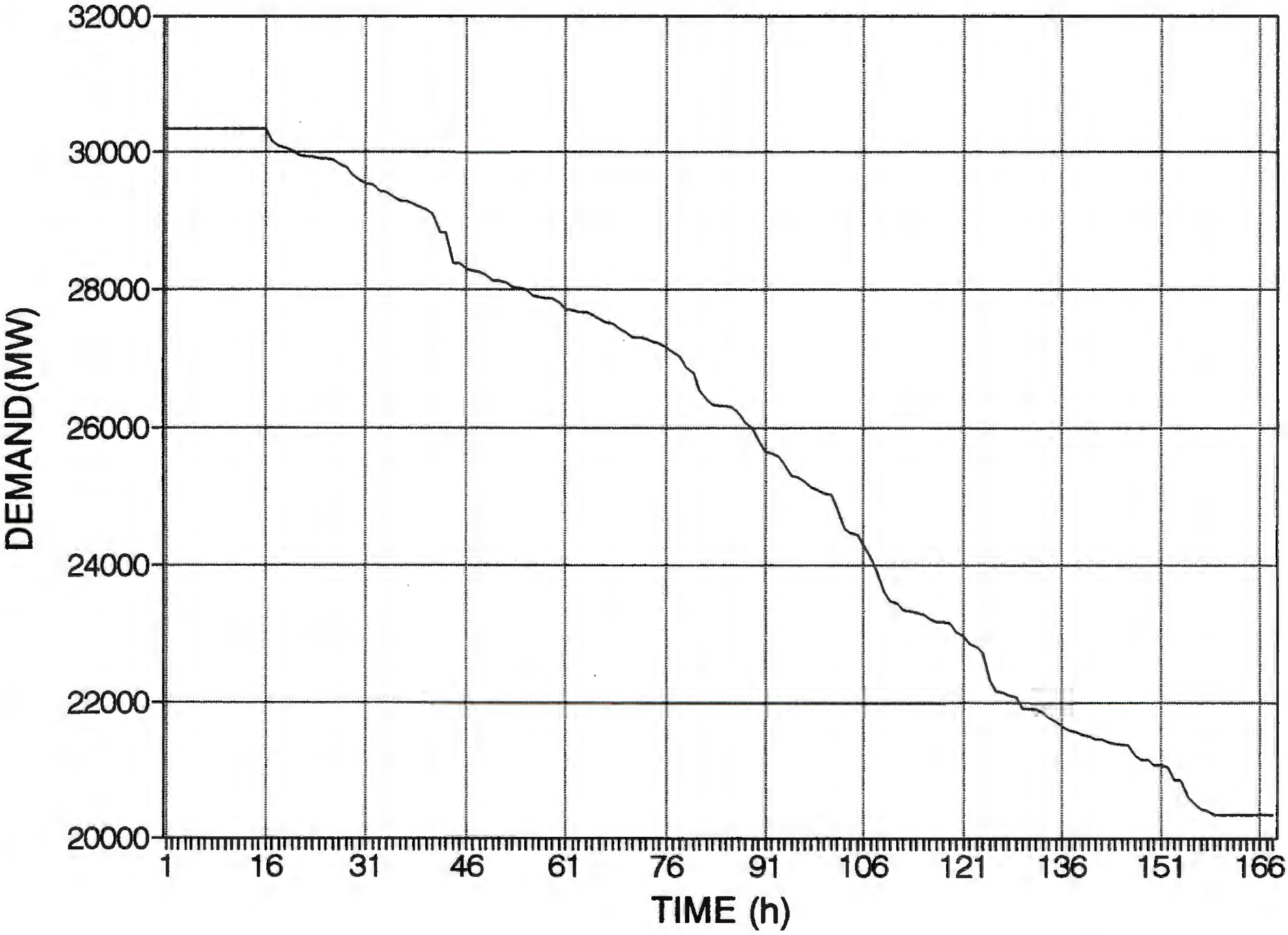
APPENDIX A

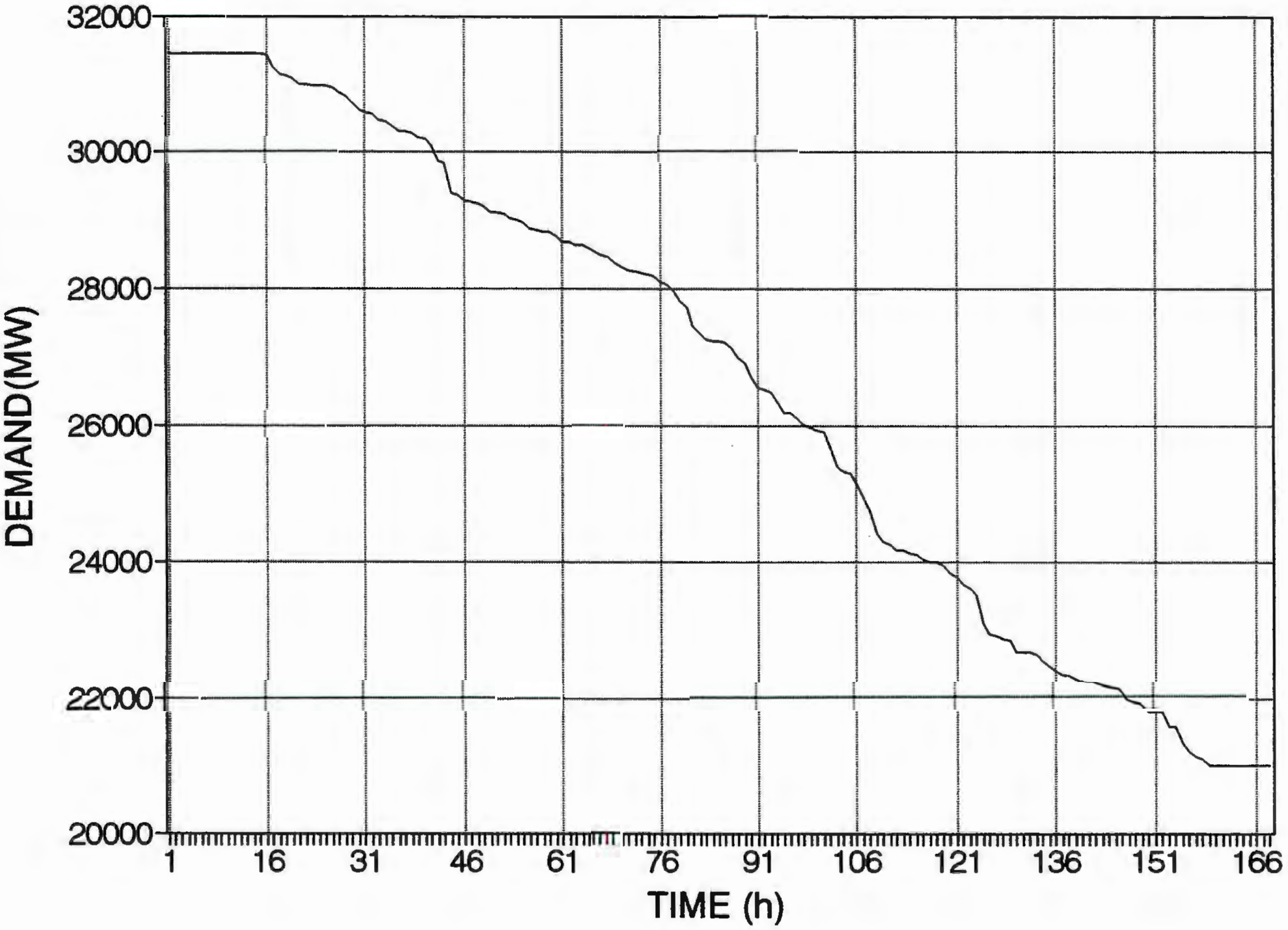
THE EFFECT OF PUMPED STORAGE on ESKOM'S SYSTEM LOAD



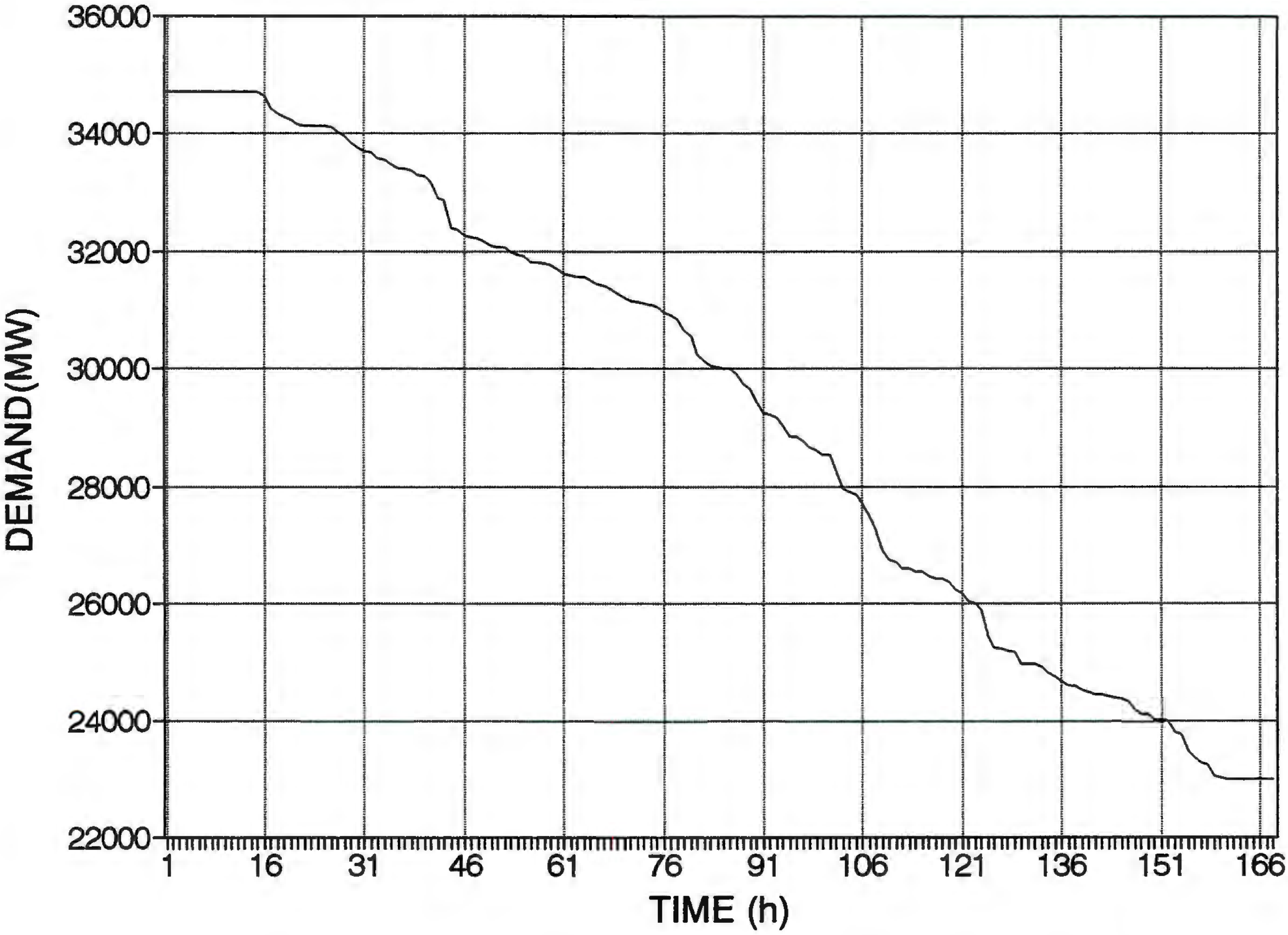
EFFECTS OF PUMPED STORAGE
YEAR 2000 - 3,3%



EFFECTS OF PUMPED STORAGE
YEAR 2000 - 4,0%

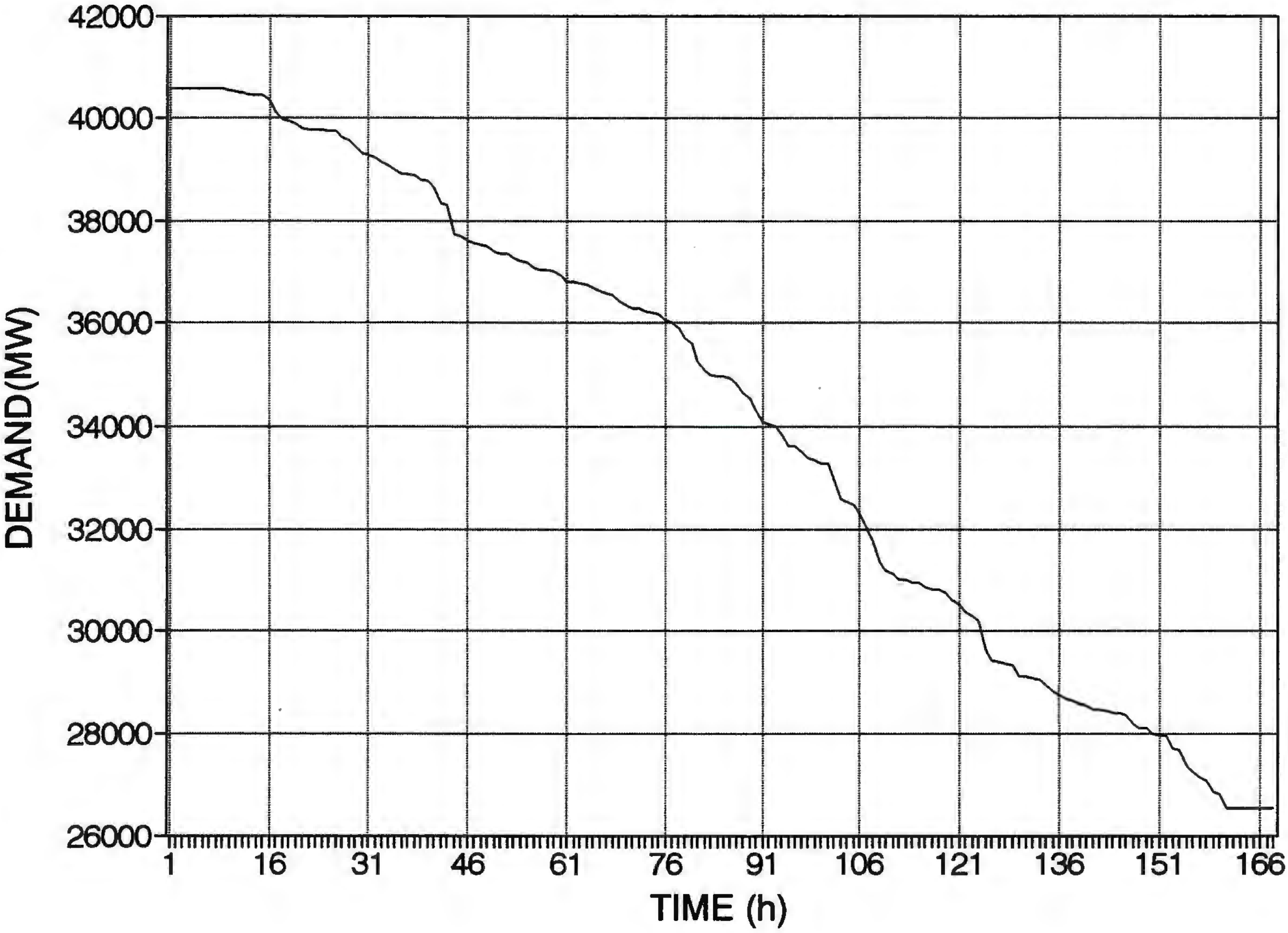


EFFECTS OF PUMPED STORAGE
YEAR 2000 - 4,6%



EFFECTS OF PUMPED STORAGE
YEAR 2000 - 6,3%

EFFECTS OF PUMPED STORAGE
YEAR 2010 - 3,3%



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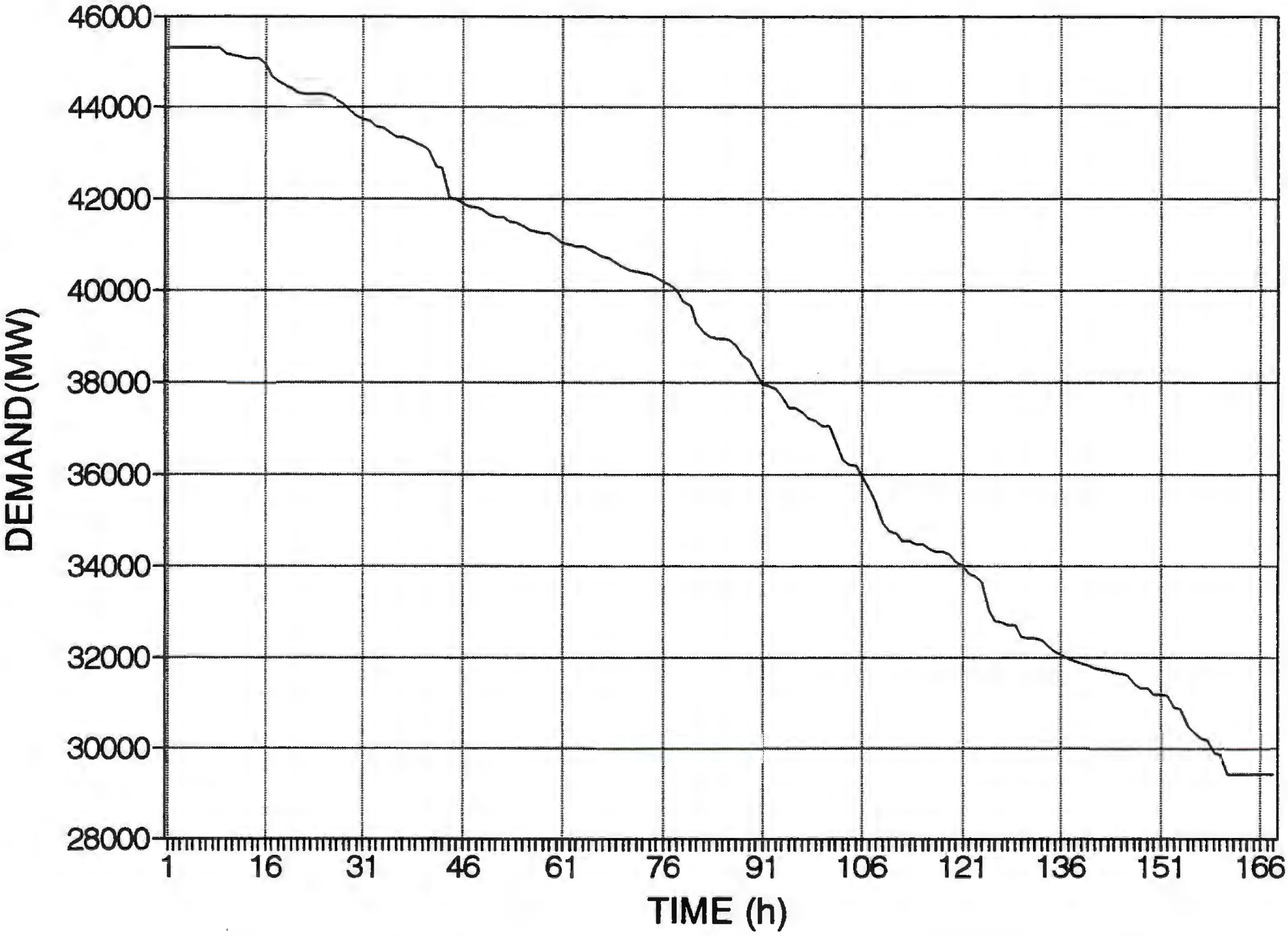

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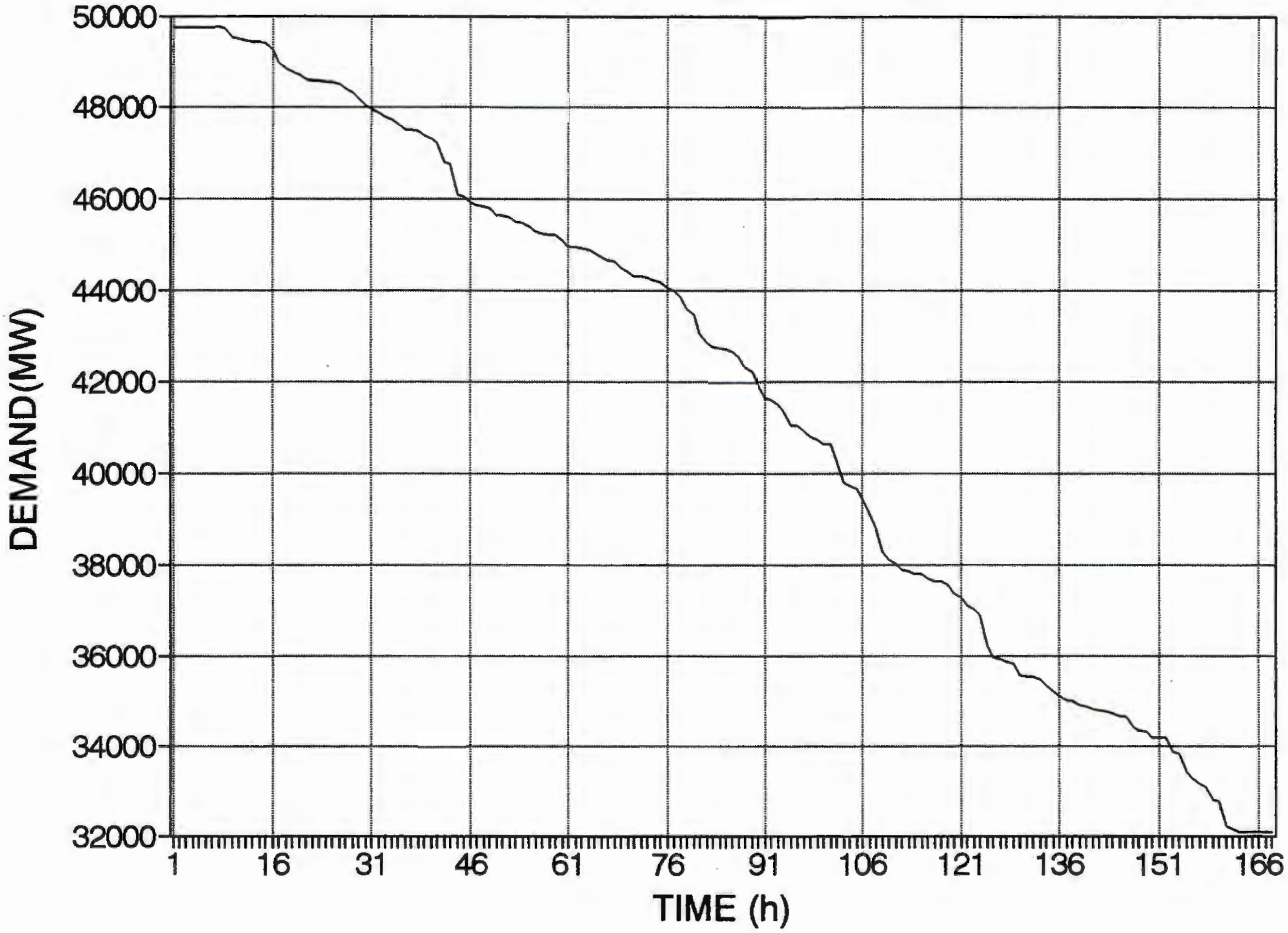
YEAR 2010 - 4,6%



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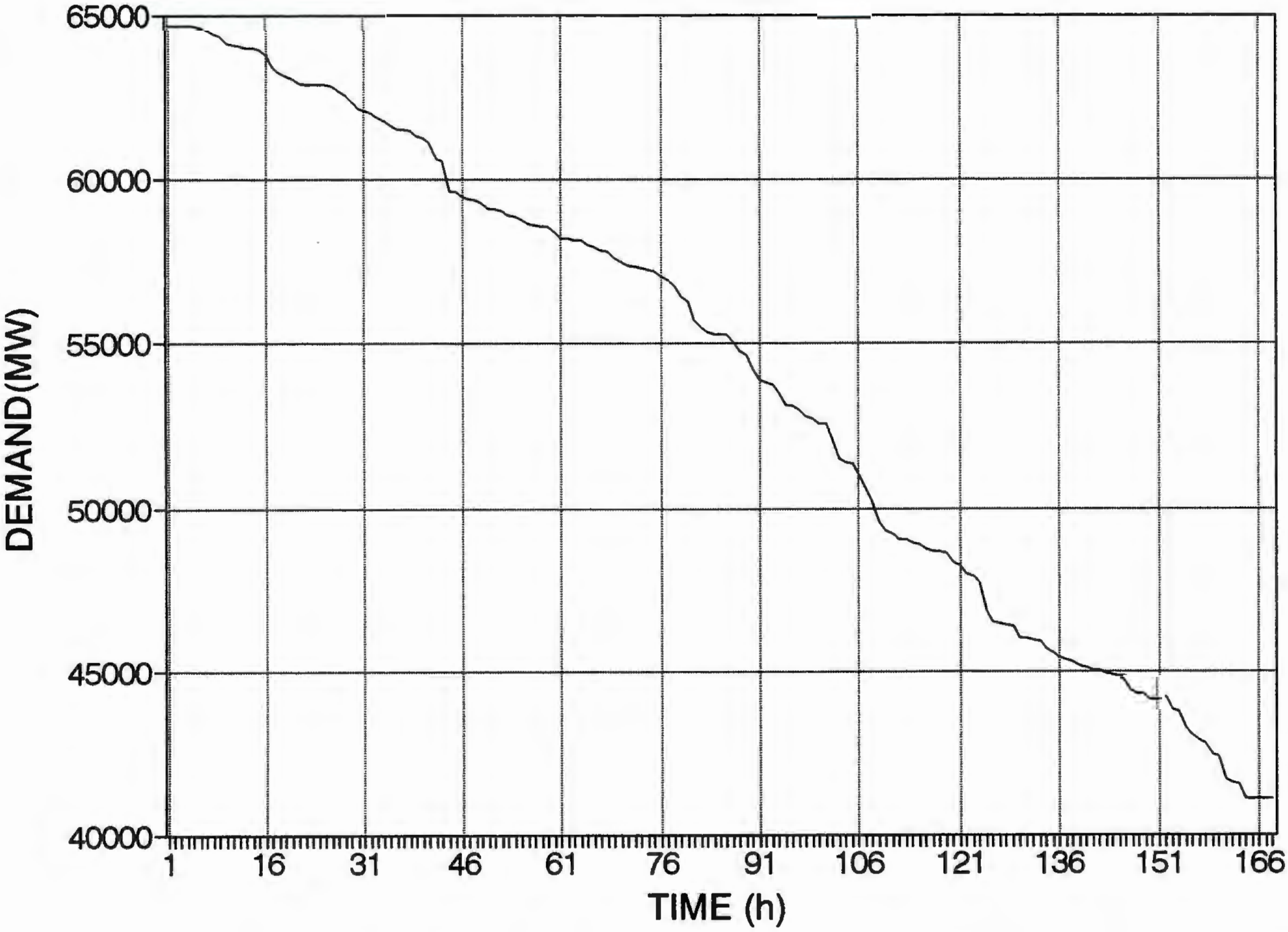
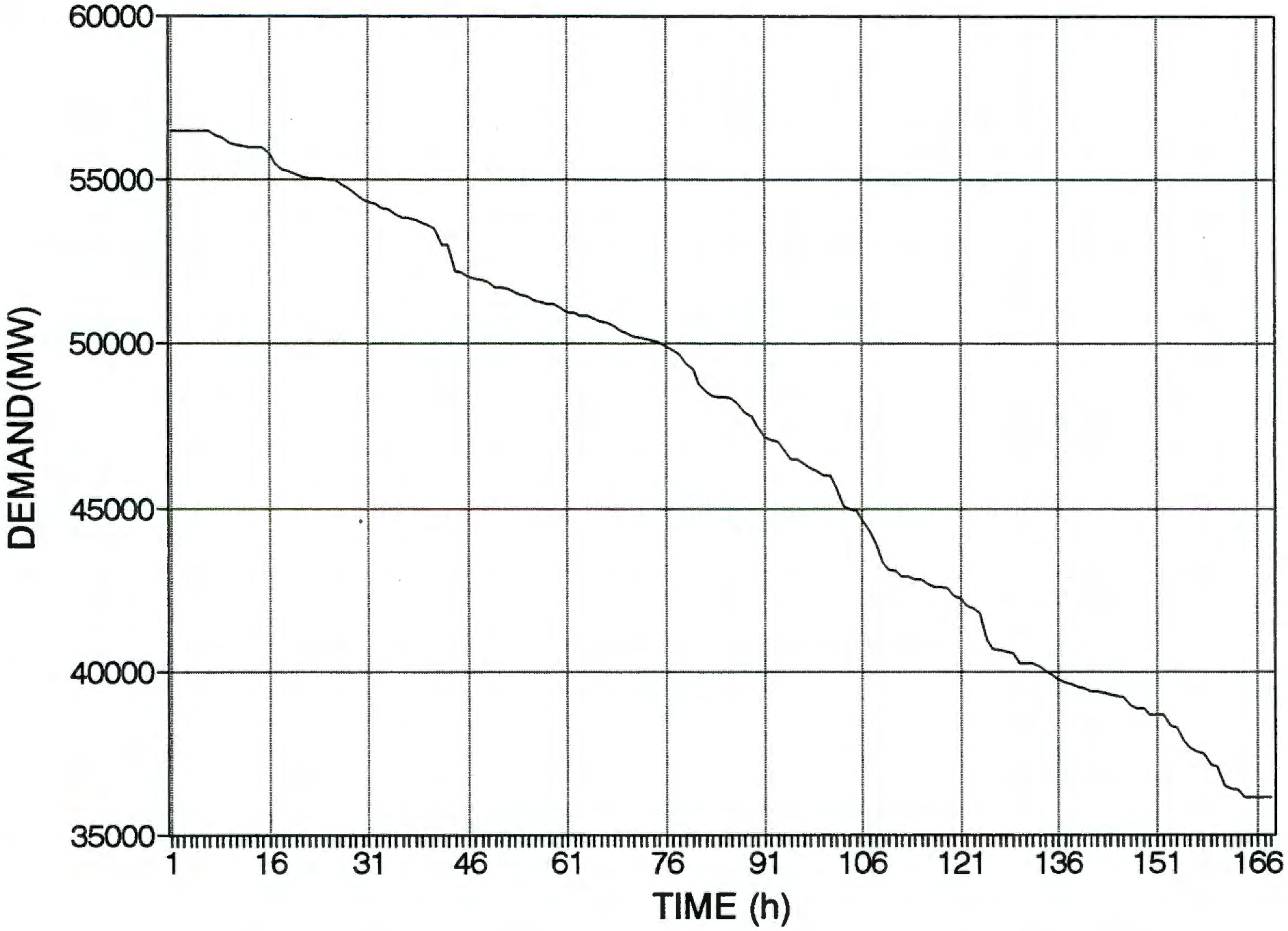
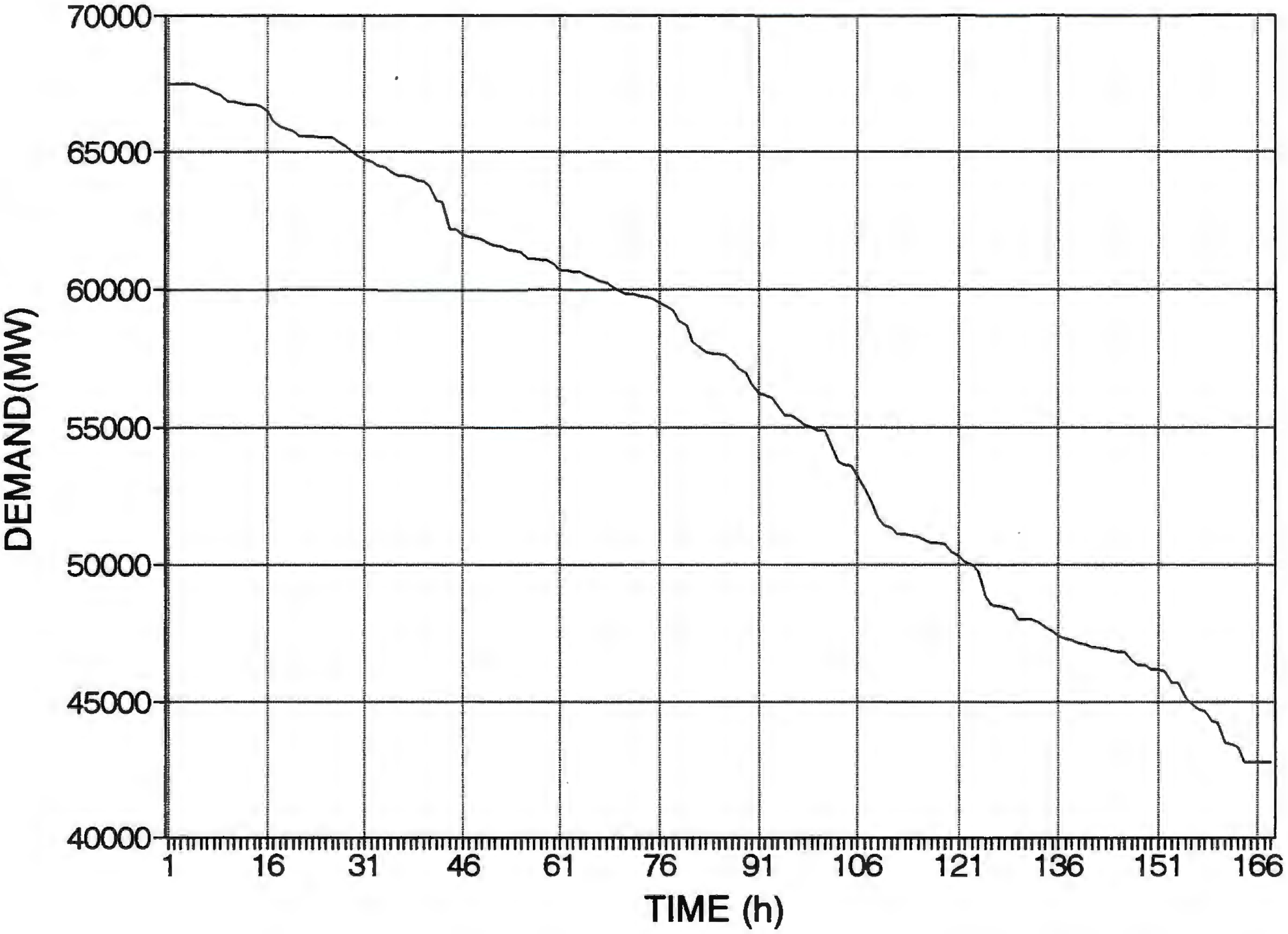




EFFECTS OF PUMPED STORAGE
YEAR 2020 - 3,3%

EFFECTS OF PUMPED STORAGE
YEAR 2020 - 4,0%



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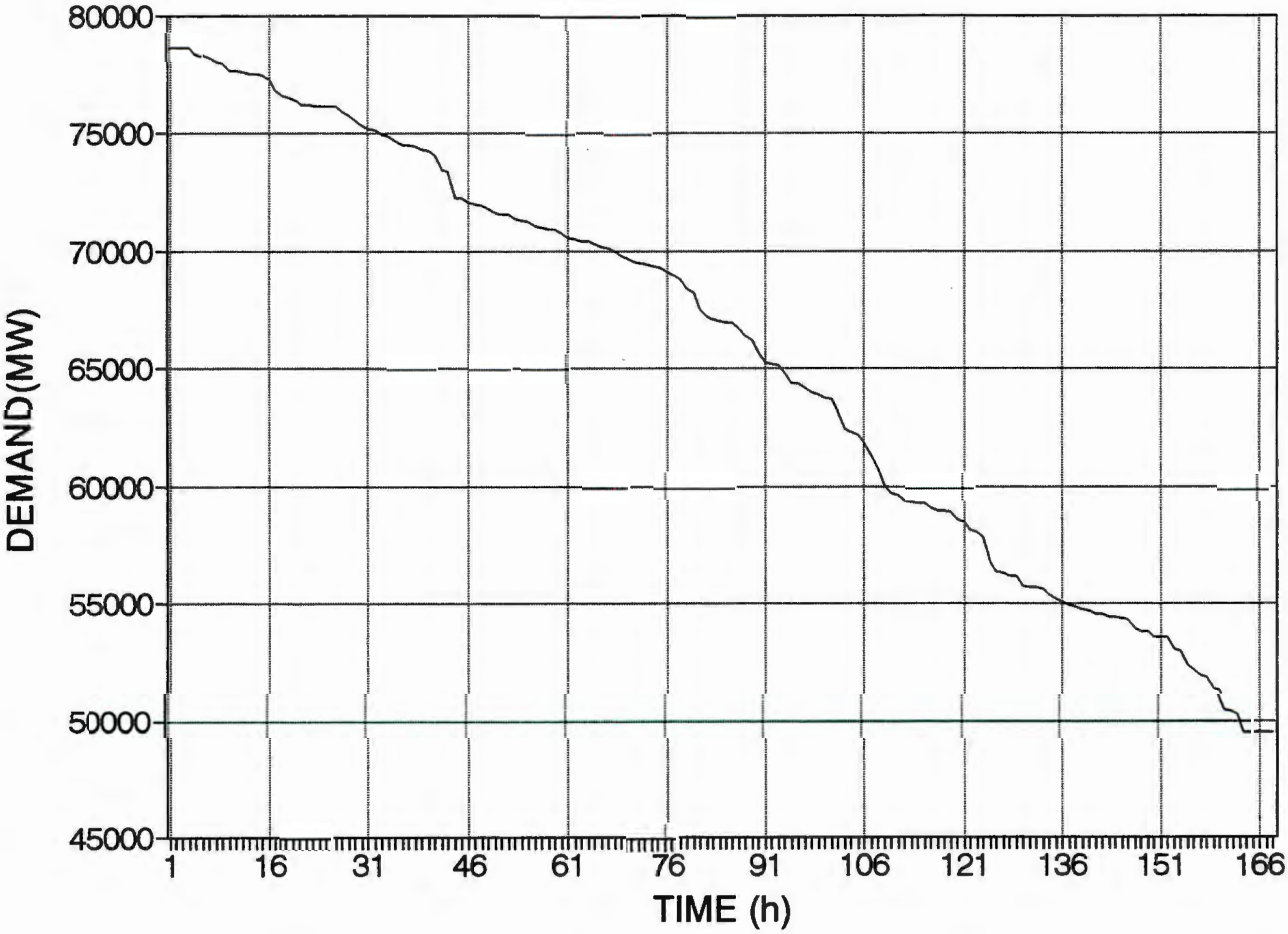
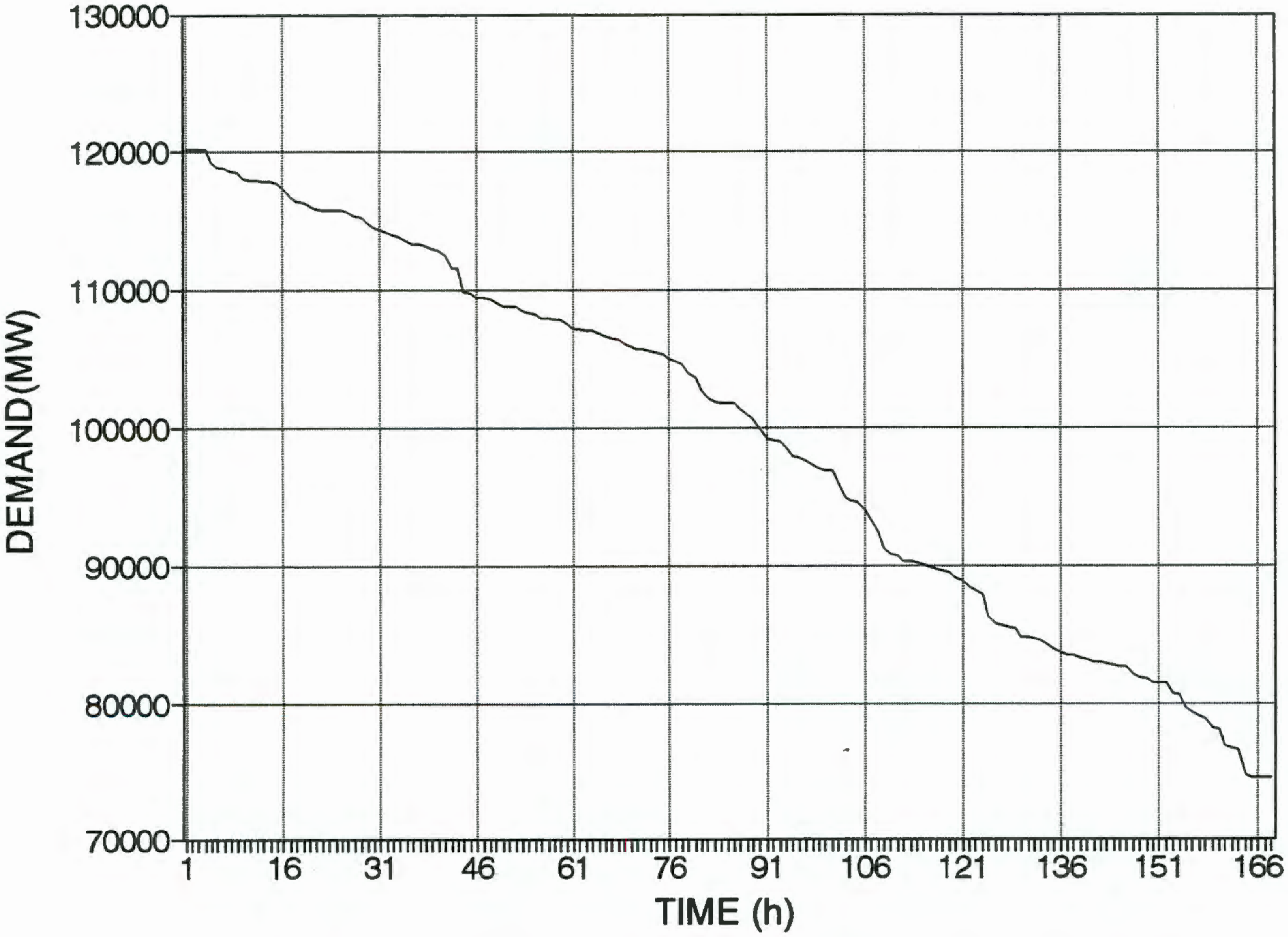




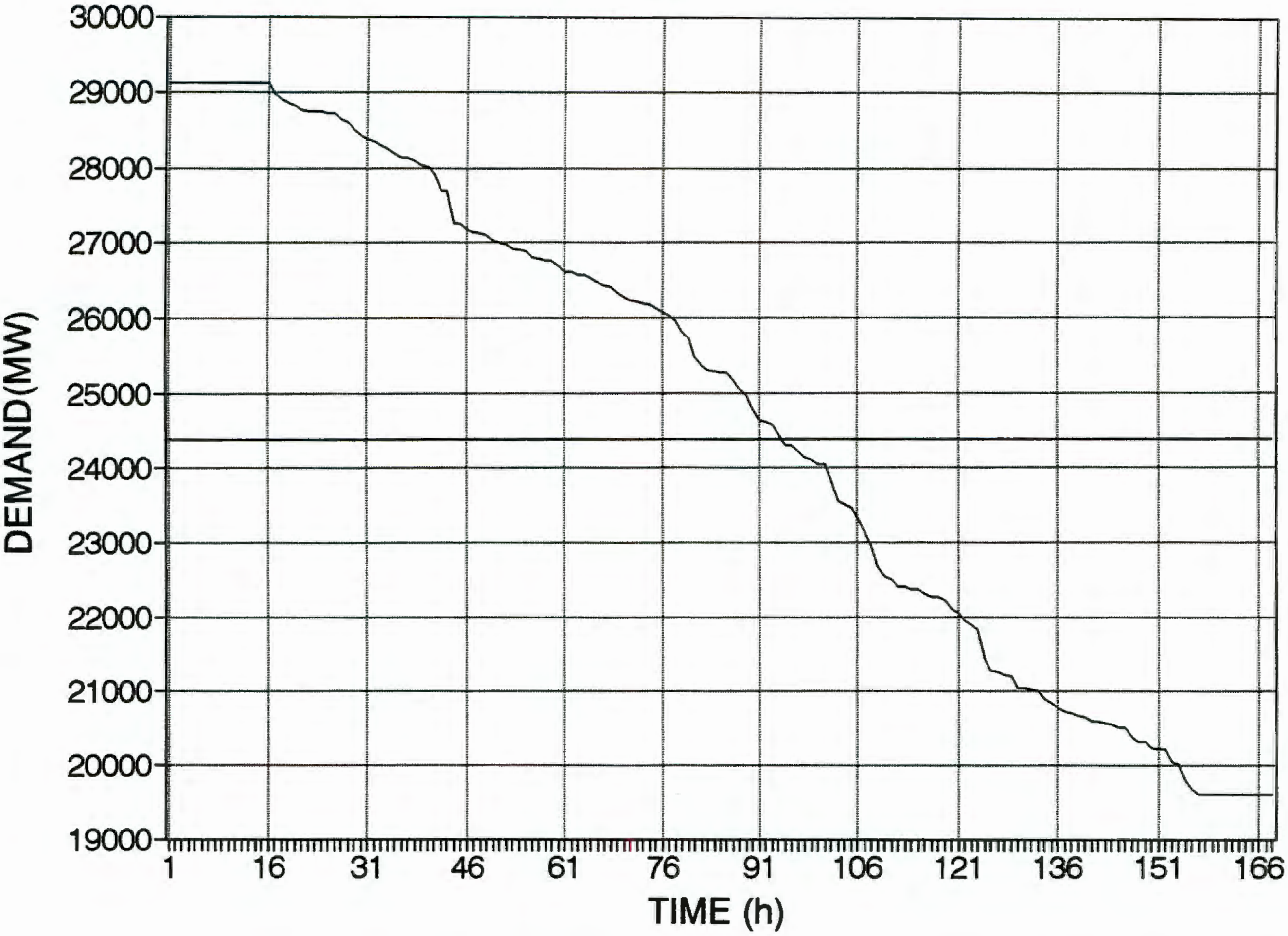
EFFECTS OF PUMPED STORAGE
YEAR 2020 - 6,3%

APPENDIX B

THE EFFECT OF CAES

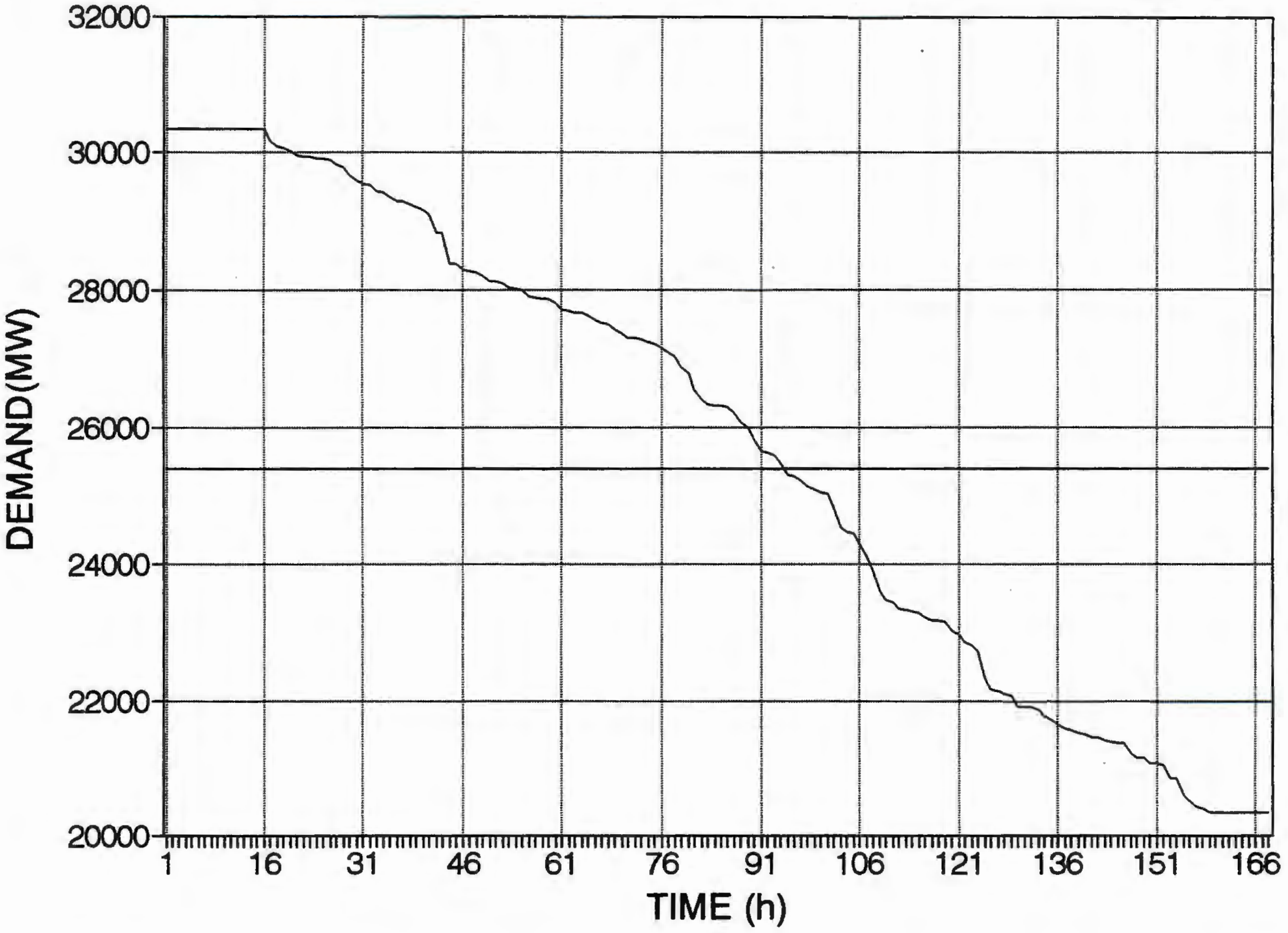
on

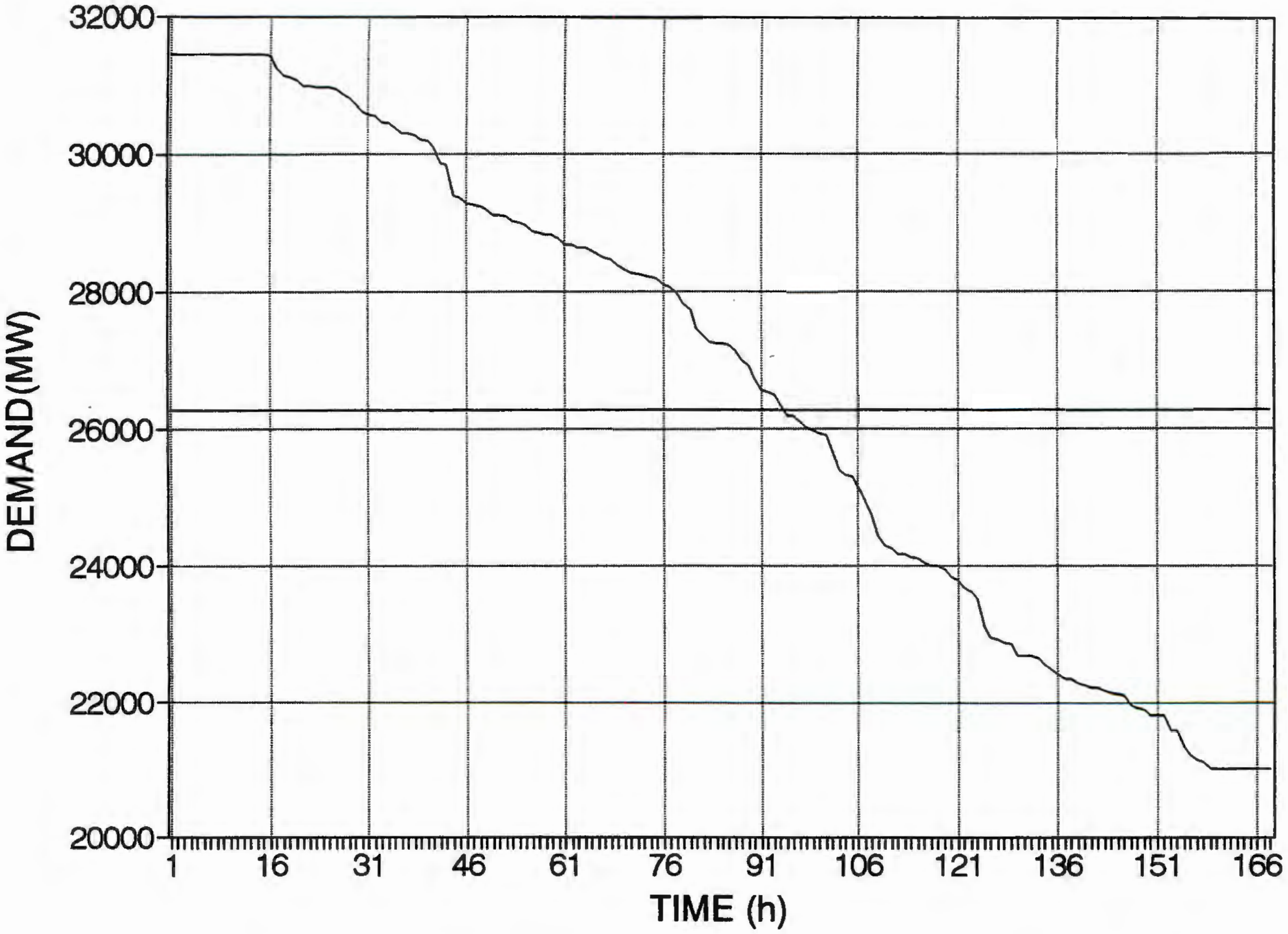
ESKOM'S SYSTEM LOAD



EFFECTS OF CAES
YEAR 2000 - 3,3%

EFFECTS OF CAES
YEAR 2000 - 4,0%





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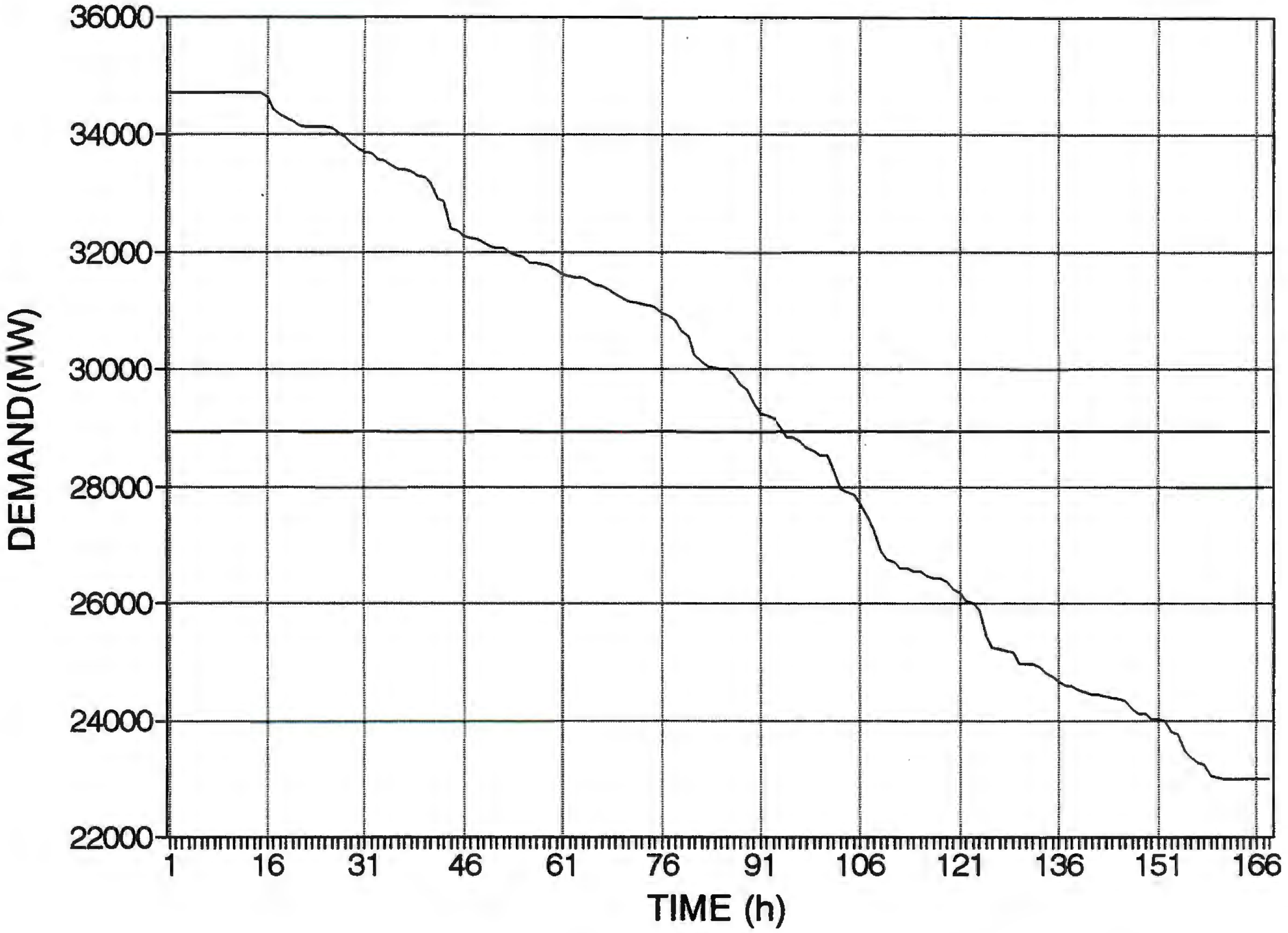
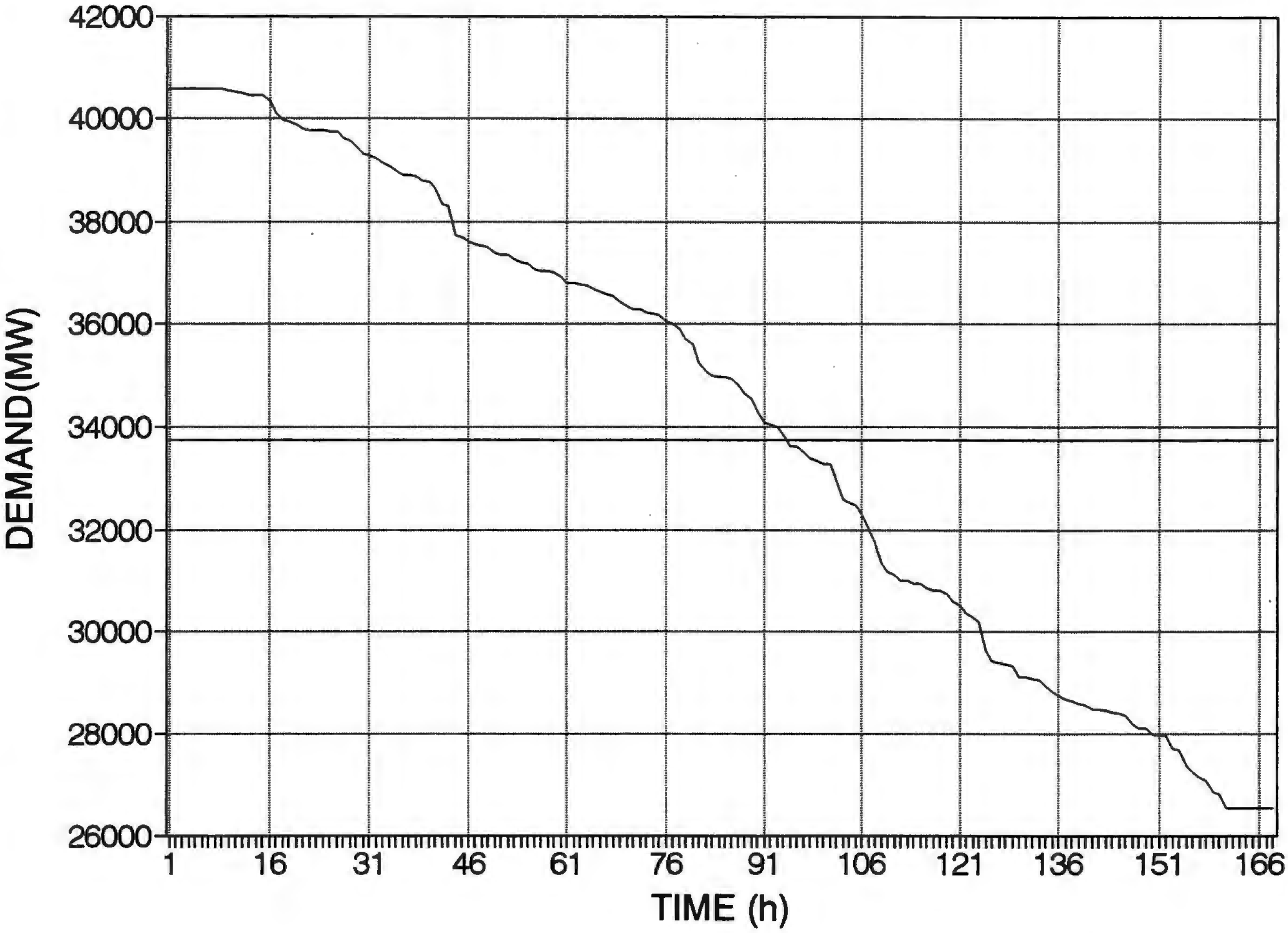
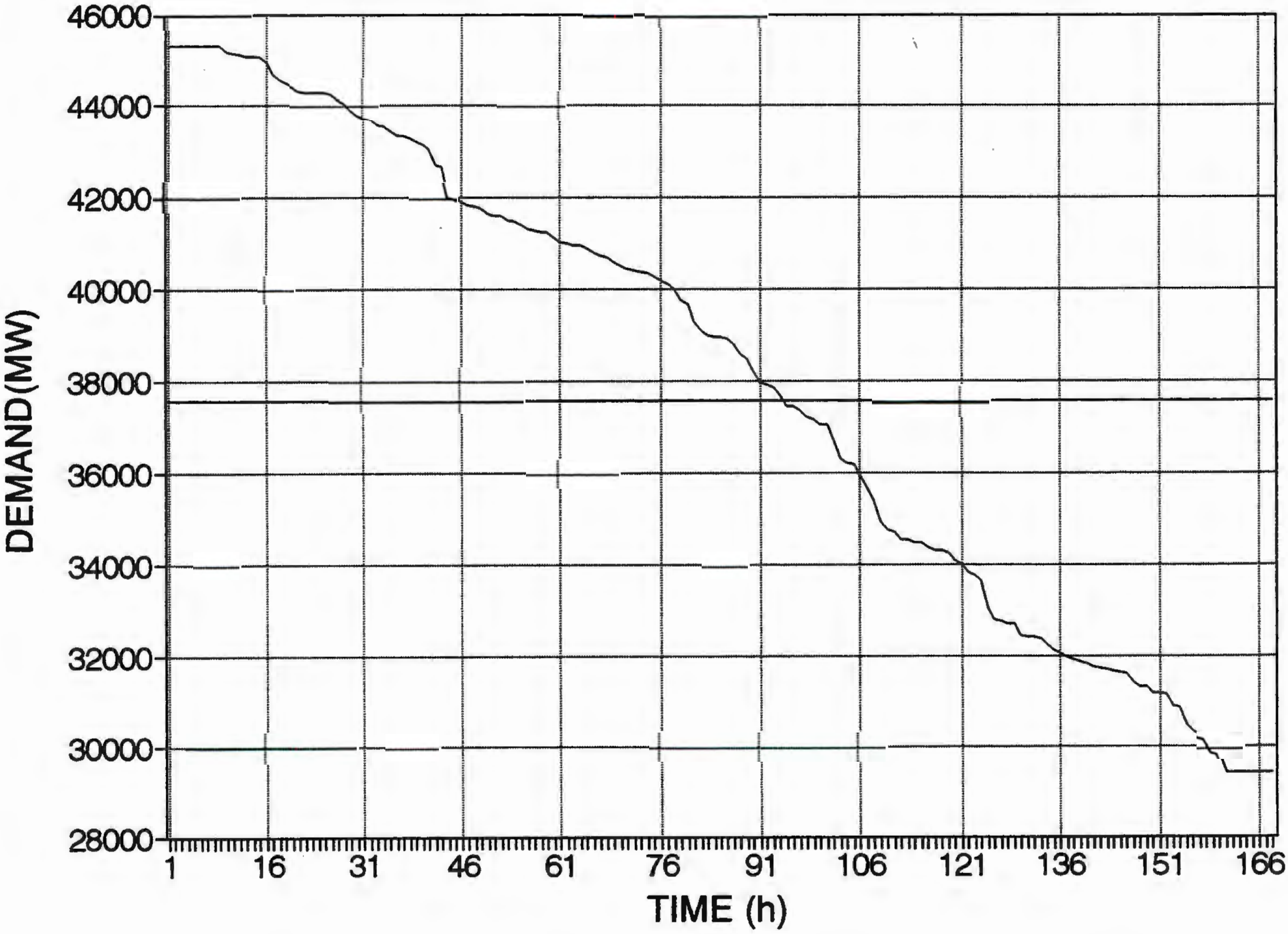


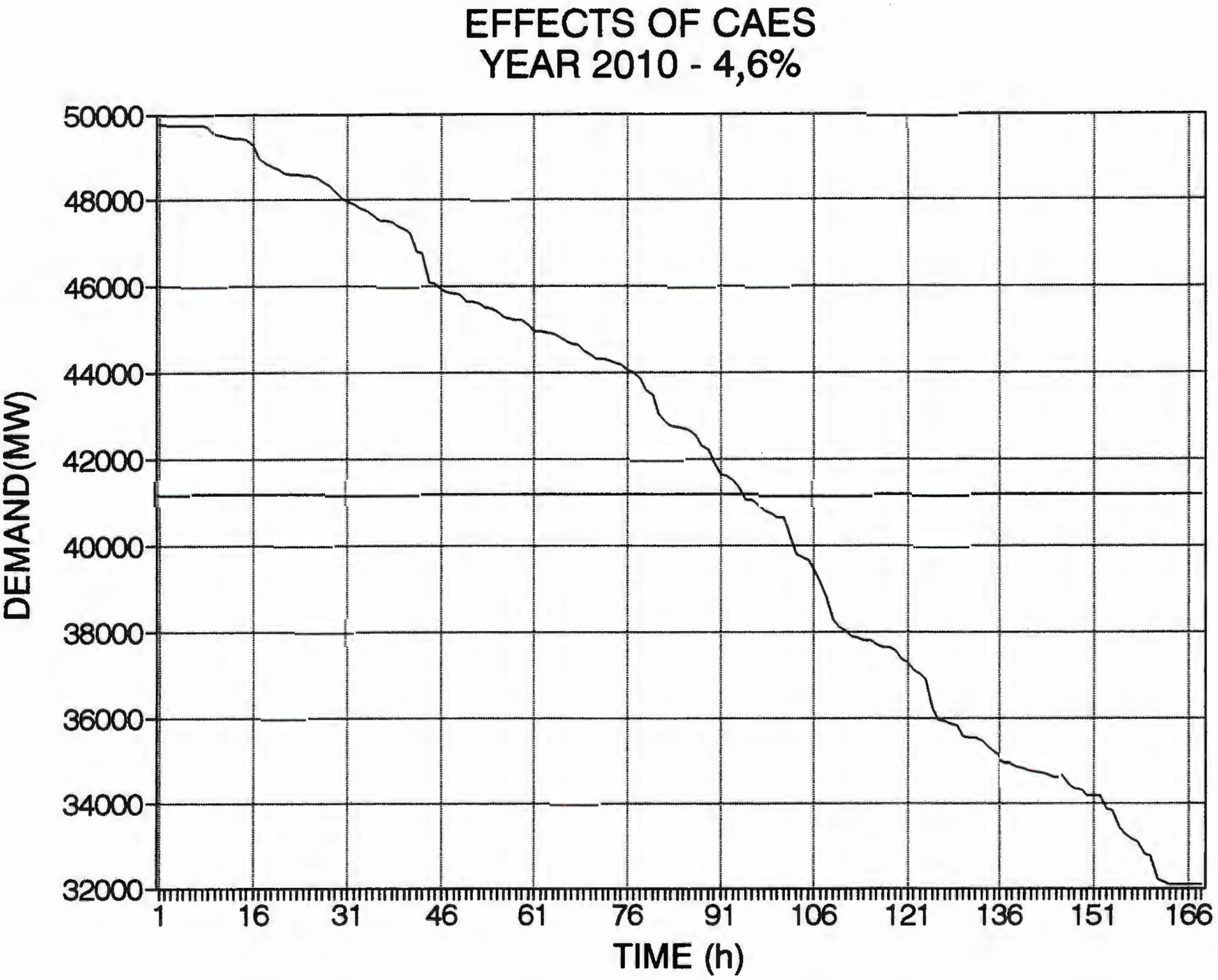
EFFECTS OF CAES
YEAR 2000 - 6,3%

EFFECTS OF CAES
YEAR 2010 - 3,3%

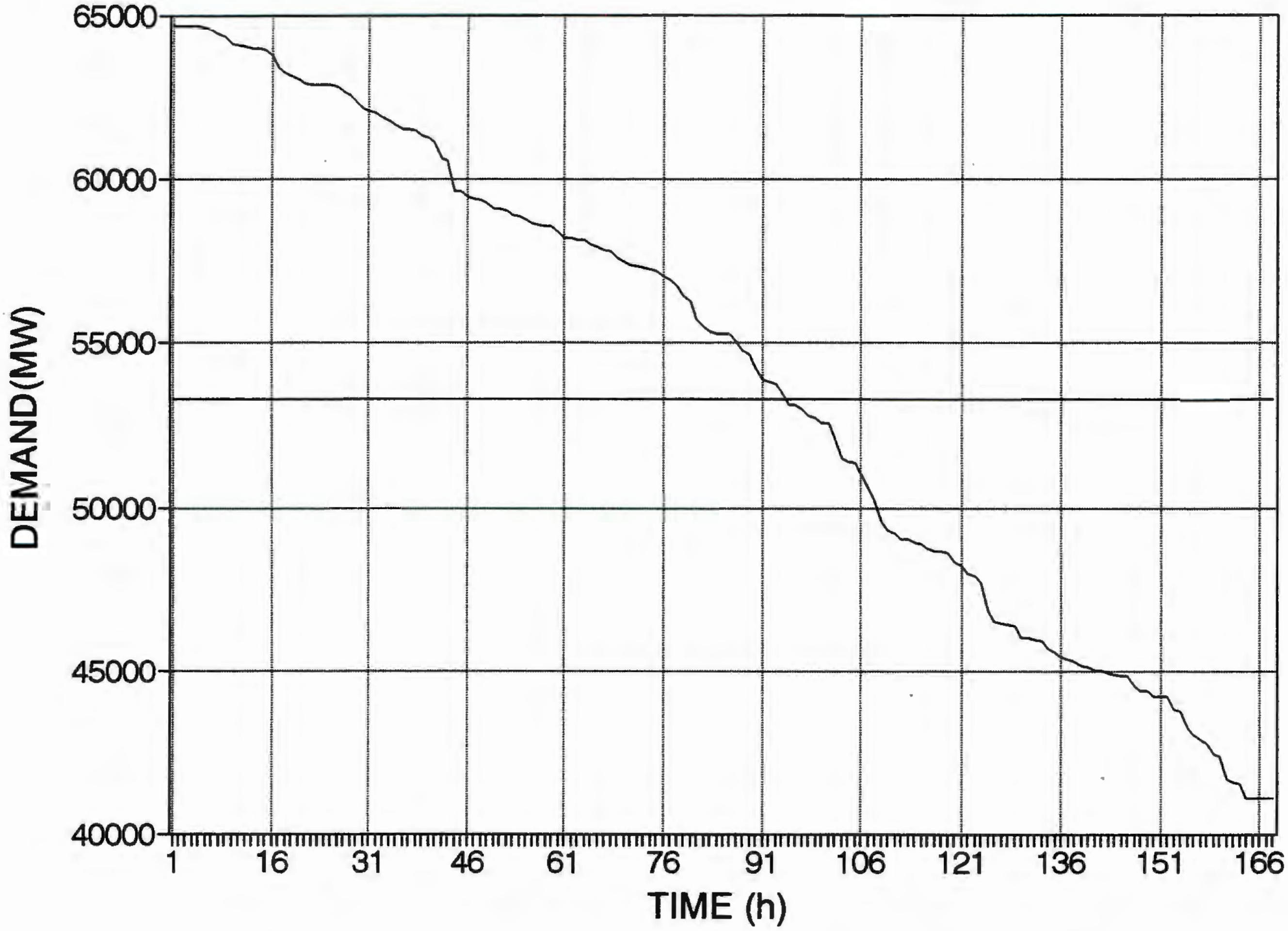


EFFECTS OF CAES
YEAR 2010 - 4,0%

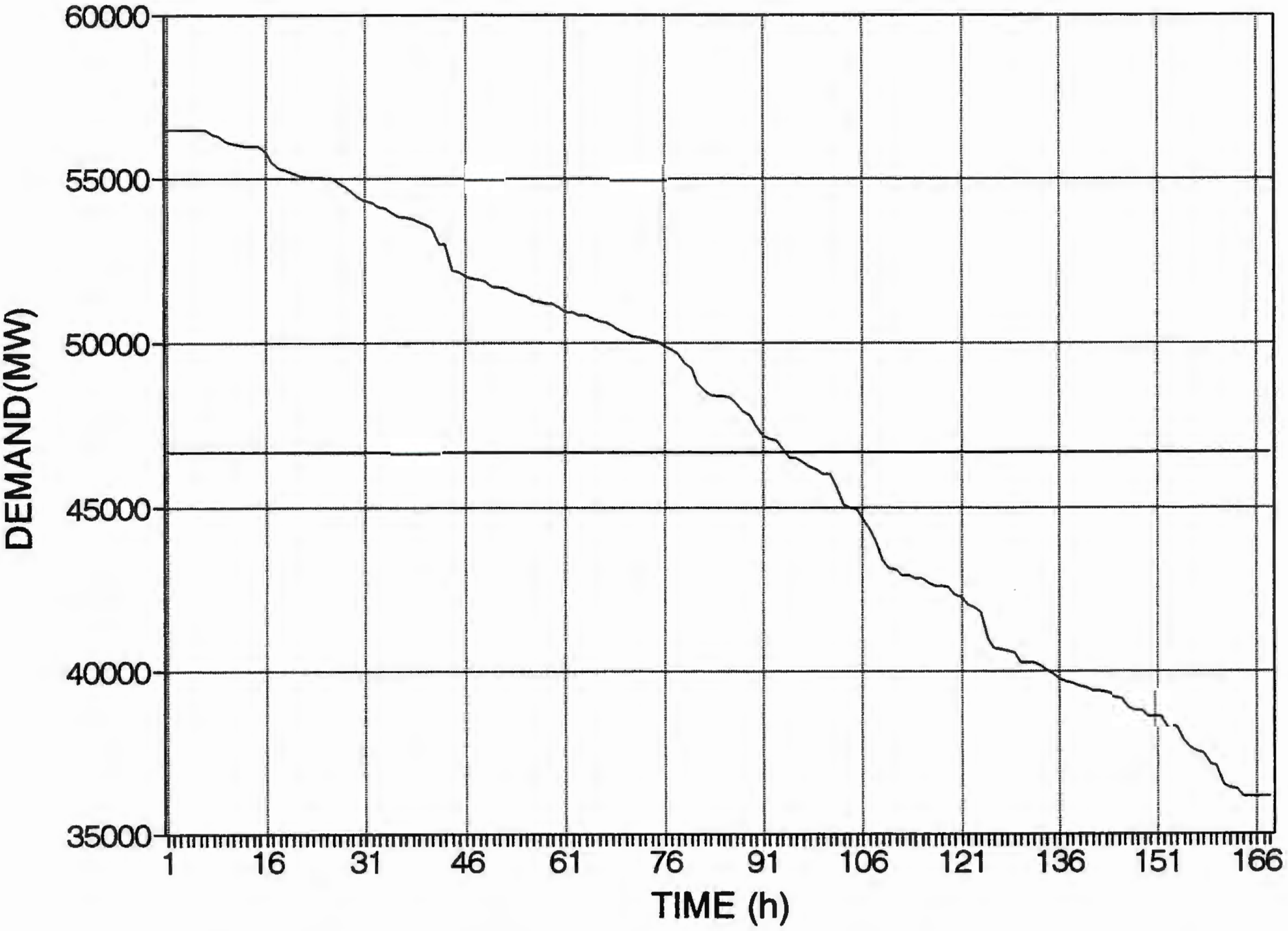


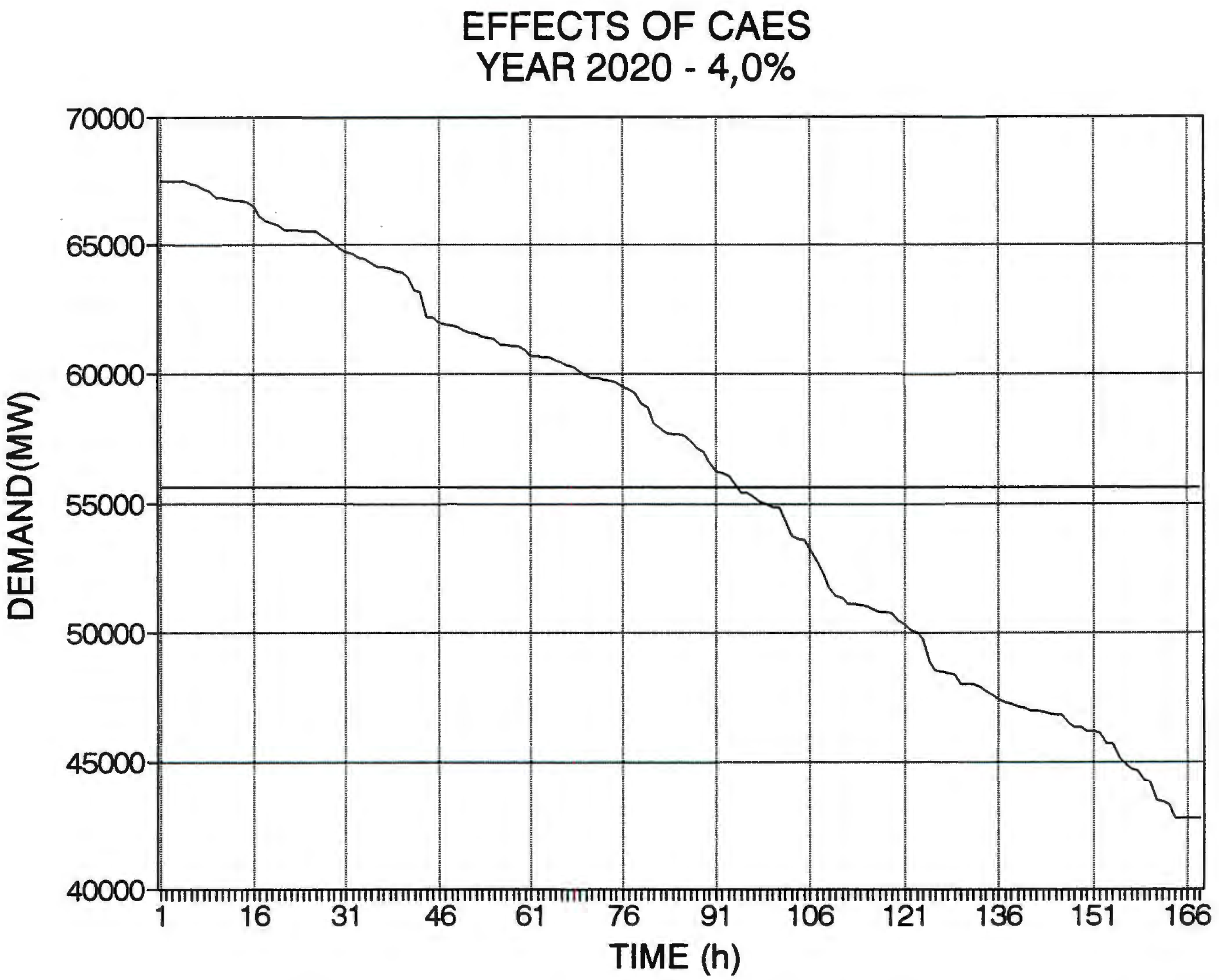

EFFECTS OF CAES
YEAR 2010 - 4,6%
DEMAND(MW)
50000
48000
46000
44000
42000
40000
38000
36000
34000
32000
1
16
31
46
61
76
91
106
121
136
151
166
TIME (h)

EFFECTS OF CAES
YEAR 2010 - 6,3%



EFFECTS OF CAES
YEAR 2020 - 3,3%

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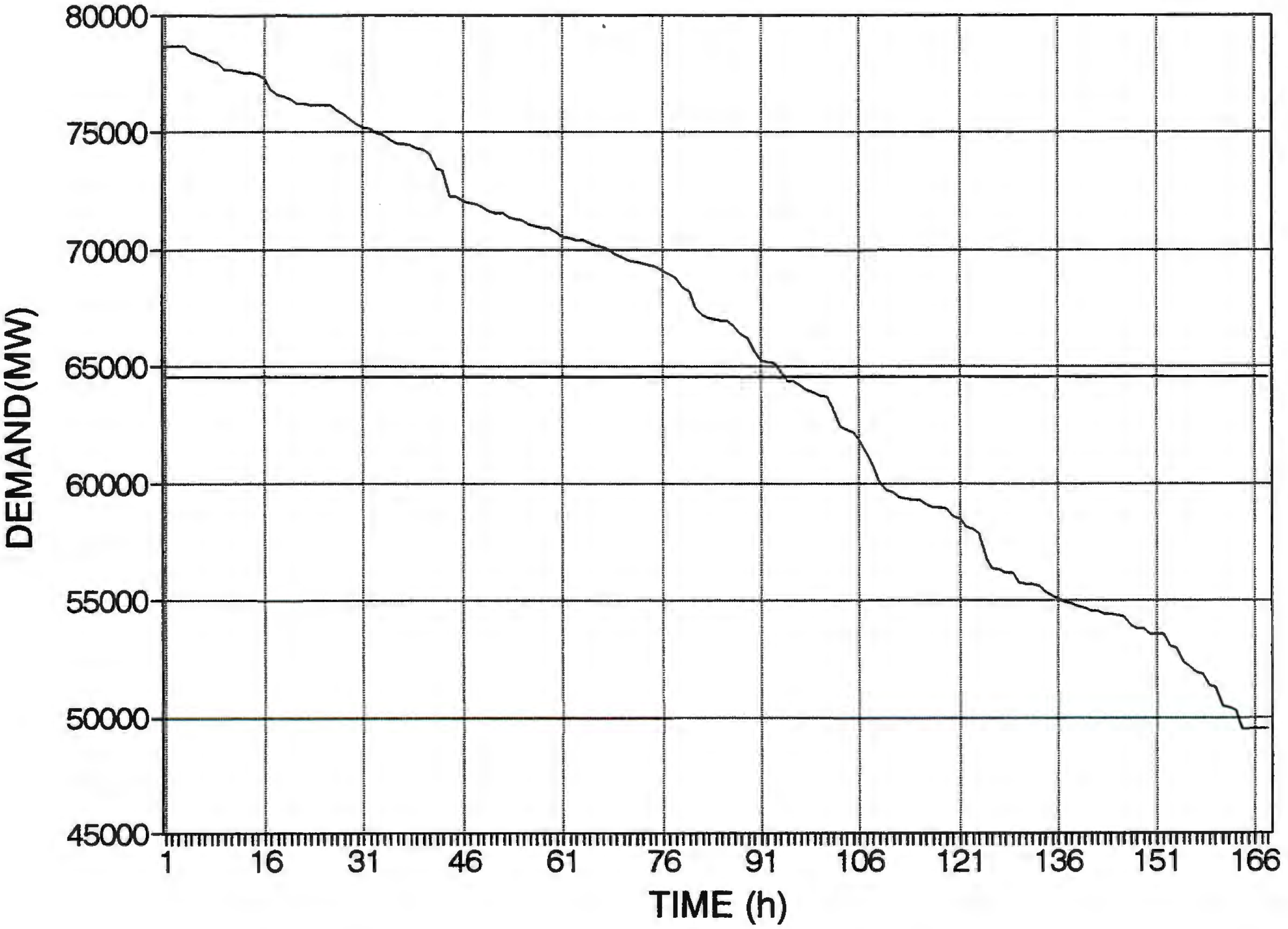
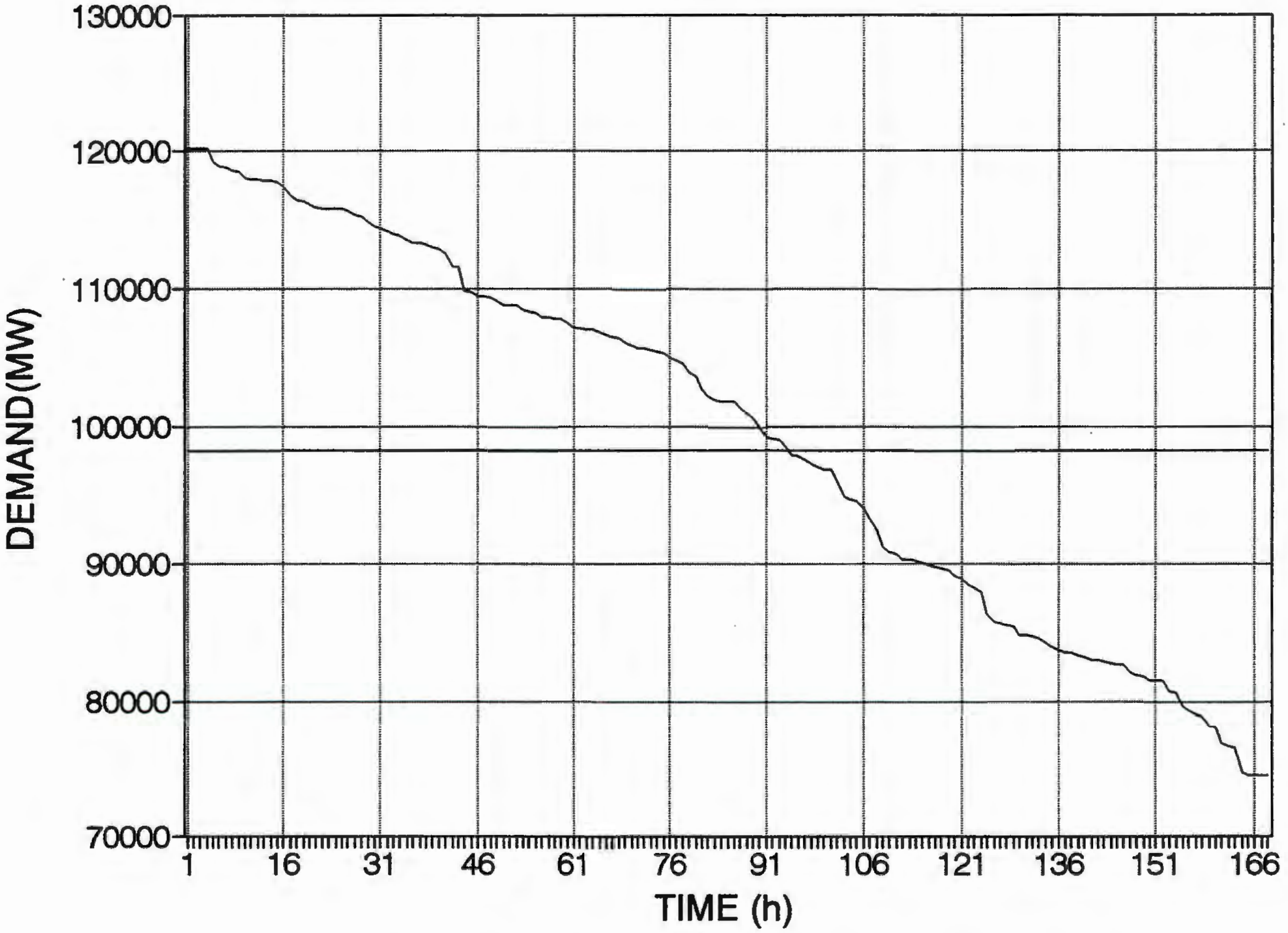


EFFECTS OF CAES
YEAR 2020 - 4,6%

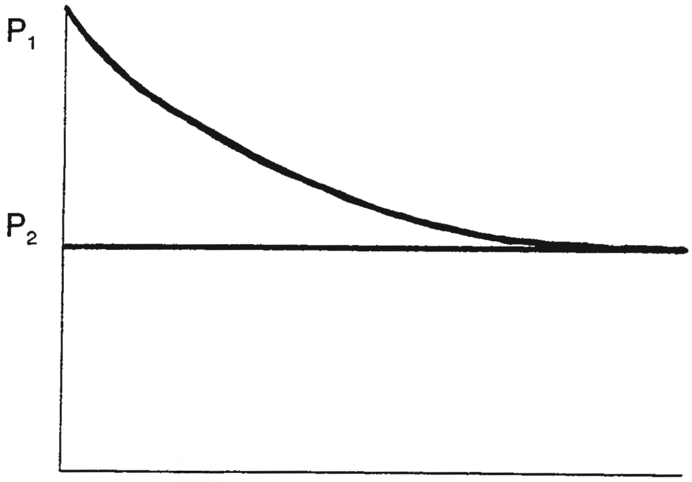
EFFECTS OF CAES
YEAR 2020 - 6,3%



APPENDIX C

CONSTANT VOLUME vs CONSTANT PRESSURE

For a constant volume receiver:



Fully charged:

$$P_1 V_v = m_1 R T_1 \tag{C.1}$$

Completely discharged:

$$P_2 V_v = m_2 R T_2 \tag{C.2}$$

Where: P_1 = Fully charged pressure of receiver
P_2 = Completely discharged pressure of receiver
V_v = Constant volume of receiver
m_1 = Mass of the air in the charged receiver
m_2 = Mass of the air in the discharged receiver
T_1 = Temperature of the air in the charged receiver
T_2 = Temperature of the air in the discharged receiver
R = Gas constant for air
Δm_v = Mass of air extracted from the constant volume receiver
k = Constant

$$\therefore \Delta m_v = m_1 - m_2 = \frac{P_1 V_v}{T_1 R} - \frac{P_2 V_v}{T_2 R}$$

(C.3)

For an isothermal process $T_2 = T_1$

$$\Delta m_v = \frac{V_v}{T_1 R}(P_1 - P_2)$$

(C.4)

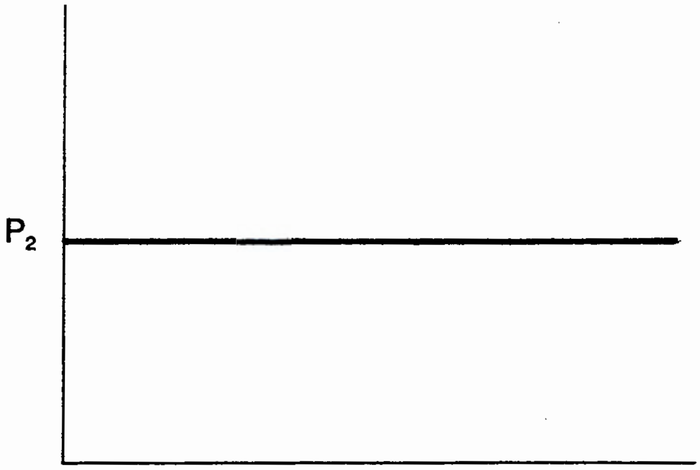
Mass flow x ΔP α Energy (Potential)

$$Energy = \frac{kP_2 V_v}{T_1 R}(P_1 - P_2)$$

$$Energy = \frac{kV_v}{T_1 R}(P_1 P_2 - P_2^2)$$

(C.5)

For the constant pressure receiver:



$$\Delta m_p = \frac{P_2 V_p}{RT_1}$$

(C.6)

$$\therefore Potential\ Energy = kP_2 \times \frac{P_2 V_p}{RT_1}$$

(C.7)

P_2 = Pressure of receiver (Charged to discharged)
V_p = Starting volume of receiver
m_1 = Mass of the air in the charged receiver
m_2 = Mass of the air in the discharged receiver = 0
T_1 = Temperature of the air in the receiver
R = Gas constant for air
Δm_p = Mass of air extracted from the constant pressure receiver
k = Constant

On this basis for equal energy extracted from both types of receiver:

$$V_v(P_1 P_2 - P_2^2) = V_p(P_2)^2$$

$$\frac{V_p}{V_v} = \frac{P_1 P_2 - P_2^2}{P_2^2} = (\frac{P_1}{P_2} - 1)$$

(C.8)

From equation C.8 the following is deducted:

For:

$$P_2 \prec P_1 \prec 2P_2$$

$$\frac{V_p}{V_v} \prec 1$$

$$V_v \succ V_p$$

(C.9)

For:

$$P_1 = 2P_2$$

$$V_p = V_v$$

(C.10)

For:

$$P_1 \succ 2P_2$$

$$\frac{V_p}{V_v} \succ 1$$

$$V_v \prec V_p$$

(C.11)

This method has disregarded the loss of efficiency due to throttling in the constant volume process.

APPENDIX D

LIST

of

CLOSED GOLDMINES IN SOUTH AFRICA

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Ruigtepoort Fluorspar Mine Tel: 484 Fax:	PO Box 117 BRITS 0250	BRITS RUIGTEPOORT 162 JQ BUFFELSPOORT 149 JQ	FLUORSPAR	Minerals Bureau No: 0549 Latitude: ---- Longitude: ---- CLOSED MINE
Slipfontein Fluorspar Mine Ferreira A D Tel: 400 Fax:	PO Box 12 LEEUPOORT 0486	BRITS SLIPFONTEIN 551 KQ	FLUORSPAR	Minerals Bureau No: 4256 Latitude: 2500 Longitude: 2740 CLOSED MINE
Transvaal Mining & Fin Co Ltd Tel: 376-9111 Fax:	PO Box 61820 MARSHALLTOWN 2107	JOHANNESBURG	FLUORSPAR	Minerals Bureau No: 1050 Latitude: ---- Longitude: ---- CLOSED MINE
African Gold Mining Ltd Anglo American Corporation Tel: (01495) 242 Fax:	PO Box 6453 OBERHOLZER 2502	VENTERSDORP DRYLANDS 64 IQ ROOIPAN 96 IQ VARKENSFONTEIN 93 IQ	GOLD SILVER	Minerals Bureau No: 2565 Latitude: 2615 Longitude: 2713 CLOSED MINE
Anglovaal Metal Refinery Tel: 838-8011 Fax:	PO Box 62379 MARSHALLTOWN 2107	ROODEPOORT	GOLD SILVER P.G.M. COPPER	Minerals Bureau No: 1500 Latitude: ---- Longitude: ---- CLOSED WORKS
Astra Lisbon Falls Mine Jolly Rogoyski CC Tel: (01315) 222 Fax:	PO Box 290 GRASKOP 1270	PILGRIMS REST LISBON 531 KT	GOLD SILVER	Minerals Bureau No: 2031 Latitude: 2452 Longitude: 3051 CLOSED MINE
Awm - Elandsrand Gold Mine Anglo American Corp of SA Ltd Tel: 82-1111 (01491) Fax:	Private Bag X2025 CARLETONVILLE 2500	POTCHEFSTROOM BUFFELSDOORN 143 IQ ELANDSRAND 135 IQ ELANDSFONTEIN 114 IQ	GOLD SILVER	Minerals Bureau No: 2642 Latitude: 2628 Longitude: 2722 CLOSED WORKS
Awm - Western Deep Levels - North Anglo American Corp Of S A Ltd Tel: 2161 Fax:	PO Box 8001 WESTERN LEVELS 2501	OBERHOLZER BLYVOORUITZICHT 116 IQ ELANDSRAND 115 IQ BUFFELSDOORN 143 IQ	GOLD URANIUM SILVER P.G.M.	Minerals Bureau No: 2750 Latitude: 2625 Longitude: 2725 CLOSED WORKS
Awm - Western Deep Levels - South Anglo American Corp of SA Ltd Tel: 2161 Fax:	PO Box 8001 WESTERN LEVELS 2501	OBERHOLZER BLYVOORUITZICHT 116 IQ ELANDSRAND 115 IQ BUFFELSDOORN 143 IQ	GOLD URANIUM SILVER P.G.M.	Minerals Bureau No: 2695 Latitude: 2625 Longitude: 2725 CLOSED WORKS

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Baderoukwe Gold Mine Tel: (01524) 5057 Fax:	PO Box 1032 PHALABORWA 1390	PHALABORWA BADEROUKWE 11 LU	GOLD SILVER	**Minerals Bureau No:** 1681 **Latitude:** 2348 **Longitude:** ---- CLOSED MINE
Barbrook Mines Ltd Rand Mines Tel: Fax:	Private Bag X1635 BARBERTON 1300	BARBERTON DAGBREEK 327 JU WAAIHEUVEL 360 JU	GOLD SILVER ARSENIC	**Minerals Bureau No:** 0037 **Latitude:** 2543 **Longitude:** 3116 CLOSED MINE
Bees Luck Gold Mine Brimstone Mining Tel: (011) 814 1460 OR 1 Fax: (011) 814 1460	PO Box 1041 NIGEL 1490	BALFOUR ROODEPOORT 598 IR	GOLD SILVER	**Minerals Bureau No:** 2787 **Latitude:** 2847 **Longitude:** 2647 CLOSED MINE
Beisa Mines Pty Ltd Union Corp Ltd Tel: (01722) 33232 Fax:	PO Box 5068 EERSTEMYN 9466	THEUNISSEN PALMIETKUIL 328	GOLD SILVER URANIUM	**Minerals Bureau No:** 0672 **Latitude:** 2810 **Longitude:** 2642 CLOSED MINE
Benoni Gold Mining Co Tel: Fax:		BENONI	GOLD	**Minerals Bureau No:** 2641 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Big Joker Mine Tel: Fax:	PO Box 1759 PIETERSBURG 0700	PIETERSBURG	GOLD SILVER SAND	**Minerals Bureau No:** 1168 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Bracken Gold Mines Ltd Genmin Tel: (0136) 24621 Fax: (0136) 9991	Private Bag X1002 EVANDER 2280	HIGHVELD RIDGE WITKLEIFONTEIN 131 IS LANGVERWACHT 282 IS SPRINGBOKDRAAI 277 IS	GOLD SILVER P.G.M.	**Minerals Bureau No:** 0065 **Latitude:** 2631 **Longitude:** 2906 CLOSED MINE
Brakpan Van Dyk Mines Egoli Consolidated Mines Ltd Tel: (011) 915 5166 Fax:	PO Box 6186 HOMESTEAD 1412	BRAKPAN RIETFONTEIN 115 IR	GOLD SILVER	**Minerals Bureau No:** 2135 **Latitude:** 2616 **Longitude:** 2819 CLOSED MINE
Breedt Gold Tel: Fax:			GOLD	**Minerals Bureau No:** 2470 **Latitude:** ---- **Longitude:** ---- CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Bushveld Pioneer Gold Mine **Tel:** 013152-2178 **Fax:**	PO Box 254 GRASKOP 1270	PILGRIMS REST GRASKOP 564 KT	GOLD SILVER	**Minerals Bureau No:** 1652 **Latitude:** 2456 **Longitude:** 3049 CLOSED MINE
Buttons Kop Gold Mine **Tel:** **Fax:**	PO Box 3 EERSTEGOUD 0701	PIETERSBURG EERSTELING 17 KS	GOLD SILVER	**Minerals Bureau No:** 1229 **Latitude:** 2407 **Longitude:** 2916 CLOSED MINE
Cemetary Mine Sheba Dump Centurion Mine **Tel:** (01311) 1211 **Fax:**	PO Box 166 KARINO 1204	BARBERTON GOVERNMENT GROUND LOT A	GOLD SILVER	**Minerals Bureau No:** 1820 **Latitude:** 2542 **Longitude:** 3108 CLOSED MINE
Centurion Mining - Sheba Oriental **Tel:** 6 **Fax:**	PO Box 2 SHEBA 1305	BARBERTON KAAP BLOK LOT 157 SECT 10/A	GOLD SILVER	**Minerals Bureau No:** 5107 **Latitude:** 2540 **Longitude:** 3108 CLOSED MINE
Centurion Mining Co Pty Ltd **Tel:** **Fax:**	PO Box 2 SHEBA 1305	BARBERTON	GOLD SILVER	**Minerals Bureau No:** 0440 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Chemwes Gold and Uranium Recovery Stilfontein Gold Mine **Tel:** (018) 4 5911 **Fax:**	PO Box 1 STILFONTEIN 2550	KLERKSDORP	GOLD URANIUM IRON-PYRITES SILVER	**Minerals Bureau No:** 1076 **Latitude:** 2645 **Longitude:** 2650 CLOSED MINE
Connatt Gold Mine Connatt Gold Pty Ltd **Tel:** (01314) 2139 **Fax:**	PO Box 137 BARBERTON 1300	BARBERTON KOELENBRANDER	GOLD SILVER	**Minerals Bureau No:** 1166 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Cons Main Reef Gold Mine Barlow Rand Ltd **Tel:** (011) 839 2411 or 35 7011 **Fax:** "LANDMARK" JOHANNESBURG	Private Bag X9 CROWN MINES 2025	ROODEPOORT PAARDEKRAAL 226 ID	GOLD SILVER	**Minerals Bureau No:** 0847 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Duchen Dump Barlow Rand Ltd **Tel:** (0152312) 3104 **Fax:**	PO Box 63 GRAVELOTTE 0895	LETABA SONDERWATER	GOLD SILVER	**Minerals Bureau No:** 1699 **Latitude:** 2358 **Longitude:** 3035 CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Dumisa Gold Mine Dumisa Mine CC **Tel:** (0323) 30806 **Fax:**	PO Box 563 UMZINTO 4170	UMZINTO LOCATION HO 2	GOLD SILVER	**Minerals Bureau No:** 2029 **Latitude:** 3017 **Longitude:** 3027 CLOSED MINE
Eastern Transvaal Alluvial **Tel:** (01314) 3665 **Fax:** GRASKOP 564 KT	PO Box 463 BARBERTON 1300	PILGRIMS REST	GOLD SILVER	**Minerals Bureau No:** 1239 **Latitude:** 2457 **Longitude:** 3049 CLOSED MINE
Eerstegeluk Gold Mine Minnaar M T **Tel:** (01521) 6743 **Fax:**	PO Box 51 PIETERSBURG 0700	PIETERSBURG EERSTELING 17 KS	GOLD	**Minerals Bureau No:** 5105 **Latitude:** 2405 **Longitude:** 2915 CLOSED MINE
Egoli East Gold Mine Johannesburg Mineral Corp Ltd **Tel:** **Fax:**	PO Box 1124 JOHANNESBURG 2000	BENONI MODDERFONTEIN 76 IR	GOLD SILVER	**Minerals Bureau No:** 1282 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Egoli West Reduction Plant **Tel:** (011) 693 2484 or 5 or 6 **Fax:**	PO Box 1564 RANDFONTEIN 1760	KRUGERSDORP WATERVAL 174 IQ	GOLD SILVER	**Minerals Bureau No:** 1420 **Latitude:** 2605 **Longitude:** 2743 CLOSED MINE
Elandsrand GM Metallurgical Div **Tel:** **Fax:**		OBERHOLZER	GOLD	**Minerals Bureau No:** 2624 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Eldorado Gold Mines Pty Ltd **Tel:** **Fax:**	PO BARBERTON 1300	BARBERTON LOUIEVILLE 325 JU	GOLD SILVER	**Minerals Bureau No:** 1322 **Latitude:** 2542 **Longitude:** 3117 CLOSED MINE
Elsburg Gold Mine Western Areas Gold Mining Co Ltd **Tel:** **Fax:**	PO Box 66 WESTONARIA 1780	WESTONARIA MODDERFONTEIN 345 IQ	GOLD SILVER	**Minerals Bureau No:** 0090 **Latitude:** 2625 **Longitude:** 2741 CLOSED MINE
Fincham Mining Pty Ltd **Tel:** (012) 28 5130 **Fax:**	PO Box 11043 BROOKLYN 0011	LYDENBURG GRASKOP	GOLD SILVER	**Minerals Bureau No:** 1190 **Latitude:** ---- **Longitude:** ---- CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Frankfort Mine Dump The Mill Creek Gold **Tel:** (011) 826 5107 or 8 **Fax:**	PO Box 7642 RAVENSMOOR 1467	PILGRIMS REST RIETFONTEIN 193 JT	GOLD SILVER	**Minerals Bureau No:** 1747 **Latitude:** 2506 **Longitude:** 3050 CLOSED MINE
Freddies Consolidated Gold Mine **Tel:** **Fax:**	PO Box 102 ODENDAALSRUS 9480	ODENDAALSRUS KALKKUIL 153 MARTHINAS GIFT 299 PHILLIPPI 414	GOLD SILVER	**Minerals Bureau No:** 0209 **Latitude:** 2750 **Longitude:** 2640 CLOSED MINE
Free Gold Metallurgical Free State Cons G M (Operate)Ltd **Tel:** 22151 **Fax:**	PO Box 3 WELKOM 9460	WELKOM FRIEDESHEIM 51 ERDEEL 18	GOLD P.G.M. SILVER IRON-PYRITES	**Minerals Bureau No:** 2594 **Latitude:** 2755 **Longitude:** 2644 CLOSED WORKS
Free Gold North Engineering Free State Cons G M (Operate)Ltd **Tel:** 22151 **Fax:**	PO Box 3 WELKOM 9460	WELKOM FRIEDESHEIM 51 ERDEEL 18	GOLD P.G.M. SILVER IRON-PYRITES	**Minerals Bureau No:** 2729 **Latitude:** 2755 **Longitude:** 2644 CLOSED WORKS
Free Gold North: No 1 # Project **Tel:** **Fax:**		ODENDAALSRUS	GOLD	**Minerals Bureau No:** 2335 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Free State Geduld Gold Mine Anglo American Corp Of S A Ltd **Tel:** (0171) 35 21271 **Fax:**	PO Box 80 WELKOM 9460	WELKOM VARIOUS FARMS	GOLD P.G.M. SILVER IRON-PYRITES	**Minerals Bureau No:** 0213 **Latitude:** 2755 **Longitude:** 2644 CLOSED MINE
Free State Saai - Metallurgical Anglo American Corp Of S A Ltd **Tel:** 3-1131 **Fax:**	PO Box 1 CONERA 9431	VIRGINIA RUSTGEVONDEN 564 DIRKSBURG 358 SAAIPLAAS 551	GOLD URANIUM SILVER IRON-PYRITES	**Minerals Bureau No:** 2570 **Latitude:** 2759 **Longitude:** 2650 CLOSED WORKS
French Bobs Tailings Dump **Tel:** - **Fax:**	PO Box 222 GRAVELOTTE 0895	LETABA SONDERWATER PTN OF LEYDSDORP TOWNLANDS 779 LT	GOLD SILVER	**Minerals Bureau No:** 2497 **Latitude:** 2400 **Longitude:** 3035 CLOSED MINE
Fumani Gold Mine Gazankulo Devel Corp **Tel:** (01526) ask 2 **Fax:**	Private Bag X9602 GIYANI 0826	MALAMULELE ALTEN 222 LT	GOLD SILVER	**Minerals Bureau No:** 0215 **Latitude:** 2312 **Longitude:** 3047 CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Geokom Inc Pty Ltd **Tel:** (011) 29 9222 **Fax:**	PO Box 7876 JOHANNESBURG 2000	ROODEPOORT ROODEPOORT 237 IQ PTN 14	GOLD SILVER	**Minerals Bureau No:** 2482 **Latitude:** 2610 **Longitude:** 2750 CLOSED MINE
Glencaim Gold Mine Pty Ltd Waverly Gold Mines Ltd **Tel:** **Fax:**	PO Box 6187 HOMESTEAD 1412	GERMISTON DRIEFONTEIN 87 IR	GOLD SILVER	**Minerals Bureau No:** 1104 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Goedehoop Mining Co Pty Ltd **Tel:** 5315 **Fax:**	PO Box 574 VRYHEID 3100	VRYHEID GOLDEN VALLEY 13506	GOLD SILVER	**Minerals Bureau No:** 1256 **Latitude:** 2750 **Longitude:** 3055 CLOSED MINE
Golden Dumps Research Pty Ltd **Tel:** 48-0253 **Fax:**	PO Box 69851 BRYANSTON 2021	JOHANNESBURG	GOLD SILVER	**Minerals Bureau No:** 1283 **Latitude:** ---- **Longitude:** ---- CLOSED WORKS
Golden Jubilee Mining **Tel:** (01315) 7 1240 **Fax:** (01315) 7 1330	PO Box 139 GRASKOP 1270	PILGRIMS REST GRASKOP 564 KT	GOLD SILVER	**Minerals Bureau No:** 1855 **Latitude:** 2457 **Longitude:** 3049 CLOSED MINE
Government Gold Mining Areas **Tel:** **Fax:**		JOHANNESBURG	GOLD SILVER	**Minerals Bureau No:** 1304 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Gravelotte Gold Mine Gravelotte Mines Ltd **Tel:** (0152312) 1/2 **Fax:** (015231) 4211	PO Box 45 GRAVELOTTE 0895	LETABA WILLIE 787 LT	GOLD SILVER	**Minerals Bureau No:** 2503 **Latitude:** 2358 **Longitude:** 3039 CLOSED MINE
Gravelotte Gold Mine East Rand Div Salene Mining Pty Ltd **Tel:** 423-1301 (011) **Fax:**	Box 50917 RANDBURG 2125	BENONI MODDERFONTEIN 76 IR	GOLD	**Minerals Bureau No:** 1883 **Latitude:** 2834 **Longitude:** 2607 CLOSED MINE
Harmony Gold Mine -South Region **Tel:** 01722 - 319111 **Fax:**	Box 1 GLEN HARMONY 9435	VIRGINIA HARMONY FARM 222	GOLD	**Minerals Bureau No:** 1857 **Latitude:** 2652 **Longitude:** 2805 CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Heatherleigh Diggings **Tel:** (01351) 6 1135 **Fax:**	PO Box 3720 WITBANK 1035	PILGRIMS REST LISBON 531 KT	GOLD SILVER	**Minerals Bureau No:** 1789 **Latitude:** 2452 **Longitude:** 3051 CLOSED MINE
Hexrivier Mine **Tel:** 228718 **Fax:**	PO Box 12095 DAGGAFONTEIN 1573	BALFOUR HEXRIVIER 598 IR ROODEPOORT 634 IR	GOLD	**Minerals Bureau No:** 1698 **Latitude:** 2654 **Longitude:** 4200 CLOSED MINE
Highland Argyle Gold Mine **Tel:** **Fax:**	PO Box 78688 SANDTON 2146	KLERKSDORP ELEAZAR 377 IP	GOLD SILVER	**Minerals Bureau No:** 0978 **Latitude:** 2638 **Longitude:** 2653 CLOSED MINE
Hope Mining Venture **Tel:** (01314) 3665 **Fax:**	PO Box 463 BARBERTON 1300	PILGRIMS REST GRASKOP 564 KT	GOLD SILVER	**Minerals Bureau No:** 1525 **Latitude:** 2456 **Longitude:** 3048 CLOSED MINE
Inyoni Mines **Tel:** **Fax:**	PO Box 112 LETABA 0870	LETABA BURGERSDORP 19 KT	GOLD	**Minerals Bureau No:** 0300 **Latitude:** 2340 **Longitude:** 3010 CLOSED MINE
John Douglas Exploration Gold Mine Carstairs J **Tel:** **Fax:**	PO Box 53 UMTENTWENI 4235	PILGRIMS REST SABIE NOOK 171 JT WATERVAL 168 JT	GOLD SILVER	**Minerals Bureau No:** 0306 **Latitude:** 2503 **Longitude:** 3050 CLOSED MINE
Jumpers Consortium **Tel:** (011) 58 7629 **Fax:**	PO Box 2973 RANDBURG 2125	RANDBURG DRIEFONTEIN 87 IR	GOLD SILVER P.G.M.	**Minerals Bureau No:** 1725 **Latitude:** 2613 **Longitude:** 2812 CLOSED MINE
Kasteel Koppies Gold Mine H J Lombard. **Tel:** (0152) 307-3836 **Fax:**	PO Box 730 TZANEEN 0850	LETABA BEGIN 765 LT	GOLD SILVER	**Minerals Bureau No:** 0671 **Latitude:** 2353 **Longitude:** 3044 CLOSED MINE
Lancaster Gold Mine Metmin Pty Ltd **Tel:** (011) 953-1117 **Fax:**	PO Box 216 KRUGERSDORP 1740	KRUGERSDORP LUIPAARDSVLEI 246 IQ	GOLD SILVER	**Minerals Bureau No:** 2691 **Latitude:** 2607 **Longitude:** 2747 CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Langlaagte Mine (Pty) Ltd Golden Dumps (Pty) Ltd **Tel:** (011) 765-1063 **Fax:** (011) 765-1611	PO Box 11 ROODEPOORT 1725	JOHANNESBURG LANGLAAGTE 224 IQ	GOLD SILVER	**Minerals Bureau No:** 1668 **Latitude:** 2612 **Longitude:** 2759 CLOSED MINE
London Gold Diggings **Tel:** **Fax:**	69 Buckingham Road KENSINGTON 2191	PILGRIMS REST LONDON 496 KT	GOLD SILVER	**Minerals Bureau No:** 0369 **Latitude:** 2448 **Longitude:** 3050 CLOSED MINE
Louis Moore Gold Mine Newman Mining **Tel:** (01526) 9 1512 **Fax:**	PO Box 2056 GIYANI 0826	GIYANI -	GOLD SILVER	**Minerals Bureau No:** 0372 **Latitude:** 2313 **Longitude:** 3041 CLOSED MINE
Luipaardsvlei Gold Mine **Tel:** (011) 660 5311 **Fax:**	PO Box 53 KRUGERSDORP 1740	KRUGERSDORP LUIPAARDSVLEI 246 IQ	GOLD SILVER	**Minerals Bureau No:** 4006 **Latitude:** 2608 **Longitude:** 2746 CLOSED MINE
Madibi Mine Pty Ltd **Tel:** **Fax:**	PO Box 464 MAFEKING 8670	MOLOPO MOLOPO BANTU RESERVE	GOLD	**Minerals Bureau No:** 0381 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Malati Gold Mine **Tel:** (0152312) 1503 **Fax:**	PO Box 9 GRAVELOTTE 0895	LETABA CASTLE KOPPIES 652 MS	GOLD SILVER	**Minerals Bureau No:** 1280 **Latitude:** 2648 **Longitude:** 2947 CLOSED MINE
Malidyke Gold Mine **Tel:** (013152) 155 **Fax:**	PO Box 189 GRASKOP 1270	PILGRIMS REST GRASKOP 564 KT	GOLD SILVER	**Minerals Bureau No:** 1704 **Latitude:** 2448 **Longitude:** 3046 CLOSED MINE
Manville G M (H A Greyling) **Tel:** **Fax:**	PO Box 27 LEVUBU 0929	MALAMULELE KIRSTEN 212 LT	GOLD SILVER	**Minerals Bureau No:** 5103 **Latitude:** 2340 **Longitude:** 3015 CLOSED MINE
Marievale Cons Gold Mine Genmin **Tel:** (011) 56 0464 **Fax:** (011) 56 4282	PO Box 445 SPRINGS 1560	NIGEL VARKENSFONTEIN 169 IR BULTFONTEIN 192 IR HOLGATFONTEIN 326 IR	GOLD SILVER	**Minerals Bureau No:** 0399 **Latitude:** 2621 **Longitude:** 2831 CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Mazoma Gold Mine **Tel:** **Fax:**	PO Box 65 DWAALBOOM 0319	THABAZIMBI LANGVERWAGT 235 KP GED 5	GOLD SILVER	**Minerals Bureau No:** 1989 **Latitude:** 2445 **Longitude:** 2658 CLOSED MINE
Mineral Beneficiation Industries **Tel:** (011) 813-2400 **Fax:**	PO Box 5086 BRENTHURST 1542	SPRINGS THE SPRINGS FARM 129 IR (PTN 22 OF)	GOLD SILVER	**Minerals Bureau No:** 1124 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Minerva Gold Mine **Tel:** (0152312) 2921 **Fax:**	PO Box 227 GRAVELOTTE 0895	LETABA LANGALANGA 141 KT	GOLD SILVER	**Minerals Bureau No:** 1583 **Latitude:** 4202 **Longitude:** 3035 CLOSED MINE
Miscallaneous Pietersburg **Tel:** **Fax:**	Ex Rand Refinery	PIETERSBURG	GOLD SILVER	**Minerals Bureau No:** 1106 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
N T J Gold Mine N T J Mining Co & Tributors Pty Ltd **Tel:** (011) 663 1614 **Fax:**	17 Merlin Crescent GREENHILLS RANDFONTEIN	VENTERSDORP RIETVALLEI 100 IQ	GOLD SILVER	**Minerals Bureau No:** 5104 **Latitude:** 2745 **Longitude:** 2708 CLOSED MINE
Natalspruit Gold Mine Natalspruit G M Co Pty Ltd **Tel:** (011) 646 9403 **Fax:**	PO Box 84192 GREENSIDE 2034	ALBERTON ROODEKOP 139 IR	GOLD SILVER	**Minerals Bureau No:** 1975 **Latitude:** 2617 **Longitude:** 2811 CLOSED MINE
Nestor Gold Mining Co Metorex Pty Ltd **Tel:** (01313) 9796 **Fax:**	PO Box 2 SHEBA 1305	PILGRIMS REST WATERVAL 168 JT SHEBA 219 JT OLIFANTSGERAAMTE 198 JT	GOLD SILVER	**Minerals Bureau No:** 1754 **Latitude:** 2508 **Longitude:** 3047 CLOSED MINE
New Machavie Gold Mine De Kaap Gold Mining Co **Tel:** (01481) 2 2888 **Fax:**	PO Box 2145 POTCHEFSTROOM 2520	KLERKSDORP ELEAZAR 377 IP	GOLD SILVER	**Minerals Bureau No:** 2007 **Latitude:** 2640 **Longitude:** 2652 CLOSED MINE
New South Roodepoort Gold Mine Rodio SA Pty Ltd **Tel:** **Fax:**	PO Box 524 ISANDO 1600	ROODEPOORT	GOLD SILVER	**Minerals Bureau No:** 1477 **Latitude:** ---- **Longitude:** ---- CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Newberry Rec Works Rietfontein **Tel:** 46-3322 **Fax:** 'SOUTHSPHERE'	PO Box 17093 GROENKLOOF 0027	GERMISTON RIETFONTEIN 63 IR	GOLD SILVER	**Minerals Bureau No:** 1832 **Latitude:** 2609 **Longitude:** 2810 CLOSED MINE
Nicomi Minerals **Tel:** **Fax:**	PO Box 651 BARBERTON 1300	BARBERTON RIVERSIDE 245 JU	GOLD SILVER	**Minerals Bureau No:** 1399 **Latitude:** 2538 **Longitude:** 3033 CLOSED MINE
Nigel Gold Mining Co Pty Ltd South East Rand Gold Holdings **Tel:** (011) 739 6709 **Fax:**	PO Box 1081 NIGEL 1490	NIGEL NOYCEDALE 191 IR VARKENSFONTEIN 169 IR	GOLD SILVER	**Minerals Bureau No:** 1497 **Latitude:** 2627 **Longitude:** 2827 CLOSED MINE
Nigel Gold Recovery Plant Multi Gold Holdings Ltd **Tel:** (011) 886 1017 **Fax:**	PO Box 41935 CRAIGHALL 2024	NIGEL VARKENSFONREIN 169 IR	GOLD SILVER	**Minerals Bureau No:** 2205 **Latitude:** 2624 **Longitude:** 2828 CLOSED MINE
Nigel Plant Multi Gold Holdings Ltd **Tel:** (011) 686-1017 **Fax:**	PO Box 41935 CRAIGHALL 2024	NIGEL VARKENSFONTEIN 169 IR PTN 50	GOLD SILVER	**Minerals Bureau No:** 2233 **Latitude:** 2623 **Longitude:** 2829 CLOSED MINE
Nuco Gold Recovery Nuco Pty Ltd **Tel:** (011) 739 7010 **Fax:**	PO Box 616 NIGEL 1490	NIGEL VARKENSFONTEIN 169 IR	GOLD SILVER URANIUM	**Minerals Bureau No:** 0439 **Latitude:** 2617 **Longitude:** 2828 CLOSED MINE
Nugo Mining Corp Ltd Heap Leach Plant **Tel:** (011) 739 3523 **Fax:**	PO Box 6187 HOMESTEAD 1412	NIGEL VARKENSFONTEIN 169 IR PTN 32	GOLD SILVER	**Minerals Bureau No:** 1452 **Latitude:** 2623 **Longitude:** 2828 CLOSED MINE
Overberg Mining (Pty) Ltd **Tel:** 27 **Fax:**	GRYSBESTOS TRANSVAAL 1307	CAROLINA SOODORST 2IU OVERGERG 1IU	GOLD	**Minerals Bureau No:** 2529 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Oversaes Mineral Distributing Corp **Tel:** (0131232) 2723 **Fax:**	Private Bag SCHAGEN 1207	NELSPRUIT RIETVALLEI 256 JT ELANDSHOOGTE 270 JT	GOLD SILVER	**Minerals Bureau No:** 2000 **Latitude:** ---- **Longitude:** ---- CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Petros Car Gold Mine **Tel:** **Fax:**	RORKE'S DRIFT 3016	DUNDEE PETROS 8307	GOLD SILVER	**Minerals Bureau No:** 4037 **Latitude:** 2822 **Longitude:** 3035 CLOSED MINE
Potberg Mines Pty Ltd **Tel:** **Fax:**	C/O Barclays Bank POTGIETERSRUS 0600	POTGIETERSRUST UITKYK 41 KS	GOLD	**Minerals Bureau No:** 0507 **Latitude:** 2409 **Longitude:** 2908 CLOSED MINE
President Brand Metallurgical Anglo American Corp Of S A Ltd **Tel:** 22-131 **Fax:**	PO Box 64 WELKOM 9460	WELKOM WELKOM 80 STUIRMANSPAN 92 MARMAGELI 20	GOLD URANIUM SILVER P.G.M.	**Minerals Bureau No:** 2683 **Latitude:** 2802 **Longitude:** 2645 CLOSED WORKS
President Steyn Metallurgical Anglo American Corp of S A Ltd **Tel:** 2-1211 // 2-1218 **Fax:**	PO Box 2 WELKOM 9460	WELKOM KLIPPAN 14 VIDEO 305 UITZIG 94	GOLD URANIUM SILVER P.G.M.	**Minerals Bureau No:** 2640 **Latitude:** 2800 **Longitude:** 2648 CLOSED WORKS
Princess Dump Multi Gold Holdings Ltd **Tel:** (011) 886 1017 **Fax:**	PO Box 41935 CRAIGHALL 2024	KLERKSDORP NOOITGEDACHT 434 IP	GOLD SILVER	**Minerals Bureau No:** 2514 **Latitude:** 2655 **Longitude:** 2638 CLOSED MINE
Prinsess (Gold) Sandwerke **Tel:** (011) 763 5023 **Fax:**	PO Box 603 ROODEPOORT 1725	ROODEPOORT ROODEPOORT 5 PTN 124 ROODEPOORT 5 PTN 125	GOLD SILVER SAND	**Minerals Bureau No:** 0520 **Latitude:** 2610 **Longitude:** 2750 CLOSED MINE
Republic Mining Co **Tel:** (011) 849 2642 **Fax:**	21 Van Rooyen Street BENONI 1500	BENONI VLAKFONTEIN 69 IR	GOLD SILVER	**Minerals Bureau No:** 1519 **Latitude:** 2611 **Longitude:** 2851 CLOSED MINE
Res Goud Pty Ltd Mineral & Exploration Pty Ltd **Tel:** (011) 789 4072 **Fax:**	PO Box 294 RANDBURG 2125	KRUGERSDORP LUIPAARDSVLEI 246 IQ PTN 143	GOLD SILVER	**Minerals Bureau No:** 2125 **Latitude:** 2607 **Longitude:** 2747 CLOSED MINE
Rietfontein Mine Gray Mining Pty Ltd **Tel:** **Fax:**	PO Box 372 SABIE 1260	PILGRIMS REST RIETFONTEIN 193 JT	GOLD SILVER	**Minerals Bureau No:** 1141 **Latitude:** ---- **Longitude:** ---- CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Roodepoort Gold Mine Pty Ltd **Tel:** (011) 724 3511 **Fax:**	PO Box 520 ROODEPOORT 1725	ROODEPOORT ROODEPOORT 237 IQ	GOLD SILVER	**Minerals Bureau No:** 1783 **Latitude:** 2609 **Longitude:** 2751 CLOSED MINE
Sevcorp Gold Mining Co Pty Ltd **Tel:** (011) 674 3307 **Fax:**	PO Box 1 FLORIDA 1710	ROODEPOORT VOGELSTRUISFONTEIN	GOLD SILVER	**Minerals Bureau No:** 0642 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Sifnos Mining Pty Ltd **Tel:** (013140) 140717 **Fax:**	PO Box 51 LOUWSCREEK 1302	BARBERTON THREE SISTERS JU 254	GOLD SILVER	**Minerals Bureau No:** 1157 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Simmer & Jack Gold Mine Simmer & Jack G M Co Ltd **Tel:** (011) 51-8571 or 51-8572 or 51-8573 **Fax:** "SIMPRO" GERMISTON	PO Box 192 GERMISTON 1400	GERMISTON ELANDSFONTEIN 90 107 & 108 IR JOYCE 90 IR DOORNFONTEIN 92 IR	GOLD SILVER	**Minerals Bureau No:** 0586 **Latitude:** 2610 **Longitude:** 2809 CLOSED MINE
Simmer and Jack Mines - ERGO Anglo American Corporatio **Tel:** (011) 825-3180 **Fax:** (011) 825-7304	PO Box 980 BRAKPAN 1540	GERMISTON ELANDSFONTEIN 90 IR	GOLD IRON-PYRITES SILVER	**Minerals Bureau No:** 1463 **Latitude:** 2610 **Longitude:** 2812 CLOSED MINE
Southern Sphere Mining & Dev G M **Tel:** (011) 788 1910 **Fax:** "SOUTHSPHERE"	PO Box 50065 RANDBURG 2125	BEAUFORT WEST BADENHORSTKUIL 356 JAGERSKRAAL 327	GOLD SILVER	**Minerals Bureau No:** 2132 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Spaarwater Gold Mine First Contract Mining Pty Ltd **Tel:** (011) 739 7719 **Fax:**	PO Box 585 NIGEL 1490	NIGEL SPAARWATER 171 IR	GOLD SILVER	**Minerals Bureau No:** 2115 **Latitude:** 2625 **Longitude:** 2823 CLOSED MINE
Sub Nigel Gold Mining Co Ltd **Tel:** **Fax:**	PO Box 14 DUNNOTTAR 1590	NIGEL GROOTFONTEIN 165 IR VARKENSFONTEIN 169 IP	GOLD SILVER	**Minerals Bureau No:** 0237 **Latitude:** 2621 **Longitude:** 2828 CLOSED MINE
Vaal Reefs G M Engineering + Plant **Tel:** **Fax:**		KLERKSDORP	GOLD	**Minerals Bureau No:** 1075 **Latitude:** ---- **Longitude:** ---- CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Vaal Reefs Gold Mine - East Anglo American Corp of SA Ltd **Tel:** (018) 78 9111 **Fax:**	PO Box 5010 VAAL REEF 2621	KLERKSDORP VAALKOP 439 IP MODDERFONTEIN 440 IP GOEDGENOEG 433 IP	GOLD IRON-PYRITES SILVER URANIUM	**Minerals Bureau No:** 2320 **Latitude:** 2655 **Longitude:** 2645 CLOSED MINE
Vaal Reefs Gold Mine - South Anglo American Corp Of SA Ltd **Tel:** (018) 78 9111 **Fax:**	PO Box 5010 VAAL REEF 2621	KLERKSDORP VAALKOP 439 IP MODDERFONTEIN 440 IP GOEDGENOEG 433 IP	GOLD IRON-PYRITES SILVER URANIUM	**Minerals Bureau No:** 2377 **Latitude:** 2655 **Longitude:** 2645 CLOSED MINE
Vaal Reefs Gold Mine - West Anglo American Corp of SA Ltd **Tel:** (018) 78 9111 **Fax:**	PO Box 5010 VAAL REEF 2621	KLERKSDORP VAALKOP 439 IP MODDERFONTEIN 440 IP GOEDGENOEG 433 IP	GOLD IRON-PYRITES SILVER URANIUM	**Minerals Bureau No:** 2415 **Latitude:** 2655 **Longitude:** 2645 CLOSED MINE
Vaal Reefs: New Mines (NO 10 #) **Tel:** **Fax:**		KLERKSDORP	GOLD	**Minerals Bureau No:** 2492 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Vlakfontein Gold Mine Gold Fields of SA Ltd **Tel:** (011) 734 2118 **Fax:**	PO Box 22 DUNNOTTAR 1590	BRAKPAN VLAKFONTEIN 130 IR	GOLD SILVER P.G.M.	**Minerals Bureau No:** 0686 **Latitude:** 2620 **Longitude:** 2826 CLOSED MINE
Vlakfontein Heap Leach Dunnottar Bullion Recoveries Pty Ltd **Tel:** (011) 826 5107 or 8 **Fax:**	PO Box 7642 RAVENSMOOR 1469	NIGEL	GOLD SILVER	**Minerals Bureau No:** 1762 **Latitude:** 2621 **Longitude:** 2825 CLOSED MINE
Volkmar Gold Recovery **Tel:** (011) 660 7736 **Fax:**	PO Box 243 KRUGERSDORP 1740	KRUGERSDORP LUIPAARDSVLEI 246 IQ	GOLD SILVER	**Minerals Bureau No:** 1539 **Latitude:** 2607 **Longitude:** 2746 CLOSED MINE
Volschenk J C C **Tel:** (01521) 7 3598 **Fax:**	PO Box 1205 PIETERSBURG 0700	PIETERSBURG FRISCHGEWAAGD 88 KS	GOLD SILVER	**Minerals Bureau No:** 1386 **Latitude:** 2414 **Longitude:** 2920 CLOSED MINE
Vroegeveld Gold Mine **Tel:** 976-2145 **Fax:**	PO Box 12247 CHLOORKOP 1624	PIET RETIEF VROEGEVELD 509 IT	GOLD SILVER	**Minerals Bureau No:** 1972 **Latitude:** 2656 **Longitude:** 3045 CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Welkom Gold Mine Anglo American Corp of SA Ltd **Tel:** (0171) 35 25331 **Fax:** "ORANGEGOLD"	PO Box 1 WELKOM 9460	WELKOM MIELIEBULT 49 ARRARAT 56 BOTHMASRUST 59	GOLD SILVER P.G.M.	**Minerals Bureau No:** 0704 **Latitude:** 2758 **Longitude:** 2645 CLOSED MINE
Weltevreden Mines Ltd Genmin **Tel:** (018) 63 4520 **Fax:** (018) 63 4520	PO Box 1307 ORKNEY 2620	VILJOENSKROON BOSHOEK 466 PTN WELTEVREDEN 130 PTN BELLEVUE 365 GROOTVADERSBOSCH 222	GOLD SILVER	**Minerals Bureau No:** 2755 **Latitude:** 2702 **Longitude:** 2638 CLOSED MINE
Western Areas Gold Mine South **Tel:** **Fax:**		WESTONARIA	GOLD	**Minerals Bureau No:** 2593 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Western Areas Gold Mine South Deep **Tel:** **Fax:**		WESTONARIA	GOLD	**Minerals Bureau No:** 2601 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Western Areas Gold Mine: North **Tel:** **Fax:**		WESTONARIA	GOLD	**Minerals Bureau No:** 2634 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Western Deep GM Central Services **Tel:** **Fax:**		OBERHOLZER	GOLD	**Minerals Bureau No:** 2433 **Latitude:** ---- **Longitude:** ---- CLOSED MINE
Western Deep Levels - East Anglo American Corp of SA Ltd **Tel:** (01491) 70 2040 **Fax:**	PO Box 8044 WESTERN LEVELS 2501	OBERHOLZER BLYVOORUITZICHT 116 IQ ELANDSRAND 115 IQ BUFFELSDOORN 143 IQ	GOLD URANIUM SILVER P.G.M.	**Minerals Bureau No:** 2717 **Latitude:** 2625 **Longitude:** 2725 CLOSED MINE
Western Deep Levels - North Anglo American Corp of SA Ltd **Tel:** (01491) 2161 **Fax:**	PO Box 8001 WESTERN LEVELS 2501	OBERHOLZER BLYVOORUITZICHT 116 IQ ELANDSRAND 115 IQ BUFFELSDOORN 143 IQ	GOLD URANIUM SILVER P.G.M.	**Minerals Bureau No:** 2656 **Latitude:** 2625 **Longitude:** 2725 CLOSED MINE
Western Deep Levels - South Anglo American Corp of SA Ltd **Tel:** (01491) 2161 **Fax:**	PO Box 8001 WESTERN LEVELS 2501	OBERHOLZER BLYVOORUITZICHT 116 IQ ELANDSRAND 115 IQ BUFFELSDOORN 143 IQ	GOLD URANIUM SILVER P.G.M.	**Minerals Bureau No:** 2700 **Latitude:** 2625 **Longitude:** 2725 CLOSED MINE

NAME OF MINE AND OWNER TEL AND FAX NUMBER	ADDRESS	DISTRICT AND FARM NAME	COMMODITY	MINERALS BUREAU NUMBER, LATITUDE, LONGITUDE AND STATUS OF MINE
Western Deep Levels - West Anglo American Corp of SA Ltd **Tel:** (01491) 2161 **Fax:**	PO Box 8001 WESTERN LEVELS 2501	OBERHOLZER BLYVOORUITZICHT 116 IQ ELANDSRAND 115 IQ BUFFELSDOORN 143 IQ	GOLD URANIUM SILVER P.G.M.	**Minerals Bureau No:** 2461 **Latitude:** 2625 **Longitude:** 2725 CLOSED MINE
Western Holdings - Erfdeel **Tel:** **Fax:**	PO Box 61587 MARSHALLTOWN 2107	HENNENMAN ERFDEEL 188 DANKBAASHEID 187	GOLD SILVER	**Minerals Bureau No:** 1325 **Latitude:** 2758 **Longitude:** 2653 CLOSED MINE
Western Holdings Gold Mine Anglo American Corp of SA Ltd **Tel:** (0171) 35 22151 **Fax:**	PO Box 3 WELKOM 9460	WELKOM FRIEDESHEIM 51 ERFDEEL 18 MERIBAH 16	GOLD URANIUM SILVER P.G.M.	**Minerals Bureau No:** 0714 **Latitude:** 2759 **Longitude:** 2640 CLOSED MINE
Witwatersrand Nigel Gold Mine Witwatersrand Nigel Ltd **Tel:** (0151) 2161 or 2162 or 2163 **Fax:**	PO Box 206 HEIDELBERG 2400	HEIDELBERG(TVL) HOUTPOORT 392 IR MARAISDRIFT 190 IR POORTJE 389 IR	GOLD SILVER	**Minerals Bureau No:** 0733 **Latitude:** 2640 **Longitude:** 2825 CLOSED MINE
Worcester Gold Mine **Tel:** (01314) 3128 **Fax:**	PO Box 500 BARBERTON 1300	BARBERTON LOTS 84, 85, 86 SECTION C KAAPBLOCK	GOLD SILVER	**Minerals Bureau No:** 1544 **Latitude:** 2527 **Longitude:** 3058 CLOSED MINE
Askew's Quarry Grinaker Constructoin Pty Ltd **Tel:** 0351-51511 **Fax:**	PO Box 492 EMPANGENI 3880	LOWER UMFOLOZI UMHLATUZI NO. 14086	GRANITE GRAVEL	**Minerals Bureau No:** 0226 **Latitude:** 2845 **Longitude:** 3156 CLOSED MINE
Askews Granite Quarry **Tel:** 5-1511 **Fax:**	PO Box 1461 RICHARDS BAY 3900	LOWER UMFOLOZI REM OF LOT 149 EMPANGENI 14086	GRANITE	**Minerals Bureau No:** 1431 **Latitude:** 2547 **Longitude:** 3154 CLOSED MINE
B & E Granite Quarry **Tel:** 41-4144 (041) **Fax:**	PO Box 14079 PORT ELIZABETH 6061	GEORGE KRAAIBOSCH	GRANITE	**Minerals Bureau No:** 1637 **Latitude:** 3400 **Longitude:** 2230 CLOSED MINE
B & E Quarry -Sedgefield Blasting And Excavating **Tel:** 41-4144 (041) **Fax:**	PO Box 14079 PORT ELIZABETH 6061	GEORGE DRIE VALLEYEN 186	GRANITE	**Minerals Bureau No:** 1701 **Latitude:** 3402 **Longitude:** 2244 CLOSED MINE