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The Potential Benefits of Strategically Located Energy Storage and the Integration of Power from Renewable Sources

by

Robert John Bass

A Doctoral Thesis

Submitted in partial fulfilment of the requirements for the award of Doctor of Philosophy of Loughborough University

Wolfson School of Mechanical and Manufacturing Engineering
Loughborough University

January 2008

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Abstract

Ultimately there will be a limit on the amount of power from variable sources of renewable energy which can be absorbed by the electricity supply system and continue to remain stable and secure. New technical solutions are required.

The development of energy storage technology could provide a potential solution. However, all the current methods involve either a significant loss of energy during the process or are unsuitable for the bulk storage of power.

The research work reviews current methods of energy storage and examines the supply chain in order to resolve where energy storage should best be located. Most benefits could be gained if the energy storage units were placed adjacent to the final customers. The power lost during transmission and distribution could be minimised and the capital invested in the infrastructure would be more productive. It would require energy to be stored in relatively small quantities using simple technology, be remotely controlled and offer a long operational life. Few current methods match these requirements.

In order to support the analysis of benefits which may be delivered by storing energy, the performance of a modern CCGT power station was monitored while it was operating with a number of different output profiles. The consequences were recorded and analysed for fuel used, CO₂ emitted, operational costs and maintenance as the plant produced power below its optimum performance.

The Flow Battery was identified as the technology likely to deliver most characteristics required of an embedded energy store. However, the flow battery requires space to store the electrolyte and can be expensive to employ in urban areas where land prices are high.

An enhancement of the hydraulic accumulator could be developed as an energy store. The initial analysis suggests that it offers the potential technical characteristics required and could be designed for minimum land requirements. Hence it could be located adjacent to existing electricity sub-stations or even within domestic premises, industrial complexes and commercial enterprises where land may already in the hands of the potential user.
Acknowledgements

The help and encouragement of my supervisors Professor W Malalasekera, Mr Versteeg and Dr P Willmot are gratefully acknowledged.

The permission by the owners of 'Plant C' to use data from their plant and for the extensive discussions concerning plant operations and maintenance is also gratefully acknowledged. This information gained during the early stages of the work formed an important base from which it was possible to explore the potential benefits which may be achieved through embedded energy storage.

Information supplied by Escape Energy Advisers Ltd, National Grid Company, Ofgem, iTi Ltd Scotland, VBR Europe, and Phoenix Hydraulics Ltd was all of significant value.

My thanks are also due to my wife Wendy and my family for their encouragement and proof reading.
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### Abbreviations

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<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>AC</td>
<td>Alternating Current</td>
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<tr>
<td>BETA</td>
<td>British Electricity Trading Arrangement</td>
</tr>
<tr>
<td>BWEA</td>
<td>British Wind Energy Association</td>
</tr>
<tr>
<td>CAES</td>
<td>Compressed Air Energy Store</td>
</tr>
<tr>
<td>CAP</td>
<td>Common Agricultural Policy</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
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<tr>
<td>CCL</td>
<td>Climate Change Levy</td>
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<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
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<tr>
<td>CPI</td>
<td>Core Inflation Index</td>
</tr>
<tr>
<td>DC</td>
<td>Direct Current</td>
</tr>
<tr>
<td>DTI</td>
<td>Department of Trade and Industry (UK)</td>
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<tr>
<td>Duos</td>
<td>Distribution use of system</td>
</tr>
<tr>
<td>DNuos</td>
<td>Distribution Network use of system</td>
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<tr>
<td>EA</td>
<td>Environment Agency</td>
</tr>
<tr>
<td>Economy 7</td>
<td>Electricity tariff for night–time rates</td>
</tr>
<tr>
<td>EDF</td>
<td>Electricity de France</td>
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<tr>
<td>EOH</td>
<td>Equivalent Operating Hours</td>
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<tr>
<td>ERAQS</td>
<td>Expert Panel on Air Quality Standards</td>
</tr>
<tr>
<td>ETS</td>
<td>Emissions Trading Scheme</td>
</tr>
<tr>
<td>EWEA</td>
<td>European Wind Energy Association</td>
</tr>
<tr>
<td>GE</td>
<td>General Electric Company</td>
</tr>
<tr>
<td>Gen Co</td>
<td>Generating Company</td>
</tr>
<tr>
<td>GSP</td>
<td>Grid Supply Point</td>
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<tr>
<td>GT</td>
<td>Gas Turbine</td>
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<tr>
<td>Ha</td>
<td>hectare</td>
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<tr>
<td>HH Customer</td>
<td>Half Hourly metered customer</td>
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<tr>
<td>HRSG</td>
<td>Heat Recovery Steam Generator</td>
</tr>
<tr>
<td>IPPC</td>
<td>Integrated Pollution Prevention and Control</td>
</tr>
<tr>
<td>ITER</td>
<td>European Fusion project</td>
</tr>
<tr>
<td>M/G</td>
<td>Motor–Generator set (electrical)</td>
</tr>
<tr>
<td>Max Gen</td>
<td>Call for Maximum Generation (by NGC)</td>
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<tr>
<td>MER</td>
<td>Maximum Economic Rating</td>
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</table>
MT  Metric tonne
Min D  Minimum Demand
Max D  Maximum Demand
NETA  New Electricity Trading Arrangement
NOx  Oxides of Nitrogen
O & M  Operations and Maintenance
OCGT  Open Cycle Gas Turbine
P/M  Pump – Motor set (hydraulic)
PPI  Petroleum Price Index
PV  Photo Voltaic
RE  Renewable Energy
REAG  Renewable Energy Advisory Group
RPI  Retail Price Index
S & H  Starts and Hours
SMES  Superconducting Magnetic Energy Store
SO  System Operator
ST  Steam Turbine
T & D Loss  Transmission and Distribution Loss
TNuos  Transmission Network use of system (charge)
Tuos  Transmission use of system
UN  United Nations
VRB  Vanadium Redox Battery
WHO  World Health Organisation
Chapter 1
Introduction

1.1 Background

Under the terms of the Kyoto Agreement (2001), the UK is committed to reduce CO₂ emissions by 2010 to a level 12% below the level emitted during 1990 [1, 2]. The provisions of the Kyoto Protocol were ratified at the 2005 UN Climate Change conference in Montreal [3]. To meet these obligations, renewable energy is required to deliver 10% of the UK electrical power demand by 2010 and 20% by 2020 with an expectation of reaching an output of 60% by 2050 [4].

Almost all sources of renewable energy have the characteristics which cause problems:

(a) They are unpredictable in output power produced (wind, solar, wave, tidal).
(b) They do not provide secure supplies.
(c) They are difficult to integrate economically into the national electricity grid due to the remote locations of many renewable energy sources and the long distances to the customers
(d) They require backup generation capacity to produce power as the renewable sources are highly variable in power output e.g. wind power [5]

By the year 2020 much of the existing coal fired and nuclear power generation will be obsolete and retired from service [6]. Unless a decision is made in the near future to build nuclear power plants to provide the lost capacity most of the replacement generation will be provided by gas using Combined Cycle Gas Turbine (CCGT) plants [7].

At present wind power is the most developed and probably the most widely adopted technology for extracting renewable energy from the environment. It is accepted that there is little potential for hydropower left to exploit in the UK. The options of generating power using tidal barrages are expensive, environmentally invasive and take many years to implement. The extraction of energy from tidal steams is under development and may
deliver power sometime in the future. Other options such as solar energy are currently expensive to install and find application for small special applications in the UK.

Hence wind energy is well positioned to deliver the major proportion of the 20% of electrical power planned for 2020 from non-polluting sources. The high-speed wind areas are located in the North and West of the UK. Unfortunately, the electrical load centre is situated towards the South and Southeast of the country. It will require long transmission lines to bring the power to the customers and this will be subject to significant transmission and distribution losses, which could be in excess of 10% of the power, exported from the wind farms.

If the renewable sources of power are available they will be given priority to supply the customer demand in preference to fossil fuel generation to help the UK can meet its targets for CO₂ reduction.

As the amount of renewable generating capacity increases, the gas-fired plants will be required to continually adjust their power output so the total generation matches the instantaneous customer demand. When the fossil fuel stations are reduced to a balancing role they will be subjected to many more stops and starts than currently experienced. When generating power they will be required to produce at output levels significantly removed from their design optimum operating conditions for long periods of time. This will have several consequences:-

(a) More fuel will be used per unit of electricity produced
(b) More CO₂ will be produced per unit of power exported
(c) There will be higher costs per unit of output for
   (i) Maintenance
   (ii) Capital funding
   (iii) Fixed overhead costs
   (iv) Carbon trading
(d) Increased pollution from NOX emissions
1.2 Scope of the research work

To date no research work has been carried out to evaluate the impact of variable demand upon new large CCGT plants. In this research work an attempt is made to address this issue and to identify the consequences, data has been collected from a modern 800MW CCGT plant. The parameters investigated will allow a better perspective to be placed upon the cost consequences and the increased emissions, which result from this type of plant output power modulation.

Under present UK power generation and distribution market arrangements it is increasingly difficult to predict, with any degree of certainty, how much power the CCGT plants will generate and hence the revenue streams in any one year. Likewise, it will be difficult to estimate how much gas will be needed, when it should be available because it will be purchased from the ‘Day Ahead’ or ‘Within Day’ markets rather than the long term contract market. How much it will cost cannot be accurately predicted in advance. As the available energy output from renewable sources increases it will increase the revenue risk factors and make the cost of capital to finance new power plants more expensive.

The annual demand for electrical power by 2020 is estimated to be some 350TWh [7]. If wind power is set to provide just 15% of this demand, it will supply approximately 52TWh. As wind turbines operate with a load factor of between 24% and 35% annually, it will require an approximate total installed capacity of between 22 and 32 GW. This assumes that a mixed range of other renewable energy sources should be available to produce the remaining 5% of carbon free emission power.

The operation of the electricity grid (i.e. the national grid, System Operator (SO)) must have a generating margin available, traditionally set at 20% of the current demand, to ensure the security of supply. This reserve capacity provides a buffer to deal with transient load changes sudden power station outages and system faults. It consists of spinning reserve, plant in hot standby and some stationary reserve capacity (on cold standby).

The UK demand is expected to grow due to increased industrial demand and growth in population. New generating capacity will be required to replace the old coal and nuclear
plants retired between 2005 and 2020 and to accommodate the anticipated growth in demand of approximately 1% per annum during the intervening period.

The impact of all these factors suggests that there could be significant cost implications, which this research work attempts to address. There will also be changes in the plant emissions as the gas turbines are switched in and out of production and their power output levels are adjusted to each new situation. This work investigates the consequences of such demand changes.

Whilst new power plants will undoubtedly be required, other important factors have an influence upon the overall cost of delivering electricity to the consumer. Power is lost in the transmission and distribution systems and currently accounts for an average of 9% of that exported from the power stations. This figure disguises the fact that the losses are significantly higher when the demand is high, as the actual losses are proportional to the square of the current flowing in the conductors. During times of high demand the power dissipated into the environment can be greater than 15%, whilst during low demand periods at night the losses fall to about 4% of the exported power.

To this end this research work explores the potential for reducing these losses by strategically located energy storage capacity. Such storage could:

(a) enable power plants to produce power continuously using optimum operating conditions,

(b) reduce the transmission and distribution losses,

(c) reduce the number of new fossil fuel power plants and nuclear power stations required,

(d) maximise variable wind energy input,

(e) reduce the capital required for new electricity and gas transmission infrastructure,

(f) provide a new source of balancing power and grid ancillary services.

(g) reduce maintenance and operating costs of power plants,

A literature survey of the currently available energy storage technologies was carried out to assess the potential advantages to be gained. Some storage techniques are already employed in the UK such as pumped storage and hydroelectricity. They require special
geographic characteristics therefore they are not generally applicable across the country. Some of the techniques are expensive or have a low turn round efficiency. Hence they are only suitable for special applications where back-up supplies are needed for strategic reasons of continuity of supply, (e.g. computer systems).

To-date it has been considered that energy storage can only be successful if it passes the simple commercial test, ‘Is the method used able to operate commercially by purchasing power during the cheap period at night-time and then selling it during the expensive periods during the day time.’

Many of the benefits which could be provided through the storage of energy at different locations throughout the electricity supply chain have not received the attention which they deserve.

No strategic account has been taken of:

(a) the savings of fossil fuels (a finite resource)
(b) reduced CO₂ and NOx emissions
(c) reduced capital expenditure on electrical and gas system infrastructure
(d) fewer new nuclear and CCGT power stations
(e) smaller amounts of nuclear waste to process and store
(f) improved ancillary services for national grid control

1.3 Objectives of the Present Study

The current state of the electricity supply position discussed above highlights a number of major issues, which will impact upon future development, and operation of the UK power generation infrastructure. The CO₂ reduction targets which the UK has accepted are both difficult to achieve and complex to deliver.

The main objectives of this research are:-

1. To identify the renewable energy sources available to produce electrical power in the UK, to examine the nature of the energy produced and indicate the issues of integration into the supply network.
2. To measure the physical and financial impact upon a gas fired combined cycle power plant when it is required to operate below optimum conditions. Hence, to examine the impact upon such plants when required to compensate for variable input power from increasing amounts of renewable energy.

3. To review proven energy storage technologies and evaluate their potential application for the integration of renewable energy into the supply network. To extend the analysis to include the use of storage to allow the fossil fuelled plant to operate at or near to their optimum operating conditions.

4. To examine the power losses incurred during electricity transmission and distribution and to quantify the wider benefits of storing power in a distributed form around the network.

5. To propose and evaluate a new method of storing and generating electrical power suitable for distributed application embedded in the distribution network.

During the course of this work a number of sub-objectives were entered into in order to deliver the main objectives, namely

(a) Data collection and analysis from a new 800MW CCGT power plant.

(b) Identification of the resulting pollution, fuel consumption, operational costs, maintenance routines and capital funding implications due to the imposed variable output.

(c) The impact upon CCGT plant of meeting the National Grid Code and delivering ancillary services.

1.4 Methodology

The works commenced with a literature survey of a number of discrete subjects. The following topics have been reviewed - renewable energy sources, energy storage, future fossil fuel technology, nuclear technology, the UK transmission and distribution network, the 'British Electricity Trading Arrangement (BETA), the gas trading system, international treaties concerned with global warming, carbon trading.

The various potential sources of renewable energy (RE) were identified, their possible contribution analysed and the implication of unpredictable availability examined.
The consequences of the variable nature of supply, its integration into the national electricity supply network and the impact upon power plants which have to provide the 'balancing' supply from alternative fuel sources.

Data was collected from a new 800MW gas fired power plant and used to investigate the commercial and environmental impact caused by operating the plant at various output power levels. The analysis was contrasted with the plant characteristics when operating at its most economic rating (MER).

Two separate studies were then carried out namely:

(a) The power losses that occur in the transmission and distribution system.

(b) A review of the Energy Storage techniques and their potential role in improving the supply of electricity system across the country.

The analysis then led to a differentiation between central large energy storage units (e.g. pumped storage) and widely distributed smaller forms of storage.

It is worth noting that the aims of the work reported in this thesis are supported by a paper commissioned by the DTI to study 'The future Value of Storage in the UK with Generator Intermittency', by The Manchester Centre for Energy (UMIST) [9]. This paper examines whether the renewable energy sources of generation will be able to replace the capacity and flexibility of conventional generating plant and evaluates the benefits to be gained by storing wind energy at times of low demand compared with the generation of power using ‘Open Cycle Gas Turbines’ (OCGT) at times of high demand.

The conclusions of our work on CCGT power plant identify potential savings in operational, maintenance and capital costs together with reduced polluting emissions by the use of energy storage. The loss of thermal efficiency due to the part loading of the OCGT plant has been estimated to be between 10 and 20% [10]. The present work did not consider the use of multiple CCGT plants to carry out the system balancing but as these plants are more efficient than the OCGT plants they would provide higher efficiencies and lower pollution.
Various storage technologies were examined with the objective of identifying any tangible benefits of storing excess wind power until it was required and of operating fossil fuel plants at or near their MER for longer periods. The strategic value of distributed storage was quantified. The need for a simple long life, remotely controlled, high turn round efficiency method of energy storage was identified. This led to the proposal for a system based upon storing energy in the very high-pressure gas/ fluid cylinders. The proposal was described physically and analysed mathematically to evaluate the potential benefits.

An initial Environmental Impact analysis was carried out to identify any potential damage which might arise and to any issues of public concern such as noise and electromagnetic radiation.

The research work followed the logic diagram set out below in Fig 1.1

Fig 1.1 Research programme work flow
1.5 Structure of the thesis

The material in this thesis follows the following pattern. Chapter 2 describes the sources and the variability of energy obtained from the renewable energy sector. Chapter 3 examines the consequences of varying the output from a modern combined cycle gas turbine (CCGT) power station and the increases in fuel used, the CO₂ emitted and the overall cost per MWh generated. Chapter 4 reviews the current methods of storing energy and the applications within the UK electricity supply chain. Chapter 5 analyses the power losses which occur throughout the transmission and distribution system as the power flows vary to meet the customer demand in order to identify the optimum location for energy storage. Chapter 6 investigates the potential benefits which may be gained through the use of energy storage embedded within the distribution system. Chapter 7 then determines the technical requirements of an embedded energy storage device and the environmental constraints which may have to be accommodated in an urban location. Chapter 8 reviews the capabilities of the current energy storage methods to meet the characteristics required to perform the duties of an embedded store identifying the most suitable developed technology. Chapter 9 postulates a proposal for a new energy storage device which could provide embedded energy storage without the disadvantages of existing storage methods. Chapter 10 describes a financial evaluation of embedded energy storage and tests its economic viability within the current UK tariff system. Further potential benefits delivered by this form of storage are identified but due to the current regulatory arrangement would either: not be rewarded by the tariff arrangements or only captured by creating special financial structures. Finally, Chapter 11 draws together the conclusions derived from the research work and proposes future work to achieve the potential gains offered by energy storage to reduce pollution and costs from fossil fuel power plants and to increase the amount of renewable energy which could be safely absorbed within the electricity supply system.
Chapter 2

The Variability of Energy from Renewable Sources

2.1 Introduction

The Renewable Energy Advisory Group (REAG) defines renewable energy as:
"The term to cover those energy flows that occur naturally and repeatedly in the environment and can be harnessed for human benefit. The ultimate sources of the most of this energy are the sun, gravity and the earth's rotation".[11]

The Earth captures this energy in seven different ways, which can be liberated by a range of methods for use by society;

i. Through biomass, (which converts sun light into stored carbon in plants, using the photosynthesis process).

ii. By the direct conversion of the radiation from the sun
   (a) to raise the temperature of water.
   (b) into electricity using photovoltaic cells.

iii. By capturing the water vapour liberated from the oceans and storing it at a high level in the mountains and hills from rainfall. The stored potential energy may be used to generate electricity (hydropower).

iv. By using solar energy absorbed in the atmosphere and using the wind to drive wind turbines.

v. By converting the kinetic energy in the waves to drive electric generators.

vi. By trapping the gravitational energy in the ocean tides caused by the sun and the moon. The energy may be gathered:
   (a) by a barrage and using differential heights of the sea to drive water turbines.
   (b) by a submerged propeller driven turbines or hydrofoils powering hydraulic systems in the tidal steams as the tides ebb and flow.
A seventh source of non-fossil fuel power (i.e. a very large reserve) is that of geothermal energy. This reservoir of heat energy is stored in the core of the planet. It was created during the formation of the earth. As the planet was built from the collision of planetismals, a great deal of heat was created some 4.6 billion years ago. This energy may be used to produce hot water and steam for the generation of electricity.

2.2 The Energy Sources

The sources of renewable energy may be divided into three main groups based upon their characteristics to deliver power;

1. The predictable group: biomass, geothermal and hydropower.
2. The predictable but variable and intermittent group: tidal barrage and tidal stream.
3. The unpredictable, variable and intermittent group: solar, wind and wave.

In terms of integrating these renewable sources with existing power generation and distribution systems, Groups 2 and 3 cause technical and economic difficulties when they are integrated into the energy supply chain to the customer. Group 1 can be accommodated by the system without any integration problems. Hydro-electricity is particularly useful as it may be readily and speedily adjusted to help balance changes in customer demand.

2.3 Potential Contributions

The contribution of each of the renewable energy sources in any specific region of the globe depends upon many factors. The access to geothermal is governed by the thickness of the earth’s crust and type of rock formation at a particular location. The solar power available is dependent upon the latitude and the tidal rise and fall is influenced by the tidal resonant effect generated and shape of the local coastline. Biomass is dependent upon the local climate and water supply which influence the yields that can be achieved.
2.3.1 Group 1 Renewables

2.3.1.1 Biomass

The first of these sources, biomass, involves the combustion of materials which generate carbon dioxide as an effluent gas. However, it is claimed that the growing plants, which provide the biomass, reabsorbs the CO$_2$ and there is no net atmospheric gain in the airborne content of this gas.

Some of the materials in this sector include cereal straw, forest wastes and purpose grown crops. The crops being developed include willow coppice and special grasses such as miscanthus. The government energy task force (2005), [11] has indicated that up to 1 million hectares could be made available to produce biomass for the energy market and claim that this source together with recoverable wood waste of up to 2.9m tonnes a year could supply both the direct heating sector and the power generation sector.

The combustion of these materials can be carried out in purpose built units using a conventional furnace and steam turbine cycle. As these units are small (typically 15 to 30MW) by comparison with coal fired plants (1000MW), their overall efficiency is low, (25 to 30%). As an alternative, some forms of biomass can be co-fired with coal in conventional power stations. However, this is only an option where the existing units are operational before they are retired from service.

Biomass presents a number of problems as an energy source.

1) The yield of biomass per hectare tends to be low. For example cereal straw produces approximately 2.5 tonne / ha / year. Willow coppice yields between 3.1 and 9.8 tonne / acre / year.

2) The biomass crops are harvested at specific times of the year and must be stored for up to 10 months of the year if they are to provide a continuous source of energy.

3) Biomass must be kept dry as any water addition reduces the useful energy, which can be extracted.

4) The bulk density of the biomass material is low and it requires large storage where it can be protected from any fire risk and the weather.
5) It is expensive to transport due to the low bulk density and is therefore only economically processed into energy within a short distance from its source.

6) Recent attempts to raise the combustion efficiency by gasification of the biomass material and using the combined cycle process, (see chapter 3 of this thesis), have failed and been abandoned. [12]

Experience with biomass to-date, in the United Kingdom, has been less successful than predicted. The need for state subsidies, to support the development work and the difficulties of raising the necessary capital, to fund the construction of suitable power generation plant, have conspired to make progress very slow, [13].

The future of purpose grown crops in the UK will depend upon a favourable outcome of changes to the Common European Agricultural policy (the CAP). Should there be a new guaranteed long-term market for these crops, the biomass task force foresees the potential contribution illustrated in Table 2.1.

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Realised Electrical Energy (TWh)</th>
<th>UK Electrical Demand %</th>
<th>Heat Energy Potential (TWh)</th>
<th>UK Heat Demand %</th>
<th>Potential CHP Energy (TWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Municipal Soft waste</td>
<td>1.43 - 5.30</td>
<td>0.36 - 1.35</td>
<td>4.5 - 16.98</td>
<td>4.73 - 17.78</td>
<td>4.22 - 5.63</td>
</tr>
<tr>
<td>Forestry Waste</td>
<td>1.63 - 1.93</td>
<td>0.41 - 0.49</td>
<td>4.33 - 5.14</td>
<td>4.56 - 5.41</td>
<td>4.06 - 4.62</td>
</tr>
<tr>
<td>SRC Willow</td>
<td>0.03 - 0.05</td>
<td>0.01</td>
<td>0.06 - 0.14</td>
<td>0.08 - 0.15</td>
<td>0.07 - 0.13</td>
</tr>
<tr>
<td>Miscanthus</td>
<td>0.003 - 0.01</td>
<td>0.001 - 0.002</td>
<td>0.007 - 0.019</td>
<td>0.01 - 0.02</td>
<td>0.007 - 0.02</td>
</tr>
<tr>
<td>Straw (cereal)</td>
<td>10.95 - 13.39</td>
<td>2.77 - 3.36</td>
<td>29.21 - 35.7</td>
<td>30.74 - 37.57</td>
<td>27.38 - 33.47</td>
</tr>
<tr>
<td>Sewage Sludge</td>
<td>1.733 - 1.95</td>
<td>0.44 - 0.49</td>
<td>4.62 - 5.2</td>
<td>4.87 - 5.47</td>
<td>4.32 - 4.88</td>
</tr>
<tr>
<td>Totals</td>
<td>15.8 - 22.7</td>
<td>4.0 - 5.7</td>
<td>42.7 - 63.0</td>
<td>45.0 - 66.4</td>
<td>40.1 - 59.1</td>
</tr>
</tbody>
</table>
2.3.1.2 Geothermal Energy

The extraction of energy from the interior of the Earth has been successfully captured in some 20 countries, principally to generate hot water and steam. It is used for space heating and the generation of electrical power. On a world-wide basis, geothermal sources accounted for the generation of approximately 5800 MW of electrical power and approximately 4000 MW of direct heat during the 1990s, [14].

The locations where this form of energy can be extracted are concentrated at points where the Earth’s internal heat comes near to the surface. In some cases the heat generates steam by heating the aquifers, which can be tapped and used directly. At other points, where hot rocks can be reached by drilling to obtain access for water pipes, heat can be extracted using water pumped into these areas after the rocks have been drilled and fractured by explosives.

In the United Kingdom one significant experiment has been carried out in Southampton. Here the underlain rocks are hot and contain water in the form of brine. This has been used to heat buildings in the city centre since 1989. Originally the scheme started with a test borehole in 1981 which located a layer of Sherwood Sandstone where the water temperature was 70 °C [5]. A production unit was commissioned during 1989 with an expected life of 20 years. The project continues to operate (2006) with 40 commercial customers and 1,400 domestic customers and has recently gained a 25 year extension to the original contract. It is claimed that a reduction of carbon dioxide emissions by more than 11,000 tonnes per year is achieved over alternative methods of heat input using fossil fuels.

The future of geothermal power in the UK will depend upon technological developments to reduce the cost of extracting energy from deeper and deeper locations and upon the rate of fossil fuel price increases over the coming years.

2.3.1.3 Hydro Power

Approximately 20% of the world demand for electricity is met by hydropower. It is a technology, which has been developed over a long time, with a range of turbines specifically designed to exploit power from very high heads of water in the mountains to those involving low head high volume installations. The electrical generation schemes are
reliable, long lasting and are able to provide a variable output to meet the demands of consumers. This storage capability has two significant benefits,

(1) the power output can be increased or decreased quickly to match the demand.

(2) the quick response characteristic can be used to correct short-term frequency deviations. These occur on the transmission system due to line and switch gear faults on the system or power generating plant failures.

Hydropower requires the largest possible head of water above the water turbines to be effective. All the suitable locations are in the mountains. Many of the best sites have already been utilised to store water and generate power. During 2003 these plants generated approximately 1% of the national electricity demand [15]. It was produced by 68 hydroelectric stations throughout the UK.

Unfortunately, two factors have reduced the potential of this source of power.

(1) The environmental impact of the dams and lakes created to supply hydro schemes has become a significant hurdle. Not only are they expensive to construct but public objections to new proposals have had an adverse impact upon the planning process with the result that no large schemes have been constructed.

(2) The remote locations of hydroelectric plants require them to be connected via long transmission lines to the centre of the power demand. New overhead power lines, built through environmentally sensitive areas such as the ‘Highland of Scotland’, raise major objections during the permitting process and often result in time consuming and expensive public enquiries.

New micro-hydroelectric projects, where streams are used to supply small local demands, are still encouraged with government support. The local impact is small and there is often insufficient power generated to require new connections to the electricity distribution system.

While hydroelectricity has all desired characteristics of the ideal source of renewable energy as it is predictable and can be called upon to deliver power ‘On Demand’, it suffers from its dependency on variability of annual rainfall and the size of its reservoir to store water. During dry summer periods the reservoirs often have insufficient reserves to supply
the turbines for other than a few hours a day. However, where the power can be generated during the times when power prices are high, the station profitability can be maximised.

Several stations have the facility to pump water from the lower reservoir back to the head basin by using cheap power available during the night. Although power is lost during this process (a turn round efficiency of 75 to 80% is often achieved) and when the day / night power price is sufficiently wide it is profitable to exploit.

2.3.2 Group 2 Renewables

Group 2 renewable sources of energy have the potential to deliver significant quantities of electrical power to the UK grid system in the future. As the amount of energy they could provide is predictable, even though it varies with the lunar cycle, it could be more readily integrated into the supply system than the power obtained from Group 3 renewables.

Considerable research and development work is currently being pursued in these areas and some solutions related to tidal stream devices are undergoing pre-production trials. The profile of the electricity generated by these two potential sources will be examined in detail as the integration of this power into the electrical transmission and distribution system has important consequences for the security of the supply.

2.3.2.1 Tidal Power (Tidal Rise and Fall)
The energy available in the regular rise and fall of the water levels around the coastline represents a source of renewable power. It could make a very big contribution to achieving the target reduction in CO₂ emissions currently being discharged into the atmosphere by the fossil fuel power stations. However, to be generally acceptable to the public, any system that is devised to capture the energy and produce electricity efficiently has to have a minimal effect upon the environment.

Two methods of gathering this energy are possible:
An example of the method one is the La Rance tidal barrage that has been operational in France since 1966 which makes use of the rise and fall of the water levels.
The second uses the tidal stream in locations where the ebb and flow of the tide causes water currents to flow approximately 4 times per day, reversing direction each 6 hours. These currents are used to drive propellers or hydrofoils, which in turn are used to drive the electric generators. Both the tidal stream devices are still under development and will be discussed later.

At a number of locations around the world the geographical features cause the rise and fall of the tides to be accentuated. Fig. 2.1 illustrates the tidal ranges the most important locations. To-date very few of these locations have been exploited, the most notable exception being the La Rance tidal power plant in northern France shown in Fig. 2.2. Here a 240MW power station has been built and operated successfully since 1966 [5].

Fig. 2.1 The best tidal ranges for generating power around coastlines. Adapted from: Boyle [4]. Shown in brackets are the tidal ranges in meters
The available head of water trapped behind the barrage varies between 5 and 10 meters during the lunar cycle. This is small compared with most hydroelectric projects where heads of 500 meters are more common. With these small pressure heads, large volumes of water are required to generate power, which in turn requires very significant civil engineering works and proportionately large turbines to handle and extract the power as the tide rises and falls. The annual average electricity produced at this plant is 544 GWh.

In the UK the best potential location is found on the river Severn. The tidal range experienced varies up to 14 m and is the second largest in the world. There have been several proposals to construct a barrage to make use of the renewable energy available. Fig. 2.3 shows the location and the shape of the barrage, which would be 16 km long across the Bristol Channel. The maximum power generated is designed to be 8640 MW delivering an annual average output of 17 TWh per year.
The proposal has been the subject of two Department of Trade and Industry (DTI) studies, one in 1981 (The Watt Committee) [17] and a later study during 2001 [18]. The latter work estimated the capital cost to be £12 billion but a government review in 2003 failed to recommend that it should proceed due to the capital cost, long construction time and the un-quantified environmental impact, but the Sustainable Development Commission is to investigate the potential power generation further.

Barrages have been proposed for the generation of tidal energy at other estuary locations in the UK. The most suitable include the Mersey estuary, the Solway Firth, the Wash and the Humber estuary. Fig 2.4 illustrates the position of the proposed barrages. If all four proposals were constructed, it is estimated that it would produce approximately 35TWh per year.
The tidal range may be enhanced in some locations by resonance in the estuary and across the ocean. The tidal cycle is repeated every 12.4 hours. The distance between coast of Europe and the coast of America is approximately 4000 km, which is sufficient to cause resonance. When this is added to the shape of the Severn Estuary it causes complex resonances. The resulting tidal range produced is much wider than it would be in the absence of the effect. Fig. 2.5 demonstrates extent of the resonance effect.

The power produced from the tidal barrage can be taken out in one of two forms. During the flood tide the generation commences when the head of water is sufficient to drive the turbines. It stops when basin level approaches the sea level and the head difference is inadequate. The power output cycle produced is shown in Fig. 2.6.
Fig. 2.5 The resonance effect in the south west of England and the Severn Estuary.

Source: Boyle [5].

When the ebb tide is used to produce power, generation commences after the high tide point and at a time when the sea level has fallen far enough to create a head to drive the turbines. It ends when the tide has passed through the low tide point and starts to rise again thereby eliminating the differential head between the basin and the sea. The power generation pattern produced is illustrated in Fig. 2.7.
The third option available is to generate power both during the flood tide and the ebb tide. The water turbines and civil engineering structures required are both larger and more expensive for this option. This is due to the lower differential head that can be achieved between the basin and the sea and the requirement for the increased flow of water. Fig. 2.8 shows the pattern of power generated during the tidal cycle where it can be seen that the power extracted is lower on each generation period. Although the supply of power occurs over an extended period compared with generation during either the flood tide or the ebb tide patterns, the net power produced is the same.

The plans devised for the Severn Estuary scheme were built around generation during the ebb tide. The power output would have been two pulses of power during each circulation of the moon around the earth. Unfortunately these pulses vary during the 28-day lunar cycle.

As the gravitational forces of the sun and the moon either add together to produce high forces and high tidal ranges (Spring Tides) or oppose one another producing lower tidal ranges (Neap Tides). During the periods between the spring tide and the neap tide, the gravitational forces vary from a maximum to a minimum producing a smooth change in tidal range from the highest sea level to the lowest. These changes are illustrated in Fig.
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2.9, which shows a period from spring tide to neap tide. The power pulses last for approximately five to six hours during a spring tide and just three hours during a neap tide.

Fig. 2.8 Power generation during the Flood and Ebb tidal periods. Adapted from Kerr [16].

Fig. 2.9 The basin & sea during a period from maximum to minimum tidal range & the Power produced for the Severn barrage. Adapted from: Watt Committee on Energy [17].

The maximum tidal range is also influenced by the trajectory of the moon over time. It does not follow an identical line across the face of the earth during each circulation. Its path oscillates between a maximum northerly track and southerly track. This varies the
gravitational pull upon the oceans and hence changes the tidal height. As a result the power available varies. The Severn barrage project could produce a peak power output of 8GW for short periods, but the average output would be less than 2GW. The area of the enclosed basin would be 746 sq. km giving an annual output of 228kwh/sq.m/year.

The main attraction of tidal power is its predictability. All the factors discussed above can be calculated in advance and although it represents a huge problem to integrate this pulsed energy into the UK electrical system it could be planned in advance with confidence.

The main factors, which militate against the tidal barrage, are:

1. Capital cost. (At least 8 years before the project contributes revenues).
2. Construction time. There would be major disruption to a wide area during the build operation.
3. The environmental impact. The local microclimate is predicted to change, the salinity of the basin area would change and there would be an impact upon the ecology.

2.3.2.2 Tidal Power (tidal stream)
The tidal ebb and flow causes currents of water to be driven in consistent patterns across the oceans around the coast and in and out of estuaries. It represents a source of kinetic energy, which can be captured in locations where the speed of flow is high enough.

The tidal stream resource has been collated by the DTI and mapped in the ‘Atlas of UK Marine Renewable Energy Resource’ 2004. [19]. The Carbon Trust has estimated that the total energy available is 110TWh/year and that some 22TWh/year could be used to produce energy, [16]. Fig. 2.10 is a reproduction of the DTI map UK tidal stream resource which show the mean power density measured in kW/m². It is claimed that most of this energy is below a depth of 40m and would therefore require special equipment to operate at these pressures. Three different approaches have been followed to extract the energy in tidal streams. Two are based upon the propeller and one on the hydrofoil concepts.

A 300 kW machine, known as the Seaflow twin rotor, was tested during 2002 in the Bristol Channel. It has an 11m rotor coupled to a generator mounted on a single pole structure fixed to the seabed. At a tidal flow of 2.7m/s it achieved its rated output. The Seaflow is
illustrated in Fig. 2.11. The further development is to proceed with a 1MW machine to be built and tested in the future.

![Fig. 2.10 The mean spring tide tidal stream velocities around the UK. Source: The Atlas of UK Marine Renewable Energy Sources, [107].](image)

The Stingray concept illustrated in Fig. 2.12(a) and (b) is a tidal stream device, which extracts power using a hydrofoil (developed by Engineering Business Ltd, [19-21]). The power in the water flow acts to lift and depress the hydrofoil in the vertical plane and in doing so operates a hydraulic pump. The high-pressure fluid is then used to drive a hydraulic motor-generator set.
Fig. 2.11 The Seaflow twin rotor tidal stream generator.

Source: DTI Report [19]
(a) An artistic impression of the tidal stream generator

(b) Photograph of the actual demonstrator device

Fig. 2.12 The Stingray tidal stream generator. Source [20,21]
The prototype machine (shown in Fig. 12.2(b)) has been tested in waters off the Shetland isles, where a 150kW unit produced power during a number of tidal periods. During a test period over 14 tides (173.2 hours) it produced 1963 kWh. This was equivalent to an average output of 11.3kWh / hour. The results of these tests [22] are shown in Fig. 2.13. The footprint of the unit covered 240 sq. m, giving a nominal output of 412kWh / sq. m / year.

![Cumulative Gross Power Collected](image)

**Fig. 2.13** The cumulative output of the Stingray machine over 14 tides.
Adapted from [22]

There is considerable development required to increase the scale of this device before it can be deployed commercially. Unfortunately, the power extracted per square meter of the seabed will be further reduced if it is deployed in numbers on the same site as there needs to be a separation between units to stop local interference between the devices.

The final device considered here, is the machine developed by Lunar Energy Ltd [23], which has a fixed blade bi-directional rotor, coupled to a hydraulic pump and motor generator set, contained in a sealed unit, Fig. 2.14. The device is built into a specially shaped duct, which is held in place on the seabed by gravity. The principle is shown in Figure 2.15.
A 50KW prototype has been tested at Glasgow University and a 1MW machine is due to be tested in the sea during 2006/7. A larger unit (1.5MW) is planned for a designated site where the tidal flow pattern, shown in Fig. 2.16, is predicted to produce 3,000MWh per year [23].
Fig. 2.16 illustrates the variation in the tidal stream speeds over a tidal cycle and the difference in the stream flow rates between a spring tide and a neap tide. The footprint covers approximately 600 sq.m, producing an output of 5MWh / sq. m / year. But the actual variation would be zero to 1.5MW following the pattern of the tidal speeds.

![Simplified 14 Day Tidal Cycle](image)

Fig. 2.16 The tidal stream flow rates during spring and neap tides. Adapted from: [24].

### 2.3.3 Group 3 Renewables

The energy generated from group 3 renewables is unpredictable and variable. Although it represents a very significant source of renewable energy, it also brings problems of integration into the national supply system for a number of reasons.

The group includes wind energy and solar energy. In general electricity generated from the wind is best suited to areas in the Temperate Zone and the solar energy units around the equator. However, in remote areas where it is expensive to build a connection to an electricity network for applications such as illuminated road signs and recording metrological instruments, solar cells or small wind turbines can provide an economic solution.
In the case of both technologies, the energy supplied can be forecast to a degree in the short term, but in the complete absence of wind or solar radiation on occasions, there is always the need for complete backup resources from secure generation plant.

### 2.3.3.1 Wind Power

The technology of extracting energy from the wind has seen advances in all the important sectors such as, efficiency and size of the turbines, the cost of their manufacture and installation and the control and reliability of the mechanisms during the past 20 years. Individual turbines can be produced with capacities up to 5MW and built for installation on shore and at sea. Wind turbines respond with a power output proportional to the cube of the wind speed and will begin to produce power when the wind velocity reaches 4 m/s. Fig. 2.17 for example illustrates a typical modern design offshore wind farm in Liverpool Bay. This kind of large wind installation can be where the location provides adequate wind over a longer period.

Fig. 2.17. The 60 MW North Hoyle wing farm in Liverpool Bay, commissioned in 2003, was the first major offshore wind farm, Source: Price [25].

Power from wind varies with the available wind speed. Only a small amount of power is available at low speeds while more power is available at high wind speeds. Fig.2.18 for example shows the power production over a range of wind speeds up to a maximum of 25 m/s. Above this speed the turbine is shut down to avoid physical damage. Between a wind speed of 4 m/s and 16 m/s the output rises from zero to full load. Hence the power output is
sensitive to small changes in wind speed. Most sites selected for wind turbine installation have an annual mean speed in the range 5m/s to 9 m/s.

![Power curve of a typical modern wind turbine, showing potentially significant effects of wind-speed forecast accuracy of +/-1.5 m/s on output, Source: Sharman [26]](image)

Integration of wind power plants into electrical power systems presents challenges to power system planners and operators due to natural characteristics of wind farms [27]. Wind plants operates when the wind is available, and their power levels vary with the strength of the wind. Therefore power systems integrating wind should be able to handle significant load variations on a routine basis. Wind speed fluctuates over the short term as a result of gusts that create small scale variations. Over long term wind speed is subject to weather fronts, temperature conditions, time of the day (windier during the day than during the night). This makes wind energy more variable than other sources. The effects of variability of wind power is further documented in [28-35]

The wind power produced by a large wind farm of 103.5MW capacity over a period of 5 days shows a different characteristic when shown over a period of 24 hours. Fig.2.19 (a) and (b) compares the output over these two intervals and illustrates some of the potential problems, which will occur as the amount of wind capacity on the system grows as a percentage of the secure generating capacity.
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Fig. 2.19 (a) and (b) A series of wind generation patterns from a 103.5MW wind farm
Lake Benton, adapted from Hurst [36]

Further Fig 2.20 illustrates the monthly power output variations from a typical on shore wind farm in the UK (Beinn Ghias Argyle Scotland) during the period April 2002 to January 2007. The annual load factor of this wind farm varied from 24.7 to 28.3 during this period.
The geographic spread across a wide area can smooth the impact of local short term power output variations but the seasonal variations between winter and summer can have very significant consequences. Fig 2.21 illustrates the seasonal wind energy delivered into the Danish electricity network over the period of one year and Fig 2.22 shows the requirement for back-up fossil fuel power plants as the wind sector fails to deliver power. It also illustrates the fact that excess wind power can be generated above the total power demand on occasions.

![Fig. 2.20 Monthly Generation Statistics, adapted from UK Renewable Energy Data:[37].](image)

![Wind Energy Index, Denmark (average=100)](image)

Fig. 2.21 Seasonal variation in wind energy (Denmark) Data from: [39]
2.3.3.2 Wind Turbine Technology

The turbine average efficiency of converting the energy in the wind into electricity is marginally above 20%. However, the design of the turbine blades can be adjusted to extract the maximum energy from the wind at the mean wind speed for any specific site. When this is achieved the actual overall efficiency at this speed can be raised up to 40% to match local conditions. The efficiency at higher wind speed falls off significantly as indicated in Fig. 2.23, where a graph of the power coefficient illustrates the turbine characteristics.

The overall position of wind energy extraction is illustrated in Fig. 2.24 below where the graph shows the total power in the wind, the usable power, and the final power output generated by the turbine. The theoretical usable power is given by a law known as the Betz’s law. Betz’ law dictates that less than 16/27 (or 59%) of the kinetic energy in the wind could be converted to mechanical energy using a wind turbine. Figure 2.24 further illustrates this, which shows how the power output of a typical turbine varies with wind speed. At all wind speeds the actual power out put of a turbine is somewhat less than that given by the Betz law.
Fig. 2.23 The power coefficient curves for a modern three blades wind turbine, Adapted from Seman et al. [35]

Fig. 2.24 The Wind Energy available, the usable energy and the actual energy produced. Adapted from: [39]
Fig. 2.25 The predicted contribution probability from 7.5GW of wind turbine capacity.

Source: [48]

Fig. 2.25 is the graphical results of a National Grid Company simulation of the probability of a wind power of 7.5GW delivering a percentage of the installed capacity power during one year of operation. This simulation indicates that there is always likely to be an output of some capacity but that the full installed capacity will never be realised. With this degree of variation and unpredictability, wind power cannot be regarded, as contributing to the secure supply needed to guarantee the stability of the grid system.

During 2004 the grid controllers at Alberta Electric System Operator (USA) commenced a project to evaluate the impact of wind power on their network. [40]. The first phase of this work was 'designed to establish technical rules, requirements and performance that a wind facility must comply with in relation to their connection to and operation on the Alberta Interconnected Electric System'. This study indicated there was a need to understand the effects of increasing amounts of wind power on the system.

The Alberta system had 254MW of wind capacity connected and the research was to study the effect of increases to 850, 1,400 and 2,000MW of installed wind capacity. Because of their increasing concern for the short-term variability of the impact on the system of this
wind power, the potential impact has been modelled. The first reports of their findings [41] of modelling one complete year suggest that:

1) the variability does not increase in proportion to the growth in wind power capacity.
2) as wind power capacity increases, the relative variability (% of total capacity) decreases.
3) the absolute variability (MW) does increase as wind power increases.

The International Energy Agency in their study of wind power variability, [42] has stated a number of general conclusions after reviewing a number of specific areas:

1) The wind power currently supplied does not require one-to-one backup capacity. Electric grids already operate with high levels of reserves due to the conventional mix of power plants connected absorbing the incrementally added variability due to wind power thus far.

2) Costs show large differences between countries due to climatic differences and geographic conditions, the state of the grid and levels of wind power penetration. The markets and incentives to manage intermittency in an efficient manner do not exist in all cases, thus the true costs are not always revealed in the reported prices.

3) The range suggests that gains can be achieved by pushing to the lower end of this range through, for example careful and efficient market design and optimised location of new wind plant.

In the UK, wind power development is facing a number of difficulties as the installed capacity is further increased. There are seven current issues, which are hindering progress:

1) The lack of public acceptance of onshore units and their environmental impact.
2) The supply variability and the potential upper limit on the capacity which can be absorbed into the system.
3) The continuing need for public subsidy.
4) The developments offshore and in the far north west of Scotland require new expensive and environmentally controversial connections to the national electricity grid.
5) The requirements for secure backup supply.
6) The impact of the emissions from the backup plants which are on standby.
7) The extra capital and operational cost of reserve secure supplies. (Much of the potential reserve generating capacity is old and will soon be retired).

Electing to place more of the units off shore can in part solve some of the environmental problems, but it is the more expensive option. The costs of the capital equipment and the costs of maintenance are more expensive for off shore installations and are only part compensated by the increased wind power available offshore.

The subsidies needed to support the renewable electricity produced may reduce with time. Industries, which burn fossil fuels, currently have permission to emit a specific annual tonnage of CO₂ into the environment. This allowance is set to be progressively reduced year by year and industries which exceed their quota will be required to purchase ‘Renewable Obligation Certificates’ (ROCs) [42] to equal the quantity of the excess emission. The producers of renewable energy can claim ROCs for each unit of power sold which may then be sold in the carbon market to those industries requiring to offset their emissions excess. It is anticipated that, under this mechanism, the price of the ROCs will rise and hence progressively support the funding of existing and new renewable generation capital projects.

At the present time and until these costs reduce, the subsidy being paid to the wind turbine sector will probably be accepted as part of funding the desire to achieve reductions in CO₂ emissions.

The most difficult problem facing the expansion of wind power is the variability of the output produced and the real cost of integration into an electrical transmission system which has to secure the delivery of power to customers at all times. The secure generating capacity is mainly fired by fossil fuel. Many of the coal-fired power stations are old and are due to be retired from service and by 2020 very few can be expected to be available. The need to provide continuing secure reserve capacity will require new power plants to be installed.
A significant proportion of the capital cost and subsequent operations and maintenance costs will be a direct result of supplying this power will be a direct cause of supplying secure power.

2.3.3.2 Wave Power
There is a very large energy resource stored in the waves of the oceans. Induced by the weather changes, it is caused by the action of wind on the surface of the water. Capturing the energy from the waves presents different problems at the shore in shallow water and in the deep ocean.

![Fig. 2.26 The annual mean power in the waves in deep water around Coast (MW/km). Source: Kerr [16].](image)

Fig. 2.26 shows the power available in the waves around the coastlines of the world [16]. This power can reach 100MW per km although it is an unpredictable and variable source of potential energy. Fig 2.27 is a plot of the areas with the largest wave energy around the UK coastline. It is mainly concentrated in the Northwest and Southwest. Within the territorial waters the energy equates to 40 to 60MW/km. Extracting this energy will require special engineering skills as any device will need to be protected from the severe storms which can affect these areas of the sea.
To extract wave energy a number of devices based upon an oscillating column of water have been developed. But it was only when the testing of a prototype unit (‘known as the Pelamis’) off the coast of Islay in 2000, was significant progress achieved.

The device has made progress and is moving from the prototype stage to commercial application. The Pelamis, (Fig. 2.28 and Fig. 2.29) is a hinged unit which follows the contour of the waves. As the wave passes along the device the energy is extracted by the hinged sections, which pump hydraulic fluid to a motor generator set. The power is brought ashore via an undersea cable.
Fig. 2.28 The Pelamis wave power generator. Source: Pelamis wave Power Ltd. [43]

Fig. 2.29 An illustration showing the plan view and the elevation of the Pelamis device. Adapted from Previsic et al [44].
The overall length the Pelamis device is 150 meters with a diameter of 4.6 meters. It has a rated output of 750 kW. The Ocean Power Delivery Company claims that an installation of 40 machines spread over one square kilometre would generate up to 30 MW. The annual output would depend upon the local conditions and the annual weather cycle. If the annual capacity factor anticipated by model tests is achieved at the selected site it is predicted to have an annual capacity factor of 41%. A proposed 40-machine installation to deliver a maximum of 30MW from a wave farm off the west coast of Portugal is currently in the design and construction phase. If it achieves the design capacity it will deliver:

\[
\text{Annual O/P} = \frac{(40 \times 0.75 \times 0.41 \times 8760)}{1000000} \text{ MWh} / \text{m}^2
\]
\[
= 0.108 \text{ MWh} / \text{m}^2
\]

The output pattern for 3 periods of twelve months at the West Coast of Scotland site is shown in Fig. 2.30. The seasonal variations follow a similar cycle but the shorter time periods indicate that there would be wide variations in the power that is generated.

Fig. 2.30 Seasonal variability of the output from 500kW Pelamis off the West Coast of Scotland. Source: DTI Report URN No 02/1401.
The device will suffer all the problems of the off shore wind generators, namely high maintenance costs and salt water corrosion. Some provision will have to be made for protection against storm conditions, perhaps by submerging the device below the waves.

Other devices, which have been partly developed, include:
1) the heaving float
2) the heaving and pitching float
3) the Edinburgh duck
4) the oscillating water column
5) the Tapchan (a water reservoir system on the coastline.

None of these devices have made sufficient progress to become commercially viable.

In 1996 Duckers [46] stated that "Further technological developments are needed to enable wave energy to fulfil the promise but some shore-mounted operations are already in operation". By 2006, however, none of the shore-mounted units have seen real acceptance, and only one device appears to has solved the technical problems.

2.2.3.3 Solar Power

The sun is the primary source of energy for driving the weather and hence indirectly responsible for wind, wave and hydroelectric power and the growing cycle of biomass. It is also partly involved in developing the gravitational forces driving tidal power. Finally, the radiated energy can be converted directly into electricity by the photovoltaic cell (the PV cell).

As the PV cell is made of semiconductor materials it comes in a number of forms and can be manufactured in large quantities. However, each cell produces very small quantities of power. It is only applied to special applications where its high cost can be justified.

However, the manufacturing costs have come down and the conversion efficiency has risen from the early devices making the PV cell an attractive solution to a larger group of applications. The low maintenance cost and stand-alone capability of the units makes it best suited to remote locations where there is no electricity connection and little servicing capability. Installations such as the demonstration project at Southampton University
where alternative supplies from the electricity network are available have at best a payback period of 45 years.

Fig. 2.31 A PV cell array. Southampton University. Source: Bahaj [47]

The availability of radiated power from the sun depends on position on the Earth’s surface and the cloud cover. At the Equator the radiated energy arrives at the surface perpendicular to any level collector. The energy also passes through the thinnest layer of the Earth’s atmosphere and hence suffers the lowest absorption losses, which leads to the highest solar energy collection potential per unit area. At locations such as the UK, the radiated energy arrives at an angle off the perpendicular and any collector needs to be adjusted to the optimum angle to collect the maximum energy. The energy passes through a thicker layer of the atmosphere than at the equator and a proportion of the energy is lost. Fig. 2.32 illustrates the path the sun takes viewed from the UK. The diagram shows the daily changes in the available energy as the cycle varies over a period of one year.

The solar radiation on Europe during July is shown in Fig. 2.33 where the energy varies from 2.6 kWh/m² in southern Spain and 0.4 kWh/m² in Scotland measured on a horizontal surface per day. During the winter (January) the energy is only 10% of that during the summer (July).
Chapter 2  Renewable Energy Sources

Fig. 2.32  The paths of the sun across the sky over a period of one year. Source: Boyle.[5]

Fig. 2.33  The solar radiation on a horizontal surface (kWh/m² per day) in Europe during July. Source: Boyle.[5]
The conversion efficiency of the commercially available PV cells ranges between 12% and 16%, although there are claims that laboratory devices have produced up to 32% in the latest developments.

The annual solar energy per square meter in the UK has been estimated at 1000kWh / sq. m, if the PV conversion efficiency is 15% the actual electrical power available is just 150 kWh / year / m².

Micro-Solar generation may be possible in the future if the costs are reduced sufficiently. Units with small outputs (5kW) could be installed in domestic premises to supply the household needs when available and any surplus could be exported to the local grid. Fig.2.34 (a) and (b) illustrates the power demand and solar supply on two test houses in a study reported by Bahaj [47]. The domestic demand in Fig.2.34a has a reasonable match to the solar output, but the second case (Fig.2.34b) produces peak demands before the solar energy is available. Local storage in batteries may overcome the mismatch problems but it increases the capital costs to the point where it is not yet economic. Solar micro-generation would require thousands of domestic installations to make a measurable impact upon the bulk supply position.

Solar power technology has several major disadvantages when it is considered for large-scale power delivery:

1) the power is not available during the night.
2) it is subject during the day to a reduction of output due to the cloud cover.
3) for local remote use it requires some form of energy storage in order to provide a continuous supply.
4) the power must be changed from ‘Direct Current to Alternating Current’ using an inverter if it is to be supplied to the electrical grid system.

2.4 Renewable Energy Yields

Group 1 renewable resources (biomass, geothermal & hydroelectricity) have limited application in the UK. Biomass does not produce zero CO₂ emissions, and geothermal has only produced very lower energy output at low enthalpy levels to date. The contribution of
biomass is more likely to be in providing replacement transport fuel (bio-ethanol) than to make a major impact upon electricity. Hydroelectricity already makes a contribution to the power demand and represents an ideal source, as the potential energy is storable and brought on-line on demand. The best locations for trapping the rain in the mountains have already been exploited and there are few good locations available for new development without causing environmental impact.

Group 2 renewables resources (Tidal energy) in the form of both tidal rise and fall and the tidal stream are attractive sources of energy. There is no combustion or heat transfer processes involved as both sources can be converted directly into electrical power by turbines.

![Energy balance on two neighbouring houses](image)

(a) Test house 1

![Energy balance on two neighbouring houses](image)

(b) Test house 2

Fig. 2.34 Energy balance on two neighbouring houses which incorporates photovoltaic generation on the same day. Adapted from: Bahaj [47]

Within the Group 3 renewables wind power has seen a very significant capacity increases encouraged by various government incentives. Table 2.2 illustrates the world wide capacity
installed since 1999. This pattern is set to continue as desire to meet the CO₂ reduction targets by 2010 become mandatory under the Kyoto convention. Solar power is not currently an economic proposition for large scale power generation in the UK. Bahaj [47] has claimed that "even when considering a financial model at 0% interest rate and no cost of maintenance or repair, the financial pay back time is over 45 year". Wave power must still be considered to be under development and the final form of devices to capture energy from the waves still remains to be proved over a sustained period of time in harsh conditions.

Table 2.2 wind turbine capacity installed up to 2005

<table>
<thead>
<tr>
<th>Year</th>
<th>Installed GW</th>
<th>Cumulative GW</th>
<th>Increase %</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>3.9</td>
<td>13.9</td>
<td></td>
</tr>
<tr>
<td>2000</td>
<td>4.5</td>
<td>18.4</td>
<td>32</td>
</tr>
<tr>
<td>2001</td>
<td>6.6</td>
<td>24.9</td>
<td>35</td>
</tr>
<tr>
<td>2002</td>
<td>7.2</td>
<td>32.0</td>
<td>29</td>
</tr>
<tr>
<td>2003</td>
<td>8.3</td>
<td>40.3</td>
<td>26</td>
</tr>
<tr>
<td>2004</td>
<td>8.2</td>
<td>47.9</td>
<td>19</td>
</tr>
<tr>
<td>Average</td>
<td>—</td>
<td>—</td>
<td>28</td>
</tr>
</tbody>
</table>

The land area required by each of these renewable technologies to deliver an amount of electrical power in any 12-month period depends upon many factors. As has been described above the wind energy available in any one location, the tidal rise and fall in another and the solar radiation and amount of cloud cover all have an influence. However, to obtain a first order comparison between the technologies, Table 2.3 has been compiled from available data. In the case of the tidal stream and the wave options it has only been possible to use the first test data from prototypes devices. In the case of the tidal barrage the predictions of the Watt Committee [17] have been used. The Severn barrage would be the best possible site in the UK, any other locations would produce less annual output. The data available from the Department of Trade and industry on wind turbine output is representative of a fast maturing technology and is compiled from a number of sites across the UK.
The compiled data has been used to construct the Table 2.3 and Fig 2.35 which demonstrates the land area needed by each technology (device) to produce 1 MWh/ year.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Annual power generated kW/sq.m/year</th>
<th>Required (sq.m) to produce 1 kWh/year</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tidal barrage (Severn)</td>
<td>222</td>
<td>4.5</td>
<td>Best site in UK</td>
</tr>
<tr>
<td>Tidal stream (Isla)</td>
<td>412</td>
<td>4.24</td>
<td>Few suitable sites in UK</td>
</tr>
<tr>
<td>Wind turbine</td>
<td>14.7</td>
<td>68</td>
<td>Average of on and off shore sites</td>
</tr>
<tr>
<td>Solar (pv cell)</td>
<td>150</td>
<td>6.66</td>
<td>Based on solar radiation for London</td>
</tr>
<tr>
<td>Wave (Pelemis)</td>
<td>108</td>
<td>9.25</td>
<td>Data from prototype machine</td>
</tr>
</tbody>
</table>

Table 2.3 Annual Power produced from one square meter area from different renewable energy sources
Chapter 2  Renewable Energy Sources

Renewable energy source yield

| Wind  | Wave | Solar | Tidal (barrage) | Tidal (stream) |

Fig. 2.35 An illustration of the nominal horizontal surface area of the earth required to produce 1 MWh/m² of electricity over one year.

The large area needed by wind power takes account of the need to separate the turbines by considerable distances to eliminate the shadowing effect that one machine can place down wind on an adjacent machine.

The shadowing effect may have similar consequences for both wave generators and tidal stream devices, which may be revealed as further work is done on their development.

2.5  The variable output from Group 2 and Group 3 renewables

The variable nature of the power generated by group 2 and group 3 renewable energy sources causes four important issues which impact on their ultimate contribution to the task of reducing the emission of CO₂.

Firstly, these groups offer no security of supply and there must be reserve capacity available to guarantee the flow of electrical power at all times. This assumes that the capacity is available and will be replaced as and when it becomes obsolete and is retired from service. The capital cost of the new plant does not appear to have been accounted for in the costs of supplying renewable energy.
Secondly, the back-up power will come from fossil fuel plants, which will be operating at power ratings below their most efficient level in order to respond to any changes in demand, either an increase or a decrease in output. That will cause the plants to emit higher levels of CO\textsubscript{2} than normal and increase their operating costs per unit output. Likewise group 2 and group 3 renewable sources cannot deliver power for frequency stabilisation on the grid system; this duty will fall upon fewer active plants when it is required.

Thirdly, as the amount of renewable energy available to the system increases, there is the potential for wasting increasingly amounts of power when it is not required. If this situation is to be resolved and renewable energy is to contribute to the 2050 target when 60\% of the power is scheduled to come from this source, a number of new methods of storing and returning power to the system will be essential. If these storage units were able to respond to the frequency stabilisation problem and provide the back-up power as required, the expansion of both group 2 and group 3 renewable sources of power would be a reality.

Fourthly, as the group 2 renewables based upon tidal energy represent an under developed resource of predictable power, acceptable methods need to be explored to extract this energy not only from the estuaries but at any point around the coastline which has sufficient rise and fall in tide levels. By spreading the locations over a wide range of longitude positions, the power available would have to be complimentary, as the tidal periods sequentially vary from west to east across the country.

2.6 Summary of the Chapter

The renewable sources of energy to generate electricity can be divided into 3 groups, secure sources, variable but predictable sources and variable and unpredictable sources.

- The secure sources of renewable energy are not available in sufficient quantity to provide the whole requirement. Large scale Hydro is limited to current supplies; geothermal energy is not practical in the UK for the production of electrical power. Biomass requires a large land area, is more suitable for producing liquid fuels for transport and at best is only CO\textsubscript{2} neutral.
• The variable, but predictable group (group 2) are either too expensive or have unacceptable environmental consequences (tidal barrage) or are still under early stages of development (tidal stream). These sources are not likely to contribute significant power in the next decade.

• The variable and unpredictable sources are the fastest growing sector (i.e. group 3).

• Wind power is planned to contribute a large proportion of the renewable generating capacity by 2020. As this percentage increases it will have significant consequences for security of supply and the stability of the transmission system. On occasions there may be no contribution from wind turbines across the whole of the UK when an anticyclone is centred on the British Isles.

• Solar power is only likely to generate power on a small scale with the current technology. It is expensive, the UK is not best placed geographically to capture solar radiation and it is likely to compete commercially only in remote locations without a grid connection.

• Wave power is only in the early stages of development.

• Fossil fuelled plants will be required to back-up both group 2 and group 3 renewable energy sources when they are unavailable to supply power. This will cause the back-up plants to operate at levels of output below their maximum efficiency. It is predicted that this will cause them to emit greater amounts of CO₂ and increase their costs.

• Both group 2 and group 3 renewable sources of energy could expand their contribution to the national demand for electricity if their output could be stored when the generation capacity exceeds the demand.
Chapter 3

The Impact of Variable Demand Upon CCGT Power Plants

3.1 Combined Cycle Gas Turbine (CCGT) Power Plants

Following the Electricity Act (1989) privatising the electricity industry and the ‘Vesting’ of the generating and distribution assets into the hands of a number of publicly quoted companies, the industry has selected gas fired technology to provide new sources of power. Between 1991 and 2005 some 40,000 MW of new capacity has been constructed. It includes just one nuclear station (Sizewell B) and one small CHP coal fired plant (a total of 1,400MW). The bulk of the new capacity is based upon the Combined Cycle Gas Turbine (CCGT) process, which offers many benefits.

The CCGT process delivers thermal efficiencies of up to 60%, whilst the coal fire stations deliver efficiencies between 30 to 36% and emit much higher pollution levels of CO₂, NOₓ and SOₓ. The gas plants are quicker and cheaper to build, easier to finance and achieve high levels of availability.

Figure 3.1(a) illustrates a basic gas turbine plant through compressor/combustion chamber/turbine system and its operation in the temperature (T) entropy (s) diagram is shown is shown in Figure 3.1(b). The path (1-2) is approximately an irreversible adiabatic compression process. This is followed by the constant pressure heat input in the combustion chamber (2-3) and ends in the approximate adiabatic expansion in the turbine (3-4), which is also irreversible.
The work delivered by the gas turbine is given by:

\[ W = m(h_3 - h_1) \]  
(3.1)

Compressor work input

\[ W = m(h_2 - h_1) \]  
(3.2)

Heat input

\[ Q = m(h_3 - h_2) \]  
(3.3)

Where \( W \) = work done

\( m \) = hot gases mass flow

\( h_1 \) = enthalpy of air entering the compressor

\( h_2 \) = enthalpy of gas entering the combustion chamber
\( h_3 \) = enthalpy of gas at turbine input
\( h_4 \) = enthalpy of gasses at turbine output

The thermal efficiency of the gas turbine (ignoring losses that occur at the compressor inlet, during combustion and at the turbine outlet) is given by:

\[
\eta = \frac{\text{Net Work output}}{\text{heat input}} = 1 - \frac{(h_4 - h_1)}{(h_3 - h_2)}
\]  \hspace{1cm} (3.4)

The gases exit the turbine at approximately 600 °C. In the Combined Cycle Gas Turbine (CCGT) plants the energy in the gas is used to raise steam in a Heat Recovery Steam Generator (HRSG). The gas turbine cycle and steam cycle combine together to raise the overall thermal efficiency in the latest generating plants to about 58 to 60%.

In some recently commissioned CCGT power plants ‘Duct Firing’ has been introduced to the process to increase the power output by adding extra heat to the turbine exhaust gases before the entry to the HRSG. This is achieved by firing gas in the section between the turbine outflow and the HRSG intake. A typical layout this arrangement is shown in Figure 3.2. This addition can add up to 10% extra generated power but it is at the expense of a fall in thermal efficiency as the new energy is only used in the single steam cycle.

Fig.3.2 The CCGT process flow diagram including duct firing.
The latest gas turbines are designed to produce a constant output of 280MW with a gross electrical efficiency of 38%. A typical CCGT station will consist of two gas turbines and one steam turbine. To allow each gas turbine to operate independently at different output levels, each gas turbine exhausts into a separate HRSG.

As the thermal efficiency of the gas turbine is increased with a rise in the combustion temperature, there is continual competition to upgrade the hot gas path of the gas turbine. This has enabled higher and higher combustion temperatures to be achieved by using exotic materials for the combustion chambers and turbine blades. However, the blade coatings and combustion chamber material employed are not suitable for some fuels and the most efficient machines are limited to firing on natural gas.

The operation of the turbines requires careful control of the rate of change of the temperature throughout the hot path. A particularly important period of control occurs when the turbines are started from a stationary period. Internal temperatures of the gas and steam turbines dictate the speed with which any power plant reaches its full capacity from a start. A 'Hot Start' may be achieved within 2 to 3 hours where a 'Cold Start' may take 4 to 8 hours.

The CCGT plants produce their highest thermal efficiencies when working at their maximum economic rating (MER). Any departure from this output power level causes an increase in the fuel consumed and effluent gases emitted per unit of power exported.

Chapter 2 indicated the variability of power delivered from both predictable and unpredictable sources of renewable energy. As wind power is the most developed source of renewable energy, easy to install and supported by state subsidies, it is likely to be the technology to provide the major share of the required renewable input during the next 15 to 20 years. It will be necessary to have sufficient back-up as standby generating capacity to provide the power matching required to balance the stochastic nature of the wind power input. By 2020 the gas fired CCGT power stations are the plants most likely to be available to respond and generate the 'In Fill' power.
3.2 Transmission Stability and National Grid Code

The electricity network is controlled by the System Operator (SO), a division of the National Grid Company. The duties include electrical safety, quality and continuity of supply.

The SO uses frequency response to balance the continuously changing frequency of the high voltage network to contain it within ±1% of the nominal setting of 50Hz. The balance between the total load demand and the total generation output determines the system frequency at any specific moment.

There are statutory requirements placed upon the SO to maintain the system frequency within specific levels centred on 50Hz. In order to achieve the requirements generators and distribution companies are required to follow the NGC Grid Operating code. Fig 3.3 illustrates the grid Code standards and the point at which specific action is executed.

![Graph showing grid system operational standards](image)

Fig 3.3a Grid System operational standards, Adapted from the grid code, NGC [49]
The SO has to ensure that there is sufficient generation capacity and demand side response held in readiness to manage any credible system contingency.

(Note: A demand side response is provided by large customers who are prepared to switch off their in house electrical demand upon instruction. In return they receive a favourable power price at other times).

All fossil fuelled generators who wish to use the national transmission system must agree to abide by the NGC Grid Code which requires that they provide a mandatory frequency response services. The SO can also purchase further services from the generators to support the task of ensuring the security of supply. The typical requirement of the generator frequency response characteristics is shown in Fig 3.4, which illustrates a pattern of recovery needed from a system disturbance.

As all the coal fired generating plants are gradually retired from the system, the frequency response service will be increasingly provided by the CCGT stations. This assumes that
any of the remaining or new nuclear stations will have derogation from the National Grid code to relieve them from many of these duties.

The compliant generators must maintain their output power flow as the frequency falls from 50Hz to 49.5Hz without reducing the power output level. From 49.5Hz to 47Hz the code allows a linear fall in output, such that at 47Hz the power flow is not less than 95% of the capacity being delivered at 50Hz., see Fig. 3.4

This requirement is onerous; many of the latest gas turbines suffer dangerous rises in combustion temperature. Some GT manufacturers achieve the code requirements by spraying water into the air intakes.

![Graph showing Grid Code Mandatory Requirement for connected generators, Frequency v Output](image)

The Code also requires that a plant must operate on a continuous basis between 95% and 104% of the set frequency but may disconnect automatically from the network after 20 seconds when the frequency is between 94% and 95%. Most CCGT gas turbines plants can meet the code requirements when the ambient temperature is 0°C. But as the air temperature rises the compressor operating margin of the gas turbine falls and at 25°C substantial amounts of extra fuel is needed to deliver the power.

Fig 3.5 illustrates the power short fall when the frequency is 47.5Hz. The situation can be recovered by over firing the turbine to achieve compliance with the code but this causes an
increase in the combustion temperature of 160°C. At these temperatures there is concern about combustion stability, compliance with the emission regulations and potential damage to the hot path components such as the turbine blade coatings and the rotor.

Fig. 3.5 Gas Turbine response Output v. Grid Frequency when the ambient temperature is 25°C. Source: [50]

Each Gas turbine is equipped with a water spray to wash the compressor blades. It is this wash system which is used during times of low frequency operation to reduce the combustion temperature during over firing. Fig.3.6 shows the impact of using the water wash where the maximum combustion temperature is reduced 100°C. However, there are consequences each time such an incident occurs. Such incidents attract a penalty, which reduces the time interval between maintenance intervals. The maintenance requirements increase significantly.

Several CCGT stations have been declared ‘Non Compliant’ when tested by the NGC commissioning team. At least one new plant has applied for a special derogation requesting that it should be allowed to generate such that, if the system frequency drops, the Active Power output achieved does not decrease the System Frequency by more than a ratio of 5:1.
The other important factors result from the interaction of the CCGT plant with the demands of the SO. They are:-

(a) Start Up times and fuel used in the start-up and shut-down cycles
(b) The Ramp Rates during start up and power output changes
(c) The part-load capability
(d) Pollution emitted as a result of generating at levels below the optimum output
(e) The impact upon plant maintenance times and costs
(f) The Impact upon fixed overheads
(g) The impact upon the return on capital investment

The SO has three forms of generating reserve that can be purchased to meet the obligations.

(a) Spinning reserve (part-loaded plant, which can be ordered to increase or decrease output as required).
(b) Plant on Hot standby (Whilst not connected to the transmission system, it can be brought into service with a minimum of delay).
(c) Plant on Cold standby (This plant is awaiting orders to commence the process of warming the plant prior to commencing synchronising routine).
Chapter 3 Impact on CCGT Power Plants

This study has approached the issue from a different position. In order to meet the power supply and balancing requirements by 2020, it is predicted that a number of CCGT plants will be installed. The plants are inherently more efficient than Open Cycle gas Turbine (OCGT) plants as the waste heat from the gas turbines is used to add a steam cycle to the process and generate further power. Thermal efficiencies of 58 to 60% are achieved using the combined cycle where as the open cycle can only achieve efficiencies of 36 to 38%. Both plants can deliver the necessary load following required to match the customer daily variations and the stochastic input from the increasing wind turbine capacity. However, the CCGT plants are more efficient in the use of fuel and are therefore capable of delivering lower emission levels even when they are operating on part load.

In order to examine the potential of the CCGT to fulfil the balancing duties in practice, data has been collected from a new 800MW (nominal) CCGT plant over a period of 4 months. This has enabled an analysis of fuel usage and gas emission levels to be documented for hot and cold start-up, load step changes, continual modulation and duct firing. The results were then compared with the results obtained when the plant was operating at or near its optimum (i.e. the plant MER).

A second analysis was carried out to measure the impact upon maintenance costs, operating costs and the cost of capital when the plant is required to operate below its MER to provide balancing power to the supply system.

3.3 The Experimental Investigations

The experimental data were collected from an operating CCGT plant which has the following specifications:

- Number of Gas Turbines: 2
- GT power rating: 280MW
- Steam turbine: 320MW
- Duct firing capacity: 88MW

The two gas turbines feed hot gas into separate HRSGs. The steam output is combined and then passed to a single steam turbine. The three alternators feed directly to the National Grid 400kV substation through separate step-up transformers.

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All the data were collected using the official statutory metering systems. The gas input and the power output records are used to calculate the revenue flows and the NOx measurements are those reported to the regulatory authorities. The gas flow rates were supplied from the transmitting meters sending pulses every 5 minutes. The electrical power output from each alternator was recorded individually and data collected every 5 minutes. The carbon dioxide data was taken from the calculated value reported to the statutory bodies and for carbon trading purposes. It was also recorded every 5 minutes. The oxides of nitrogen were collected from the chemi-luminescence monitoring system used for reporting purposes to the Environment Agency (recorded every 5 minutes).

The simplified layout of plant process and instrumentation diagram is illustrated in Fig. 3.7.

![Process diagram](image)

**Fig 3.7** A schematic of the test plant

### 3.4 The Test Routine and Analysis

Plant data was examined to identify a number of different operating patterns, which were then used to analyse the impact of varying load profiles.

The data groups were chosen to demonstrate the consequences of operating under various regimes such as constant load, load balancing, starts/stops and duct firing. In order to
obtain reliable data a sufficiently long period was selected to ensure the conditions represented a stable period of plant operation.

The test data were collected for following operating conditions

1. The CCGT plant operating at Maximum Commercial rating (MER)
2. A Cold Start
3. A Hot Start
4. A period of modulated power output (1)
5. A period of modulated power output (2)
6. A period of full duct firing

Each data group was analysed for the efficiency of operation, the fuel used per MWh, the CO₂ produce per MWh and the NOx emitted mg/MWh,

Let

\begin{align*}
G_f &= \text{Energy in gas flow (GJ)} \\
G_t &= \text{Total gas energy consumed over test period (GJ)} \\
P_o &= \text{Power Output (MWh)} \\
P_t &= \text{Total Power Output (MWh)} \\
C_e &= \text{Carbon Dioxide emitted (MT)} \\
C_a &= \text{Average Carbon Dioxide emitted during test period (MT/MWh)} \\
C_t &= \text{Total carbon Dioxide emitted over period (MT) (Metric Tonnes)} \\
T &= \text{test period (hrs)} \\
N_o &= \text{Nitrogen oxides emitted (mg/m}^3) \\
N_t &= \text{Average NOx emitted during test period (mg/m}^3)
\end{align*}

Then Total Gas flow over test period is given by

\begin{equation}
G_t = \sum_{i=0}^{T} G_f \quad \text{(GJ)}
\end{equation}

Total power output

\begin{equation}
P_t = \sum_{i=0}^{T} P_o \quad \text{(MWh)}
\end{equation}

Energy used per MWh during test period,

\begin{equation}
P_a = \frac{G_t}{P_t} \quad \text{(GJ/MWh)}
\end{equation}
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The total CO₂ emitted during the period \((C_t)\) in Metric tonnes (MT)

\[ C_t = \sum_{i=0}^{T} C_e \quad \text{(MT)} \quad (3.8) \]

and the CO₂ emitted per MWh generated \((C_a)\)

\[ C_a = C_t / P_t \quad \text{(MT/MWh)} \quad (3.9) \]

The standard deviations for the average of Gas flow, Power output CO₂ and NOₓ emitted were also calculated for the test periods with the exceptions of the two start-up tests.

All the following tests were carried out using data collected from an 800MW CCGT plant (hereafter known as Plant C), which is connected to the UK electricity grid system. It is supplied with natural gas from the national gas transmission system.

Each test represents a separate period of operations at Plant C. All the data collected from this plant and used in the following analysis are available in Appendix 2.

3.5 Operating at Maximum Commercial Rating

The first test was used to establish the optimum operating case for this power plant, (MER). A period of constant operation at full load, (i.e. in CCGT mode without duct firing) was selected. The gas flow, electrical output from each alternators and emission levels of NOₓ mg/cu m, and CO₂ MT/MWh were recorded.

Results shown in Fig 3.8 illustrates the constant nature of the output at MER over a 2.75 hours period of production. The graph indicates the power produced from the two gas turbines and the steam turbine. The excursion in power output varied by +/-2MW during the period. In Fig. 3.8 GTA and GTB are the two gas turbines and the ST is the plant steam turbine. The key feature here is the constant and steady nature of the operation whilst producing power at the maximum plant capacity. Under these conditions the emissions levels are low and burden on plant machinery is also very low. They represent ideal conditions for plant operation. Figure 3.9 shows the CO₂ emission pattern during MER operation and it can be seen that the CO₂ emission varied by +/- 0.006MT/MWh during the test period.
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**Power Output Constant Run (CCGT)**

![Power Output Graph](image)

**Fig. 3.8 Power output (Constant Operation) (Appendix 2 Constant Operation)**

**Constant Operation Gas Flow & Power Output**

![Gas Flow and Power Output Graph](image)

**Fig 3.9a Gas flow and power output (constant operation)**
Table 3.1 summarises the plant performance when operating at full load of the CCGT plant without the duct firing operating. This represents the Maximum Economical Rating (MER) for the plant in the current state of maintenance.

### Table 3.1 Constant Operation of the plant at full load (Appendix 2 Constant Operation)

<table>
<thead>
<tr>
<th></th>
<th><strong>Plant C – Constant Operation</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration of the run (hrs)</td>
<td>2.75</td>
</tr>
<tr>
<td>Maximum power (MW)</td>
<td>785.8</td>
</tr>
<tr>
<td>Minimum power (MW)</td>
<td>781.99</td>
</tr>
<tr>
<td>Total power output (MWh)</td>
<td>2154.43</td>
</tr>
<tr>
<td>Average power (MWh)</td>
<td>783.43</td>
</tr>
<tr>
<td>Standard deviation</td>
<td>0.79</td>
</tr>
<tr>
<td>Average CO₂ (MT/ MWh)</td>
<td>0.35</td>
</tr>
<tr>
<td>Standard deviation</td>
<td>0.003</td>
</tr>
<tr>
<td>Average NOx (mg/m^3)</td>
<td>45.46</td>
</tr>
<tr>
<td>Maximum NOx (mg/m^3)</td>
<td>53.0</td>
</tr>
<tr>
<td>Total fuel used during test</td>
<td>15107.58</td>
</tr>
<tr>
<td>period (GJ)</td>
<td></td>
</tr>
<tr>
<td>Fuel used in GJ/MWh</td>
<td>7.01</td>
</tr>
<tr>
<td>Fuel therms</td>
<td>66.46</td>
</tr>
</tbody>
</table>
The principal comparative parameters obtained from this test that will be used to evaluate the performance of the plant when the operation of the plant departs from the MER are:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Used per MWh</td>
<td>7.0105 GJ/MWh</td>
</tr>
<tr>
<td>Average Power Output</td>
<td>783.4 MWh</td>
</tr>
<tr>
<td>CO₂ emitted per MWh</td>
<td>0.3525 MT/MWh</td>
</tr>
<tr>
<td>NOx (Average emission)</td>
<td>45.45 mg/m³</td>
</tr>
<tr>
<td>Maximum NOX</td>
<td>53.0 mg/m³</td>
</tr>
</tbody>
</table>

The emissions of NOx released to atmosphere during this test is shown in Fig 3.10 below.

(Appendix 2 Constant operation)

![NOx emission rate mg/m³ in the effluent gases](image)

Fig. 3.10 Constant operation NOx emission rate mg/m³ in the effluent gases (Appendix 2 Constant Operation)

### 3.6 Cold Start Operation

The data collected during this test illustrates the performance of a CCGT plant starting from a cold condition, requiring careful attention to the speed of temperature increase to protect the hot path components of the gas turbines and the expansion of the moving parts in the steam turbine. The data is collected over a period of 8.33 hours considerably longer than the data collection time of constant operation. This is due to long time required in the cold start. The sequence of events commences with the initial firing of only one gas turbine.
(GT) followed by the start of generation from the steam turbine (ST) when the HRSG steam pressures and the turbine temperatures have achieved predetermined levels. Finally, the second GT is started and approximately 1.5 hours later the second HRSG is ready to supply steam to the common steam turbine. Fig.3.11 below illustrates the total gas consumption during the Cold start operation.

![Cold start - Gas Flow (GJ)](image)

Fig. 3.11 Cold start gas flow (Appendix 2 Cold Start)

The starting pattern of power build-up of the CCGT turbines from a cold start is illustrated in Fig. 3.12. Figure 3.13 shows the CO₂ emission pattern in the cold start operation. It can be seen that high emission levels results in during the start of the first gas turbine.
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Fig 3.12 Power generation profile from each turbine during a cold start

Fig. 3.13 Cold Start run Power Output and CO₂ emissions
(Appendix 2 Cold Start)
Table 3.2 Plant Start from Cold

<table>
<thead>
<tr>
<th>Plant C – Cold Start Operation</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration of the run (hrs)</td>
<td>8.33</td>
</tr>
<tr>
<td>Maximum power (MW)</td>
<td>785.07</td>
</tr>
<tr>
<td>Minimum power (MW)</td>
<td>781.99</td>
</tr>
<tr>
<td>Total power output (MW/h)</td>
<td>2984.76</td>
</tr>
<tr>
<td>Average power (MW)</td>
<td>358.17</td>
</tr>
<tr>
<td>Average CO₂ (per MWh)</td>
<td>0.47</td>
</tr>
<tr>
<td>Average NOₓ (mg/m³)</td>
<td>29.56</td>
</tr>
<tr>
<td>Maximum NOₓ (mg/m³)</td>
<td>207.0</td>
</tr>
<tr>
<td>Total fuel used during test period (GJ)</td>
<td>24364.19</td>
</tr>
<tr>
<td>Fuel used in GJ/MWh</td>
<td>8.16</td>
</tr>
</tbody>
</table>

The comparative parameters obtained during this test are summarised below:

- Fuel Used per MWh: 8.162 GJ/MWh
- Average Power Output: 358.17 MWh
- CO₂ emitted per MWh: 0.483 MT/MWh
- NOₓ (average emission): 29.56 mg/ m³
- NOₓ (maximum level): 207 mg/ m³

The NOₓ emissions shown in Fig. 3.14 are of serious concern during the initial period of the start-up when concentrations values (in this case above 200 mg / m³) reach levels that are only authorised by the Environment Agency for very short periods (10 to 15 minutes).
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3.7 Hot Start operation

The hot start is able to reach full load output when the temperature of the turbines and HRSGs have only fallen marginally from operating conditions. This occurs after an outage of 2 to 4 hours. A typical pattern of gas demand, turbine power production and CO₂ emissions is shown in Figures 3.15, 3.16 and 3.17 respectively.
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Fig. 3.16 Hot Start Power output from Turbines (Appendix 2 Hot start)

Fig. 3.17 Hot Start CO₂ emission (Appendix 2 Hot start)
<table>
<thead>
<tr>
<th>Plant C – Hot Start Operation</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration of the run (hrs)</td>
<td>3.917</td>
</tr>
<tr>
<td>Total power output (MW/h)</td>
<td>1349.72</td>
</tr>
<tr>
<td>Average power (MW)</td>
<td>344.61</td>
</tr>
<tr>
<td>Average CO₂ (per MWh)</td>
<td>0.5813</td>
</tr>
<tr>
<td>Average NOx (mg/m³)</td>
<td>158.68</td>
</tr>
<tr>
<td>Maximum NOx (mg/m³)</td>
<td>1587</td>
</tr>
<tr>
<td>Total fuel used during test period (GJ)</td>
<td>12468.1</td>
</tr>
<tr>
<td>Fuel used in GJ/MWh</td>
<td>9.2376</td>
</tr>
</tbody>
</table>

The comparative parameters obtained during this test are summarised below:

- Fuel Used per MWh: 9.2376 GJ/MWh
- Average Power Output: 344 MW
- CO₂ emitted per MWh: 0.581 MT/MWh
- NOx (average emission): 158 mg/ m³
- NOx (Maximum level): 1587 mg/ m³

The NOx emission pattern shown in Fig. 3.18, indicate very high levels of NOx emissions during the fast start-up routine.

![Hot Start NOx emissions](image)

Fig.3.18 NOx emissions during a fast start. (Appendix 2 Hot start)
3.8 Step Change

In this case the impact of a step change in the power output of the plant was monitored to measure the change in environmental emission. Generated power and gas flow rate in a load reduction of 12% are shown in Fig.3.19 and the individual turbine output adjustments are shown in Fig.3.20. The CO₂ emission and the Power output are illustrated in Fig 3.21.

![Step Change Gas Flow & Power output](image1)

**Fig. 3.19 Step Change - Gas Flow and Power Output (Appendix 2 Step Change)**

![Step change - Power Output MW](image2)

**Fig. 3.20 Step Change Turbine Power Outputs (Appendix 2 Step Change)**
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Fig. 3.21 CO₂ Emission & Power Output (Appendix 2 Step Change)
Table 3.4 The effect of a step change in power output

<table>
<thead>
<tr>
<th>Plant C – Step Change Operation</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration of the run (hrs)</td>
<td>3.75</td>
</tr>
<tr>
<td>Maximum power (MW)</td>
<td>729.89</td>
</tr>
<tr>
<td>Minimum power (MW)</td>
<td>517.92</td>
</tr>
<tr>
<td>Total power output (MWh)</td>
<td>1951.87</td>
</tr>
<tr>
<td>Average power (MW)</td>
<td>520.50</td>
</tr>
<tr>
<td>Average CO₂ (per MWh)</td>
<td>0.3811</td>
</tr>
<tr>
<td>Excess CO₂ (MT/h) (at 520MW)</td>
<td>14.89</td>
</tr>
<tr>
<td>Average NOx (mg/m³)</td>
<td>30.74</td>
</tr>
<tr>
<td>Maximum NOx (mg/m³)</td>
<td>40.7</td>
</tr>
<tr>
<td>Total fuel used during test period (GJ)</td>
<td>14805.20</td>
</tr>
<tr>
<td>Ave. Fuel used in GJ/MWh</td>
<td>7.585</td>
</tr>
</tbody>
</table>

The comparative parameters obtained during this test are summarised below:

- Fuel Used per MWh: 7.585 GJ/MWh
- Average Power Output: 520.4 MW
- CO₂ emitted per MWh: 0.3811 MT/MWh
- NOx (average emission): 30.73 mg / m³
- NOx (maximum emission): 40.7 mg / m³
As the firing temperatures in the gas turbines are lower during reduced power output levels below the MER condition, the NOx level emitted in the flue gases are lower as seen in Fig. 3.22. Average NOx in this case is 30.7mg/m^3 as compared to 45.4mg/m^3 while operating under full load conditions.

![Step Change - NOx emissions (mg/cu m)](image)

Fig. 3.22 NOx emission during the Step Change test (Appendix 2 Step Change)

### 3.9 Modulation 1 & 2

Two periods of variable power production at Plant C were selected to demonstrate the consequences of modulating the output to simulate the plant performing the role of a power balancing unit. The first period examined the case where the output varied by +/- 20%, the second period measured the performance when the load varied by +/- 26%.

#### 3.9.1 Modulation test 1

Modulation 1 covered a production period, which lasted 20 hours. During this period the load on the station oscillated between 500MW and 780MW. The pattern of gas flow rate and the exported power is shown in Fig. 3.23 and Fig. 3.24 respectively.

The variation of CO₂ emissions with the station load changes is plotted in Fig 3.25 where departures from optimum operation are clearly reflected in increases in CO₂ output per MWh.
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Fig. 3.23 Modulation Run 1  Gas flow 9 (Appendix 2 Modulation1)

Fig. 3.24 Turbine power output MW (Appendix 2 Modulation1)
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The results of the analysis are consolidated in Table 3.5 below.

<table>
<thead>
<tr>
<th>Plant C – Modulation 1</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration of the run (hrs)</td>
<td>8.5</td>
</tr>
<tr>
<td>Maximum power (MW)</td>
<td>785.40</td>
</tr>
<tr>
<td>Minimum power (MW)</td>
<td>464.12</td>
</tr>
<tr>
<td>Total power output (MW/h)</td>
<td>5073.97</td>
</tr>
<tr>
<td>Average power (MW)</td>
<td>596.94</td>
</tr>
<tr>
<td>Average CO₂ (per MWh)</td>
<td>0.3707</td>
</tr>
<tr>
<td>Average NOx (mg/m³)</td>
<td>38.038</td>
</tr>
<tr>
<td>Total fuel used during test period (GJ)</td>
<td>37175.59</td>
</tr>
<tr>
<td>Fuel used in GJ/MWh</td>
<td>7.33</td>
</tr>
<tr>
<td>Modulation MW</td>
<td>321.275</td>
</tr>
</tbody>
</table>

Table 3.5 Plant Modulated output 1. Data analysis of +/-20% change in power between full load and 60% load. (Appendix 2 Modulation 1)
The comparative results obtained during this test are:

<table>
<thead>
<tr>
<th>Fuel Used per MWh</th>
<th>7.33 GJ/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Power Output</td>
<td>596.9MW</td>
</tr>
<tr>
<td>CO$_2$ emitted per MWh</td>
<td>0.3707 MT/MWh</td>
</tr>
<tr>
<td>NOx (average emission)</td>
<td>38.03 mg/ m$^3$</td>
</tr>
<tr>
<td>NOx (maximum level)</td>
<td>52.0 mg/ m$^3$</td>
</tr>
</tbody>
</table>

The NOx emissions during this test are shown in Fig.3.26. The occurrence of a large perturbation during the run is explained by a plant adjustment by an operator, no other parameter deviated from the expected level.

![Plant C Modulation Run NOX mg/cu m](image)

Fig.3.26 NOx record during Modulation test run 1 (Appendix 2 Modulation1)

### 3.9.2 Modulation Test 2

The modulation 2 test lasted 5.9 hours and the power output varied by +/- 26%. The generated output oscillated between 380MW and 785MW while both gas turbines shared the load equally during the test after the second turbine was brought up to load at the beginning of the test, as illustrated in Figs.3.27 and 3.28.
The emission of CO₂ during this test is compared with the power output in Fig. 3.29 where it is demonstrated that the degree of pollution increases as the generated load on the station falls.

During this test run the CO₂ emission levels can be seen to rise as the load on the plant falls. Small perturbations below half the station capacity (i.e. below 400MW) appear to introduce significant rises in emissions of CO₂.

![Modulation 2 - Gas Flow and Power output](image-url)

Fig. 3.27 Power modulation test 2  Gas Flow & Power output  
(Appendix 2 Modulation 2)
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Fig. 3.28 Modulation test 2. Power sharing between gas turbines. (Appendix 2 Modulation2)

Fig. 3.29 Modulation test 2 Power Output & CO₂ emissions (Appendix 2 Modulation 2)
Table 3.6 Plant Modulated Output 2. Data analysis of a +/− 26% change in power output between full load and 48% load. (Appendix 2 Modulation2)

<table>
<thead>
<tr>
<th>Plant C – Modulation 2 +/− 25%</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration of the run (hrs)</td>
<td>5.83</td>
</tr>
<tr>
<td>Maximum power (MW)</td>
<td>778.86</td>
</tr>
<tr>
<td>Minimum power (MW)</td>
<td>371.88</td>
</tr>
<tr>
<td>Total power output (MWh)</td>
<td>3453.2</td>
</tr>
<tr>
<td>Average power (MW)</td>
<td>575.73</td>
</tr>
<tr>
<td>Average CO₂ (per MWh)</td>
<td>0.3793</td>
</tr>
<tr>
<td>Average NOx (mg/m³)</td>
<td>22.17</td>
</tr>
<tr>
<td>Total fuel used during test period (GJ)</td>
<td>308596.6</td>
</tr>
<tr>
<td>Fuel used in GJ/MWh</td>
<td>7.47</td>
</tr>
<tr>
<td>Modulation MW</td>
<td>380 to 785</td>
</tr>
</tbody>
</table>

The comparative results obtained from this test are summarised below:

- Fuel Used per MWh: 7.47 GJ/MWh
- Average Power generated: 592 MW
- CO₂ emitted per MWh: 0.3792 MT/MWh
- NOx (average emission): 22.17 mg/ m³
- NOx (maximum level): >250 mg/ m³

The NOx emissions during the test period are shown in Fig.3.30. The first 30 minutes of the test when the emission levels were high occurred during a period when the station was at the lower end of the output range investigated.
3.10 Duct Firing

The period was selected to demonstrate the impact of adding heat to the hot gases after they exit the gas turbines and before they enter the HRSGs. This increases the energy input to the steam and hence the power produced from the steam turbine. The additional power produced uses significantly more fuel and emits more CO₂ per MWh as it is only operating on the simple cycle.

Fig. 3.31 shows the gas flow and power output during the test and Fig. 3.32 illustrates the change in turbine loading. Whilst the two gas turbines remain constant the total increase in power generated is delivered by the steam turbine.

The impact of the extra CO₂ produced per MWh is shown in Fig. 3.33 where the total emission level rose by 0.02 MT/MWh. The increased CO₂ on the incremental power output was 0.44 MT/MWh.

Fig. 3.34 demonstrates the impact of emissions from Duct Firing operation. The CO₂ emissions have been extracted from the data for a period when the plant was producing full
output from this unit and compared with a similar period when the plant was operating at MER.

The extra CO\(_2\) produced is equal to an average 0.51MT/MWh for the incremental power produced. However, the cost of producing this power is small as the capital cost of the plant involved is low and the fixed overheads and maintenance is of a minor order.

![Graph showing duct firing HRSG operation gas & power](image-url)

Fig. 3.31 Duct Firing Gas Flow & power output (Appendix 2 Duct Firing)
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Fig 3.32 Duct firing Turbine power output (Appendix 2 Duct Firing)

Fig 3.33 Duct Firing Power Output & CO₂ emissions (Appendix 2 Duct Firing)
Table 3.7 Duct Firing (Appendix 2 Duct Firing)

<table>
<thead>
<tr>
<th></th>
<th>Plant C – Modulation 2 +/- 25%</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration of the run (hrs)</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Maximum power (MW)</td>
<td>867.23</td>
<td></td>
</tr>
<tr>
<td>Minimum power (MW)</td>
<td>759.35</td>
<td></td>
</tr>
<tr>
<td>Total power output (MW/h)</td>
<td>5098.41</td>
<td></td>
</tr>
<tr>
<td>Extra power per HRSG (MW/h)</td>
<td>66.24</td>
<td></td>
</tr>
<tr>
<td>Average power (MW)</td>
<td>849.74</td>
<td>25.96</td>
</tr>
<tr>
<td>Average CO₂ (MT per MWh)</td>
<td>0.3702</td>
<td>0.0048</td>
</tr>
<tr>
<td>Maximum CO₂ (MT per MW/h)</td>
<td>0.375</td>
<td></td>
</tr>
<tr>
<td>Average NOx (mg/m³)</td>
<td>66.68</td>
<td>9.67</td>
</tr>
<tr>
<td>Total fuel used during test period (GJ)</td>
<td>37061.84</td>
<td>7.26</td>
</tr>
<tr>
<td>Fuel used as CCGT (GJ)</td>
<td>32954.01</td>
<td></td>
</tr>
<tr>
<td>Extra gas duct firing (GJ)</td>
<td>4062.83</td>
<td></td>
</tr>
<tr>
<td>Incremental gas for duct firing GW/MWh</td>
<td>10.22</td>
<td></td>
</tr>
<tr>
<td>Fuel used in GJ/MWh</td>
<td>7.47</td>
<td></td>
</tr>
<tr>
<td>Extra cost of gas £/MWh</td>
<td>38.77</td>
<td></td>
</tr>
<tr>
<td>Incremental gas therms/MWh</td>
<td>96.92</td>
<td></td>
</tr>
</tbody>
</table>
The increase in the NOx concentrations during the Duct Firing period can be attributed solely to the gas firing into the HRSG inputs as shown in Fig.3.35.

![HRSG operation NOX](image)

**Fig. 3.35 The NOx emissions during Duct Firing (Appendix 2 Duct Firing)**

### 3.11 Consolidated results

By operating the power plant at different output levels it has been possible to compare the fuel demand, the variations in emissions (CO$_2$ & NOx) and hence the costs per unit of power produced. The fuel used is analysed in table 3.8.
Table 3.8 Fuel used and cost impact during various modes of plant operation (Appendix 2 Consolidated results Sheet 2)

<table>
<thead>
<tr>
<th>Run</th>
<th>Duration</th>
<th>Gas Used GJ</th>
<th>Gas Used GJ/MWh</th>
<th>Gas Thems MWh</th>
<th>Gas cost £/MWh (40p/therm)</th>
<th>Gas % increase above standard</th>
<th>Load variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant Op (std)</td>
<td>2.75</td>
<td>181291</td>
<td>7.012</td>
<td>66.477</td>
<td>26.591</td>
<td>4MW</td>
<td>+/- 2 MW</td>
</tr>
<tr>
<td>Cold Start-Up</td>
<td>8.33</td>
<td>292370</td>
<td>8.163</td>
<td>77.384</td>
<td>30.954</td>
<td>16.407</td>
<td>0 to 778MW</td>
</tr>
<tr>
<td>Hot Start-up</td>
<td>3.916</td>
<td>149617</td>
<td>9.238</td>
<td>87.572</td>
<td>35.029</td>
<td>31.733</td>
<td>0 to 778MW</td>
</tr>
<tr>
<td>Step change (-33%)</td>
<td>3.917</td>
<td>177662</td>
<td>7.585</td>
<td>71.907</td>
<td>28.763</td>
<td>8.168</td>
<td>518 to 730MW</td>
</tr>
<tr>
<td>HRSG (duct firing)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall</td>
<td>6</td>
<td>444202</td>
<td>7.260</td>
<td>68.829</td>
<td>27.532</td>
<td>3.538</td>
<td>759 to 849MW</td>
</tr>
<tr>
<td>Modulation 1 (+/- 20%)</td>
<td>8.417</td>
<td>446107</td>
<td>7.327</td>
<td>69.457</td>
<td>27.783</td>
<td>4.483</td>
<td>464 to 787MW</td>
</tr>
<tr>
<td>Modulation 2 (+/- 25%)</td>
<td>6.5</td>
<td>340212</td>
<td>7.576</td>
<td>71.820</td>
<td>28.728</td>
<td>8.037</td>
<td>778 to 371MW</td>
</tr>
<tr>
<td>Year ahead gas price p/therm</td>
<td>40</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Chapter 3 Impact on CCGT Power Plants

Fig. 3.36 Gas used GJ/MWh for various operating conditions (Appendix 2 Consolidated results Sheet 2)

It can be seen that the demand and hence the cost of fuel is increased by 3.5% to 8.1% when the plant was operated under conditions below the MER, Fig. 3.36.

This also leads to an increase in the CO₂ produced, which in turn increase the costs of purchasing CO₂ permits. The consequences are summarised in table 3.8 and illustrated in Fig. 3.37. The cost of the CO₂ permits varies depending upon the supply and demand in the trading market. In order to place a realistic measure upon this cost, a nominal figure of £20/tonne has been used to compute the impact of CO₂ emissions on the plant operations, (note: £20/tonne is the predicted charge under the second phase of the CO₂ trading regime). Tables 3.9a and 3.9b identifies the cost of cold and hot starts and the impact of operating below MER for one hour during load following. The extra CO₂ emitted (MT/MWh) during periods when the power plant is operating below MER is illustrated in Fig 3.7.
Table 3.9a Carbon Dioxide Emissions and Carbon Certificate Costs (Appendix 2 Consolidated Results Sheet 4)

<table>
<thead>
<tr>
<th>Carbon Dioxide Emissions</th>
<th>Duration of test hrs</th>
<th>CO₂ Emissions Average MT/MWh</th>
<th>CO₂ excess Certificates Above MER MT/MWh</th>
<th>Carbon Certificates @ £20/MT* £</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant Operation</td>
<td>2.75</td>
<td>0.35</td>
<td>0.00</td>
<td>7.05</td>
</tr>
<tr>
<td>Cold Start</td>
<td>8.33</td>
<td>0.48</td>
<td>0.12</td>
<td>9.56</td>
</tr>
<tr>
<td>Hot Start</td>
<td>4.00</td>
<td>0.59</td>
<td>0.24</td>
<td>11.88</td>
</tr>
<tr>
<td>Step Change</td>
<td>3.90</td>
<td>0.39</td>
<td>0.04</td>
<td>7.85</td>
</tr>
<tr>
<td>Modulation 1</td>
<td>8.42</td>
<td>0.39</td>
<td>0.04</td>
<td>7.76</td>
</tr>
<tr>
<td>Modulation 2</td>
<td>6.50</td>
<td>0.37</td>
<td>0.02</td>
<td>7.41</td>
</tr>
<tr>
<td>Duct firing</td>
<td>6.00</td>
<td>0.37</td>
<td>0.01</td>
<td>7.30</td>
</tr>
</tbody>
</table>

*MT = Metric Tonne

Table 3.9b Carbon Costs £/hr of operation (Appendix 2 Consolidated Results Sheet 4)

<table>
<thead>
<tr>
<th>Run</th>
<th>Average Power MWh/h</th>
<th>CO₂ Certificates £/hour</th>
<th>Excess CO₂ Cost above MER £/hr</th>
<th>Excess CO₂ Cost £/Year (8000hrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant Operation</td>
<td>783.42</td>
<td>15668</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Step Change</td>
<td>539.63</td>
<td>10793</td>
<td>168</td>
<td>1342335</td>
</tr>
<tr>
<td>Modulation 1</td>
<td>596.94</td>
<td>11939</td>
<td>163</td>
<td>1306236</td>
</tr>
<tr>
<td>Modulation 2</td>
<td>568.44</td>
<td>11369</td>
<td>74</td>
<td>595688</td>
</tr>
<tr>
<td>Duct firing</td>
<td>849.74</td>
<td>16995</td>
<td>75</td>
<td>597753</td>
</tr>
</tbody>
</table>

Fig 3.37 CO₂ Emissions Average (MT/MWh)

CO₂ Emissions Average (MT/MWh)

Duct firing
Modulation 2
Modulation 1
Step Change
Constant Operation

Fig 3.37 CO₂ Emissions Under different Operating Conditions (Appendix 2 Consolidated Results Sheet 4)
Figure 3.38 shows CO₂ emissions during start-ups in comparison to constant operation. During the starting periods the emission of CO₂ (MT/MWh) increases significantly. From Fig. 3.38 it can be seen that between 0.12 tonnes /MWh during a cold start and up to 0.24 MT/MWh are emitted above the MER operating levels.

![CO₂ Emissions Ave. (MT/MWh) during Start-Up](image)

Fig. 3.38 Average CO₂ emissions during the Start-Up compared with continuous operation (Appendix 2 Consolidated Results Sheet 4)

When these emissions are converted into the purchasing of Carbon Certificates, the impact of operating the plant below MER continuously adds significant costs to the operation. Fig 3.39 illustrates a hypothetical case where the plant might be required to compensate for the variability of renewable generation. In this example the plant is assumed to have availability of 91% (i.e. 8000 operational hours per year).
Chapter 3 Impact on CCGT Power Plants

**Excess CO₂ Cost £/Year (8000hrs)**

<table>
<thead>
<tr>
<th>Duct firing</th>
<th>Modulation 2</th>
<th>Modulation 1</th>
<th>Step Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>250,000</td>
<td>650,000</td>
<td>1,050,000</td>
<td>1,650,000</td>
</tr>
</tbody>
</table>

Fig 3.39 Increased cost of Carbon Certificates (£/year) during extended operations below MER (Appendix 2 Consolidated Results Sheet 4)

The more serious emission levels occur during the starting period. A second hypothetical case examines the excess emissions which would occur if the plant was required to balance daily load fluctuations during week days and switch off during the night. For the purposes of this analysis the plant is assumed to operate during the daytime only and start up each week day (i.e. 4 starts per week) using the hot start process and require one cold start per week (i.e. Monday) for 50 weeks per year. Table 3.10 records the consequences for the operational costs of approximately £19M/ year.

Table 3.10 Carbon Cost during Start-Up (Appendix 2 Consolidated Results Sheet 4)

<table>
<thead>
<tr>
<th>Start Type</th>
<th>Average Power per start MWh</th>
<th>Carbon Certificates Cost per start £</th>
<th>Excess CO₂ Cost Per Start £</th>
<th>Excess CO₂ Cost per year £</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold Start (35/y)</td>
<td>35817</td>
<td>342377</td>
<td>89508</td>
<td>3132793</td>
</tr>
<tr>
<td>Hot Start (200/y)</td>
<td>16197</td>
<td>192402</td>
<td>78054</td>
<td>15610757</td>
</tr>
<tr>
<td>Annual Extra Cost of Multiple starts</td>
<td></td>
<td></td>
<td></td>
<td>18743550</td>
</tr>
</tbody>
</table>
3.12 Impact on plant performance below MER

When the CCGT plant is required to match the inverse of power generated from unpredictable generation sources, it will invariably operate at power output levels less efficiently than operating at MER.

The results of the measurements analysed above indicate the order of these penalties, (extra fuel used, extra CO₂ emitted and consequential extra cost involved). The important parameters are summarised in tables 3.11 & 3.12 below.

Table 3.11 Cost penalty of Stop/Start operations Appendix 2 (Consolidated Analysis)

<table>
<thead>
<tr>
<th>Penalties</th>
<th>Of Start /Stop Operations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold Star Up</td>
<td>Extra Fuel therms per start</td>
</tr>
<tr>
<td></td>
<td>Extra CO₂ emitted MT/start</td>
</tr>
<tr>
<td></td>
<td>Fuel Cost Penalty/Start £ @ 40p/therm</td>
</tr>
<tr>
<td></td>
<td>CO₂ Cost Penalty /Start £ @£20/tonne CO₂</td>
</tr>
<tr>
<td></td>
<td>Total Cost above MER £/Start</td>
</tr>
<tr>
<td>Hot Start Up</td>
<td>32564.392</td>
</tr>
<tr>
<td></td>
<td>360.1688</td>
</tr>
<tr>
<td></td>
<td>13025.7568</td>
</tr>
<tr>
<td></td>
<td>7203.376</td>
</tr>
<tr>
<td></td>
<td>20229.1328</td>
</tr>
<tr>
<td></td>
<td>28868.6</td>
</tr>
<tr>
<td></td>
<td>151.2229</td>
</tr>
<tr>
<td></td>
<td>11547.44</td>
</tr>
<tr>
<td></td>
<td>3024.458</td>
</tr>
<tr>
<td></td>
<td>14571.898</td>
</tr>
</tbody>
</table>

Fig 3.12 Cost consequences of operating below MER (Appendix 2 (Consolidated Analysis)

<table>
<thead>
<tr>
<th>Penalties of operating below MER</th>
<th>Extra Fuel therms / hour</th>
<th>Extra CO₂ MT / hour</th>
<th>Fuel Cost £ / hour @ 40p / therm</th>
<th>CO₂ Cost £ / hour @£20 / tonne CO₂</th>
<th>Total Cost above MER £ / hour</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant Operation (MER)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Step Change</td>
<td>2702.582934</td>
<td>14.89</td>
<td>1081.033173</td>
<td>297.8</td>
<td>1378.833173</td>
</tr>
<tr>
<td>Modulation 1</td>
<td>1795.998951</td>
<td>10.95</td>
<td>718.3995804</td>
<td>219</td>
<td>937.3995804</td>
</tr>
<tr>
<td>Modulation 2</td>
<td>3076.063707</td>
<td>20.569</td>
<td>1230.425483</td>
<td>411.38</td>
<td>1641.805483</td>
</tr>
<tr>
<td>Duct Firing</td>
<td>1998.746667</td>
<td>15.028</td>
<td>799.4986668</td>
<td>300.56</td>
<td>1100.058667</td>
</tr>
</tbody>
</table>

The three test results on the CCGT plant (i.e. without the duct firing test run) were averaged to determine a cost to apply to the next stage.
3.13 Emission of Oxides of Nitrogen

The power plant is fuelled by natural gas with no oil fuel back up for any gas supply interruption. The combustion of natural gas, which consists principally of methane (CH4), produces emissions of water vapour, carbon dioxide, nitrogen oxides (NOx) and very small quantities of sulphur dioxide and carbon monoxide. These latter two pollutant concentration levels are insignificant compared with the maximum levels set by the World Health Organisation (WHO) and by the Department of the Environment Expert Panel on Air Quality Standards (EPAQS). It is therefore assumed they can be neglected.

The combustion of natural gas at high temperatures (say, 1000°C) causes the generation of small quantities of NO and NO2. As the gases are emitted to atmosphere the Nitrogen Oxide is steadily converted to Nitrogen Dioxide, which is toxic and the concentration at ground level is tightly regulated.

All the major manufacturers of large gas turbines have methods of controlling the emissions by restricting the combustion temperature with the addition of water or steam into the gas turbine burners. However, it is not possible to start this process until the machines have reached relatively high loads.

During start up periods the emission levels can be well above the Environment Agency (EA) authorised levels and special dispensation has to be given for these specific operations. To ensure that no one power plant can cause excessive concentrations, the number of starts in a given time may be limited by the terms of the IPPC authorisation.

Fig.3.40 illustrates the NOx emissions during both a cold start and a hot start. It can be seen that the maximum levels of NO2 attained were 200 mg/m³ and 1600 mg/m³ respectively for short periods. When this is compared with the average level of NOx concentration during operating at MER of 0.35 mg/m³, it can be seen that there is a real danger of the resulting ground level concentrations around the plant reaching levels above the WHO guidelines. These guide lines call for maximum levels of NO2 not to exceed an annual mean value of 40-50 µg/cu m, a 24 hour mean of 150 µg/cu m and a 1hour mean of 200µg/cu m.
Chapter 3 Impact on CCGT Power Plants

Fig. 3.40 NOx emissions during cold & hot starts (Appendix 2 Consolidated Analysis Sheet 5)

As significant pollution occurs during starting the number of cold and hot starts in any specific period of time are limited and set by the EA in the ‘Integrated Pollution Prevention and Control’ (IPPC) document.

Each new power station must obtain an agreed set of operating conditions with the EA before it can become operational. If it should fail to meet the conditions, the Agency has a number of sanctions, which can ultimately culminate in an injunction commanding the station to stop operating.

All the continuous tests carried out during these observations indicated that the NOx emission levels were within the EA permitted levels.

However, as shown in Fig. 3.41 it can be seen that the NOx emissions are some 20% higher during periods of Duct Firing compared with operation at MER. Figure 3.42 shows NOx emissions during duct firing compared to other modulating test periods and MER operation. The emissions during duct firing are significantly above all the modulating test periods as seen from Fig. 3.42. The implications being that if the plant has to respond to an increase in demand by using duct firing, the resulting emissions can have a significant effect.
Chapter 3 Impact on CCGT Power Plants

Comparison of NOX emissions of Duct Firing and Constant Operation

Fig 3.41 NOX Emissions comparison Duct Firing & Constant Operation
(Appendix 2 Consolidated analysis Sheet 5)

Fig. 3.42 NOX emission levels during duct firing compared with operations during the modulation tests. (Appendix 2 Consolidated analysis Sheet 5)
3.14 The impact upon CCGT Power Plant of Variable Renewable Energy

The power generated from Renewable Energy sources is variable and unpredictable (Chapter 2); there will be the need for alternative generating capacity to adjust instantaneously to maintain the security of supply by increasing or decreasing output.

As discussed earlier, with the retirement of coal fired plant (and confirmed by a major UK generator in response to the government energy review 2006 [51], Fig. 3.43), the duties of matching the demand will fall upon the only other suitable plant, the gas fired CCGT stations. It will require these plants to modulate their output to balance the overall system demand.

The number of CCGT stations, which will be available by 2020, can only be a matter of speculation at the present time. It will depend largely upon whether the government decides to reinvest in nuclear power. If the answer is no to further investment in nuclear power, there will be a much larger number of gas fired stations constructed to share both the UK overall demand and the balancing load. (This assumes that the potential clean coal technologies contribute little or no input by 2020).

The impact of a large number of wind turbines, supplying variable quantities of power, would be significant and require many of the CCGT plants to continually modulate their power output.

If the answer is yes and new nuclear stations are constructed, the UK electricity demand will require fewer CCGT plants to meet the predicted load. As the nuclear power plants are unable to start and stop quickly or modulate their power output sufficiently fast to match changing circumstances, they will form part of the ‘base load’ supply. The remaining gas stations will, therefore, be subjected to much greater degrees of modulation under this regime, as the share of balancing the supply will fall upon a smaller number of plants.
Chapter 3 Impact on CCGT Power Plants

The chart below shows the expected profile of UK generating plant closures.

![Profile of generation plant closures](chart.png)

The UK will have a generation gap of 32GW in 2016, assuming moderate demand growth and expected growth in renewables in line with the Renewables Obligation (RO). Even under very optimistic scenarios regarding grid electricity demand reduction the generation gap will still be 25GW in 2016.

Fig 3.43 The EDF response to the Government Energy review April 2006 [51]

In order to gain an insight into the inefficiencies caused by these operational conditions, it has been necessary to estimate the actual installed wind turbine capacity, which will be required to meet the government targets. Currently, it is planned to supply 7% of the annual power demand from wind energy by 2010 and to raise this to 15% by 2020. During 2003 the Department of Trade and Industry confirmed these estimates [52].
In order to estimate the required wind turbine capacity, the following assumptions were compiled:

a) The wind turbines will produce approximately 25 to 30% of their rated installed capacity annually (Annual Load factor) when located in the best geographical locations [54].

b) All the power produced will be supplied to the system as and when it is available unhindered, when the national electricity demand is sufficient to absorb it.

c) The output from the turbines will vary continuously, with a maximum excursion from zero to full capacity on a few occasions.

d) The number of operational days / year will be 365 (i.e. 8760 hours per year)

e) The UK annual power demand will be approximately 385TWh (i.e. 1% annual increase on the 2003 demand).

f) The power to be delivered from wind energy will be 15% of the total annual demand, (i.e. 57.57TWh)

Estimated annual output is given by

\[ P_t = T_f \times T_a \times A_p \times H_y / 1000 \] (TWh)  

Where \( P_t \) = Power produced per year (TWh)
\[ T_i = \text{Installed turbine capacity} \quad \text{(GW)} \]
\[ T_a = \text{Turbine availability} \quad \text{(%)} \]
\[ A_p = \text{Turbine annual production} \quad \text{(% of installed capacity)} \]
\[ H_y = \text{Hours per year} \quad \text{(hours)} \]

Hence

\[ T_i = P_i \times 1000 / (T_a \times A_p \times H_y) \quad (3.11) \]

Using this equation Table 3.13 has been compiled to demonstrate the consequences and to identify the backup fossil fuel generation needed. For the purposes of the analysis data was taken from DTI Dukes tables of UK Annual Power Demand [55] and a number of further assumptions have been made, namely:

(a) By 2010 and 2020 the government projections for installed capacity will be achieved (i.e. 7% and 15% respectively)
(b) The majority of new wind turbine installations will be Off-Shore with higher hub heights where the annual load factors are marginally higher than current levels. A nominal Annual Load Factor of 28% has been selected.
(c) The annual power demand will grow during the period to 2020 at an annual average rate of 1%
(d) The Modern CCGT plant will deliver an availability of 90%
(e) In order to secure the country’s power supplies energy from wind cannot be regarded as a secure source of electricity and will need full back-up from fossil fuel plants
(f) The most likely back-up facilities will be provided by gas fired CCGT plants
(g) By 2016 some 32GW of fossil fuel power plants will have come to the end of their useful life span and have been retired [51]
Table 3.13a Assumed parameters Wind Turbine Contribution (Appendix 2 Consolidated Analysis Sheet 2)

<table>
<thead>
<tr>
<th>RE generation required % of UK Annual Demand</th>
<th>Year</th>
<th>% required From Wind sector</th>
<th>Estimated UK Total Annual Power Demand TWh</th>
<th>Wind contribution required TWh</th>
<th>Wind Turbine Average hourly contribution MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>10%</td>
<td>2010</td>
<td>7%</td>
<td>350</td>
<td>24.5</td>
<td>2797</td>
</tr>
<tr>
<td>20%</td>
<td>2020</td>
<td>15%</td>
<td>385</td>
<td>57.75</td>
<td>6592</td>
</tr>
<tr>
<td>Selected Case</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20%</td>
<td>2020</td>
<td>15%</td>
<td>385</td>
<td>57.57</td>
<td>6592</td>
</tr>
</tbody>
</table>

Table 3.13b Wind Turbine Annual Load Factors and required Back-Up Capacities with turbine annual load factors of 25 & 30% (Appendix 2 Consolidated Analysis Sheet 2)

<table>
<thead>
<tr>
<th>RE generation required % of UK Annual Demand</th>
<th>Year</th>
<th>Wind Turbine Annual Load Factor</th>
<th>Required installed Wind Turbine Capacity MW</th>
<th>Back Up CCGT Annual Availability %</th>
<th>Number of 800MW CCGT Plants Required (Balancing Capacity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10%</td>
<td>2010</td>
<td>25</td>
<td>11187</td>
<td>90</td>
<td>16</td>
</tr>
<tr>
<td>10%</td>
<td>2010</td>
<td>30</td>
<td>9322</td>
<td>90</td>
<td>13</td>
</tr>
<tr>
<td>20%</td>
<td>2020</td>
<td>25</td>
<td>26369</td>
<td>90</td>
<td>37</td>
</tr>
<tr>
<td>20%</td>
<td>2020</td>
<td>30</td>
<td>21974</td>
<td>90</td>
<td>31</td>
</tr>
<tr>
<td>Selected Case</td>
<td>2020</td>
<td>28</td>
<td>23544</td>
<td>90</td>
<td>33</td>
</tr>
</tbody>
</table>

For the selected case:

Total Wind Power Generated in a nominal year = 57.57 TWh

However, as the potential variation in output could be between Zero and 23500 MW during the course of a year, the power short fall could vary between 23500 MW and Zero MW. This short fall will need to be replaced by alternative generating capacity as and when required. In this analysis it will be assumed that the balancing role will be delivered by the gas fired CCGT plans.

The annual power shortfall may be computed by

\[ P_d = P_i \times \frac{H_y}{1000} \]  

(3.10)
Where \( P_a \) = the annual power demand to be supplied (TWh)

Hence the power short fall, \( P_{CCGT} \) (TWh), is given by:

\[
P_{CCGT} = P_a - P_i = P_i \times H_y / 1000 - T_i \times T_a \times A_p \times H_y / 1000
\]

\[
= H_y (P_i - T_i \times T_a \times A_p) / 1000
\]

After substitution of data for the selected case (Table 3.13b) into the above equation assuming an annual load factor for the wind turbines of 28% we have:

\[
P_{CCGT} = 128 \text{ TWh/year}
\]

Assuming each CCGT plant responds with the same characteristics the balancing power profile required will produce a pattern of continual load variation similar to that analysed above for Plant ‘C’.

There are likely to be very few occasions when the wind capacity produces either zero or full output power but to assure the continuity of supply, total backup capacity will be required.

If total security is to be achieved, further assumptions are required.

a) Make-up power required is less than 50% of the current operating CCGT capacity.

b) The gas supply infrastructure is able to deliver the gas on demand 12 months of the year to all the CCGT plants

c) The CCGT plants can respond to all the wind variations even under extreme storm conditions.

d) All the individual CCGT plant, which are operational at any one time will supply between 50 and 100% of their installed capacity.

e) Some CCGT plants will shut down when operations become uneconomic.

f) Cover for plant maintenance and unplanned outages, which will require extra capacity.

g) The gas and electricity markets will operate as described below.

h) The power demand on the NGC system is always greater than the maximum power which can be delivered from all the wind turbines combined.
3.15 Energy Prices

Gas is a traded commodity. It can be traded under different contracts, being secured one year ahead, one day ahead and within day of delivery.

As the price is set by supply and demand, it can be very volatile. Fig.3.44 illustrates how the variation of the rolling ‘year ahead’ price has changed over the period 1st January 2005 to 1st December 2005. At the start of the year, a long term contract could have been made at 31p / therm, but by November that price had risen to a high of £1.70p / therm.

![Rolling Average Year Ahead Gas Price](image)

**Fig.3.45a The ‘Year Ahead’ market price for gas traded in the UK [56]**

Whilst the UK market is free to follow the supply / demand rules, it is physically tied to the continental Europe via pipe line inter-connectors and that market does not yet respond to the same price signals (2005). Hence there is currently an adverse impact upon the UK when a shortfall in supply occurs. This is a condition, which should be corrected long before the 2020 and more stable pricing result.
The day ‘ahead gas’ market is the vehicle, which is used to meet the variable elements of the demand, by most power generators. However, on occasions, this strategy has proved to be expensive. Fig.3.45 illustrates the price trends in this market, which can react with very rapid price changes when shortages of supply occur. The corresponding contract electricity price in the market during this period is shown in Fig.3.46.

By contrast the ‘day ahead’ prices (Fig.3.47) are subject to short-term price spikes as the instantaneous supply and demand is subject to both fuel price movements and power station availability. (As the coal price during this time has been relatively stable, it has had a restraining effect upon the electricity price. This may not be available in the future as the old coal nuclear plants are phased out of service.)

For the purposes of further analysis to measure the impact of variable wind energy upon the CCGT plant financial results, it was necessary to select a realistic gas and electricity price. From the market data of current prices and the future contract projections, the following prices have been adopted for the purpose of this analysis.

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Price</td>
<td>40p / therm</td>
</tr>
<tr>
<td>Electricity Price</td>
<td>£40 / MWh</td>
</tr>
</tbody>
</table>
Chapter 3 Impact on CCGT Power Plants

Fig. 3.46 The contract price for long-term electricity prices [56]

Fig. 3.47 The Day Ahead electricity prices (2003 to 2005) Source: Escape Energy Managers [56] & Various Supplier sources
3.16 Carbon Dioxide Trading

The European Union introduced individual limits upon all large companies, which emit Carbon Dioxide into the atmosphere from 1st January 2005. Each company was given an allowance based on historical data related to their previous operations (European Union Allowance or EUA.) If a company wishes to exceed this EUA, it must acquire emission certificates from other organisations, which do not intend to use all their allocation.

A new market has been established to trade the emission certificates known as the Carbon Pool Europe. It operates under the EU Emissions Trading Scheme (EU ETS). The price of certificates is established on a willing buyer / willing seller basis. Fig.3.48 indicates the movements in pricing, which have occurred since the market commenced (01 Jan 2005).

![Trading Price EURO for 2005](image)

Fig.3.48 Carbon trading prices since 1st Jan 2004 Source: Escape Energy Managers [56]

When generating power, coal plants emit CO₂ at an average rate of 0.95 tonnes / MWh and gas (CCGT) plants emit 0.35 tonne / MWh at MER. The emission certificates are currently priced at £20/ tonne and have to be purchased in the Carbon Pool to meet the obligations. This will add £19/MWh to the cost of generating electricity from coal and £7/ MWh to the price from gas (in a modern CCGT plant).

During the periods when the generators are starting up or operating at less than MER, the CO₂ will be greater than the standard emission rates; consequently these costs will be significantly higher.
3.17 The impact of New Nuclear Capacity

Scenario (A)
As most existing nuclear power plants will be decommissioned by the year 2020 under this scenario, if they are not replaced, the one remaining nuclear station would provide just 1.1GW of generation capacity.

The potential generating plant contributing zero or very low carbon emissions will total approximately 25.6GW (1.1GW nuclear generation, 1GW of Combined Heat and Power (CHP) and up to a maximum of 23.5GW of wind turbine capacity). From Fig 3.49 it can be seen that the summer time daily power demand may be below this potential wind power generation capacity, (line aa'), particularly between the hours of midnight and 8.30am. However, for such a condition to occur all the wind turbines across the UK must be operational and producing at or near their maximum output at a time when the demand is very low.

The results are summarised in table 3.14. It can be seen that, in balancing mode, the CCGT plants would consume an extra 730 million therms of gas and an extra 4.5M tonnes of CO₂
would be emitted annually. The combined financial penalty for working at less than MER, for fuel and Carbon trading, would be £380M/year.

Table 3.14 Consolidated costs (appendix 2 Consolidated Analysis Sheet 2)

<table>
<thead>
<tr>
<th>Penalties</th>
<th>Operation</th>
<th>Costs</th>
<th>Below</th>
<th>MER</th>
<th>Total Cost above MER</th>
</tr>
</thead>
<tbody>
<tr>
<td>33 CCGT Plants to balance wind turbine load</td>
<td>Extra Fuel</td>
<td>Extra CO₂</td>
<td>Fuel Cost</td>
<td>CO₂ Cost £m / year @ £20/tonne</td>
<td>£m/year</td>
</tr>
<tr>
<td>Modulation of output</td>
<td>Million therms / year</td>
<td>MT / year</td>
<td>£m / year @40p/therm</td>
<td>£20/tonne</td>
<td>381.4</td>
</tr>
</tbody>
</table>

The Extra Cost of fuel during balancing..................£ 292m per annum
The extra cost of CO2 certificates.........................£ 89.4m per annum

Scenario (B)

This scenario assumes that the installed nuclear capacity in 2020 will be the same as it was in 2003 following the initiation of a new construction programme. (i.e. a total of 12GW)

When this capacity is added to the industrial CHP generation, the total ‘MUST RUN’ generation (i.e. generators required for industrial process and inflexible nuclear generation) could reach 13GW by 2020. At times when the wind turbines are generating at or near maximum output, the new total capacity (i.e. wind power plus Must Run plant) will be approximately 36.5GW, (line bb’ Fig 3.49).

This capacity will exceed the summer minimum demand for long periods and even exceed winter minimum demand requirements for a significant number of days.
Chapter 3 Impact on CCGT Power Plants

Fig. 3.50 The demand pattern England & Wales maximum contribution, Source: National Grid Company (demand profile) Seven Year Statement [57]

\[
\text{Nuclear + CHP + Wind} = 48.5 \text{ GW}
\]

Fig. 3.50 indicates the extent of the problem when there could be a mismatch between demand and the excess output from the wind sector.

Fig. 3.51 illustrates multiple daily patterns and the interaction of a typical wind profile during a summer period. The difference between a weekday and a weekend demand will cause further issues, as any spilled wind power during this time will not require CCGT plant as backup generation. During such periods the excess capacity will be switched off causing the consequences of excess fuel demand and CO₂ emissions identified earlier upon restarting.
The excess wind power could be

A) stored (in pumped storage facilities)
B) exported to third parties using interconnectors between the UK and the continent (as is commonly practised by the Danish industry). Or
C) spilled (by feathering the wind turbine blades).

However, the first two options are limited in UK with some 2GW of pumped storage currently used to help balance customer demand and one electrical inter-connector with France where excess supplies of nuclear power are exported to third countries. The option C would waste the available wind turbine capacity, result in lost revenue for the wind generators and fail to deliver the annual target CO₂ reduction.

There are five further consequences as the CCGT plants attempt to balance the system:

1) The number of start/stop requirements placed on the CCGT balancing plant would increase.
2) The CO₂ and NOx emissions will increase, in line with actual number of start/stops as determined by the results obtained above.
3) As the number of starts plays an important role in determining the maintenance periods, the cost of maintenance will rise accordingly.
4) The number of units of electricity generated by the CCGT plants will fall significantly compared with scenario 1. This will increase costs of the fixed
overheads on exported power. As a result the cost of generation will increase which in turn will impact upon the viability of the plant.

5) The CCGT plant revenue stream will fall as the annual power output falls, the risks of potential interest payment default will increase and as a consequence, the cost of capital will increase to match the perceived risk involved.

All these issues would only be solved by an increase in the unit price of the balancing power exported from the plant.

During the summer period (April to September) the average minimum power demand is approximately 20GW. If the ‘Must Run’ plant is fully operational at 13GW, the wind power contribution cannot exceed 7GW (i.e. 30% of the installed capacity). It would only require 12 CCGT plants of 800MW, operating with a nominal output of 600MW, to balance the wind energy input. Hence 18 plants would be shut down at night and required to restart each day.

Likewise during the winter period when the minimum demand is nominally 24GW, approximately 11GW of wind power would be required. The balancing power would be provided by 18 CCGT plants, thus leaving 12 plants to shut down each night.

During the weekend periods the maximum and minimum demand are approximately 10 GW and 6GW lower respectively, which would cause some plants to be out of operations for 45 to 55 hours. This would require the cold start routine to be applied resulting in higher fuel demand and causing higher emissions. At least 10 plants would be involved for some 50 weekends per year.

The result of these observations would indicate that some 3000 to 4000 extra hot starts and 500 cold starts would be required caused by the need to balance the wind turbine volatility.

Using the data obtained from Plant C during the test reported in sections 3.6 and 3.7 above, the extra fuel used and the extra CO₂ emitted during the start / stop operations has been estimated. The costs involved have also been estimated using the nominal prices of 40 p / therm for gas and £20 / tonne for the CO₂ emitted.
Chapter 3 Impact on CCGT Power Plants

The consequences for increased fuel used, CO₂ emitted and the nominal extra cost involved is summarised in table 3.15.

Table 3.15 The consequences of Balancing power and Start /Stop requirements (Appendix 2 Consolidated Analysis Sheet 2)

<table>
<thead>
<tr>
<th>Operation</th>
<th>Extra Fuel therms/start</th>
<th>Extra CO₂ Emitted MT/Start</th>
<th>Fuel Cost £/Start</th>
<th>CO₂ Cost £/Start</th>
<th>Total Cost Above Start £/Start</th>
<th>Total Start costs £/m/year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold start</td>
<td>32564.4</td>
<td>360.17</td>
<td>13026</td>
<td>7203</td>
<td>20229</td>
<td>121.4</td>
</tr>
<tr>
<td>Hot Start</td>
<td>28868</td>
<td>151</td>
<td>11547</td>
<td>3024</td>
<td>14572</td>
<td>87.4</td>
</tr>
<tr>
<td>Combined Annual Impact</td>
<td>209,820,652</td>
<td>2,161,664</td>
<td></td>
<td></td>
<td></td>
<td>208.8</td>
</tr>
</tbody>
</table>

The impact of the start / stop regime upon the CCGT plants caused by the variability of wind energy (designed to deliver 15% of the UK electricity by 2020) will be:

1) £200m / year extra cost of fuel
2) 2m tonnes of extra CO₂ emitted per year
3) 200m therms of extra natural gas consumed per year.

The wind power will often be available in excess of the UK demand. The UK target of a 15% reduction in CO₂ emissions from the wind sector will not be achieved.

3.18 Maintenance and Operations Costs

The principal cost of maintaining a CCGT plant is centred upon the gas turbines. In continuous operational mode they are subject to a number of items, which degrade with operational time, such as rupture, creep deflection, high cycle fatigue, corrosion, oxidation, erosion and damage by foreign objects. In the balancing mode one further issue is important, that of thermal mechanical fatigue.
Two different methods of estimating the maintenance schedules necessary to ensure the trouble free operation have been developed, one based upon ‘Equivalent Operating Hours’ and one based upon ‘Independent Counts of starts and hours’. The life of various gas turbine components sets the dimensions of the design rectangle (Fig 3.52), which is placed well inside the failure region.

![Operating diagram for inspection & routine maintenance](image-url)

Fig 3.52 The operating diagram for inspection & routine maintenance [59]
The maintenance interval is set either by an independent count of the number of **Starts and the Hours** of operation (S&H) or by adding a number of hours equivalent to the total operational hours for each separate start-up, (the **Equivalent Operating Hours** method (EOH)).

The S&H method counts each factor separately. Fig.3.52 illustrates these counts where the number of starts allowed is set at 1200 and the number of operational hours is 24,000, either of which triggers a maintenance routine.

Under **EOH** method each start is converted into an equivalent number of hours and added to the actual hours of operation and plotted on the graph (Fig.3.53). When this line crosses the **EOH** line it triggers the maintenance work.

The actual difference between the two maintenance approaches for a CCGT plant operating on constant output and one continually operating in the balancing mode can be very significant.

To explore this issue, two cases have been considered:
Case 1  the plant operates as a base load generator (i.e. Constant operation at MER)

Case 2  the plant is operated to balance the load generated by wind energy (under the minimum nuclear generation scenario described above).

It is assumed that both plants have an availability of 90%; hence of the potential 8760 hours available per year, the plant can be expected to operate for 7884 hours during the year with a maximum output of 800MW.

Then for the S&H method,

Case 1 The plant will deliver

\[ P_y = \text{Power O/P X Number of operational hours / year} \]
\[ P_y = 800 \times 7884 = 6,300\text{GWh per annum} \]

and require an outage for maintenance every

\[ M_r = \frac{\text{Maintenance interval hrs / Number of operational hrs / year}}{7884} = 3.045 \text{ year intervals} \]

Case 2 The plant will operate for the same time period (i.e. 7884 hours) but produce less power depending upon the load factor achieved by the wind energy available. Using the figures for a typical wind turbine load factors of 25, 28 and 30%, with annual power production of 46.3, 51.9 and 55.6 TWh respectively.

In both cases, the CCGT plant operating times will be the same at 7884 hr/year whilst operating either in ‘Constant mode’ or when in ‘Modulating mode’. When the CCGT plants are providing the balancing service they will produce a smaller annual output as the wind turbine load factor increases. Hence when the CCGT annual output would be
Chapter 3 Impact on CCGT Power Plants

CCGT annual output = Total Power required - Wind energy output

Wind Load factor %    CCGT Annual Output TWh
25%.......................... 139.2TWh
28%.......................... 133.4TWh
30%.......................... 129.7TWh

Under the S&H method, the maintenance intervals will be identical as long as the number of starts per year for any individual CCGT plant does not exceed 400. However, the cost of maintenance will be approximately 33%, 38.5% and 42% more expensive, when allocated as a price per unit of electricity generated.

The EOH method of calculating the required maintenance schedule subtracts the equivalent 20 hours from the potential total operational hours for each conventional start up of the gas turbines. When in the balancing mode to support the variable input from wind turbines, each CCGT plant was estimated to require some 165 starts more per year than the constant operation units. This number of starts adds the equivalent of 3300 hours per year to the actual operating hours of 7884 hours making a total of 11,184 hours each year.

Under the EOH method of setting maintenance intervals, the operational period is reduced to 2.15 years, which represents a loss of 0.89 years, a reduction of 29% compared with the S&H method.

'Counts of Hours and Starts' calculation

The cost of maintaining two gas turbines and related plant at the end of each scheduled operational period for an 800 MW CCGT plant is approximately £14m. (source: Plant C)

In the continuous operational mode over a one-year period an 800MW plant would have supplied

\[
\text{Power Output} = \text{Annual Hours of operation} \times \text{Full Load Output} \\
= 7884 \times 800 / 1,000 \text{GWh/year} \\
= 6,307 \text{GWh/year}
\]

Total Turbine Maintenance cost per year

\[
= \text{Cost of maintenance} / \text{Maintenance Interval}
\]
= 14,000,000 / 3.045 £/year
= £ 4,597,700 / year

Cost per MWh generated

\approx \frac{4,597,700}{63,707,000} = £0.728 / MWh

In Modulating mode balancing wind variability using the Count of S&H method over a period of one year would have supplied:

Wind load factor 30%, hence CCGT plant output 70%

\text{Power output} = 7884 \times 800 \times 0.7 / 1000 \text{ GWh/year} \\
= 4,415 \text{ GWh / year}

Total turbine maintenance cost per year (assuming maintenance interval as above of 3.045 years).

= £4,597,700 / year

Cost of maintenance /MWh generated

= £1.04 / MWh

Similarly when the Wind load factor is 25%

\text{Power output} = 7884 \times 800 \times 0.75 / 1000 \text{ GWh/year} \\
= 4,730 \text{ GWh / year}

Cost of Maintenance / MWh generated

= £ 0.972 / MWh

The Extra Cost of Maintenance due to modulating the output to balance the variability of wind energy input per year for a single 800 MW CCGT plant may be calculated from the difference between the constant case and the modulation cases

\textit{30\% load factor case}

\text{Extra cost / MWh} = (1.041 - 0.728) = £0.313 / MWh

Extra cost of maintenance per year

= 4,415,000 \times 0.313 = £1.388m /year
25% load factor case
Extra Cost of maintenance per year
\[ = 4730000 \times (0.972 - 0.728) \text{ £/year} \]
\[ = \text{£1.155m/year} \]

When these costs are applied to the 33 CCGT plants dedicated to the balancing duties the annual extra cost is

30% Wind Load factor case
Extra Gas turbine maintenance cost........£ 45.1m/year

25% Wind Load factor case
Extra Gas Turbine Maintenance cost........£38.1 m/year

The EOH calculation method
As indicated above the time interval between gas turbine maintenance is 29% shorter than for Counts of Hours and Starts method.

The maintenance cost is shared across the units generated during the 2.15-year period.
Annual cost of maintenance  \[ = \frac{14,000,000}{2.15} = \text{£6.511m} \]

30% Wind Load Factor
Cost of Gas turbine Maintenance \[ = \frac{6150000}{4415000} = \text{£1.474 /MWh} \]

Hence extra cost of maintenance above Constant Operation
\[ = (1.474 - 0.728) = \text{£0.747 /MWh} \]

Annual extra Cost of GT Maintenance
\[ = (0.747 \times 4415000) \]
\[ = \text{£3.3m} \]

25% Wind Load factor
Cost of Gas Turbine Maintenance \[ = \frac{6150000}{4730} = \text{£1.30 /MWh} \]
Hence the extra cost of maintenance above Constant Operation
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Annual extra cost of GT maintenance

\[ = (1.3 - 0.728) = £0.572 \text{ MWh} \]

Again when these costs are applied to the 33 CCGT plants the balancing wind power the annual extra costs are

30% Wind Load Factor .................................. £109 m / year
25% Wind Load factor ................................. £89.3 m / year

It can be seen that both the wind turbine load factors achieved and the method of calculating the annual cost of Gas Turbine maintenance are important factors in arriving at a true cost of annual maintenance. The final numbers vary between £38m (for the S&H method) and £109m per annum (for the EOH method).

For the purposes of further calculations of the overall effect of power plant modulation due to following wind power variability has been estimated. The average wind turbine load factor of 28% used earlier has been adopted here together with the assumption that 50% of the CCGT plants will follow the ‘Count of Hours and Starts’ method of maintenance scheduling and 50% will use the EOH method.

A 28% load factor gives an annual power production of

\[ = 7884 \times 800 \times 0.72 = 4541 \text{ GWh/year} \]

Cost of GT Maintenance per MWh from 50% of plant using ‘Counts of Hours & Starts method is given by

\[ \text{Cost £/MWh} = \frac{4597700}{4541000} = £1.012 / \text{MWh} \]

Extra cost of GT maintenance / MWh

\[ = 1.012 - 0.728 = £0.285 / \text{MWh} \]

Extra Annual cost (for half the plants) £ / annum

\[ = 4541000 \times 0.285 \times 33 / 2 \]
= £21.35m per year

The costs for the other half of the plants using the EOH method will be given by

\[\text{Cost} = 6150000 \times 4541000 = £1.354 \text{MWh}\]

Extra cost of GT maintenance

\[£ / \text{MWh} = 1.354 - 0.728 = £0.626 / \text{MWh}\]

Extra Annual cost (for half the plants) £ / Annum

\[= 4541000 \times 0.626 \times 33 / 2\]

Hence the extra cost of Maintaining the EOH plants is = £46.9m per year

The Total Annual Cost of GT maintenance in all 33 plants may therefore be obtained by combining these results

The estimated Total Annual extra cost of GT Maintenance £68 m per year

3.18.1 Non Gas Turbine Operations and Maintenance Cost

All the operations and maintenance costs, which are not associated with the gas turbines, may now be defrayed against the number of units generated each year to arrive at comprehensive cost per MWh generated.

Table 3.16 illustrates the annual costs of Operations and Maintenance (O&M) (excluding the GT cost) for an 800MW CCGT plant, (source: Plant C)

Using this data, the cost of operating in the Modulating Mode has been calculated and compared with the optimum case of constant operation.
Table 3.16 O&M budget for an 800MW CCGT plant excluding maintenance cost. Source: Plant C.

The cost per MWh for constant operation of the plant for 7884 hours per year is given by:

\[ \text{Cost per MWh} = \frac{9399000}{7884 \times 800} = £1.49 / \text{MWh} \]

The cost in Modulation Mode when balancing wind turbine load factor of 28% will be assuming the annual power production derived above of 4541GWh will be:

\[ \text{Cost per MWh} = \frac{9399000}{4541000} = £2.07 / \text{MWh} \]

Hence the extra cost of operating in Modulation Mode over one year is:

\[ \text{Extra annual cost} = (2.07 - 1.49) \times 4541000 \]
\[ = £2.634 \text{ m} / \text{year} \]

When this applied to the 33 CCGT plants the annual extra cost of balancing wind power over one year is £87M.
3.18.2 Capital Funding & Variable Power Generation

The capital needed to fund the construction, operation and maintenance of a modern CCGT plant is most likely to be structured with bank loans (senior debt) and equity from the project developers.

The balance between the amount of senior debt and equity depends upon the project risk perceived by funding banks. The ratio of debt to equity typically varies from 80% to 20% for low risk projects and from 60% to 40% when the banks have concerns about the marginal nature of the project. The principal analysis focuses on the strength of the earnings during the period of the senior debt, which typically varies between 12 and 20 years.

Early CCGT projects constructed during the 1990s were funded by a debt to equity ratio of 80% to 20% and supported by long term power purchase contracts. Projects were considered low risk, the return on equity was attractive and many power plants were constructed across the country. No coal or nuclear units have been built since the privatisation of the industry following the Electricity Act 1989, as they have been unable to compete with the gas fired units.

During the period from 1990 to date (2005) a number of significant changes have occurred with the methods of payment for power generation. The trading arrangements have changed from the Electricity Pool funding method to the New Electricity Trading Arrangement (NETA) and more recently to the British Electricity Trading arrangement (BETA). When this is added to the new gas trading system where the long term price risks have increased, the problems of securing the necessary capital have become complex. The debt to equity ratio has become less favourable with increased risk being born by the developer. Many recently proposed CCGT projects have either abandoned or suspended for the foreseeable future.

In order to evaluate the cost of capital for an 800MW CCGT power plant, the funding arrangements have assumed a 70% / 30% debt to equity ratio spread over a 20 year funding period.
The total current development cost of a plant similar to Plant C is approximately £600m. (This includes the associated costs of land purchase, connection to the national gas transmission system and the national electricity grid, the station permitting and planning permission together with the fund raising costs and associated legal costs plus potential construction and commissioning delays.

In this case, the funds provided by the senior debt would be £420m requiring an owner’s equity input of £180m. The lending banks set the cost of the senior debt. The perceived project risk and the current market money rates influence the rate of interest charged. The rate to be applied in this case has been selected to be consistent with current charges of 8%, (2006). The rate of return on the equity input has to reward the higher risk taken and equal returns from alternative projects available to the investor. The cost of the equity input has been set at 20%, which could be seen as conservative in the current electricity market in the absence of a government policy on the future capacity of nuclear generated power. (2005/6)

Annual cost of capital

\[
\text{Annual cost of Capital} = \text{Senior debt } \times 0.08 + \text{Equity } \times 0.20
\]

\[
= (420 \times 0.08) + (180 \times 0.20)
\]

\[
= £33.6m + £36m
\]

\[
≈ £70m
\]

The only source of funds to service this debt and pay a dividend to the equity holders is provided by the revenue stream from the sale of electricity and ancillary services which may have been contracted by NCG. This revenue stream varies depending on the market conditions and will be heavily influenced by the input from the growing sources of renewable energy.

Following the methodology adopted for maintenance charges above this cost has been defrayed across all the units generated in one year.
Cost of Capital per unit Generated

**Case 1** Constant operation
Number of units generated per year: 6,300GWh

The annual cost of capital defrayed over the units generated is given by
Cost of Capital per MWh = \( \frac{70,000,000}{6,300,000} \) = \( \frac{11.11}{MWh} \)

**Case 2** Modulation operation (to balance the wind energy input)
Wind turbine load factor assumed: 28%
Power Plant Generation: 72%

Power generated by the CCGT plants per year:

Hence cost of capital defrayed over the MWh generated is given by
Cost of Capital per MWh generated = \( \frac{70000000}{4541000} \) = \( \frac{15.41}{MWh} \)

Hence the extra cost of capital to support the Modulation case is given by
Extra Cost of Capital per MWh = (15.41 - 11.11) = £4.3 / MWh
Extra Cost of Capital per year = (4.3 x 454100) = £19.52m / year

When this cost is applied to the 33 balancing power plants the annual cost of capital is estimated to be
Annual Extra Cost of capital = (33 x 19.52) = 644m / year

**3.18.3 Total Aggregated Extra Cost of Balancing Mode Scenario A**

The total cost of supporting the power plants, which provide the continuing power input as the renewable energy sources vary their input to the system, may be estimated by summing the costs of each extra elemental increase identified above.
Extra Annual Costs:

Plant Maintenance

GTs ..................................... £ 68.00m
General Plant ............................. £ 87.00m
O & M General costs ............... £ 87.00m
CO2 Certificates ...................... £ 88.00m
Fuel Costs ............................. £262.00m
Capital Cost .......................... £644.00m

Total Extra Cost ..................... £ 1,236.00m per annum

The resultant extra cost of electricity per unit generated:

The power generated by 33 (800MW) CCGT plants per year is given by:

\[
\text{Power Output} = 800 \times 7884 \times 0.72 \times 33 \\
= 149,859,072 \text{ MWh/year}
\]

Hence the total extra cost of balancing the input from the wind turbines is given by;

\[
= 1,236,000,000 / 149,859,072 \text{ £/MWh} \\
= £8.247 / \text{MWh}
\]

As this cost is entirely due to the variable nature of the wind energy input and not by the changes in customer demand, it can be argued that the full cost should be added to the cost of this input source.

In this example the nominal annual power generated by the wind turbines is equivalent to 28% of the installed capacity (assuming a 90% availability of the turbines) is given by;

\[
= 800 \times 7884 \times 0.28 \times 33 \\
= 58,278,528 \text{ MWh / year}
\]

When the extra cost of operating the CCGT power plants is set against the power delivered by the wind turbines, the extra cost per MWh is given by:
\[ = 1,235,000,000 \div 58,278,528 \ \text{£/MWh} \]

\[ = \text{£21.20 /MWh} \]

The adjusted wind energy price (Pwe)

\[ \text{Pwe} = \text{the market price of energy} + \text{the ROC} \]

\[ + \text{ Extra cost due to balancing} \]

Where the ROC or renewable energy certificates which are currently priced at £36/MWh as a state subsidy. This subsidy is index linked. See Appendix 2.

Hence extra cost to be added to the wind energy unit price is give by

\[ \text{Pwe} = 40.00 + 36.00 + 21.20 \]

\[ = \text{£9720 /MWh} \]

**Scenario B**

Under this scenario the retired nuclear plants are replaced with similar plant by 2020. As a consequence, the planned wind turbine capacity will present more complex problems of integration.

The potential supply and demand profiles could follow an annual pattern set out in fig.3.54.
2) There will be many more CCGT starts and stops required as the plants are taken off line to balance the wind capacity, hence causing an increase in maintenance requirements.

3) The Gas turbine plants will generate fewer units of electricity to balance the wind input. Whilst the total annual CO₂ emissions will be reduced, the total power produced exported will fall and revenues will fall. If the plants are to remain viable the unit price of power to rise to cover the fixed overheads and the consequential increase in the cost of capital per unit of power exported from the plant.

The financial losses of spilling wind energy will result in falling wind farm incomes and will be directly proportional to the energy spilled.

If there are export opportunities to third countries the income is not likely to match the income generated in the UK market. The market regimes for renewable energy are different and the reward structures have developed in unique patterns. The Danish and North Germany experience when exporting excess wind power does not indicate a profitable outcome [60].

The one potential useful solution to the problem is that of energy storage. Although there is an energy penalty to be paid by storage caused by the losses involved, which amounts to approximately 20%, the potential gains could be important. Such a system would allow excess energy to be supplied when required. If it allowed the renewable sector to provide a secure source of electricity, it could transform and expand the approach of integrating unpredictable and / or variable sources of energy into the network. It would also allow the amount of CCGT balancing power to be reduced with the attendant benefits of reduced capital investments, reduced fuel usage and reduced CO₂ emissions.

3.19 Consequences of the Variable Renewable Energy Generation

The financial impact upon the CCGT plants of excess wind energy output will be disproportionate to the financial loss of spilled or exported energy. The lost opportunity to generate power and the increased number of start / stops involved will increase costs in a
Fig. 3.54 Potential over supply of wind power (2020) if the nuclear capacity is replaced.

Compiled from multiple sources.

It is assumed that the nuclear plant and the CHP capacity will all operate as base load. This implies that no longer will the wind power be absorbed by the system when it is available but utilised only when the UK demand is sufficiently high to absorb it. On occasions when the supply exceeds demand the energy produced can be spilled by feathering the wind turbine blades, stored in some form for future use, or exported to third countries.

Although the potential total wind generation does not exceed the maximum daily demand as illustrated in Graph 3.38, it does exceed the night-time minimum demand, (yellow shaded area). Therefore the balancing power supplied by the CCGT plants will need to be fully operational during the day time period and cut back during the low demand periods.

This leads to three important issues;

1) The total wind power delivered to the system will be reduced by the amount of energy spilled, hence the revenues generated by the turbines will be reduced.
number of different ways. The ‘Risks’ of predicting the revenue stream from a CCGT plant will increase with the uncertainty of the actual power demand and the price of the capital to fund these plants will rise.

1) the maintenance cost will rise due to the increased number of starts.

2) the average cost of Carbon Trading Certificates (per unit of power generated) will rise as the number of power plant starts and stops rise.

3) the total gas demand from the CCGT stations will reduce in total. But as the demand pattern placed upon the CCGT plants becomes more uncertain, it will be necessary to purchase more of the gas from the ‘Day Ahead’ market. This will make annual profitability predictions increasingly difficult.

4) the lost revenue (and therefore profit) will impact upon the investment return to the equity partners. As their capital input is the expensive element of the funding package, it will require a disproportionate rise in export electricity prices to correct the position.

The actual conditions, which will prevail in 2020, can only be speculation at the present time. The following calculations give an indication of the potential impact upon the return on equity should the price of power remain constant as the output from the CCGT plants falls.

Here the assumption has been made that the return on the senior debt (i.e. the interest paid to the banks) will remain constant and the full impact of lost revenues will fall on the equity partners.

Consider the case of a fall of 5% in output power.

Number of units generated would fall from 45410 GWh to 43410 GWh. The cost of capital per MWh generated would rise from £15.41/MWh to £16.23/MWh or an annual reduction in return on equity of £0.816/MWh which represents a reduction £35m annually. The power plant can therefore only survive financially with an equivalent price increase. A greater fall in annual power output would cause a proportionate decrease in revenue and even greater capital funding problems. Hence making good the consequences of variable
renewable energy power sources will cause inevitable price increases in the cost of power from fossil fuel stations.

3.20 Chapter Summary

The electricity supply industry, has always required generating capacity, which provides power to balance variable consumer demand. This capacity has attracted higher unit prices to compensate for the variable nature of the demand and the extra costs incurred.

The unpredictable and variable nature of the power supplied by those renewable sources energy readily available in the UK will require backup from reliable sources of generation, which will need to be rewarded for this service.

When providing this service the backup plant will not be operating at its maximum efficiency and will incur,

(a) the use of extra fuel,
(b) higher maintenance costs,
(c) higher operational and fixed over heads,
(d) higher cost of capital
(e) higher rates of CO₂ and NOx emissions
(f) higher carbon trading costs per unit of power exported

In Chapter 3 the characteristics of a modern CCGT were examined as it was operated at different power output profiles. It was found that there were measurable consequences as the plant departed from optimum performance, namely:

1. The fuel used increased per unit of power exported.
2. The life of the gas turbines between maintenance cycles decreased
3. The operations and maintenance costs increased per unit of power exported
4. The Capital costs increased per unit of power exported increased
5. The environmental pollution from CO₂ and NOX increased per unit of power exported.
A conservative value of these extra cost and emissions has been made, using the most fossil fuel efficient plants available at the present time.

Where the necessity to vary the output of the CCGT plant can be attributed to the variability of the renewable energy source (e.g. wind power) the extra costs involved in absorbing that power should be directly charged to the source of renewable power. There needs to be true understanding of the real cost of delivering group 3 renewable energy sources.

This analysis was compiled assuming that the retiring nuclear plants will not be replaced. If this lost capacity is rebuilt and the wind energy is still required to deliver 15% of the power demand the costs will be greater than reported above.

As some of the existing fossil fuelled power generation equipment is retired from service it will be come increasingly difficult to fund capital investment for replacement plant. The developers will face increasing uncertainty of their revenue streams as the renewable sources of energy contribute a larger share of the total power demand.

Payments will be required to be made to the fossil fuelled plants to recognise 'the availability to the immediate supply of electricity' they will be providing. Without such payments the risks of financial failure will deter capital funding necessary to deliver new generating capacity.

The integration of variable and unpredictable sources of renewable energy into the electricity supply system together with the optimisation of CCGT plant utilisation is an important challenge.

A new radical approach is required if renewable energy is to play a major role in providing a substantial proportion of the future energy needs.

If energy could be stored in sufficient quantities with acceptable losses storage could provide a solution.
Chapter 4
Energy Storage and Renewable Energy

4.1 Introduction

Chapter 2 indicated the volatility of group 2 and group 3 renewable sources of energy and chapter 3 identified some of the problems that this volatility will bring to the system including environmental and cost consequences. If renewable energy is to make an increasingly significant contribution towards the proposed government target of 60% by the year 2050, it will be necessary to capture any excess power generated so it may be stored and returned to the system when required.

The options available for solving this problem are:

(1) expand the use of existing methods of energy storage
(2) seek new technical solutions for retaining the energy in a form whereby it can be easily produced as electrical power for the system ‘On Demand’ (i.e. supplied when the renewable sources fail to meet the required output).

The storage methods currently available come in several different forms. All have their limitations. If these methods are to be effective they have to be carefully matched to the specific duty such as bulk storage at one level and small-scale units (computer standby) at the other. Their physical position in the transmission system and the distribution networks can also play an important role in the selection of the storage method, which may be employed.

If the storage of energy is to be used to best advantage it is necessary to evaluate the potential of each energy storage technology. In this chapter the specific advantages and disadvantages of each technology option are explored to determine whether it may be employed to match variable demand with variable power generation and hence it may be possible to improve the operating efficiency of fossil fuel plants together with accommodating high volumes of power input from renewable energy sources.
4.2 A Review of Mechanical / Hydraulic Energy Storage Technology

A number of solutions have been developed to equalise the demand upon the generating and transmission systems. By storing energy from electricity generated at night and releasing it during the peak periods of demand during the day more efficient use of both the generators and the transmission network is possible.

4.3 Pumped Storage

Pumped storage is the principal method to capture energy used in the UK electricity network. It is located in mountainous areas as it uses high level reservoirs to store water before it is released to flow through water turbines at a lower level. The energy is stored by pumping water to the high level during the night time period when the power demand on the system is low and returning it to the low level reservoir via turbines (which directly drive alternators) during periods of peak demand the following day.

The plant at Dinorwig in North Wales Fig 4.1 is a good example of this technique. It is one of two large schemes, which together can store 10GWh over night ready to deliver it the following day (a technique known as ‘Load Shifting’). The Dinorwig plant [61] has been operating since 1984 and can be called into service to help meet the peak load demands.

Pumped storage can also provide many of the ancillary services required by the grid system operator. If the turbines are spinning—in air when required to supply power it takes just seconds to reach full load generation. However, their reserve capacity can only be used once during the 24-hour cycle. When the water in the high level reservoir has been exhausted, the plant is non-operational until it is recharged the following night.
The Dinorwig plant can deliver 1320 MW within 12 seconds of any instructions being issued and can supply the full range of ancillary services (including 'Black Start') to the grid system from six 330 MVA generators. There is sufficient capacity in the high level reservoir to supply the full electrical output for a period of 5 hours. However, it takes 7 hours to recharge the high level reservoir. Using the generators as synchronous motors supplied from the grid system, the reservoirs are refilled by returning the water from the base reservoir to the high level basin.

Unfortunately, the plants are capital intensive, remote from the major centres of load and involve extensive civil engineering work. (The complete installation at Dinorwig required the excavation of more than 12 million tonnes of rock). Each plant requires to be connected to high voltage overhead line grid at 275 kV or 400 kV. This involves long lines of towers and cables through often picturesque countryside. The overall impact is now regarded as environmentally unattractive. It is therefore doubtful if any further pumped storage units will be constructed in the foreseeable future.
4.4 Mechanical Devices

In this method of storage a flywheel stores energy in a spinning mass. The development of the modern flywheel has been sufficient for it to provide a source of stored energy for applications such as un-interruptible power supplies for essential equipment and load levelling for distribution companies [62].

The development of solid state devices (inverters and rectifiers) enables a generator driven by the spinning flywheel to produce power down to 25% of its maximum operational speed. Fig.4.2 illustrates the system. As the speed of the flywheel slows during the power output stage the frequency of the supply changes. In order to match the power output to the frequency of the supply system, it is necessary to rectify the AC output from the generator into DC current and then inverted it back to the correct grid frequency.

Using modern composite materials with high material strength, running with speeds of 100,000 rpm and tip speeds of 1,000 m/s using magnetic bearings and operating in a partial vacuum, the latest devices can deliver up to 100 kW for 10 to 25 seconds [63]. This is sufficient for some very special Ultimate Power Source (UPS) and strategic military applications but it is an expensive source of stored energy. A typical flywheel storage device looses approximately 1% of the stored energy per hour.

The flywheel storage technology is unlikely to provide an answer to the integration of renewable energy where large amounts of power will be required to be stored over night and during times of high wind speeds.
The high-speed flywheel has a high turn round efficiency, low maintenance costs and little noise associated with it. A number of flywheel storage devices are available commercially [65], two examples are illustrated in Fig 4.3. There are safety issues with this technology with the high speed of the rotating mass. Most modern units use magnetic bearings and the composite materials which are expensive.

Flywheels find their principle applications where short term power inputs are required. They can bridge the power supply gap which occurs where a fossil fuelled standby generator takes approximately 10 seconds to come on-line following main a power supply failure.

4.5 Electrical Storage Batteries

Development in this sector has been very successful during with the emergence of a number of new battery technologies. Electrochemical compounds store the energy.
Charging these units with electricity stores the power in chemical form, which is reversed when the power is required.

4.5.1 The Lead Acid battery

The classic lead-acid battery has been used to store and return power for many years. It has been further developed to handle large amounts of energy, with units now capable of storing up to 80MWh [62]. The power can be returned to the network over a 2-hour period. These devices are being used to store energy generated by solar (PV) cells and by some remote wind turbines with no connection to the electricity grid. There is a limited life predicted of approximately 5 years for the new Valve Regulated Lead Acid (VRLA) batteries and a turn-round efficiency of 78%. The life cycle of the lead acid battery can perform up to 1500 cycles when subjected to a shallow discharge (100% to 90%) but this is reduced to 500 cycles when the battery is subjected to a routine of charge and full discharge each cycle.

4.5.2 Advanced Batteries

The new group of advanced technologies include Lithium ion, Nickel / Cadmium, Sodium / nickel chloride and Sodium-Sulphur batteries. These devices are in the development stage with the expectation of improved life cycles of up to 10 years. ‘Turn-Round’ efficiencies of 80 to 90% are being suggested with projected lower capital and operating costs [66]. A summary of the performance of these batteries is shown in Table 4.1

If the development objectives are realised, they could provide a distributed energy storage system spread throughout a complete transmission and distribution system, with the proviso that the environmental impact of both operation and final disposal at the end of their working life are acceptable.
Table 4.1 Performance Characteristics of battery systems

<table>
<thead>
<tr>
<th>Battery Type</th>
<th>Lead acid</th>
<th>Nickel Cadmium</th>
<th>Sodium sulphur</th>
<th>Lithium ion</th>
<th>Sodium nickel Chloride</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demonstrated Upper Power limit</td>
<td>Multiple tens of MW</td>
<td>Tens of MW</td>
<td>MW scale</td>
<td>Tens of kW</td>
<td>Tens / low Hundreds of kW</td>
</tr>
<tr>
<td>Specific energy (Wh/kg)</td>
<td>35 to 50</td>
<td>75</td>
<td>150 to 240</td>
<td>150 to 200</td>
<td>125</td>
</tr>
<tr>
<td>Specific power (W/kg)</td>
<td>75 to 300</td>
<td>150 to 300</td>
<td>90 to 230</td>
<td>200 to 315</td>
<td>130 to 160</td>
</tr>
<tr>
<td>Cycle life (cycles)</td>
<td>500 to 1500</td>
<td>2500</td>
<td>2500</td>
<td>100 to 10000+</td>
<td>2500+</td>
</tr>
<tr>
<td>Charge/Discharge Efficiency</td>
<td>~80</td>
<td>~70</td>
<td>Up to 90</td>
<td>~95</td>
<td>~90</td>
</tr>
<tr>
<td>Self Discharge</td>
<td>2 to 5% per month</td>
<td>5 to 20% per month</td>
<td>1% per month</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Although there is no self-discharge reaction, there is a parasitic loss associated with maintaining the battery temperature. Source DTI Report [65]

More advanced electrochemical batteries are under development. Their principal application is predicted to be in the electric car, but should they prove economic and their storage capacity be successfully increased from the current level of 250kw there may well be a number of applications in the power supply industry.

4.5.3 Flow Batteries

The flow battery works upon an old principle developed during the latter part of the 19th century and allowed to remain dormant until the 1980s. It generates power by bringing two electrolytes together in a tank separated by an ion sensitive membrane, where chemical energy is converted to electrical energy. A proton exchange occurs across the membrane as one electrolyte is oxidised and the second is electrochemically reduced. The two electrolytes are contained in plastic lined tanks separate from the reaction cell and pumped into it. As this is a reversible reaction the process can be used to store energy as it is charged and then called upon to deliver the energy when required. As this is a direct
current process it requires an AC to DC conversion during charging and a DC to AC conversion during regeneration. The process is shown in Fig. 4.4.

The efficiency of the flow battery is approximately 65 to 80% with a life of between 2,000 to 12,000 cycles depending on the electrolytes employed and a relatively low energy density.

The performance of three different electrolyte combinations (Vanadium Redox, Zinc Bromide and Polysulphide Bromide) is summarised in Table 4.2.
Table 4.2 Performance Characteristics of Redox Flow Cell Battery Systems Source: Department of Trade and Industry Report [65]

<table>
<thead>
<tr>
<th></th>
<th>Vanadium</th>
<th>Zinc bromide</th>
<th>Regenesys #</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size range (MWh)</td>
<td>0.5 to 6.0</td>
<td>0.05 to 1</td>
<td>Up to 120</td>
</tr>
<tr>
<td>Energy Density (Wh/litre)</td>
<td>16 to 33</td>
<td>Up to 60</td>
<td></td>
</tr>
<tr>
<td>Cycle Efficiency (%)</td>
<td>78 to 80</td>
<td>65 to 75</td>
<td>60 to 75</td>
</tr>
<tr>
<td>Cycle life (cycles)</td>
<td>&gt; 12,000</td>
<td>&gt; 2,000</td>
<td></td>
</tr>
<tr>
<td>Unit design lifetime (years)</td>
<td>5 to 10</td>
<td>5 to 10</td>
<td>15</td>
</tr>
</tbody>
</table>

# Note: Regenesys is the trademark of the Polysulphide bromide flow cell.

4.5.4 Capacitors

The original storage capacitors were developed to improve the quality of the power supplies for small electrical and electronic equipment. Using electrolyte to separate the electrodes they could deliver very small amounts of power nominally 7 to 10 W [66]. Capacitors have been in use in industrial applications to correct the system power factor, where they can be economically justified by reducing the system charges for low power factor penalties built into the supply company tariffs.

4.5.5 Superconducting Magnetic Energy storage (SMES)

This system requires super-conducting material in the form of a coil, which is kept at a very low temperature in a bath of liquid helium in a cryostat to achieve the minimum electrical resistance. It is vacuum insulated and any helium which boils off is passed through the refrigeration plant and then returned to the superconducting coils which are held at a temperature of 50 to 75 K. (Fig 4.5).

The SMES system could be capable of providing a range of energy storage duties including correcting transient disturbances, reactive power demand and bulk energy storage for load shifting. The losses are reputed to be approximately 0.1%/hour, which equates to a turn round efficiency of 97 to 98% of each 24 hour storage period.

The environmental concerns are focused upon the high magnetic fields created. There is no direct evidence of magnetic fields causing identifiable health problems, however, many
studies have been conducted to investigate possible links with childhood leukaemia caused by the high magnetic fields developed around very high voltage transmission lines.

It remains to be seen if the capital cost and the operational costs of SMES devices prove competitive with other forms of energy storage.

![Diagram of Super Conducting Magnetic Store](image)

**Fig. 4.5 The Super Conducting Magnetic Store.**

### 4.6 Hybrid Storage Devices

#### 4.6.1 Compressed Air Energy Storage (CAES)

The compressibility of air to store energy has been employed for a very long time. The energy may be returned to the system either by using the compressed air to drive a turbine or by feeding it to the combustion section of a combined cycle plant. The idea of feeding a gas turbine with compressed air instead of using an integral compressor / motor / generator set was proposed by Stal-Laval in the late 1940s [62]. Two power plants have been built with underground caverns to store the high-pressure air [62, 67].

Fig 4.6 illustrates the original approach where an underground reservoir was created by forcing air into an aquifer or into a cavern in rock. The air was sealed by hydrostatic
pressure created from a surface reservoir. Later it became possible to create large caverns in salt layers situated up to 800 to 2000m below the surface. The maximum air pressure in the cavern is limited by the capability of the compressor equipment and the geo-static pressure, which may be supported by the cavern walls. The current maximum pressure achieved at the Huntorf plant is 70 bar [66].

The Compressed Air Energy Storage (CAES) system brings the ability to increase power output from a Gas Turbine by reducing the power taken by the internal compressor. The compression of the air before it is stored consumes energy from the grid, if this power is generated by a nuclear or renewable energy source; there is a positive reduction of CO\textsubscript{2} emissions. If, however, a fossil fuel plant provides the power, it can only be regarded as energy storage. As energy is lost during compression and energy input is required during the reheat process (to heat the gas before entering the turbine), there is a net increase in the CO\textsubscript{2} emitted.

![Fig. 4.6 A schematic of the CAES operating principle](image-url)
Fig. 4.7 illustrates the CAES storage and generation cycle. The compressor can deliver air directly to the turbine or it can be diverted to the cavern store. After the air is compressed it is cooled before entering the storage cavern. When the power is required it is expanded back into the turbine via the reheat system. As there is often a significant delay between the compression and start of energy retrieval, the heat has to be provided from a new source, hence the reduction in turn-round efficiency of this process.

The major disadvantage of the CAES system is its requirement for a site with a deep storage cavern. This limits the application of this technique to areas with a suitable geological structure to support the high pressures generated in the air reservoir.

Power plants also have to be constructed on sites where there is a connection to both the national gas transmission network and the electricity high voltage grid.

Whilst the CAES technology offers all the response characteristics and grid system support services of the typical gas fired CCGT plant, the potential contribution is restricted by the above physical requirements.
Chapter 4 Energy Storage and Renewables

4.6.2 Hydrogen and the Fuel Cell

The fuel cell converts chemical energy of a fuel such as hydrogen into electrical power using an oxidant (e.g. oxygen). The only effluent produced is water. The process requires an electrolyser to split the water into the constituent parts. The gases have to be stored either as high-pressure gases in purpose-built containers or in special absorbent materials. When the extra equipment is added to the fuel cell, the efficiency of the overall process (electrolyser, gas store and fuel cell) is somewhat less efficient being in the range 45 to 55%. The gas store requires a significant amount of space. Fig. 4.8 illustrates the fuel cell process for the Hydrogen/Oxygen reaction.

Much research effort has been applied to fuel cell development and storage of hydrogen over many years. These technologies are applicable to transport for powering vehicles as well as providing energy for the electricity supply industry.

Different types of fuel cells are advancing towards commercial viability as the overall efficiencies achieved increases. The gas storage capacity and the size of the available fuel cells are making this form of energy storage more attractive to the point where systems of up to 2MWh are commercially available [66].

Fig. 4.8 The Fuel Cell (here using Hydrogen / Oxygen as inputs)
4.7 Applications for Energy Storage

There are a number of very different reasons driving the requirements for energy storage.

4.7.1 Bulk storage of energy.
These schemes are designed to deliver load shifting by storing energy from times of low customer demand and later to return it to the system at times of high demand. Very large schemes are limited to the high voltage part of the network (e.g. pump storage).

4.7.2 Storage placed adjacent to generating stations.
The CAES application is an example of this design. It enables load shifting to be implemented and allows the power plant to provide grid system ancillary services. It would also provide ‘Black Start’ facilities.

4.7.3 Storage placed at ‘Grid Supply Points’ (GSP)
By providing some form of energy storage at the transmission exit points the ‘Distribution Network Operators’ (DNOs) have a convenient method of reducing the Grid System exit charge levied on the maximum annual demand on that supply point and help to reduce the impact of ‘Triad’ charges. (see Appendix 3).

By placing an energy storage device at a Grid Supply Point (GSP), it would also be in the ideal position to reduce transmission losses by conveying power to these locations when the current in the network is at its lowest point during the 24 hour cycle. Such systems would also be ideal to support the full range of ancillary services for grid system stability including voltage and reactive power correction.

4.7.4 Distribution Network energy storage
Distribution substations have been the most remote points in the system from the major generating plants. Storage placed within these networks could provide most of the services identified above and provide DNOs with local voltage and power factor correction facilities. Load shifting at these points would provide the greatest savings from transmission and distribution losses.
4.7.5 Special Situations
Supply points that have low load factors but high daily peak demands could benefit from storage by removing the need for new capital investment where increased local demand would require expensive reinforcement, (e.g. remote rural communities).

4.7.6 Demand Management
Some large electricity customers provide the grid system operator with demand-side load control. By shedding load at times of high demand, they reduce the overall peak demand. Local storage adjacent to the customer could replace the need for any production interruptions whilst providing grid services and ensuring any 'Triad' charges are as low as possible. It would also provide emergency power to protect expensive process equipment in the event of a grid system failure and for supply safety shut down systems.

4.7.7 Strategically Important Electricity Supplies
A number of electricity customers have need of uninterruptible power supplies, including hospitals, military installations and certain dangerous industrial processes. Diesel generators on 24-hour standby have provided these supplies. They are expensive and require regular maintenance and routine testing and must have a secure fuel oil supply on site. A reliable and simple form of energy storage would provide useful alternative.

4.7.8 Variable Electricity Generation and Energy Storage
As the sources of power from renewable energy have increased the problems of the electricity grid operators to maintain stable conditions have increased as they balance supply and demand. Germany and Denmark have both reported concerns with managing their wind generation portfolios [67].

The European Wind Association (EWA) has also joined the debate and called for significant structural, commercial, and international cross border cooperation to prevent system limitations from placing severe limits upon the future exploitation of the wind power resource [67].

Strategically located energy storage could make a significant contribution to smoothing the power delivered from variable power inputs from intermittent renewable sources. Storage placed at the point of generation could save wastage of power at times of over supply and
extend both the potential maximum capacity that could be installed on the system whilst providing a degree of secure supply and frequency response when required.

Fig.4.9 illustrates the position where storage is applicable in the supply network and identifies the potential energy storage technologies, which could be applied at these points.
Chapter 4 Energy Storage and Renewables

Fig. 4.9 Potential location of Energy Storage in the Transmission and Distribution Systems
4.8 Energy Storage Potential

The potential contribution of each of the energy storage systems described in section 4.2 and 4.3 above are each limited to particular sectors of the supply network.

The details associated with these systems are described in table 4.1. They cover capital and operational costs, capacity, maturity and life estimate of each technology [66]. From this table it is seen that just four of these technologies offer anything approaching attractive solutions. All are expensive compared to the direct generation of electricity from power stations. Pumped storage and CAES technologies are geographically or site specific, and therefore have limited application, fuel cell are not efficient when the electrolysis process is added to the evaluation and large SMES systems have high magnetic radiation and environmental issues yet to be resolved.

Table 4.3 Comparison of Energy Storage Characteristics [66].

<table>
<thead>
<tr>
<th>Storage Method</th>
<th>Fuel Cell</th>
<th>Flywheel (low speed)</th>
<th>Flywheel (high speed)</th>
<th>UTES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital cost (/MWh)</td>
<td>$15,000</td>
<td>$300k</td>
<td>$25k</td>
<td>$550</td>
</tr>
<tr>
<td>Weight /MWh</td>
<td>30kg</td>
<td>7,500kg</td>
<td>3,000kg</td>
<td>300,000kg</td>
</tr>
<tr>
<td>Efficiency</td>
<td>0.45-0.8</td>
<td>0.9</td>
<td>0.93</td>
<td>0.8</td>
</tr>
<tr>
<td>Maintenance /MWh</td>
<td>$10</td>
<td>£3</td>
<td>$4</td>
<td>$15</td>
</tr>
<tr>
<td>Maturity</td>
<td>Commercial</td>
<td>Commercial</td>
<td>New Commercial</td>
<td>Commercial</td>
</tr>
<tr>
<td>Capacity</td>
<td>0.3-2000kWh</td>
<td>50kWh</td>
<td>750kWh</td>
<td>400MWh</td>
</tr>
<tr>
<td>Lifetime</td>
<td>10 years</td>
<td>20 years</td>
<td>20 years</td>
<td>40 years</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Storage Method</th>
<th>Pumped Hydro</th>
<th>CAES</th>
<th>SMES</th>
<th>Super capacitor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital cost (/MWh)</td>
<td>$7,000</td>
<td>$2,000</td>
<td>$10,000</td>
<td>$28m</td>
</tr>
<tr>
<td>Weight /MWh</td>
<td>3,000kg</td>
<td>2.5kg</td>
<td>10kg</td>
<td>10,000kg</td>
</tr>
<tr>
<td>Efficiency</td>
<td>0.8</td>
<td>0.85</td>
<td>0.97</td>
<td>0.95</td>
</tr>
<tr>
<td>Maintenance /MWh</td>
<td>$4</td>
<td>$3</td>
<td>$1</td>
<td>$3</td>
</tr>
<tr>
<td>Maturity</td>
<td>Commercial</td>
<td>Commercial</td>
<td>Commercial</td>
<td>Commercial</td>
</tr>
<tr>
<td>Capacity</td>
<td>22,000MWh</td>
<td>2,400MWh</td>
<td>0.8kWh</td>
<td>0.5kWh</td>
</tr>
<tr>
<td>Lifetime</td>
<td>40 years</td>
<td>30 years</td>
<td>40 years</td>
<td>40 years</td>
</tr>
</tbody>
</table>

4.9 Current Financial Support

Sources of income, which currently applies to stand-alone energy generated from storage, are limited to:

151
(a) the difference between the night-time price for electricity and that paid for power delivered during the daytime peak demand. Fig 4.10 illustrates the average wholesale price of electricity for the 12 month period 1st January to 31st December 2005. It is shown for each of the ‘Half Hour’ trading period (HH period) over 24 hours. The average minimum wholesale price occurred between 02.30 hours and 06.30 hours, whilst the peak demand occurred between 16.30 hours to 20.00 hours. Cost per unit of power varied from a average minimum price of 1.3p/kWh to an average maximum price of 2.55p/kWh.

(b) the prices available for ancillary services from the National Grid services are
   i) Voltage and frequency correction.
   ii) Standby capacity to respond to plant failure on the system
   iii) Black start facilities to enable the system to recover from a catastrophic failure on the network, which shuts down multiple generating stations.

(c) the potential reduction of the Triad charge (for DNOs and customers)(note: A Triad is a charge made by the National Grid Company designed to reflect the cost of the infrastructure they are required to provide. Readings of the three highest maximum power demands which occur on the whole system are used to calculate the transmission charges for the year. It is always calculated after the events and is paid by industrial and commercial customers with maximum demands above 100kW).

4.10 Load Shifting

The spread of the price differential between the low point and the subsequent high point has been computed from the Half Hour Contract price for each of the days reported during 2005 (see Appendix 3). Fig 4.10 illustrates the wide spread of these prices as the demand for power and the supply of power on the system fluctuated. Fig 4.11 shows the actual daily price difference that occurred during 6 days during a typical winter period and Fig.4.12 shows the pattern for 6 days during a summer time low period during August.

The average differential between the highest and lowest daily prices ranged from £24.00/MWh to £55.10/MWh with an average price of £36.53/MWh during the period.
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Average price for each HH period £/MWh (2005)

![Average price for each HH period £/MWh (2005)]

Fig. 4.10 The average price for wholesale electricity for each HH period during 2005, Source [56]

HH prices for 6 days during winter 2005

![HH prices for 6 days during winter 2005]

Fig. 4.11 The HH price pattern for wholesale electricity for the period 05 December to 10th December 2005. Source: Escape Energy Manager (Appendix 3)
Fig. 4.12 The HH price for wholesale electricity for the period 23rd August to 28th August 2005 approximately £33 /MWh. Source: Escape Energy Managers (Appendix 3)

Table 4.4 illustrates the average minimum and the maximum daily price and the price difference, which occurred during 2005 and would have been available to fund the capital and operational costs of an energy storage device. The operational costs would need to include a charge for the purchase of power lost during the storage process.

Table 4.4 The Average daily wholesale prices for 2005 (Appendix 3)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Totals £</td>
<td>8502.32</td>
<td>24,587.91</td>
<td>16085.59</td>
</tr>
</tbody>
</table>

Table 4.5 summaries the net revenue gain by storing energy that could be achieved after making an allowance for the power lost due to the ‘Turn Round’ efficiency. (These calculations include for the purchase cost of power assuming a nominal Turn Round Efficiency of 80% during the storage period at the prevailing night time price). Hence a sum of £10,200 would be available annually to fund and operate a 1MWh storage facility, (See Appendix A3).
Table 4.5 The net annual revenue from 1MWh returned to the network during each 24 Hour period. (Appendix 3)

<table>
<thead>
<tr>
<th>Annual Gross revenue £</th>
<th>One MWh stored each 24 hour period</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Revenue £</strong></td>
<td>10,202.78</td>
</tr>
<tr>
<td>(Inc allowance for 80% turn Round Efficiency)</td>
<td></td>
</tr>
</tbody>
</table>

The daily power demand profile often exhibits two or more peak price periods. It is therefore possible to use the energy storage more than once every 24 hours if the difference between the maximum and the minimum prices is sufficient to fund the storage losses and to show a positive income.

Fig 4.13 illustrates a typical multiple peak period of time where at least two storage periods could have been achieved within a 24 hour period (i.e. periods 1 to 13 and 31 to 34 fig 4.13).

Fig.4.13 A typical two price peak during a 24 hour period with the 20% energy loss allowance (Appendix 3)
If the energy storage is used between 23.00 and 11.00 hours for the first storage period and during 11.00 and 23.00 hours for the second period, the net income can be increased.

Table 4.6 illustrates the annual net income, which would have been generated by 1MWh of stored energy twice a day for 2005, where it can be seen that the revenue increases to £17,300 from £10,200 per annum.

### Table 4.6 The annual net income from two storage periods per 24 hours (Appendix 3)

<table>
<thead>
<tr>
<th>Annual Session</th>
<th>1MWh stored 23.00-11.00hrs</th>
<th>1MWh stored 11.00-23.00hrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Revenue</td>
<td>7850</td>
<td>13416</td>
</tr>
<tr>
<td>Net Revenue</td>
<td>6143</td>
<td>11200</td>
</tr>
<tr>
<td>Post turn round efficiency of 80%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total annual Net Revenue</td>
<td>17343</td>
<td>24616</td>
</tr>
</tbody>
</table>

The potential for further revenue increase may be possible as storage opportunities exist whenever the peak power wholesale price exceeds the cost of the input power (yellow curve in fig.4.13).

### 4.11 Demand-Side Tariffs

The commercial industrial customers who purchase power on the higher voltage supplies (11kV and 33kV) by buying over the half hourly measured metering system can elect to be charged against a number of different tariff structures.

Table 4.7 illustrates one such tariff in operation during 2006 and 2007. When it proves economically attractive such customers can restrict their demand during the peak tariff period between 16.00 and 19.00 hours during the period November to February. However, it would also be legitimate to gain a similar cost advantage if power was stored on site.
during the minimum tariff period at night and restore it to the system during the peak charging period.

Table 4.7 indicates the order of revenue, which could be generated by storing 1MWh each weekday during the high charge period and the potential saving which would come from the difference between the daytime rate and the night time rate during the rest of the year.

Table 4.7 The Annual Margin available for an HH customer (from InterGen UK Ltd. [68], Appendix 3b)

<table>
<thead>
<tr>
<th>Winter Period Tariff (Nov-Feb)</th>
<th>Daily Cost</th>
<th>Daily Saving</th>
<th>Daily Margin</th>
<th>Number of days</th>
<th>Annual Margin</th>
</tr>
</thead>
<tbody>
<tr>
<td>Night rate</td>
<td>£/day</td>
<td>£/day</td>
<td>£/day</td>
<td>Nov-Feb</td>
<td>£/year</td>
</tr>
<tr>
<td>Peak rate</td>
<td>60</td>
<td>145</td>
<td>85</td>
<td>85</td>
<td>7225</td>
</tr>
<tr>
<td>Summer Period Tariff (Mar-Oct)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day rate (Week day)</td>
<td>75</td>
<td>15</td>
<td>178</td>
<td>2670</td>
<td></td>
</tr>
<tr>
<td>Weekend period Tariff</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Night rate</td>
<td>60</td>
<td>61</td>
<td>1</td>
<td>102</td>
<td></td>
</tr>
<tr>
<td>Weekend rate</td>
<td></td>
<td></td>
<td></td>
<td>102</td>
<td></td>
</tr>
<tr>
<td>Total Annual margin</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>9997</td>
</tr>
</tbody>
</table>

The potential saving obtained by a Half Hourly metered customer against the above tariff would be approximately £10,000 per year by storing 1MWh each day.

4.12 Ancillary Services

The contracts for the supply of these services are negotiated between NGC and the companies concerned. Some of the services are at published prices such as frequency
response and some are negotiated as confidential arrangements such as those for 'Black Start' facilities.

Income may be gained by energy storage installations from the ancillary services required to ensure the stable operation of the national transmission system. These contracts are commissioned by the Grid Operator and are structured to ensure the system is operated within the statutory requirements for voltage and frequency limits and upon the long term stability of the whole network. The ability to service such requirements would best be delivered by the bulk energy storage installations.

The transmission system is operated as an active network by the System Operator NGC alone is responsible for the stability of the whole network as the power flows down to the customers. There is no active intervention within the distribution network to control supply frequency. The voltage of the local circuits can be altered by tap changing equipment on the distribution transformers. Electrical demands with low lagging power factor characteristics may be corrected with the use of capacitors in the circuits. There is no attempt to contribute further to the stable operation except to disconnect loads following fault conditions or under instruction from the grid System Operator for load shedding in cases of emergencies. The automatic circuit protection systems have been designed to accommodate power flow in one direction only.

The advent of embedded generation (CHP projects) and renewable energy, (in particular wind turbines,) has begun to change the passive response of the network. Power flows may now flow alone the lines in either direction as variable generation combines with variable customer load requiring new protection systems to be installed.

4.13 The Triads Charging system

The Triad charging system could offer financial rewards to an embedded energy storage device situated within the distribution network.

The National Grid system is funded by three principal charges under the Transmission Network Use of System charging regime (TNUos).
Chapter 4 Energy Storage and Renewables

1) Entry Charges for Generators
Each generating station has to pay a charge to supply its customers when the National Grid carries the power. This ‘Entry Charge’ is levied at the power plant sub-station and is set by the maximum level of power exported during a 12-month period or the capacity that has been reserved on the system. The charge is dependent upon the actual geographic entry into the network. As many power stations are concentrated in the Midlands and the North of England, the charge is higher in these locations to reflect the capital cost and the transmission losses involved in delivering the power to the far extremes of the network.

2) Exit Charges for Electricity Supply Companies
The electricity supply companies pay an Exit Charge when they extract power from a GPS. This charge is also dependent upon the geographic position in the network. The charge is higher for Grid Supply Points (GPS) situated at the locations furthest from centre of gravity of the generating stations to reflect the costs in providing and maintaining the service.

3) Triad Charges for Major Power Users
The final of the three major charges is levied upon the major power customers. The electrical power supplied to these organisations is metered on a Half Hourly basis as indicated above in Table 4.8 and a Triad charge is levied by the NGC to reflect the costs of the transmission. It is determined annually by measuring the customer demand made on the system during three half-hour periods when the national demand is at its peak level during the winter period set as November to February. However, there must be a 10-day period between each peak level in order to remove the impact of an extreme period of cold weather.

The Triad half-hour periods almost always occur during the 17.00 to 18.00 hours of the day. Hence the large customers can reduce their annual charges by reducing their electrical loads during these periods. The Triad charges are determined by nominal distance of the GPS supply point from the centre of gravity of the generation capacity.

During 2005 the Triad charges varied from £10,000/MW for customers in the central areas for England to £20,000 MW for customers located in the South West of the country. Table 4.8.
Energy storage could be used by the HH charged customers to reduce their Triad charges if they were able to supply power stored each night and delivered during potential Triad charging periods.

Such an arrangement would not only reduce their annual electricity charges but it would allow operations to continue unhindered and hence add to the savings involved.

<table>
<thead>
<tr>
<th>Annual Triad Charges 2005</th>
<th>HH Customers</th>
<th>3 Peak Periods</th>
</tr>
</thead>
<tbody>
<tr>
<td>South West region</td>
<td>Central Regions</td>
<td></td>
</tr>
<tr>
<td>£/kW of demand</td>
<td>£/kW of demand</td>
<td></td>
</tr>
<tr>
<td>20,000</td>
<td>10,000</td>
<td></td>
</tr>
</tbody>
</table>

When these savings are added to the savings due to differential HH customer tariff prices indicated in section 4.53 power prices above, the total potential annual revenue savings for 1MWh stored and returned to the system every day for 12 months ranges between £20,000 per annum and £30,000 per annum.

The greatest reward is obtained in the areas remote from the bulk of the generating capacity which is situated in the Midlands. Hence the greater the distance from the ‘Geographic Centre of Power Generation’ the more expensive the tariffs as indicated in Table 4.9 where the South Western Sector is more than twice as expensive.

The calculations assume that the stored power is generated and exported back into the system during all three Triad periods.
Table 4.9 Triad Charges (NGC, [69]) Collated Appendix 3b

<table>
<thead>
<tr>
<th>Combined Annual Savings for HH Customers 2006</th>
<th>South West Grid Exit Point £/MWh Stores</th>
<th>Central Grid Exit Point £/MWh Stores</th>
</tr>
</thead>
<tbody>
<tr>
<td>Triad Charge Savings (1MWh delivered 17.00 – 18.00 hrs)</td>
<td>23000</td>
<td>10000</td>
</tr>
<tr>
<td>Load Shifting (once /24 hours)</td>
<td>9997</td>
<td>9997</td>
</tr>
<tr>
<td>Total Annual Savings</td>
<td>32997</td>
<td>19997</td>
</tr>
</tbody>
</table>

4.14 Future Wind Energy Development

The European Wind Energy Association (EWEA), 2005 [67], has warned that the current physical state of the European electricity grid system and the internal market operation and regulation will place a severe limit upon the future development of wind energy expansion within the European Union.

By contrast the EWEA claim that:

"The already established control methods and backup availability for dealing with variable demand and supply are more than adequate for dealing with the additional variable supply such as wind power at penetration levels of up to around 20% of gross demand" [67]

The EWEA has called for a number of changes to be implemented:

1) Increased cross border transmission, (i.e. more inter-connectors).

2) Improved methods of short-term local weather forecasting of wind speeds. This would change the current perception of wind power to one of a variable input but predictable hence it could be more readily accommodate within the supply side planning routines.
3) A more flexible approach to the technical requirements within the various grid codes and other regulatory issues by the transmission system operators and governments.

4) Cross Border market rules should be changed so that the current authority (European directive RES-E) which enables wind power to receive national priority dispatch is applied across the whole European Union uniformly.

However, no recognition is made in EWEA report about the consequences of accommodating this increased variability. There would be increased CO$_2$ emissions associated with the backup fossil fuel power plants, together with the range of increased costs identified in chapter 3 of this thesis.

If wind energy is to deliver the potential increase it claims should be possible, it would be better implemented using energy storage to solve the political and technical issues rather than attempting to challenge many vested interests. There would be other real benefits. Not least amongst these would be a change in the current perception that wind power is a source of insecure supply and one, which requires special accommodation within the regulatory system if it is to prosper.

4.15 UK Government Energy Storage Strategy

During July 2004 the Department of Trade and Industry held a technical workshop with the express objective of formulating national strategy for energy storage.

The need for additional energy storage to facilitate achieving the declared renewable energy input targets allied requirement to reduce the variable nature of wind energy was one of the important issues.

There was a requirement to understand the technical potential of the available storage techniques, which might be suitable to meet any perceived need.

The main conclusions of the workshop can be summarised as:
(1) There was a desire on the part of the department to establish a defined need for storage before any national technology development support programme could be established.

(2) Demand side management can be regarded as providing a similar service for grid system control as energy storage when dealing with wind energy variability.

(3) The ‘Value Chain’ for funding energy storage operators was considered to be difficult to compete and a barrier to encouraging the development of further energy storage projects.

(4) There was a desire to consider all forms of energy storage.

(5) It was acknowledged that energy storage situated nearer the final customer improved the security of the supply.

4.16 Chapter Summary

Energy Storage technologies and their potential role as a buffer for group 2 and group 3 renewable sources of energy has been examined in Chapter 4. The conclusions are:

1) The Bulk storage of energy is commonly used to provide load shifting and security of supply within the current power supply chain using ‘Pumped Storage’

2) Energy storage has provided emergency back-up supply for important applications where a sudden loss of power could be unacceptable. These Ultimate Power Supplies (USP) are expensive and financially justified by the damage which could result when the national power supply fails

3) Bulk energy storage (pumped storage) is concentrated in remote mountainous locations. It causes environmental problems as it changes the local ecology. This may restrict further developments in the future.

4) The volatility of energy generated from renewable energy sources on the supply side has increased the problems of grid system control. Energy storage could make a significant contribution to maintaining the stability of the total supply chain.

5) The wind energy industry has expressed concern that there could be a severe limitation on the future expansion of the wind energy if the supply networks across
Europe are not modified to accommodate the variability of the output. Any excess output power could be stored and returned to the system when required. It would also provide an element of secure supply to an energy source often criticised for the lack of this characteristic.

(6) As energy storage has developed using new technological solutions, it has become possible to apply these solutions at a number of different points along the supply chain. Distributed storage closer to the final customer offers the potential benefit of increased security of supply.

(7) The income earned by storage projects comes from a number of disparate sources. There is a need to collate these sources to ensure that all the real benefits are suitably recognised.

(8) Whilst energy storage located adjacent to wind turbines could provide a more consistent flow of energy to the network, when this power was injected into the supply chain during peak demand periods, it would be subjected to higher transmission and distribution losses.

(9) The Half Hourly charged customers may be suitable candidates to benefit from energy storage on site during the night at low prices and by using it during the peak day time rates (Load Shifting). These customers might also profit by using storage energy to avoiding Triad charges during the period November to February each year with careful use of the storage regeneration period.
Chapter 5
An Analysis of the Optimum Location for Energy Storage

5.1 Introduction

In this chapter the power losses which occur in the distribution network are analysed and areas where high energy losses occur are identified and their implications are discussed. Using this data and analysis is carried out to identify optimum locations for energy storage. The study attempts to identify the kind of storage that could be economic at various points within the distribution network and analysis is presented to quantify and make comparisons along the whole supply chain from generator to customer.

Energy storage capacity may be located in a number of different positions along the supply chain from the generators through to the final consumer. In England and Wales the power supply chain (shown in Fig.5.1) is the responsibility of two different operators.

(1) The transmission system is owned and operated by the National Grid Company (NGC). It receives power from the generators at high voltage (400kV or 275kV) across the network and transmits it to a number of Grid Supply Points (GSP) across the country.

(2) The Distribution Network Companies (DNOs) receive the power at the GSP and distribute to customers within their regions. It is transformed down to a number of different voltages. (33kV, 11kV, 415V and 230V).

Power is lost during the transmission and distribution processes. The average power lost annually during transmission is declared to be 1.9% (source: NGC seven year plan).

The amount of power lost in the distribution networks varies between the DNOs. The average power lost is declared to be 7.0% (source: Office of Gas and Electricity
Management (Ofgem) Jan 2003) of the power supplied at the GSP. Table 5.1 illustrates the variation of the percent losses across the different DNO regions. These losses vary from 5.4% in the Midlands region to 9.1% in the Manweb region. See Table 5.1. These losses are further illustrated graphically in Figure 5.2.
Table 5.1 Distribution losses for individual DNOs during 2001. Source: Ofgem [70]

<table>
<thead>
<tr>
<th>Distribution company</th>
<th>Area (Sq. km)</th>
<th>Customers (000's)</th>
<th>Circuit length (km)</th>
<th>Prop. of circuits underground</th>
<th>Quantity distributed (GWh)</th>
<th>Prop. LV (%)</th>
<th>Prop. HV (%)</th>
<th>Prop. EHV (%)</th>
<th>Losses 2000/01 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern</td>
<td>20300</td>
<td>3322</td>
<td>89747</td>
<td>61%</td>
<td>34217</td>
<td>74%</td>
<td>24%</td>
<td>2%</td>
<td>7.1%</td>
</tr>
<tr>
<td>East Midlands</td>
<td>16000</td>
<td>2300</td>
<td>67751</td>
<td>64%</td>
<td>28187</td>
<td>60%</td>
<td>37%</td>
<td>3%</td>
<td>6.0%</td>
</tr>
<tr>
<td>London</td>
<td>665</td>
<td>2011</td>
<td>30160</td>
<td>100%</td>
<td>25518</td>
<td>74%</td>
<td>24%</td>
<td>2%</td>
<td>7.3%</td>
</tr>
<tr>
<td>Manweb</td>
<td>12200</td>
<td>1393</td>
<td>45313</td>
<td>53%</td>
<td>16941</td>
<td>60%</td>
<td>26%</td>
<td>14%</td>
<td>9.1%</td>
</tr>
<tr>
<td>Midlands</td>
<td>13300</td>
<td>2260</td>
<td>63802</td>
<td>60%</td>
<td>27216</td>
<td>60%</td>
<td>37%</td>
<td>3%</td>
<td>5.4%</td>
</tr>
<tr>
<td>Northern</td>
<td>14400</td>
<td>1451</td>
<td>43937</td>
<td>61%</td>
<td>16687</td>
<td>63%</td>
<td>22%</td>
<td>15%</td>
<td>6.6%</td>
</tr>
<tr>
<td>Norweb</td>
<td>12500</td>
<td>2140</td>
<td>58772</td>
<td>76%</td>
<td>25216</td>
<td>65%</td>
<td>31%</td>
<td>3%</td>
<td>6.2%</td>
</tr>
<tr>
<td>Seaboard</td>
<td>8200</td>
<td>2126</td>
<td>44773</td>
<td>73%</td>
<td>20745</td>
<td>78%</td>
<td>13%</td>
<td>9%</td>
<td>7.6%</td>
</tr>
<tr>
<td>Southern</td>
<td>16900</td>
<td>2652</td>
<td>71934</td>
<td>61%</td>
<td>32320</td>
<td>67%</td>
<td>26%</td>
<td>7%</td>
<td>7.2%</td>
</tr>
<tr>
<td>South Wales</td>
<td>11800</td>
<td>980</td>
<td>32873</td>
<td>43%</td>
<td>12518</td>
<td>55%</td>
<td>22%</td>
<td>24%</td>
<td>7.2%</td>
</tr>
<tr>
<td>South West</td>
<td>14400</td>
<td>1344</td>
<td>48009</td>
<td>39%</td>
<td>15116</td>
<td>71%</td>
<td>24%</td>
<td>4%</td>
<td>7.9%</td>
</tr>
<tr>
<td>Yorkshire</td>
<td>10700</td>
<td>2088</td>
<td>54268</td>
<td>71%</td>
<td>24074</td>
<td>60%</td>
<td>34%</td>
<td>6%</td>
<td>6.6%</td>
</tr>
<tr>
<td>ScottishPower</td>
<td>22950</td>
<td>1870</td>
<td>64396</td>
<td>62%</td>
<td>22561</td>
<td>69%</td>
<td>22%</td>
<td>10%</td>
<td>7.2%</td>
</tr>
<tr>
<td>Hydro-Electric</td>
<td>54390</td>
<td>640</td>
<td>44113</td>
<td>31%</td>
<td>8407</td>
<td>81%</td>
<td>14%</td>
<td>5%</td>
<td>9.1%</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td><strong>16336</strong></td>
<td><strong>1898</strong></td>
<td><strong>21161</strong></td>
<td><strong>61%</strong></td>
<td><strong>22123</strong></td>
<td><strong>67%</strong></td>
<td><strong>27%</strong></td>
<td><strong>7%</strong></td>
<td><strong>7%</strong></td>
</tr>
</tbody>
</table>

![Losses % by regions](image)

Fig.5.2 Distribution Losses for each region 2001. Source: Data from Table 5.1
5.2 Power Loss

The power losses may be divided into three different categories:

(1) Fixed losses
(2) Variable losses
(3) Commercial and measurement losses

5.2.1 Fixed losses

Fixed losses are due to power needed to energise the network and are independent of the electrical load being transported. This power is dissipated in the cores of transformers due to eddy currents induced in the laminations and to establish the electromagnetic fields. Leakage of power occurs due to capacitance and resistance between the conductors of different phases. As power lines often involve very long distances, the leakage potential increases as the extent of the whole network develops.

Fixed losses account for approximately 25% of the annual technical losses. They are influenced by the number of transformers used in the supply chain and by the quality of the materials used in the manufacture of the transformer. Some of these losses can be reduced by using expensive special steels and amorphous iron cores to reduce eddy current circulation. The selection of material is a simple cost and benefit calculation.

5.2.2 Variable Losses

The major loss occurs due to the heating effect of current flowing in the circuits. The loss is proportional to the square of the current flowing at any specific time and accounts for approximately 75% of the lost energy. Variable losses may be minimised by using high voltages transmission where possible. However, the power has to be transformed down to acceptable levels for industry and domestic customers before it can be used both practically to match the equipment and for safety reasons.

5.2.3 Commercial and Measurement Error Losses

Some electrical power is supplied via un-metered connections, e.g. street lighting. Charges are made on estimates rather than meter readings.
Measurement errors may be introduced into accounting for electricity usage due to the age and type of metering employed. Many domestic premises have old metering technology recording the usage of power. As these units are electromechanical devices (the Ferraris meter) they are subject to wear and have a tendency to record lower values with time. Initially, they are required to operate within an accuracy of between +2.5% to -3.5%.

The final factor in the electricity supply accounting is the illegal abstraction of power from the networks. It has been estimated by the UK Revenue Protection Service to account for approximately £100m per year [70].

The position within the distribution systems is more complex. The losses incurred vary as the network changes to meet the continual changing pattern of local demand for power. New industries are connected to the system, old ones decline and leave the network and population movements shift the domestic power demand.

The variation in the losses on the DNO networks (Table 5.1) for the different areas of the country reflect the differences in the age of the system, the geographical spread of the demand and the policy of the local company where the mix of voltages influences the actual power loss that results. Until recently, both the transmission and distribution costs has been regarded as a direct pass through charge to the consumer and is reflected in the cost of power. Some minor incentives to reduce these losses have been introduce by Ofgem since 2003 but they are restricted to analysis of the average loss, which occurs over a period of time (Ofgem 2004, [71])

This has lead over the year to little focus upon the need for loss reduction in the transmission and distribution systems.

5.2.4 Combined Transmission Loss
The annual power delivered from by generators is approximately 350TWh. The average combined transmission and distribution loss is nominally 9% (31.5TWh during 2004) which is the equivalent of 4.5 modern 800MW gas fired power plants operating at full load 24 hours a day, 7 days a week throughout the year.
5.3 Variable Losses and System Power Demand

As indicated above the heating loss, which occurs in the supply network, varies with the square of the current being transmitted at any specific instant. Hence the losses during times of peak demand are disproportionately greater than those which occur during demand the night when the load is much lower.

Unfortunately, no continuous measurements of power flow are recorded within the domestic distribution networks. As this sector accounts for 30% of the total power demand, it is therefore not possible to report accurate data of the actual losses, which occur as the demand varies.

If a realistic appraisal is to be made of the potential for savings to be effected by placing energy storage within the distribution network, it is essential to deduce the losses incurred beyond the declared average loss data. Only then will it be possible to obtain a measure of the extent of these losses and hence the benefits to be gained by distributing the energy storage facilities in the best locations along the supply chain.

5.4 Estimation of Power losses with Load Variations

The National Grid transmission system and the DNOs distribution systems in the UK are always changing and expanding. Power lines are some times out of use for maintenance or due to faults. The generating power stations are geographically spread over a wide area and switch in and out of operation for a number of reasons including technical and commercial factors. The power demand from customers is volatile over a 24-hour period both in magnitude and location. The weather conditions, the time of day, the season of the year and many other factors produces a complex supply and balancing problem where the power lost during transmission and distribution is not considered the major priority when maintaining a dynamically stable overall system.

However, in order to develop a picture of the potential to be gained from local energy storage, it is essential to estimate the loss profile, which occurs as the demand oscillates between the daily minimum demand and the maximum demand. This required a number of
assumptions to be adopted. Here an analysis is undertaken to develop a model for the loss profile.

Assumptions:

1) It is assumed that both the power factor of the system and the voltages remain constant from the lowest demand through to the maximum demand. Although both the power factor and the voltage may vary due to the customer demand, the characteristics of the connected load at any point in time and upon the connecting circuits, for the sake of simplicity this has been disregarded in the model and both the Voltage and Power factor have been assumed to be constant.

2) The average network configuration remains unaltered (i.e. the impedance, or resistance, inductance and capacitance remain unaltered).

3) It is assumed that the heating losses (i.e. the variable losses) are proportional to the square of the current on the system. In order to simplify the computations, it has been assumed that the current is proportional to the system load (i.e. customer demand).

4) The un-metered losses have been disregarded and the system losses split between the average fixed losses and the variable losses of 25% and 75% respectively.

Here the power demand data taken for the 12-month period of 2004 as recorded in the DTI statistical records and reported in the Dukes tables are used in the analysis. [73]

The electricity supply data is shown in Table 5.2 and the key information is summarised in Table 5.3 and the average hourly power generation and losses are computed assuming 8760 hours per year. The following quantities are calculated using this data.

Let

\[ P = \text{Average Power dispatched per hour (2004)} \text{ GW and} \]
\[ L = \text{Average Power Lost per hour GWh then} \]
\[ P = P_a / H_y \]
\[ L = L_a / H_y \]

Where

\[ P_a = \text{Annual Power output GWh (2004)} \]
\[ H_y = \text{Annual hours} \]
\( L_a = \text{Annual power lost during transmission \\ & Distribution GWh (2004)} \)

Table 5.2 Electricity supply data 2004, Source: DTI Statistics Dukes tables [73]

<table>
<thead>
<tr>
<th>Electricity Supply Data (Dukes Tables DTI 2005)</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply GWh</td>
<td>392979</td>
</tr>
<tr>
<td>Production</td>
<td>2649</td>
</tr>
<tr>
<td>Other sources</td>
<td>9784</td>
</tr>
<tr>
<td>Imports</td>
<td>-2294</td>
</tr>
<tr>
<td>Exports</td>
<td>403118</td>
</tr>
<tr>
<td>Total Supply</td>
<td>401811</td>
</tr>
<tr>
<td>Total demand</td>
<td>340043</td>
</tr>
<tr>
<td>Energy Industry Usage (for electricity production)</td>
<td>3104</td>
</tr>
<tr>
<td>Electricity Generation</td>
<td>17186</td>
</tr>
<tr>
<td>Oil and gas extraction</td>
<td>558</td>
</tr>
<tr>
<td>Petroleum refineries</td>
<td>6177</td>
</tr>
<tr>
<td>Coal &amp; coke</td>
<td>468</td>
</tr>
<tr>
<td>Blast furnaces</td>
<td>3497</td>
</tr>
<tr>
<td>Pumped storage</td>
<td>2037</td>
</tr>
<tr>
<td>Other sources</td>
<td>30728</td>
</tr>
<tr>
<td>Losses</td>
<td>340043</td>
</tr>
</tbody>
</table>

The average load during 2004 was 38.8GWh/h and the average loss 9.04GWh/h. This average annual load occurred at approximately 73% of the maximum demand during 2004. (i.e. Average hourly demand / Annual Maximum demand)

When the power demand varies above and below 38.8 GW, the variable losses change with the square of the current demand while the fixed loss remains constant.

Table 5.3 Key data for 2004 [73]

<table>
<thead>
<tr>
<th>2004 Date</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Consumed GWh/ year</td>
<td>340,043</td>
</tr>
<tr>
<td>Average hourly Power Demand 2004 GWh</td>
<td>38.82</td>
</tr>
<tr>
<td>Power lost 2004 GWh/year</td>
<td>30,728</td>
</tr>
</tbody>
</table>

As it is impractical to arrive at an average current without developing a complete system model, it has been assumed that the variable losses will change in proportion to the square of the load.
Hence it has been assumed that a first order estimate of the changing variable losses can be obtained by using the ratio

\[ L_v = L \times \left( \frac{P^2}{P^2} \right) \]

where

- \( P \) = Instantaneous Load
- \( L_t \) = Total Loss
- \( L_v \) = Variable loss
- \( L_f \) = Fixed loss

Hence Total Loss \( L_t = L_v + L_f \)

Table 5.4 below shows the calculated losses based on above equations.

<table>
<thead>
<tr>
<th>Calculated Averages 2004</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Power lost % of power sent out</td>
<td>9.03 %</td>
</tr>
<tr>
<td>Fixed loss GWh (25% of lost power)</td>
<td>7,682 GWh</td>
</tr>
<tr>
<td>Variable Losses GWh (75% of lost power)</td>
<td>23,046 GWh</td>
</tr>
</tbody>
</table>

Table 5.4 Calculated Average Lost Power 2004

When a full computation is carried out across the maximum annual variations of the power demand from no-load to full load, the extent of the potential total system transmission and distribution losses becomes more apparent (Appendix 4). During the higher power demands it would appear the losses are increasingly costly as illustrated in Figure 5.3.

![Transmission & Distribution Loss GW 2004](image)

Fig. 5.3 Total Transmission & Distribution losses GW of Maximum Demand for year (2004) Appendix 4 Sheet 1
The wide range of distances over which the power is conveyed and the variation in the number of changes in voltage levels, (i.e. the number of transformers in the circuits), implies that the maximum losses are incurred when delivering power to the more remote locations. They must be significantly greater than the declared average levels. In the absence of any data, it is suggested that the pattern of these losses follows a normal statistical distribution and there is therefore a spread either side of the average value.

As an example Fig.5.4 illustrates the potential losses, which would be involved, where the losses are +10% and +20% greater than average levels.

When the case of DNOs with reported average losses above 7% (Table 5.1 & Fig 5.2) are considered, the overall power losses incurred during the daily maximum demand in those regions will be significantly above those indicated in Fig 5.4.

Fig.5.4 Potential Transmission & Distribution Losses plus cases 10% & 20% above the declared average values as the demand varies (Appendix 4 Sheet I)

The load demand during 2004 ranged from a minimum 20GW to a maximum of 53GW. However, the daily variation was significantly smaller, typically varying with a spread from 30GW to 50GW during the winter period and between 24GW and 38GW during the summer.
Using the data indicated in Fig.3.49 (Chapter 3), it can be deduced that the average losses incurred during the daily variations in demand would vary typically between nominally 6% to 15% during the winter and 4% to 10% during the summer. When the variation in losses that occur above the average quoted figures are considered, the losses may translate into markedly higher values with the consequential increase in the spread between maximum and minimum values.

Table 5.5 summarises the estimated losses, which occurred during the maximum and minimum demands during 2004. The losses may be regarded as conservative estimates of the actual losses, incurred at the remote sectors of the transmission and distribution system.

<table>
<thead>
<tr>
<th>Period</th>
<th>Min. demand GW</th>
<th>Max. demand GW</th>
<th>Losses spread average case GW between maximum and minimum demand</th>
<th>Losses Potential spread 15% above average</th>
<th>Losses spread average case % daily MD</th>
<th>Losses Potential spread 15% above average % daily MD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Typical Winter day</td>
<td>30</td>
<td>50</td>
<td>1.73</td>
<td>1.99</td>
<td>3.46</td>
<td>3.98</td>
</tr>
<tr>
<td>Typical Summer day</td>
<td>24</td>
<td>38</td>
<td>1.87</td>
<td>2.15</td>
<td>4.93</td>
<td>5.67</td>
</tr>
</tbody>
</table>

5.5 Energy Storage in the Supply Network

It is possible to place energy storage devices at a number of different locations in the power supply delivery chain. The optimum point depends upon the transmission and distribution losses, which occur between the storage unit and the customer. Secondary factors to be considered include the economic capacity of the energy storage technology,
(which makes it viable), and the availability of the network to handle the power flows at some locations.

![Energy storage points diagram](image)

Fig. 5.5 Potential Energy storage points along the power supply chain.
Chapter 5 Optimum Location for Energy Storage

On the distribution networks, smaller versions of the pumped storage principle are employed particularly where hydroelectric plants already exist (e.g. in the Highlands of Scotland).

Fig. 5.5 illustrates the potential points where energy could be stored along the supply chain. The nominal amount of power, which can be extracted from and returned to the network at particular points, reduces as the operating voltage level falls along the supply chain.

As bulk energy stores are capable of handling large amounts of power (e.g. pumped storage), it is best accommodated at the 400kV and 275kV levels where the switch gear installed on the system is capable of handling and controlling the very large currents that can occur due to system faults.

To-date few energy storage technologies have proved to be economically attractive under the current financial incentives. The few exceptions to this occurs where the loss of supply is unacceptable such as hospital services, some strategic military installations and computer systems. Such applications are often covered by relatively small but expensive devices (the uninterruptible power supply or USP) where the cost is judged against the consequential loss of interruptions to the organisation.

5.6 The Optimum Position for Energy Storage

Three locations have been selected for analysis to determine the advantages and disadvantages associated with energy storage locations.

The first position considered was influenced by the location of the existing pumped storage facilities, i.e. operating in remote locations in the mountains fed from the National Grid at high voltage.

The second location was positioned at an average GSP, i.e. at the interface between the NGC and the local DNO.
The final location was selected to be at the extreme end of the distribution networks furthest from the source of generation adjacent to a customer on the low voltage side of the local DNO substation.

The simplified arrangement is illustrated in Fig.5.6 where S1, S2 and S3 represent the three locations identified above.

The losses in the separate parts of the network are represented by:

- \( D \): Power demand
- \( D_{\text{max}} \): Maximum power demand
- \( D_{\text{min}} \): Minimum power demand
- \( P_1 \): Loss during transmission direct to the GSP at Min D
- \( P_2 \): Loss during distribution from the GSP to the customer at Min D
- \( P_3 \): Loss during transmission direct to the GSP at Max D
- \( P_4 \): Loss during distribution from the GSP to the customer at Max D
- \( P_5 \): Loss during transmission to S1 at Min D
- \( P_6 \): Loss during transmission from S1 to the GSP at Max D
- \( P_7 \): Loss during transmission to the S2 at Min D
- \( P_8 \): Loss during distribution from the GSP to the customer at Max D
- \( P_9 \): Loss during distribution from the GSP to S3 at Min D
- \( P_{10} \): Loss during distribution from S3 to the customer at Max X D

The loss, which occurs due to storage and the regeneration of power, is represented by:

- \( S_1 \): Bulk energy storage on the HV network
- \( S_2 \): Energy storage at the GSP
- \( S_3 \): Energy storage distributed at the DNO substations

Power flow direct to the customer

At Minimum Demand
\[
\text{Loss} = P_1 + P_2
\]
At Maximum Demand
\[
\text{Loss} = P_3 + P_4
\]

Power Flow via storage (i.e. to store during Min D and to the Customer at Max D)
Fig. 5.6 Simplified diagram of storage locations within the power supply chain

For S1

Loss = P5 + S1 + P6 + P4

For S2

Loss = P7 + S2 + P8

For S3

Loss = P1 + S3 + P9 + P10

5.6.1 Calculation of the Loss Factors

The calculations of the loss factors have been completed assuming that the fixed and variable losses are in the ratio 25% / 75% (as the un-metered losses are small they may be disregarded).
Hence the average winter transmission variable losses may be deduced from the average losses and adjusted in the ratio of the average winter minimum demand (Table 5.5) to the average demand.

Hence PI is given by

\[
PI = \text{Fixed grid loss} + \text{Variable grid Loss}
= 0.25 \times \text{Average grid loss} + 0.75 \times \text{Average Variable grid loss} \times (\text{Min D} / \text{AD})^2
\]

where

\begin{align*}
\text{Min D} & = \text{Winter average minimum demand} \\
\text{Max D} & = \text{Winter average maximum demand} \\
\text{AD} & = \text{Grid system average demand (38.8GW for 2004)}
\end{align*}

Likewise P3 is given by

\[
P3 = 0.25 \times \text{Average grid Loss} + 0.75 \times \text{Average Variable grid loss} \times (\text{Max D} / \text{AD})^2
\]

The calculations have been completed for both the winter and summer demand conditions. (See Appendix 4 sheet 1) and the results recorded in Table 5.6a and 5.6b for the transmission system.

The case for the distribution network has been treated in similar manner (see Appendix 4 sheet 1) where the average declared loss across all the DNO networks of 7% has been adopted. (Table 5.7a & 5.7b)

A second set of values has been calculated for the DNOs with the highest declared average loss of 9.1%. These results are listed in Table 5.8a.
Table 5.6a Average losses transmission system winter 2004 (Appendix 4 Sheet 1)

<table>
<thead>
<tr>
<th>Transmission system Losses Winter Average</th>
<th>Average DNO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average declared % Loss</td>
<td>1.9</td>
</tr>
<tr>
<td>Fixed loss % (25% of losses)</td>
<td>0.475</td>
</tr>
<tr>
<td>Variable loss % (75% at average)</td>
<td>1.425</td>
</tr>
<tr>
<td>Variable loss % during winter Min D</td>
<td>0.852</td>
</tr>
<tr>
<td>Variable loss % during winter Max D</td>
<td>2.366</td>
</tr>
<tr>
<td>Total Loss % during winter Min D</td>
<td>1.327</td>
</tr>
<tr>
<td>Total Loss % during winter Max D</td>
<td>2.841</td>
</tr>
</tbody>
</table>

Note: Max D = Maximum Daily Demand
Min D = Minimum Daily Demand

Table 5.6b Average losses for transmission system summer 2004 (Appendix 4 Sheet 1)

<table>
<thead>
<tr>
<th>Transmission system Losses Summer Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variable loss % Summer Min D</td>
</tr>
<tr>
<td>Variable loss % Summer Max D</td>
</tr>
<tr>
<td>Total loss % Summer Min D</td>
</tr>
<tr>
<td>Total loss % Summer Max D</td>
</tr>
</tbody>
</table>

Table 5.7a Average losses distribution system winter 2004 (Appendix 4 Sheet 1)

<table>
<thead>
<tr>
<th>Distribution system Losses Winter Average</th>
<th>Average DNO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average declared % loss</td>
<td>7</td>
</tr>
<tr>
<td>Fixed loss % (25% of losses)</td>
<td>1.75</td>
</tr>
<tr>
<td>Variable Loss % (75% of losses)</td>
<td>5.25</td>
</tr>
<tr>
<td>Variable loss % during winter Min D</td>
<td>3.60</td>
</tr>
<tr>
<td>Variable loss % during winter Max D</td>
<td>8.72</td>
</tr>
<tr>
<td>Total Loss % during winter time Min D</td>
<td>5.35</td>
</tr>
<tr>
<td>Total Loss % during winter time Max D</td>
<td>10.47</td>
</tr>
</tbody>
</table>

Table 5.7b Average losses distribution system summer 2004 (Appendix 4 Sheet 1)

<table>
<thead>
<tr>
<th>Distribution System Losses Summer Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variable loss % Summer Min D</td>
</tr>
<tr>
<td>Variable loss % Summer Max D</td>
</tr>
<tr>
<td>Total Loss % Summer Min D</td>
</tr>
<tr>
<td>Total loss % Summer Max D</td>
</tr>
</tbody>
</table>
Chapter 5 Optimum Location for Energy Storage

Table 5.8a. Losses for the High Loss DNOs (Appendix 4 sheet 1)

<table>
<thead>
<tr>
<th>Average Daily T &amp; D Losses 2004 for daily peak and trough case</th>
<th>Total Losses High Loss DNO (Distribution loss 9.1%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average &amp; High loss DNO cases</td>
<td></td>
</tr>
<tr>
<td>Average Losses during Winter (2004) Min D</td>
<td>8.29</td>
</tr>
<tr>
<td>Average Losses during Summer (2004) Max D</td>
<td>10.66</td>
</tr>
<tr>
<td>Average Losses during Summer (2004) Min D</td>
<td>4.34</td>
</tr>
</tbody>
</table>

Table 5.8b Average losses for the T & D system Winter & Summer. Appendix 4 Sheet 1

<table>
<thead>
<tr>
<th>Average Daily T &amp; D Losses 2004 for daily peak and trough case</th>
<th>Losses Transmission (Average 1.9%)</th>
<th>Losses Distribution Average (7.0%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Losses during Winter (2004) Max D</td>
<td>2.84</td>
<td>10.47</td>
</tr>
<tr>
<td>Average Losses during Winter (2004) Min D</td>
<td>1.33</td>
<td>5.35</td>
</tr>
<tr>
<td>Average Losses during Summer (2004) Max D</td>
<td>1.84</td>
<td>6.79</td>
</tr>
<tr>
<td>Average Losses during Summer (2004) Min D</td>
<td>1.02</td>
<td>2.55</td>
</tr>
</tbody>
</table>

Table 5.8b illustrates the loss position for the average NGC transmission case and the average DNO case.

Likewise as it is known that the average loss within some DNO networks is larger than the 7% average (e.g. Manweb 9.1% table 5.1), the overall loss may be expected to be significantly greater than the general case in. An estimate of the increase is illustrated in Table 5.9.

When this data is added to the transmission losses it is predicted that the average within the high Loss DNO sectors, could be responsible for losses in excess of the 16% during winter periods. Table 5.10 illustrates the position with the average losses across the supply chain.
Table 5.9 Comparison of Losses within an Average DNO and a high loss DNO

<table>
<thead>
<tr>
<th>Distribution system Losses Winter Average</th>
<th>Highest DNO</th>
<th>Average DNO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average declared % loss</td>
<td>9.1</td>
<td>7</td>
</tr>
<tr>
<td>Fixed loss % (25% of losses)</td>
<td>2.28</td>
<td>1.75</td>
</tr>
<tr>
<td>Variable Loss % (75% of losses)</td>
<td>6.83</td>
<td>5.25</td>
</tr>
<tr>
<td>Variable loss % during winter Min D</td>
<td>4.68</td>
<td>3.60</td>
</tr>
<tr>
<td>Variable loss % during winter Max D</td>
<td>11.33</td>
<td>8.72</td>
</tr>
<tr>
<td>Total Loss % during winter time Min D</td>
<td>6.96</td>
<td>5.35</td>
</tr>
<tr>
<td>Total Loss % during winter time Max D</td>
<td>13.61</td>
<td>10.47</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Distribution System Losses Summer Average</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Variable loss % Summer Min D</td>
<td>2.61</td>
<td>2.01</td>
</tr>
<tr>
<td>Variable loss % Summer Max D</td>
<td>6.55</td>
<td>5.04</td>
</tr>
<tr>
<td>Total Loss % Summer Min D</td>
<td>3.32</td>
<td>2.55</td>
</tr>
<tr>
<td>Total loss % Summer Max D</td>
<td>8.82</td>
<td>6.79</td>
</tr>
</tbody>
</table>

Table 5.10 High DNO Loss regions and average overall transmission and distribution losses

<table>
<thead>
<tr>
<th>Average Daily T &amp; D Losses 2004 for daily peak and trough case</th>
<th>Total Losses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average &amp; High loss DNO cases</td>
<td>(Distribution loss 7%)</td>
</tr>
<tr>
<td>Average Losses during Summer (2004) Min D</td>
<td>3.57</td>
</tr>
</tbody>
</table>

As this value is computed to be the average loss once again it is anticipated that there will be some parts of the distribution networks in the high loss regions where the loss could markedly exceed the 16%.

The difference, which occurs between power lost during the daily minimum demand and the maximum demand offers the opportunity of making energy savings through storing energy and regenerating at the appropriate time. However, the savings to be made will be effected by the losses, which occur en-route to the final customer at the time of the maximum demand.
The results in Table 5.11 have been derived from the data obtained above by recording the differences between the daily maximum and minimum losses for both the winter average and summer average conditions. Table 5.11 illustrates these differences for:

1. the average case
2. the situations where the losses may be 15% greater than average.
3. the case for the high loss DNO positions +15%.

Table 5.11 The power loss differences between Maximum and Minimum Demand

(Appendix 4 Sheet1)

<table>
<thead>
<tr>
<th>Transmission &amp; Distribution Difference Losses%</th>
<th>Loss Comparisons</th>
<th>High DNO</th>
<th>High DNO+15%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average, High Loss DNO &amp; High Average High DNO Cases</td>
<td>Difference (Max D-Min D)</td>
<td>Difference (Max D-Min D)</td>
<td>Difference (Max D-Min D)</td>
</tr>
<tr>
<td>Average Difference Summer (2004) (Max D-Min D)</td>
<td>5.05</td>
<td>6.32</td>
<td>7.27</td>
</tr>
</tbody>
</table>

These results are shown graphically in Fig. 5.7 below.
5.6.2 Losses incurred supplying via Energy Stores

The three locations selected for the energy stores illustrated in Fig.5.6 have different supply routes when delivering power to the customer. This therefore involves different transmission and distribution losses in supplying those customers.

In the following analysis it has been assumed that each store is charged with energy during the minimum demand period each day and then released during the system maximum demand the same day. Whilst this may be the case for small storage facilities where the amount of power stored is small compared to the demand, it is not realistic for some facilities. Such installations where significant amounts of power are involved (e.g. large pumped storage units) it takes time to store and release the energy over several hours. In these cases the savings will be proportionately lower than the ideal case as the differential between the losses which occur will be lower than indicated.

Using the equations developed in sections 5.6 and 5.61 above, the losses that occur when power is delivered direct from the generator during maximum demand can be compared with the losses supplied from the various energy store locations. It is assumed that the
power delivered from the energy stores during maximum demand will have been stored during the minimum demand period.

For the purposes of this analysis it has also been assumed that:

1. The energy stored at SI suffers the same losses as P1 on the HV system
2. The energy supplied from SI to the GSP suffers the same loss as P3
3. The energy supplied to S2 suffers the same loss as P1
4. The energy supplied from S2 suffers the same loss as P4
5. The energy supplied to S3 suffers the same loss as P2
6. The energy supplied from S3 is zero (i.e. adjacent to the customer)

The results of the calculations (see Appendix 4 sheet 2) are shown in table 5.12 and graphically shown in Fig.5.8.

The loss due to the turn round efficiency of energy storage has been assumed to be 20% of the energy supplies which equates to the current losses experienced by pumped storage facilities [74]. Where the turn round efficiency is better and a higher turn round efficiency is achieved the overall losses would be reduced.

![Graph](image)

**Fig.5.8** The supply chain sector losses for daily averages summer & winter (Appendix 4 sheet 2)
Table 5.12 Losses along the power supply chain for Maximum & Minimum demand cases summer & winter. (Appendix 4 Sheet 2)

<table>
<thead>
<tr>
<th>Transmission &amp; Distribution Sector Losses</th>
<th>Winter Case</th>
<th>Summer Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>P1</td>
<td>1.33</td>
<td>1.02</td>
</tr>
<tr>
<td>P2</td>
<td>3.60</td>
<td>2.55</td>
</tr>
<tr>
<td>P3</td>
<td>2.84</td>
<td>1.84</td>
</tr>
<tr>
<td>P4</td>
<td>10.47</td>
<td>6.79</td>
</tr>
<tr>
<td>P5</td>
<td>1.33</td>
<td>1.02</td>
</tr>
<tr>
<td>P6</td>
<td>2.84</td>
<td>1.84</td>
</tr>
<tr>
<td>P7</td>
<td>1.33</td>
<td>1.02</td>
</tr>
<tr>
<td>P8</td>
<td>10.47</td>
<td>6.79</td>
</tr>
<tr>
<td>P9</td>
<td>5.35</td>
<td>2.55</td>
</tr>
<tr>
<td>P10</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

When the power travels via an energy store it is necessary to account for the losses within the storage operation.

The total power losses with each circuit are recorded in Table 5.13, where the average system losses via an energy store under the conditions considered can be up to 34% of the energy delivered compared with 13.4% when supplied direct to the customer.

These losses are illustrated in Fig.5.9 where it can be concluded that the closer the energy store is located to the final customer the lower the overall loss that would be experienced. (Store 3 experiences approximately 10% lower loss than that of S1 under average conditions).

Table 5.13 The average loss case (Appendix 4 Sheet 2)

<table>
<thead>
<tr>
<th>Average Loss Case Period</th>
<th>Transmission &amp; Distribution Losses</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>% power Lost (Winter)</td>
</tr>
<tr>
<td>Power Lost Direct Mn D</td>
<td>4.9</td>
</tr>
<tr>
<td>Power Lost Direct Mx D</td>
<td>13.3</td>
</tr>
<tr>
<td>Power Lost via S1</td>
<td>34.6</td>
</tr>
<tr>
<td>Power Lost via S2</td>
<td>31.8</td>
</tr>
<tr>
<td>Power Lost via S3</td>
<td>24.9</td>
</tr>
</tbody>
</table>
Fig 5.9 Supply chain daily average losses during the maximum & minimum demand periods summer & winter (Appendix 4 Sheet 2)

When the case of supply to sectors with a 15% loss factor above average loss is considered the difference between the performance of the different store locations increases. Table 5.14

Table 5.14 T & D Losses 15% above average case winter & summer

<table>
<thead>
<tr>
<th>T &amp; D Power Loss Above average case</th>
<th>Transmission &amp; Distribution Losses 15% above the 15% above the Average Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Via Energy Stores</td>
<td>Winter</td>
</tr>
<tr>
<td>Direct (low demand)</td>
<td>5.67</td>
</tr>
<tr>
<td>Direct (high demand)</td>
<td>15.31</td>
</tr>
<tr>
<td>Via S1</td>
<td>36.83</td>
</tr>
<tr>
<td>Via S2</td>
<td>33.56</td>
</tr>
<tr>
<td>Via S3</td>
<td>25.67</td>
</tr>
</tbody>
</table>

Likewise when the high loss DNO regions are studied and the 15% above average case is included, the loss position between the performances of the stores increases yet again. Table 5.15.
Table 5.15 T & D losses for the High loss DNO cases and plus 15% above the average
(Appendix 4 Sheet 2)

<table>
<thead>
<tr>
<th>T &amp; D Power Losses</th>
<th>15% Above Average case</th>
<th>High DNO case +15% above average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Supply Route</td>
<td>Winter</td>
<td>Summer</td>
</tr>
<tr>
<td>Loss % Direct &amp; via Energy Store</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Direct (low demand)</td>
<td>5.67</td>
<td>4.47</td>
</tr>
<tr>
<td>Direct (high demand)</td>
<td>15.31</td>
<td>10.78</td>
</tr>
<tr>
<td>Via S1</td>
<td>36.83</td>
<td>32.06</td>
</tr>
<tr>
<td>Via S2</td>
<td>33.56</td>
<td>29.76</td>
</tr>
<tr>
<td>Via S3</td>
<td>25.67</td>
<td>24.47</td>
</tr>
</tbody>
</table>

The performance of the energy stores is further analysed by comparing the amount of power that has to be generated at the power plant in order to deliver 1MWh of electricity at the terminals of the ‘Nominal Customer’.

The same cases as those used above have been selected (i.e. power supplied direct at the time of demand and power stored during the previous minimum demand at the three different store locations and delivered during the maximum demand).

Using the data from the above calculations of the losses involved for each case

\[ G_p = \frac{100}{(100 - P_i)} \]

Where

\[ G_p = \text{the power generated to meet the demand} \]

\[ P_i = \% \text{ total power lost during transmission, storage & distribution} \]

The results are recorded in Table 5.16 and illustrated graphically in Fig.5.10 where it can be deduced that, for the four cases considered, the direct route of power supply is the most efficient in power required from the power generator. The best performance amongst the energy stores is provided by the distributed energy store, S3. Whilst the power lost supplying from S3 is between 14 and 18% greater than that when supplying directly from the generator, it is markedly better than either of the other two storage locations. It is interesting to note that, the current use of pumped storage (S1) is subject to a high overall
loss of between 38 to 45% when complete analysis of supplying the final customer is taken into account.

Table 5.16  Power required to deliver 1MWh during the winter peak demands

<table>
<thead>
<tr>
<th>Power required to deliver 1. MWh during the winter during Daily Maximum Demand</th>
<th>Supply Chain Route</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct MWh</td>
</tr>
<tr>
<td>Power MWh (Average Loss case)</td>
<td>1.15</td>
</tr>
<tr>
<td>15% above average Losses</td>
<td>1.18</td>
</tr>
<tr>
<td>High Loss DNO 15% above average losses</td>
<td>1.23</td>
</tr>
</tbody>
</table>

Fig 5.10 A comparison of the power required from the generator to deliver a specific power demand to the customer direct and via energy stores. (Appendix 4 Sheet 2)
5.7 The Geographic Variation of Power Losses

The variation in the declared average losses across the DNO regions illustrated in Table 5.1 show a wide spread from 5.4% at the lowest to 9.1% for the highest losses. There are no data available for the spread of losses, which occur across the transmission system. However, with the concentration of power stations in the centre of the country (Fig. 5.12) it may be reasonably assumed that a similar spread in the range of losses exists for this network as that for the distribution system. The NGC publicised power flow map (Fig. 5.13) would endorse this conclusion. The earlier work in this chapter proposed that a spread of losses on the combined supply chain between 10% and 20% above the average loss might exist on the network.

![Distribution of Average DNO % Losses](image)

Fig. 5.11 the range of declared average losses for the DNO regions, Source: Table 5.1
Chapter 5 Optimum Location for Energy Storage

Fig. 5.12 The NGC transmission system and the location of major generation stations.

Source: NGC
Without an extensive investigation into the true state of the losses, which occur, it will not be possible to draw firm conclusions. However, if the pattern of losses follows a normal distribution curve such as that illustrated in Fig.5.14 it may be anticipated that some parts of the supply chain are subject to very high losses especially during the maximum daily demand period. Hence any part of the system which experienced losses to the right hand side of the line ‘cd’, Fig.5.14 would be an economic target for distributed energy storage.

If this loss exceeds the summation of the energy lost due to the storage process and the loss due to transporting power from the store in the final circuit to the customer during the maximum demand period, then there would be a positive energy balance in favour of the energy storage process.
Fig. 5.14 A Normal Distribution Curve where ‘ab’ represents the average loss and line ‘cd’ the potential sector beyond which distributed storage would achieve a positive energy balance.

5.8 Future Increases in Power Demand

The power demand in the UK has been growing continually and the infrastructure has expanded to meet this demand (Fig. 5.15). Besides the increase in the generating capacity the transmission and distribution systems have also expanded. This has involved the construction of long distances of high voltage (400 & 275kV) lines. Further expansion of these lines and the installation of new overhead lines have become increasingly difficult as the granting of planning permission is being resisted by public opinion. The strategic use of energy storage within the existing distribution network could enable the average load carrying capacity of the current infrastructure to be increased in a number of these cases. This would in part mitigate the need for new lines and help to solve the need for increased capacity. Likewise the careful integration of energy storage into the distribution system could eliminate or postpone the need for major capital investment in the urban and rural low voltage networks.
Fig 5.15 Average Electricity demand 1996 to 2004 (Dukes Tables) and a nominal 1% growth projection to 2010

5.9 Summary of the Chapter

Chapter 5 attempts to quantify the areas of high power losses occurring in sectors of the transmission and distribution system, which are not revealed by the current regulatory regime and the tariff structure.

(1) The analysis was intended to:

(a) Explore the depth and breadth of the real power losses experienced across the transmission and distribution systems and hence to discover the extent of the opportunity to apply energy storage technologies which could improve the current supply chain efficiency.

(b) Seek the best location within the power supply chain for the application of energy storage.

(2) It was revealed that:

(a) No attempts are made to measure the total system losses and local losses, which occur in real time across the transmission and distribution networks.
Hence there is little focus on the reduction of high losses that occur in the more remote sections of the system.

The method of allocating transmission and distribution losses is based upon allocating the average loss as a charge upon every unit of power delivered to the customer without any recognition of where the real losses actually occur.

Without a true recognition of the costs and therefore benefits which might be gained by the most efficient use of energy storage, there is no opportunity to make the maximum impact on transmission and distribution of loss reduction. Further benefits may be gained at the power plant of lower fuel usage, lower emissions and lower capital investment into power generation together with reduced power losses during delivery.

The current use of Pumped Storage, located on the high voltage network situated well away from the centre of the demand in the mountains, causes high overall losses. It is the worst place to store energy.

The optimum location for an energy store is adjacent to the final customer.

The ‘Turn Round’ efficiency and the capital cost of energy storage technology employed are major determining factors of a viable application.

Embedded energy storage units would add to the local potential fault level of local circuits. This would need to be accommodated within the circuit protection design.

Without a ‘True Measurement of the Real Losses’ incurred across the transmission and distribution system coupled with appropriate tariff incentives the opportunities to make energy savings and reduced CO₂ emissions, will be lost.
Chapter 6

The Potential Benefits of Distributed Energy Storage

6.1 Introduction

A number of factors have to be considered when evaluating the costs and benefits of energy storage beside those quantified in Chapter 5 above.

First, the benefits that can be achieved by operating the power plant at the optimum power output.

Second, the costs involved in providing the capital necessary to provide the infrastructure to supply the marginal capacity, e.g. extra generating capacity, new transmission and distribution capacity and fuel supply networks with the associated fuel storage.

Third, the environmental impact of the increased emissions as the power output is varied to match demand and the visual impact of new high voltage overhead power lines to transmit the extra power during peak demand.

Fourth, strategically placed energy storage could help keep the transmission network stable under transient changes. This would remove the necessity of operating some fossil fuel power plants below their optimum conditions.

Fifth, the use of energy storage would improve the acceptability of intermittent renewable energy generation as well as increase the quantity of wind turbine capacity which may be connected to the network. If excess power generated by wind, solar and tidal sources were stored it would improve the integration of these sources of energy as they could then provide more consistent supplies and meet the National Grid Operational Code for ancillary services.
Sixth, the use of energy storage to improve the capability of Nuclear Power plants to respond to variable demand and hence move above the current limit of being constrained to supply the base load demand.

In this chapter the above factors are considered and an analysis is carried out using a number of different power station operating scenarios. These scenarios are based upon observations of actual production profiles to demonstrate the impact upon the plant efficiency, commercial performance and the environmental impact which results when the plants are operated below their optimum design levels.

6.2 Consistent Operation of Generating Stations

The studies of the impact of variable power demands upon gas fired CCGT plants considered in chapter 3 have demonstrated that it leads to higher fuel usage, greater CO₂ emissions, lower productivity per worker, higher maintenance costs and less reliable operation per unit of electricity produced. It can be assumed that similar consequences apply to the other power plants fuelled by coal and oil but with greater releases of CO₂. Hence a system which would allow such plants to operate more continuously at or near the designed optimum operational output may offer significant economic and environmental gains.

The analysis presented in chapter 5 suggests that energy storage facilities should be located adjacent to the final customer in order to minimise transmission and distribution losses when being employed to load shift between periods of the daily maximum and minimum demand. As the six issues raised in the introduction to this chapter offer possible additional benefits in favour of the case for energy storage, an attempt will be made to quantify some of those gains. However, quantifying the economic value of these benefits depends upon many factors. Some of these factors, particularly the price of fuel and interest rates on capital, change significantly over short time scales. The investment in capital intensive ventures such as power plants, transmission systems and energy storage equipment is dependent upon the certainty of future earnings where price stability is a key factor required to attract the necessary funds.

Whilst an economic benefit may be attributed to some of these factors, others are dependent upon changes to the current industry regulations. These include carbon trading, climate
change and fossil fuel levies and interstate transfer of electrical power within Europe, all of which are subject to political influences and may be modified significantly in the short and medium term.

Other factors, such as obtaining the required authority to proceed with a project, (with the necessary planning and environmental consents) may be difficult to negotiate. The consequences of visual impact upon the environment and in the case of high voltage transmission lines the potential health risks of electromagnetic radiation all conspire to activate public opinion. The imposition of a public enquiry into the planning process can add significant expense, time delays and uncertainty of the outcome to a project. Hence there is a real need behind the desire to make better use of existing assets, something which may be achieved with the selective use of energy storage.

6.3 CCGT Operating Efficiency and Supply Chain Losses

In this chapter a set of four simple scenarios is postulated to contrast the performance of a CCGT power station when operating in-conjunction with energy storage. Each case attempts to identify the power produced, fuel used and CO₂ emitted when a CCGT plant is operated under different regimes with and without the availability of energy storage.

Case 1

This scenario contrasts a CCGT plant following two different operational routines and compares the fuel used and CO₂ emitted when supplying power during the evening peak demand.

1a assumes the CCGT plant is operating continuously by storing power local to the customer when it is not required and supplying that power to customers latter during the peak demand period.

1b assumes the CCGT plant is operating continuously and supplying the peak demand by boosting output through the use of the ‘Duct Firing’ option analysed in section 3.5. The generation / storage / supply profiles of each case are illustrated in figures 6.1 a and b.
Cases 2, 3 and 4 consider the consequences of matching the performance of different operational production routines between continuous production and energy storage with that of modulating the power plant output to meet the supply requirements.
Case 2

This scenario is designed to demonstrate the contrast between the CCGT plant operating continuously using energy storage and the same plant modulating the power output to match demand.

2a considers the position of all the variable elements of demand being provided from energy storage while the plant operates continuously at optimum output during the 24 hour cycle. The excess stored power is supplied during the evening peak demand period as shown in figure 6.2a.

2b provides the variable demand from a plant as requested by the system operator, varying the output by +/- 26% except for the times of peak demand during the morning and evening periods when it produces the full output. This is illustrated in figure 6.2b.

The supply profiles are illustrated in figure 6.2a and figure 6.2b. The pattern of storage is shown in figure 6.2c.

Case 3

The third case examines the contrast between a continuously operating power plant with that of a plant starting and stopping each day to supply a constant block of the demand profile between 09.30 – 22.00 hours.

3a assumes that any power not required to meet demand is stored and ultimately delivered when required. In this scenario it is assumed that the stored power is supplied into the network during the peak demand periods.
Fig. 6.2 Case 2 Scenario The supply of variable demand direct and with energy storage.

3b considers the case when the CCGT plant meets the demand by stopping at 22.00 hours each day and restarting via a 'Hot Start' at 06.00 hours ready to deliver full power from approximately 09.00 hours each day. The demand and storage patterns are illustrated in Fig.6.3a and Fig.6.3b. Fig 6.3c illustrates the power flow into and out of the energy.
storage device.

Fig. 6.3 Case 3 Scenario Start/Stop operation compared with energy storage and continuous operation.
Case 4

Finally, case 4 contrasts the position of two different operational scenarios to supply a variable day time demand where the load supplied changes continually within a +/- 26% band.

4a describes the position of a plant operating continuously supplying the variable demand from locally positioned energy storage units. Figure 6.4

4b follows the start/stop programme of case 3b above with the added complication of supplying the variable demand. Figure 6.4
Fig. 6.4. Case 4 Scenario Stop/start and variable output operation compared with continuous operation combined with energy storage.
6.4 Case Analysis

In order to obtain a first order indication of the potential benefits of local energy storage a simple model has been constructed. The analysis is restricted to a 24-hour cycle, which is divided into 5 sessions. Each session is chosen to represent different system power demands. Different transmission and distribution loss factors have been allocated to each session. Table 6.1 illustrates the selected time intervals for each session and the combined transmission and distribution losses presumed to occur during that session. As no definitive information is available, the loss factors have been selected by inspecting the average daily demand profiles. There will be significant skewing of the losses which occur between the winter high demand periods and summer low demand periods, however, without a detailed study of the exact position, it is only possible to adopt average conditions for this initial evaluation.

The customers considered in this study are situated within the low voltage distribution networks (i.e. the 415 volt 3 phase sector). The average losses, which occur during each session, have been projected from the average declared losses on the transmission system and the losses within the DNO distribution networks plus the analysis carried out in chapter 5.

The actual losses incurred supplying domestic customers, who make up more than 30% of the total national demand, may be underestimated. The delivery voltage to these customers, (230 volts), requires there to be more transformers in the supply circuits compared with the industrial and commercial customers who receive supplies at 33kV and 11kV. When this effect is added to the many thousands of kilometres of low voltage cabling delivering the power, the final power loss could be well in excess of the numbers adopted in table 6.1 below.

The model first attempts to derive the power delivered to customers during each session, the fuel used and the CO₂ emitted by a CCGT power station of the type described in chapter 3 when operating at its optimum output throughout the 24-hour period.

The model architecture is illustrated in figure 6.6 and the calculations used are described below.
Table 6.1 Adopted 24-hour delivery pattern of combined transmission and distribution losses in the supply chain to the customer

<table>
<thead>
<tr>
<th>Session times</th>
<th>Allocated Average loss (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>00.00 - 06.30</td>
<td>4.9</td>
</tr>
<tr>
<td>06.30 - 08.30</td>
<td>13.3</td>
</tr>
<tr>
<td>08.30 - 16.30</td>
<td>9.1</td>
</tr>
<tr>
<td>16.30 - 18.30</td>
<td>13.3</td>
</tr>
<tr>
<td>18.30 - 24.00</td>
<td>9.1</td>
</tr>
</tbody>
</table>

The second part of the model describes the financial cost comparisons which result from the technical findings by calculating the cost of fuel, cost of over heads and maintenance and the cost of capital investment as a charge per MWh delivered to the customer:

Let

\[ T_1 = \text{the time period of session 1 (hrs)} \]
\[ P_o = \text{the power plant output when operating under optimum conditions (MW)} \]
\[ P_{slg} = \text{the power generated during session 1 (MWh)} \]
\[ P_{sld} = \text{the power delivered during session 1 (MWh)} \]
\[ L_{sl} = \text{the loss transmission & distribution loss factor during session 1 (%)} \]
\[ F_o = \text{Fuel used to generate 1 MWh at optimum (GJ/MWh)} \]
\[ F_{sl} = \text{Total fuel used during session 1 (GJ/session 1)} \]
\[ F_{slg} = \text{fuel used (per MWh generated) during session 1 (GJ/MWh generated)} \]
\[ F_{sld} = \text{fuel used (per MWh delivered) during session 1 (GJ/MWh delivered)} \]
\[ C_o = \text{CO}_2 \text{ output under optimum condition (MT/MWh)} \]
\[
C_{slg} = \text{CO}_2 \text{ emitted during session I (MT/MWh (ex.generated))}
\]
\[
C_{std} = \text{CO}_2 \text{ emitted during session I (MT/MWh delivered)}
\]

Then power generated session 1

\[
P_{slg} = T_1 \times P_o \quad \text{(MWh)}
\]

Power delivered the customer

\[
P_{std} = P_{slg} \times (100 - L_{sl}) / 100 \quad \text{(MWh)}
\]

The fuel used during session 1

\[
F_{sl} = F_o \times P_{slg} \quad \text{(GJ/session)}
\]

The fuel used during session 1 / MWh delivered

\[
F_{std} = F_{sl} / P_{std} \quad \text{(GJ/MWh delivered)}
\]

The \text{CO}_2 \text{ emitted during session 1}

\[
C_{slg} = C_e \quad \text{(MT/MWh)}
\]

The \text{CO}_2 \text{ emitted during session 1 (per MWh delivered)}

\[
C_{std} = C_e \times P_{slg} / P_{std} \quad \text{(MT/MWh)}
\]

The same calculation routine is applied to the remaining 4 sessions of the 24-hour period.

The results of this analysis are subsequently used to compare the performance of the 4 scenarios described above. (Cases 1 - 4).

Cases 2, 3 and 4 involve the supply of a specific load demand profile. Part ‘b’ of each case analyses the consequences of supplying all power direct to the customer from the power plant. Part ‘a’ makes use of local energy storage facilities to store power whenever it is not required to meet the instantaneous demand which enables the CCGT plant to operate continuously under optimum performance.

Two separate analyses are made following the same calculations described above. The power flows are illustrated in figure 6.5a (the direct flow with no storage) and figure 6.5b where energy store is introduced adjacent to the demand.
Chapter 6 Benefits of Energy Storage

Figure 6.5 a

Fig. 6.5a The power flow without the use of an energy storage facility.

Figure 6.5 b

Fig. 6.5b Power flows direct to the customer and via local storage.

The model architecture for the power flow analysis is illustrated in figure 6.6. The technical model provides the main output parameters for the financial calculations, i.e. power produced, fuel used, CO₂ emitted by the CCGT plant during a 24-hour period when operated under the different production profiles. The results are reported per MWh delivered to the final customer where an average transmission and distribution power loss is experienced.

The output from the technical model is fed directly into the financial analysis model designed to produce an indication of the economic impact, which might be achieved with local energy storage facilities. The source of the input data and the case scenarios is shown in figure 6.7.
Power flow analysis with and without local energy storage

Fig. 6.6 The model architecture, Scenario case analysis

Input data
- Chapter 3 - Test results
- Session times / T & D losses
- Energy loss during storage
- Plant availability

Operational Scenarios
- Constant operation (control test)
- Case 1 - Duct firing
- Case 2 - Variable output/constant output + storage
- Case 3 - Hot start + constant operation / constant output + storage
- Case 4 - Hot start + variable output / constant output continual storage

Output Data
- Power ex-generator
- Power delivered
- CO2 emitted
- CO2 emitted / MWh delivered

Fig. 6.7 The technical model used to analyse the power demand profiles with and without energy storage in the circuit.
Chapter 6 Benefits of Energy Storage

6.5 Technical Results of the Scenario Analysis

6.5.1 Constant operation
The results of the model calculations when operating the CCGT power plant at constant optimum output for 24 hours are listed in table 6.2. These results will be used as the basis for compression with the results obtained when operating the plant under the different production profiles represented by cases 1 to 4 below.

Table 6.2 Optimum CCGT operational performance over 24 hours.

<table>
<thead>
<tr>
<th>Constant operation</th>
<th>Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Produced</td>
<td>MWh/24 hrs</td>
</tr>
<tr>
<td>Power delivered</td>
<td>MWh/24 hrs</td>
</tr>
<tr>
<td>Fuel used</td>
<td>GJ/24hrs</td>
</tr>
<tr>
<td>Fuel used</td>
<td>GJ/MWh (gen)</td>
</tr>
<tr>
<td>Fuel Used</td>
<td>GJ/MWh(delivered)</td>
</tr>
<tr>
<td>CO₂ emitted</td>
<td>MT/MWh (gen)</td>
</tr>
<tr>
<td>CO₂ emitted</td>
<td>MT/MWh (delivered)</td>
</tr>
</tbody>
</table>

6.5.2 Case 1 - Load Shifting and Duct Firing
The results of the computations (Appendix 5) are tabulated below Table 6.3 and illustrated graphically figures 6.8 a-c.

Table 6.3 Scenario 1 Cases 1a & 1b

<table>
<thead>
<tr>
<th>Case 1</th>
<th>Optimum Case</th>
<th>Case 1a</th>
<th>Case 1b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power delivered MWh/24 hrs</td>
<td>17173</td>
<td>17139</td>
<td>17288</td>
</tr>
<tr>
<td>Fuel Used GJ/MWh delivered</td>
<td>7.675</td>
<td>7.690</td>
<td>7.756</td>
</tr>
<tr>
<td>CO₂ emitted MT/MWh delivered</td>
<td>0.3859</td>
<td>0.3867</td>
<td>0.3900</td>
</tr>
</tbody>
</table>
Both cases 1a and 1b are compared with the performance of the plant operating at its MER and delivering the power direct to the customer without the use of intermediate energy storage or duct firing. The results indicate that at locations, where average transmission and distribution losses apply, the direct route to the customer delivered the highest quantity of power over the 24-hour cycle.
CO2 emitted MT/MWh delivered

0.391
0.390
0.389
0.388
0.387
0.386
0.385
0.384
0.383

Optimum Case  Case 1a  Case 1b

The amount of power supplied during the duct firing period is a small fraction of the 24-hour power output. The impact upon fuel usage, CO2 emitted and operational, maintenance and capital costs are very small. However, the fuel used and the CO2 emitted per MWh of power generated by the duct-firing element of the output is high. The fuel required is approximately 10.22 GJ/MWh and the CO2 emitted is 0.5141 MT/MWh. This compares with 7.012 GJ/MWh and 0.3526 MT/MWh receptively when operating in the pure Combined Cycle mode. In principal, therefore, ducting firing wastes energy and produces more CO2 per MWh delivered. In practice it is achieved with no increase in staff compliment, no measurable increase in general maintenance costs, no increase in Gas Turbine maintenance and only a marginal increase in the capacity of the gas supply system, turbo-alternator and the air condenser system. The capital cost is therefore small per MW of installed capacity and under the current market conditions there is an economic gain when used to provide high priced power during peak demands.

The present market payment systems reward the generator for the power exported in one of two ways.
Firstly, the payments for power may come through a long term contract, which is dictated by the forward expectation of electricity prices during the contract period and upon the profile of the load to be delivered.

Secondly, the reward may come through the 'Day Ahead Market' where the price is set by the prediction of the costs of power for each half hour period during the coming 24 hours. The actual price in this market depends principally upon the anticipated demand during each period, the current costs of fuel and the expected generating capacity which will be producing power at the time in question. This market is significantly more volatile than the long term contract but requires the generating plant to be flexible to the change in output.

It may be noted that a comparison between Case 1a and Case 1b indicates that less fuel would be used and less CO₂ emitted, where the energy lost during storage, is less than 20% and the transmission and distribution losses are equal to or greater than the national average values.

6.5.3 Case 2 Variable demand supplied from storage or by varying power plant output.

The results of the computations of Case 2 (Appendix 5) are recorded in table 6.4 and are illustrated in figure 6.9 a-c below.

<table>
<thead>
<tr>
<th>Table 6.4 Scenario 2 Case 2a &amp; Case 2b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 2</td>
</tr>
<tr>
<td>--------------------------------------</td>
</tr>
<tr>
<td>Power delivered 24 hrs</td>
</tr>
<tr>
<td>Fuel Used delivered</td>
</tr>
<tr>
<td>CO₂ emitted delivered</td>
</tr>
</tbody>
</table>
Fig. 6.9 Results of Scenario 2 analysis compared with the constant operation operating at MER.
This scenario indicates that under Case 1a (with local energy storage)

1) More power is produced at the generating station and delivered to the customer during the 24-hour period (3000MWh)

2) Less energy is used per MWh of power delivered (0.25GJ/MWh)

3) Less CO₂ is liberated per MWh of power delivered (0.24MT/MWh)

6.5.4 Case 3 Daily Start / Stop with Constant operation whilst operating

This scenario develops the contrast between supplying day time base load from energy storage and a power plant operating at MER with that of a power plant which starts up each day to deliver the same demand profile directly to the customer before shutting down each evening.

The results of the computations (Appendix 5) are recorded in table 6.5 and illustrated graphically in figure 6.10 a-c.

<table>
<thead>
<tr>
<th>Case 3 Optimum Case</th>
<th>Case 3a</th>
<th>Case 3b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power delivered</td>
<td>17173</td>
<td>15688</td>
</tr>
<tr>
<td>Fuel Used delivered</td>
<td>7.675</td>
<td>8.401</td>
</tr>
<tr>
<td>CO₂ emitted</td>
<td>0.3859</td>
<td>0.4225</td>
</tr>
</tbody>
</table>
Figure 6.10 Case 3 Scenario compared with the constant operation at MER however, the total amount of power delivered at the end of the distribution circuits is larger from case 3a over the 24-hour period than that received from case 3b without energy storage.
In this scenario a large amount of power is placed in the energy store before onward transmission to the customer. As a result the power supplied directly to the customer uses less energy and emits less CO\textsubscript{2} per MWh delivered. Both case 3a and 3b use more fuel and emit more CO\textsubscript{2} per MWh than that achieved by the constant operation.

6.5.5 Case 4 Daily Start / Stop with Modulated Output whilst operating

In this scenario case 4b starts and stops each day at similar times to those adopted in case 3b but here it supplies the variable load whistle case 4a provides power direct to the customer and any over production not required is placed in the energy store. Here the power plant operates continuously at MER throughout the 24-hour cycle.

The results are recorded in Table 6.6 and are illustrated graphically in Figure 6.11a-c.

<table>
<thead>
<tr>
<th>Case 4</th>
<th>Optimum Case</th>
<th>Case 4a</th>
<th>Case 4b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power delivered MWh/24 hrs</td>
<td>17173</td>
<td>16438</td>
<td>6567</td>
</tr>
<tr>
<td>Fuel Used GJ/MWh delivered</td>
<td>7.675</td>
<td>8.018</td>
<td>8.283</td>
</tr>
<tr>
<td>CO\textsubscript{2} emitted MT/MWh delivered</td>
<td>0.3859</td>
<td>0.4032</td>
<td>0.4272</td>
</tr>
</tbody>
</table>

Case 4a delivers both lower fuel demand and lower CO\textsubscript{2} emissions per MWh delivered to the customer, whilst also producing more usable power at the end of the distribution line.
Chapter 6 Benefits of Energy Storage

Fig. 6.11 The results of Scenario 4 analysis compared with Constant operation at MER.
6.5.6 Summary of the findings for Case 3 & Case 4

1. The energy storage route to the customer is less effective, for both energy used and CO₂ emitted per MWh of power delivered, when the CCGT plant is delivering a base load direct for 13 hours per day.

2. Energy Storage is more effective when supplying a variable demand to the customer using less fuel and emitting less CO₂ per MWh delivered.

3. In all the cases where energy storage is employed more power is delivered over the 24-hour period than via the direct rout except for the case when the CCGT plant operates continually at optimum performance delivering the total output directly to the customer.

6.6 Overall Technical Summary

The overall position of the power generated and the power delivered to the customer is recorded in table 6.7 and illustrated in figure 6.12 below where the differences in performance during the 24-hour cycle can be compared.

Table 6.7 Power generated and Power Delivered to the customer over a 24 hour cycle

<table>
<thead>
<tr>
<th>Power Ex Generator &amp; Power delivered over 24-hours</th>
<th>Power Ex-Generator MWh/24hrs</th>
<th>Power Delivered MWh/24hrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant operation</td>
<td>18802</td>
<td>17173</td>
</tr>
<tr>
<td>Case 1a</td>
<td>18802</td>
<td>15715</td>
</tr>
<tr>
<td>Case 1b</td>
<td>18935</td>
<td>17288</td>
</tr>
<tr>
<td>Case 2a</td>
<td>18802</td>
<td>15715</td>
</tr>
<tr>
<td>Case 2b</td>
<td>14728</td>
<td>12708</td>
</tr>
<tr>
<td>Case 3a</td>
<td>18802</td>
<td>15688</td>
</tr>
<tr>
<td>Case 3b</td>
<td>10826</td>
<td>9746</td>
</tr>
<tr>
<td>Case 4a</td>
<td>18802</td>
<td>16438</td>
</tr>
<tr>
<td>case 4b</td>
<td>7296</td>
<td>6567</td>
</tr>
</tbody>
</table>
The variations in the power produced under each of the above scenarios and the actual power delivered to the final user could have a significant impact upon the financial viability of the power plant and upon the funding of energy storage devices.

The results obtained in the technical evaluation are next used to gain a measure of the variations in financial returns available to the power plant and hence to estimate the investment which might be justified into local energy storage.

6.7 Financial Analysis

The financial model attempts to compute the costs associated with each of the above supply and storage scenarios. The inputs and outputs to this model are shown schematically in Figure 6.13.
The input data is either taken from previous identified sources or from the results of computations (Chapter 3, & Chapter 5) plus new sources identified below.

The plant availability adopted has been set at 90% which is the experience gained at Plant C (Chapter 3 test plant).

Gas turbine major plant maintenance cost at the end of the time and starts allowances set by the manufactures has been adopted. The cost adopted has been taken from Plant C. It is set at £7m per turbine i.e. for the 800MW CCGT plant with two machines the cost is £14m per major rebuild.

Using the manufacturer’s published data of each ‘Hot Start’ is considered being equivalent to 20 hours of continuous operation. In the ‘Equivalent Operational Hours’ (EOH) method of computing the maintenance intervals, the interval is given by:

\[ S_y = 365 \times A \]

\[ T_m(EOH) = \frac{240000}{(S_y \times 20 + T_o \times 365 \times A)} \]

where (for the EOH method)
Chapter 6 Benefits of Energy Storage

\[ T_m(EOH) = \text{Time interval between Gas Turbine maintenance (years)} \]

\[ S_y(EOH) = \text{Starts /year} \]

\[ T_o(EOH) = \text{Operational hours per day (hours)} \]

\[ A = \text{Plant availability (\%)} \]

The ‘Counts of Starts and Hours’ (S & H) is limited by the high number of starts each year and not by the number of operational hours during the same period, hence the maintenance interval is given by:

\[ T_m(S & H) = \frac{1200}{S_y} \]

where

\[ T_m(S & H) = \text{Time interval between Gas Turbine maintenance (years)} \]

The cost of fuel for each session of the day for each case is determined by:

\[ F_{si} = F_{cl} \times P_{si} \times T_{si} \]

Where

\[ F_{si} = \text{Cost of fuel for session 1 (£/session)} \]

\[ P_{si} = \text{Power generated per hour during session 1 (MWh/h)} \]

\[ T_{si} = \text{Time period of session 1 (i.e. 6.5 hrs (00.00-06.30)) (hrs)} \]

Likewise the power for the other four sessions may be computed and the total daily production at the generator output terminals computed.

This process is continued for each of the 4 cases described above and the cost of fuel is determined for supplying 8 different demand profiles. (Appendix 5)

The carbon emissions are computed and a nominal cost attributed to each case.

Hence

\[ C_{si} = C_c \times C_{sc} \times P_{si} \times T_{si} \]

where

\[ C_{si} = \text{Cost of carbon certificates for carbon dioxide produced during session 1 (£/session)} \]
\[ C_e = \text{Cost of carbon certificate (\(£/\text{MT}\))} \]
\[ C_{sc} = \text{Carbon produced when operating at constant optimum output (MT/MWh)} \]

Again the total daily cost is computed from the cost incurred during each session of the 24-hours cycle.

6.7.1 Maintenance Costs

These costs have been divided into two separate calculations, one focused on the general plant maintenance (Fixed) and the other on the particular issues of the gas turbines.

**Fixed Maintenance**

The costs of fixed maintenance for the constant operation mode are derived as follows.

\[ C_{mf1} = C_{mf} \times P_{s1} \times T_{s1} \]

where

\[ C_{mf} = \text{Cost of fixed maintenance charges under constant operation (\(£/\text{MWh}\))} \]
\[ C_{mf1} = s1 \text{ Cost of fixed maintenance charges for session 1 \(£/\text{session}\)} \]

The sum of the 5 sessions during the 24-hour cycle represents the daily cost of fixed maintenance.

**Gas Turbine Maintenance**

The costs of gas turbine maintenance for the constant operation mode are computed using data derived in chapter 3 as follows:

\[ C_{GTm1} = C_{GTc} \times P_{s1} \times T_{s1} \]

where

\[ C_{GTm1} = \text{Cost of Gas turbine maintenance for session 1 (\(£/\text{session}\))} \]
\[ C_{GTc} = \text{Cost of gas turbine maintenance (\(£/\text{MWh}\))} \]

The sum of the costs for the 5 sessions during the 24-hour cycle is a measure of the gas turbine maintenance costs.
6.7.2 Cost of Capital

The cost of the capital investment depends upon the methods used to fund the power plant, the interest rates on the loan capital, the mezzanine finance and required dividend payments on the equity stack.

Here an attempt has been made to compute the cost of capital as an element of the cost of producing one MWh. This approach is valid where the power is produced continually over the 24-hour period, which is relevant to cases 1a, 1b, 2a, 3a and 4a. However, it is not a true measure when applied to cases 3b and 4b where the plant is not producing power for 6 hours per day and less than half output for 3 hours each day during start-up.

These two cases will be treated differently to accommodate the impact of the lower annual output.

Cost of capital for the constant operation and for Cases 1a, 1b, 2a, 3a, and 4a

The cost of capital for session 1 when operating in constant operation mode at full output is given by:

\[ R_{c1} = R_c \times P_{sl} \times T_{sl} \]

where

\[ R_{c1} \] = cost of capital for constant optimum operation (£/session 1)  
\[ R_c \] = cost of capital for constant optimum operation (£/MWh)  
(Data required for these are obtained from chapter 3)

The annual revenue required to service the capital may be computed from the sum of the daily cost of capital and the number of operating days per year:

\[ R_{casd} = \sum_{s=3}^{S} R_{sc} \]

\[ R_{casy} = R_{casd} \times 365 \times A \]

where

\[ R_{casy} \] = Cost of capital for one year (£/year)  
\[ R_{casd} \] = Cost of capital for one day (£/24-hours)  
\[ S \] = session number
For case 3b and Case 4b the annual cost of capital is assumed to be the same as that derived for the constant operation case above $R_{\text{sty}}$. Hence, if the power plants each operate the same daily production routine described above the Cost of Capital per MWh delivered for (case 3) is given by:

$$R_{\text{ery}}(3b) = R_{\text{sy}} / (P_{3b} \times 365 \times A)$$

where

- $R_{\text{ery}}(3b) = \text{Annual cost of Capital delivered £/MWh}$
- $P_{3b} = \text{The daily power delivered MWh}$

The same analysis was performed for Case 4b (See Appendix 5)

6.7.3 The Scenario Costing Results for Case 1

The cost analysis results for load shifting and duct firing are recorded in table 6.8 and are illustrated graphically in figure 6.14. Again the constant optimum operation supplying the customer direct 24-hours a day is used as the control against which all other supply patterns are compared.

Table 6.8 Costings £/MWh for each scenario (Appendix 5 Sheet 2)

<table>
<thead>
<tr>
<th>Case 1 Costs</th>
<th>Optimum Case</th>
<th>Case 1a</th>
<th>Case 1b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power delivered (£/MWh)</td>
<td>43.70</td>
<td>43.57</td>
<td>43.80</td>
</tr>
<tr>
<td>Fuel Used (£/MWh delivered)</td>
<td>29.11</td>
<td>29.17</td>
<td>29.21</td>
</tr>
<tr>
<td>CO₂ emitted (£/MWh delivered)</td>
<td>7.719</td>
<td>7.719</td>
<td>7.746</td>
</tr>
<tr>
<td>Maintenance - Fixed (£/MWh</td>
<td>1.635</td>
<td>1.635</td>
<td>1.626</td>
</tr>
<tr>
<td>delivered)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance – GT (£ MWh</td>
<td>0.797</td>
<td>0.799</td>
<td>0.792</td>
</tr>
<tr>
<td>delivered)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital (£/MWh)</td>
<td>12.16</td>
<td>12.19</td>
<td>12.17</td>
</tr>
</tbody>
</table>
Fig. 6.14 Case 1 Cost Analysis
Case 1 indicates that:

1. The total cost of power delivered to the customer is equal for all three power delivery patterns.

2. The Duct Firing analyses in case 1b is only a very small percentage of the total daily production and as such makes little difference to the costs. The income received by the increase in output will be dependent upon the daily forward market price or the balancing market price. This will vary widely from day to day as it depends upon many factors such as gas supply failure, power station and transmission line outages and public demand etc.

3. The power storage costs do not include an element for capital and maintenance costs. Hence, in this scenario, there is no margin to cover such costs and it may be excluded from further consideration.
6.7.4 The Scenario Costing Results for Case 2

The results of the computations identifying the costs of power delivery to the average domestic customer located in the distribution network for the Case 2 Scenario are listed in Table 6.9.

<table>
<thead>
<tr>
<th>Case 2 Costs</th>
<th>Optimum Case</th>
<th>Case 2a</th>
<th>Case 2b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power delivered</td>
<td>£/MWh</td>
<td>43.70</td>
<td>47.76</td>
</tr>
<tr>
<td>Fuel Used delivered</td>
<td>£/MWh</td>
<td>29.11</td>
<td>31.81</td>
</tr>
<tr>
<td>CO₂ emitted</td>
<td>£/MWh</td>
<td>7.72</td>
<td>8.43</td>
</tr>
<tr>
<td>Maintenance (Fixed)</td>
<td>£ MWh</td>
<td>1.63</td>
<td>1.78</td>
</tr>
<tr>
<td>Maintenance (GT)</td>
<td>£ MWh</td>
<td>0.80</td>
<td>0.87</td>
</tr>
<tr>
<td>Capital</td>
<td>£/MWh</td>
<td>12.16</td>
<td>13.29</td>
</tr>
</tbody>
</table>

These results are presented graphically in Fig.6.15 below.
Fig.6.15 Case 2, Cost associated with delivering power to the average customer embedded in the distribution system
Comments on case 2:

1. The cost of power delivered by the control case (continuous operation) is the lowest when delivering directly to the customer without the losses incurred in energy storage.

2. When the power station is supplying a variable load (Case 2) the cost of power delivered is lower when the proportion of power not required immediately is stored locally and subsequently delivered during peak demand periods.

3. The cost analysis indicates that power delivered to the final customer using the local energy storage results in:
   - Less fuel
   - Lower maintenance cost
   - Less CO₂ liberated /MWh

6.7.5 The Scenario Costing Results Case 3

The results of the computations identifying the costs associated with delivering power to the average customer in the distribution network are listed in table 6.10 below.

Table 6.10 Case 3 cost analysis for power delivered.

<table>
<thead>
<tr>
<th>Case 3 Costs</th>
<th>Optimum Case</th>
<th>Case 3a</th>
<th>Case 3b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power delivered</td>
<td>£/ MWh</td>
<td>43.70</td>
<td>47.84</td>
</tr>
<tr>
<td>Fuel Used delivered</td>
<td>£/MWh</td>
<td>29.11</td>
<td>31.87</td>
</tr>
<tr>
<td>CO₂ emitted delivered</td>
<td>£/MWh</td>
<td>7.72</td>
<td>8.43</td>
</tr>
<tr>
<td>Maintenance (Fixed) delivered</td>
<td>£ MWh</td>
<td>1.63</td>
<td>1.79</td>
</tr>
<tr>
<td>Maintenance (GT) delivered</td>
<td>£ MWh</td>
<td>0.80</td>
<td>0.87</td>
</tr>
<tr>
<td>Capital</td>
<td>£/MWh</td>
<td>12.16</td>
<td>13.32</td>
</tr>
</tbody>
</table>

These results are presented graphically in Fig.6.16 below.
Fig. 6.16, Case 3 cost analysis.
Comments on case 3.

1. The costs of power delivered by the control case are the lowest.
2. The costs of delivering the power demand profile are lower using energy storage.
3. The quantity of energy stored is significantly higher than in case 2. The amount of fuel used and the maintenance costs per unit of power delivered are both higher than the direct supply chain.

6.7.6 The Scenario Costing Results for Case 4

The results of the computations identifying the costs associated with delivering power to the average customer in the distribution network under Case 4 scenario are listed in table 6.11 below.

<table>
<thead>
<tr>
<th>Case 4 Costs</th>
<th>Optimum Case</th>
<th>Case 4a</th>
<th>Case 4b</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power delivered (£/MWh)</td>
<td>43.70</td>
<td>45.66</td>
<td>75.27</td>
</tr>
<tr>
<td>Fuel Used (£/MWh delivered)</td>
<td>29.11</td>
<td>30.41</td>
<td>37.89</td>
</tr>
<tr>
<td>CO₂ emitted (£/MWh delivered)</td>
<td>7.72</td>
<td>8.42</td>
<td>8.07</td>
</tr>
<tr>
<td>Maintenance (Fixed) (£ MWh delivered)</td>
<td>1.63</td>
<td>1.70</td>
<td>2.64</td>
</tr>
<tr>
<td>Maintenance (GT) (£ MWh delivered)</td>
<td>0.80</td>
<td>0.83</td>
<td>2.93</td>
</tr>
<tr>
<td>Capital (£/MWh)</td>
<td>12.16</td>
<td>12.71</td>
<td>31.81</td>
</tr>
</tbody>
</table>
Fig. 6.17, Case 4 cost analysis
General comments:
The cost of the power delivered to the final customer is lower using local energy storage.
1) The fuel used per MWh delivered is less and therefore the cost is lower
2) Maintenance costs are lower with energy storage as:
   (a) The number of starts and stops lower.
   (b) The operational hours are more productive.
3) As fewer Power plants are required the cost of capital investment per MWh delivered is significantly lower.
4) The emissions of CO₂ (MT/MWh) are lower and hence the cost of carbon certificates is lower.
5) The number of power plants required to be available to supply this load is reduced.

6.7.7 Collective Review of Scenario Results and Discussion

The comparative quantities of power delivered to the customer during a nominal 24 h period are show in table 6.12 and illustrated graphically in figure 6.18.

Table 6.12 Comparative power delivered during a 24hr period by each operating scenario. (Appendix 5 Sheet 2)

<table>
<thead>
<tr>
<th>Power Delivered to the Customer</th>
<th>Power MWh/24hrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant operation</td>
<td>17173</td>
</tr>
<tr>
<td>Case 1a</td>
<td>15715</td>
</tr>
<tr>
<td>Case 1b</td>
<td>17288</td>
</tr>
<tr>
<td>Case 2a</td>
<td>15715</td>
</tr>
<tr>
<td>Case 2b</td>
<td>12708</td>
</tr>
<tr>
<td>Case 3a</td>
<td>15688</td>
</tr>
<tr>
<td>Case 3b</td>
<td>9746</td>
</tr>
<tr>
<td>Case 4a</td>
<td>16438</td>
</tr>
<tr>
<td>case 4b</td>
<td>6567</td>
</tr>
</tbody>
</table>
The ranges of the total cost of power for each case (delivered to the ‘nominal customer’) are shown in table 6.13 and figure 6.19. It indicates the wide variation, which applies when the power plant is operated under different production schedules and illustrates the potential benefits, which could be obtained from the selective deployment and use of local energy storage.
Table 6.13 Total Cost of Power at the Generator and delivered to the customer for each case
(Appendix 5 Sheet 2)

<table>
<thead>
<tr>
<th>Total cost of Power Delivered to the customer Excluding Carbon Costs</th>
<th>Cost of Fuel *</th>
<th>Cost of Fixed Maintenance</th>
<th>Cost of GT Maintenance</th>
<th>Cost of Capital</th>
<th>Total Cost of Power Delivered</th>
<th>Total Cost of Power Ex Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>£/MWh</td>
<td>£/MWh</td>
<td>£/MWh</td>
<td>£/MWh</td>
<td>£/MWh</td>
<td>£/MWh</td>
</tr>
<tr>
<td><strong>Constant Operation</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Case 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Case 1a</td>
<td>29.17</td>
<td>1.49</td>
<td>0.728</td>
<td>12.1875</td>
<td>43.57</td>
<td>39.918</td>
</tr>
<tr>
<td>Case 1b</td>
<td>29.21</td>
<td>1.626</td>
<td>0.7917</td>
<td>12.168</td>
<td>43.80</td>
<td>40.20</td>
</tr>
<tr>
<td><strong>Case 2</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Case 2a</td>
<td>31.813</td>
<td>1.783</td>
<td>0.871</td>
<td>13.292</td>
<td>47.759</td>
<td>39.918</td>
</tr>
<tr>
<td>Case 2b</td>
<td>33.324</td>
<td>2.296</td>
<td>1.160</td>
<td>17.848</td>
<td>54.628</td>
<td>46.615</td>
</tr>
<tr>
<td><strong>Case 3</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Case 3a</td>
<td>31.867</td>
<td>1.786</td>
<td>0.871</td>
<td>13.315</td>
<td>47.839</td>
<td>39.918</td>
</tr>
<tr>
<td>Case 3b</td>
<td>30.432</td>
<td>1.717</td>
<td>1.975</td>
<td>21.432</td>
<td>55.555</td>
<td>50.014</td>
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<td><strong>Case 4</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Case 4a</td>
<td>30.413</td>
<td>1.704</td>
<td>0.833</td>
<td>12.707</td>
<td>45.658</td>
<td>39.918</td>
</tr>
<tr>
<td>Case 4b</td>
<td>37.889</td>
<td>2.643</td>
<td>2.931</td>
<td>31.808</td>
<td>75.272</td>
<td>62.473</td>
</tr>
</tbody>
</table>

*The cost of gas used in these calculations ...40p/therm
Figure 6.19 Total cost of power delivered (24 hrs) for each case

Figure 6.19 illustrates the cost of power generated and delivered to the customer varies from approximately £44/MWh to £75/MWh when considering the 5 possible scenarios. This range has been calculated using average values for the price of fuel and carbon. Both these items are volatile and may vary depending upon current market conditions. The price of gas may be more expensive for an intermittent daily demand as a contract for a specific constant gas demand may be cheaper and set within a long term agreement protected by suitable selected index adjustments (e.g., the retail price index, the price of electricity and other market indicators). Such an arrangement would be to the advantage of energy storage and increase the price differential identified above.

Figure 6.20 indicates the different costs of fuel for each scenario using a constant input price per GJ for the natural gas supply.
The costs of plant maintenance (fixed and general costs, and GT costs) are significantly higher for the case where the plant is required to stop and start once per day. The continuous plant operation also avoids the problem of false starts when control systems and plant mounted instrumentation, final elements, Interlocks etc can malfunction when a plant is restarted. Figure 6.21 and figure 6.22 illustrate the comparative costs of fixed maintenance and gas turbine maintenance respectively.

Fig.6.21 Comparative General Plant maintenance cost £/MWh (delivered)
Chapter 6 Benefits of Energy Storage

The comparative costs of capital invested in the power plant as a charge per unit delivered to the customer for each of the cases described above are shown in figure 6.23. Once again the two cases where the power plant is cycled in and out of production are the most expensive. The smaller amount of power produced during these periods makes an adverse impact upon the cost per unit of power delivered. The number of gas turbine start / stops which are required in cases 3b and 4b significantly reduces the time intervals before a major plant outage is required for major servicing of the gas turbine hot path systems.

Fig. 6.22 Comparative Gas Turbine maintenance costs £/MWh (delivered)
Fig 6.23 Comparative Costs of Capital for each of the 9 cases (£/MWh delivered).

The comparative cost of carbon emissions is illustrated in figure 6.24 where a different pattern emerges. When the full cost of CO₂ emission certificates is added to the costs of delivering power to the customer, supply a variable demand becomes progressively more expensive. Case 2b, (where the power output is continual varying by +/- 26% whilst delivering power directly 24 hours per day) is approximately 7.5% more expensive than delivering the variable element of the demand from local energy storage.

The comparison of the results from Case 3 with those of Case 4 indicates that energy storage is more expensive per MWh delivered when the power plant is delivering significant amounts of power from storage to a constant demand during the daytime. When the power plant is required to deliver a variable output the position is reversed and energy storage delivers the cheaper power as in Case 4.

There would therefore appear to be a neutral case between these two scenarios where the degree of variability and operational time each day would provide equal cost for CO₂ emissions. Little can be gained, however, from examining this aspect of the costs as the supply conditions are continually changing as individual power demands and the resulting system losses are influenced by many factors.
In the cases where lower carbon emissions are achieved by using local energy storage, two options are available to maximise power plant income:

(a) By the production and supply of more power to the final customer against the free annual allocation of carbon certificates owned by the power plant.

(b) By the sale of the excess carbon certificates on the carbon market.

![Cost of CO2 emitted delivered £/MWh](image)

**Fig.6.24** The comparative cost of carbon emissions for power delivered. (Cost of carbon certificates £20/tonne)

The final comparison (table 6.14, & figure 6.25) evaluates the overall cost position where the generated and delivered cost of power for the scenarios are summarised.

The results of this initial survey of the impact of transmission and distribution losses in the power supply chain will not be recognised until comprehensive measurements are available across the whole system. Only then will the true benefits of energy storage at different points in that supply chain be fully recognised. If the full value of potential savings, from lower fuel usage, operational and maintenance costs and lower capital investment, whilst reducing carbon emissions, it will be necessary to develop a targeted reward mechanism, which recognises these benefits.
Table 6.14 Comparative results of the costs of power with and without the full cost of carbon certificates (£20/tonne) generated & delivered to the customer.

(Appendix 5 Sheet 2)

<table>
<thead>
<tr>
<th>Case</th>
<th>Cost of Power Ex Generator £/MWh</th>
<th>Cost of Power delivered £/MWh</th>
<th>Total Cost of Inc Carbon £/MWh generated</th>
<th>Total Cost of Inc Carbon £/MWh delivered</th>
</tr>
</thead>
<tbody>
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<td>Constant Operation</td>
<td>39.918</td>
<td>43.70</td>
<td>46.97</td>
<td>51.42</td>
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<td>39.918</td>
<td>43.57</td>
<td>46.97</td>
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<td>40.20</td>
<td>43.80</td>
<td>47.27</td>
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</tr>
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<td>39.92</td>
<td>47.76</td>
<td>46.97</td>
<td>56.19</td>
</tr>
<tr>
<td>Case 2b</td>
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<td>54.63</td>
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<td>63.69</td>
</tr>
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<td>57.28</td>
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<td>45.66</td>
<td>46.97</td>
<td>53.86</td>
</tr>
<tr>
<td>Case 4b</td>
<td>62.47</td>
<td>75.27</td>
<td>70.51</td>
<td>83.88</td>
</tr>
</tbody>
</table>
Chapter 6 Benefits of Energy Storage

Fig. 6.25 The comparative costs for power generated and delivered to the customer with and without the full costs of carbon certificates (£20/tonne)

(see also Appendix 5, Sheet 2)

6.8 Energy Storage and Fossil Fuel Fired Generating Capacity

The data used in the above analysis was taken from one of the most efficient CCGT power plants currently operating in the UK. It uses the combined cycle principle fired by natural gas. It is between 5 to 10% more efficient than earlier gas stations and therefore emits less CO₂ per unit of power generated. By comparison with the simple cycle coal fired power stations operate with overall efficiencies between 30 to 50% lower than Plant ‘C’ (Chapter 3).

Natural gas consists mainly of methane with products of combustion of water and carbon dioxide, whilst coal, which largely made up of carbon, mostly emits carbon dioxide. Any savings of carbon dioxide emissions, which might be achieved by the use of locally based energy storage, indicated in this chapter, will be magnified when other UK generating stations are considered.
When the free allocation of carbon certificates were distributed at the beginning of 2005, it was necessary to take account of the lower conversion efficiencies of the coal fired plants compared with the CCGT plants. To preserve the commercial status quo the coal-fired plants were allocated approximately twice the number of free carbon certificates to produce the same net output of electricity.

As an example the 2006 carbon certificate allocation for Plant ‘C’ was approximately 1,500,000 tonnes/ year. This is equivalent to 1875 tonnes / MW of installed generating capacity. The Drax coal fired plant (the UK’s most modern plant and commissioned in 1973) had an allocation of Carbon Certificates equivalent to 3,638 tonnes / MW of installed generating capacity.

The use of local energy storage to reduce the number of coal fired units operating during periods of increased demand during the daytime would therefore have a proportionate increase compared with those claimed for the gas fuelled station above. Not only would carbon dioxide be emitted to the atmosphere but there would be more revenue available from the sale of unused Carbon Certificates when the plant is responding to a variable demand.


The major issue for the principal sources of renewable energy (wind and solar power) is that of variable supply. These sources are unpredictable and unable to contribute to maintaining the stability of the supply network through ancillary services. If energy storage was available to store a proportion of the power output it would be possible to deliver a more continuous supply and to supply some ancillary services in the short term (say 2-4 hours). It would make the power output more valuable to the market as it would increase the reliability of supply. It would also allow any power output in excess of the current demand to be retained without detrimental impact on fossil fuel plants operating at the same time and show the benefits identified above.

Finally, concern has been expressed about the amount of unconstrained wind power which can be accommodated in the network, before serious instability problems arise. Storing excess power could provide a solution.
The location of such storage would be subject to the same constraints analysed above. An energy store could be a requirement of the original installation and integrated into the power flow control systems. However, this solution would be subject to the increased losses within the network during times of high demand.

Local energy storage positioned deep within the distribution network would provide the identified benefits.

6.10 Energy Storage and Nuclear Generation Capacity

Nuclear power plants have large thermal inertia and, as such, have been operated in the past as base load stations. Their ability to vary their output to provide balancing power to the market has been limited to date. Energy Storage located in the best strategic positions within the supply chain could improve their overall contribution.

6.11 Chapter Summary

The work in this chapter examined the performance of a modern CCGT power plant under a range of different operating profiles. The results indicated that there are measurable benefits to be gained when the plant is operated continuously at its ‘Optimum Performance’ level. When energy storage is used to remove the need to vary the plant output in order to balance the variable power demand on the system, there will be savings of fuel used, operating, maintenance and capital costs and in the quantities of CO₂ and NOₓ emitted per MWh generated.

Four different scenarios were designed to represent typical operational patterns of power plant production when adjusting the output to match market requirements.

(1) The use of ‘Duct Firing’ facilities in a CCGT power plant (scenario 1):

(a) Increases the fuel used and the CO₂ emitted per MWh of power delivered during peak demand, disproportionately compared with power supplied by the CCGT plant.
(b) When local energy storage is used for load shifting to provide power during peak demand, it can be delivered at approximately the same cost as duct firing.

(2) In two of the three scenarios (cases 2 and 4) the benefits would provide:
   (a) Reduced costs through lower fuel used and lower CO₂ emissions
   (b) Better utilisation of the power plant, the gas supply infrastructure and the power transmission and distribution system.
   (c) Less damage to the combustion chambers power plant gas turbines if the energy storage units can deliver ancillary services.

(3) Scenario 3 delivers marginal benefits and the viability of the use of energy storage depends on the future price of fuel, CO₂ certificates and the costs of funding and operating the energy stores together with the actual turn round efficiency of storage technology.

(4) The benefits to be gained by using local energy storage embedded in the electricity distribution system (while allowing the power plant to operate at its maximum economic rating) are dependent upon:
   (a) the selection of the best locations within the distribution network where the load profile and the supply losses incurred are equal to or greater than the national average losses.
   (b) suitability of the energy storage equipment to deliver the power on demand with the speed and accuracy necessary to ensure continuity of supply.

(5) Local energy storage would be able to store excess energy produced from unpredictable renewable energy sources allowing this sector to claim:
   (a) A degree of secure supply
   (b) The supply of ancillary services
   (c) The ability to load shift from night-time low prices to the higher demand period during the day-time with potentially higher electricity prices.
No clear picture exists of the actual transmission and distribution losses that occur throughout the supply chain over a typical period of 24 hours. The discussion of the extent of the power losses is speculation.

Without definitive measurements of these losses and the adoption of effective commercial incentives to encourage the development of suitable energy storage devices, the current system of 'passing through the cost' to the customers will remain unchallenged.
Chapter 7

Distributed Energy Storage - Technology Requirements

7.1 Introduction

If local energy storage devices are to be successfully utilised in the electrical supply chain, they must be easily integrated into the existing distribution networks and be capable of earning the maximum revenue for their services.

In order to maximise the benefits from reduced system losses the storage must be placed as close to the customer as possible where the final circuit voltage can be as low as 415 Volts, 3 phase, (i.e. single-phase voltage of 230 Volts). As the load carrying capacity at these voltages is limited, the energy storage capability placed in these networks will also be limited.

7.2 Limitations

A number of factors will constrain the amount of energy storage capacity if it is to be installed in the low voltage distribution circuits:

1. If the devices are used for ‘Load Shifting’, it is assumed that most energy will be stored over the night-time period when demand is low and prices for power are at their cheapest. The inflow of power for storage will be set by the maximum load that can be accepted on the specific circuit, the local night-time customer demand and the period for which the energy is stored.

2. Likewise, the demand from the customers connected to these circuits during peak periods will place an upper limit on the amount of power, that can be sold during that period unless it proves economic to provide power to customers adjacent circuits. It would require two voltage transformations, (i.e.. 415 volts up to 11kV...
and 11kV back to 415 volts to deliver the power, which may prove expensive in power lost).

The characterisation of the system will be:-

(1) When an electric drive starts from zero speed, the power demand can be 5 to 7 times the full load demand. This may exceed the maximum load of the circuit and the supply transformer. The circuit protection system is designed to protect the network from damage by disconnecting the source of the overload. A large transient demand cause by the sudden current inrush would cause a significant voltage drop on the distribution lines and local customers to experience voltage fluctuations.

(2) When the electric machine is operating as a generator, the potential fault level on the system during a local short circuit will be set by the inflow from the transformer and augmented by the short circuit characteristics of the machine. If the generator has a sub-transient reactance of 20%, the fault current may reach 5 times the full load output and fast operating circuit breakers with high fault level capacity and high current rupturing capability will be required to limit potential damage. It is doubtful whether many of the existing low voltage circuits in the current distribution system would be able to handle such duties without modification.

Some of these issues would be reduced if the energy storage units were located within the 11kV network. The current flows would be proportionately lower and the capacity of the cables, transformers and switchgear would be more capable of absorbing the potential transient disturbances.

The consequences of placing the energy store on the 11 kV side of the transformer are illustrated in Fig.7.1
Fig. 7.1 Local Energy Storage placed in the Distribution system

In Figure 7.1:

- P1 = power flow to Store 2
- P2a = power flow from store 2
- P2b = power flow to load
- P3 = power flow to store 1
- P4 = power flow to load

If it is assumed that the power loss at night through the transmission and distribution networks to the 11kV and 415 V circuits is the same in both cases, the only differences in the losses that impact upon this position are those which occur at different times in the final transformation stage.

An analysis to quantify these can be undertaken with following assumptions:
Chapter 7 Distributed Energy Storage

The 'Turn Round' efficiency is 80% for each case
The transformer capacity is 1000kVA at 0.8 power factor
Nominal transformer efficiencies

<table>
<thead>
<tr>
<th>Load (%)</th>
<th>Efficiency (%)</th>
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<tbody>
<tr>
<td>25%</td>
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<td>100%</td>
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</table>

The customer peak load = 75% of the transformer capacity
Night-time customer load = 50% of the transformer capacity
11kV cable losses are neglected.

The efficiencies of storage for each case can be calculated as follows:

**Case 1 Energy Store 1 (415v store)**

- The customer day-time peak demand = P3
- Power required into store P1 = P2 X 1.20
- Power required into transformer = P2 X 1.20 / 0.979
- Hence Overall Power lost = 22.6%

**Case 2 Energy Store 2 (11kV store)**

- Power demand from customer = P3
- Power demand at transformer (11kV side i.e. from store2) = P2 / 98.2
- Power required into store P3 = P2 / 98.2 X 1.20
- Hence Overall Power lost = 22.12%

Whilst this analysis indicates that storing energy at the 11kV level may be marginally more efficient a number of other factors require consideration namely:

The energy storage charging period will be restricted by the 11kV/415V-transformer capacity in the case of the 415-volt system. If, for example, the load demand during the two peak hours is 600kWh (i.e. 1000 x 0.8 X 0.75), the energy to be delivered from store will be 1.5MWh (1.2 MWh of demand plus 300kW for the lost energy in the energy store).
This power will need to be supplied at night time in parallel with the customer demand at a
time, say 200 kW. Hence the transformer may only replenish the energy store at a rate of
400 kWh per hour. The charging time for the store will therefore be approximately 3.75
hours. If the low demand period and hence the cheapest available power occurs between
01.00 and 05.00 hours each day, the maximum power which may be stored is
approximately 1.6MWh. The selection of the capacity of the energy store for maximum
economic and environmental benefit will be a complex optimisation problem.

If the store were placed in the 11kV circuit, it would not suffer the same restrictions of
capacity. The optimisation of energy storage facilities at this level would have a
transformer capacity some 20 to 30 times greater than the case at the 415-volt level. It
would also be able to deliver power to a wider spectrum of load demand profiles and
thereby take advantage of optimising across a number of 415-volt circuits. The potential
store of energy could be as high as 50MWh. (Assuming an input 33kV/11kV transformer
of 30MVA capacity over a period of 4 hours during the night with an available 60% spare
capacity above the customer demand).

Although the energy storage modules would be similar, the installations would have to be
engineered to match individual locations as the network has been constructed over decades.
The equipment currently operating was built over time to different standards, using a wide
range of technologies and protected by increasingly sophisticated fault detection systems.

Finally, the 11kV control systems are more suitable to accommodate the motor starting
currents, the generator sub-transient current surge following a line fault and for handling
higher power flows.

7.3 Potential Sources of Income

If local energy storage is to be a reality it must attract sufficient capital investment. The
potential sources of revenue from the sale of electricity may be divided into those sources
which are currently available and those where local energy storage could claim to be
making financial savings but are not recognised by the existing market system.
7.3.1 Loads Shifting

The principal source of income, which was determined in chapter 6, Section 6.7.3, is that obtained from ‘Load Shifting’. Local energy storage devices must be available to receive power between 00.00 to 05.00 hours each day and regenerate it back into the system between 06.30 and 08.30 hours and /or 16.30 and 18.30 hours. The ability of the equipment to achieve a high availability in excess of 90% year round would be essential to capture the highest possible revenue flow. The actual selection of the exact times to store energy and regenerate power would be a judgement best made by the power trading market in combination with the local system operator.

Opportunities occur from time to time to take advantage of special situations when the price of power is very high. These occasions arise for two different reasons, namely technical failures and sudden customer demands: technically it occurs when there is a sudden breakdown of a major power plant, the failure of a power plant to start-up as planned or a major transmission line failure. The sudden increase in demand due to weather changes or when various national events occur can place the power demand beyond the capacity of the available generators to deliver.

During times of power shortages the price of the marginal supplies of electricity, which can be made available, attract very high prices. The revenue gained during these periods would make significant contributions to the funding of energy storage projects.

7.3.2 Triad Avoidance

As local energy storage is embedded within a DNO network it is in the ideal position to provide a Triad Charge reduction service (Chapter 4.61). The Distribution Network Operator (DNO), electricity supply companies and large industrial customers who take their power supply from the same network would be ideal customers of such a service. In the case of the DNO, it would allow a reduction of their power demand at the Grid Supply Point when a Triad period was predicted and hence reduces the annual Transmission Network use of System (TNuoS) charges levied by the National Grid Company. If the service was sold to a large industrial power user and electricity supply companies, it would reduce the annual power charges levied by the power provider. In cases where a company
deliberately reduces its power demand during a Triad period, it would allow production to continue uninterrupted with the consequent productivity gain.

The Triad avoidance service would need to be designed in such a manner to ensure the stored power was made available for each potential ‘Triad Period’ and that it was delivered exactly as required to ensure that the metering systems captured the reduction in demand. As the peak demand, which triggers the potential Triad, is determined by the total national power demand, the provision of this service would become progressively cheaper as the number of local energy stores in the scheme increased.

7.3.3 Ancillary Services

The ancillary services have been describes in chapter 4 (Section 4.8b) If local energy storage devices are to provide services to support the National Grid Operator by providing power ‘On Demand’ it must be available within prescribed time scales and in sufficient quantities to make a meaningful impact. This would probably rule out small stand alone energy stores, as the difficulties of integrating such devices into the national plan would require significant effort. However, if the number of local energy stores increased, such a contribution would become a real possibility. In time it could remove the need to demand the service from power generating plant with the attendant benefits identified in chapter 3 giving lower fuel demands, maintenance and operating costs and lower CO₂ emissions.

The individual services of spinning reserve, frequency response, voltage and power factor correction and black start would all require detailed engineering to incorporate them into the final system if it were to be successfully integrated into the network. As these services are currently contracted to the existing power plants it would be a major exercise to adopt new multiple power sources into existing regulations.

Energy storage devices will need to meet the performance requirements specified in the National Grid Code if they are to obtain full benefit of any of the ancillary contracts, namely:
7.3.4 Power Demand
The speed of response to requests for power from energy stores needs to equal or better the response of pumped storage facilities such as the Dinorwig storage installation that currently provide this service. When this plant is spinning-in-air and is synchronised with the electricity grid system, it is able to provide full output power within 12 seconds. When it is in stand by mode it can reach full synchronous speed within 20 seconds [75].

7.3.5 Frequency response
When the Grid Operator identifies that it is necessary to act to hold the system frequency within the mandatory limits (+/-1% of 50Hz), instructions are sent to all the relevant power generators to achieve the notified ‘Target Frequency’. There are mandatory duties on all those power plants specifically identified in the ‘Connection and Use of System Contract’ (CUSC) to respond. Further contracts are awarded to those power plants, which are able to respond by supplying stabilising power beyond the requirements of the National Grid Code for specific commercial returns. These contracts are negotiated separately on a competitive basis.

Where local energy storage facilities have available stored power and are in a position to respond to such requests, they are in an ideal position to do so without the consequential impact, that applies to fossil fuel burning power plants, identified in Chapter 3.

One of the facilities available to the SO for the frequency response service is provided by Open Cycle Gas Turbine (OCGT) under the ‘Fast Start’ provision. These plants are required to start from standstill to deliver the rated output of the plant within 5 minutes when instructed to do so by a low frequency trigger relay. They are also required to reach the same output level within 7 minutes when ordered via manual instruction.

These plants have a fuel efficiency of approximately 30 to 36% and are expensive to operate and have high emissions of CO₂. Local energy storage facilities would be in an ideal position to compete for this service where a CCGT plant was a source of the original stored power. There would be a need for such plants to be started automatically in a similar way to the OCGT plants by frequency sensitive relays or remotely by control personnel. The service attracts two payments, an availability fee and a utilisation fee. The terms of the
contract require the power to be supplied for a minimum of four hours. Such a requirement would have to be included in the original design.

7.3.6 Reactive Power
The supply of reactive power is another service required by the Grid Operator to ensure the voltage distribution across the whole transmission network stays within the statutory and operational limits. This is achieved by the injection of reactive power at certain positions within the system. Local energy storage is unlikely to contribute to this service as by its very definition is located deep within the distribution network. There may be a local requirement for voltage and reactive power adjustments within the distribution network where statutory requirements limit the voltage excursion allowed on the 11kV and 415volt levels. Such a service, if it ever becomes a commercial reality, would be negotiated with the local operator of the network (i.e. the DNO).

7.3.7 Black Start
An independent source of power is required to be available to restart fossil fuel power fired power stations if the national grid system should ever face the situation where a major incident caused the whole network to collapse. This power has to come from units equipped to restart without the injection of outside power or from units, which can supply electricity from devices such as energy storage. The availability of these facilities known as ‘Black Start’ attracts a fee for being available if ever required. Local energy storage units could provide this service if they were combined to operate together upon central instructions. However, such storage units would have to guarantee the availability of a specific amount of power and therefore be required to hold that capacity in reserve. This may place unacceptable limits on their ability to earn an income from other operations such as load shifting.

7.4 Unrecognised Advantages of Embedded Energy Storage
There could be a range of benefits that the local energy storage plants could provide. These benefits are not currently recognised within the market reward system and hence could not be claimed as a source of revenue for the purposes of raising capital funds for the project.
7.4.1 Fuel Reduction
The work described in Chapter 3 suggests the gains to be made when operating CCGT plants at or near their optimum performance produce power.

Cost advantages were identified for both the power plant operations and maintenance. It was suggested that fewer new power plants would be required if the modulation element of the plant output (i.e. load following and spinning reserve) could be removed from their duties. There would therefore be a saving in the future capital required to fund the extra plant capacity.

7.4.2 Reduction of CO₂ and NOₓ emissions
The emissions from the CCGT plant examined in Chapter 3 indicated that both the CO₂ and the NOₓ emissions are lower per unit of power produced when the plant is operated at the optimum power output.

If the power plant was operated in conjunction with local energy storage facilities, it could gain income from the sale of Carbon Certificates which could be sold in the trading market. But as no financial incentive is currently in place to encourage this type of development and there is no measurable reward to explore potential gains, it is unlikely to emerge as a potential solution at the present time.

The NOₓ emissions from CCGT plants are very much higher during the starting period particularly during the cold start routine. As these gasses are environmental hazards any reduction in their release to the atmosphere would be a positive environmental gain. There is no current financial reward for lowering the NOₓ emissions. The only requirement is to achieve the restrictions on emissions set out in the Integrated Pollution and Prevention and Control (IPPC) document by the Environment Agency at the planning stage of the power plant before construction commences. This document establishes the levels of emissions allowed during hot and cold starts together with a time limit for such releases into the atmosphere. It also determines the emission levels, which must be achieved during normal operation. However, the levels applied by the Environment Agency are determined by the practical limits of the technology being used in the power station (using the principle of the current ‘Best Available Technology’).
If the contribution of local energy storage was to be made part of the IPPC requirements at the planning stage, it would help advance the development of the necessary technologies. The only other alternative which might reward power plant owners for reducing the emissions would be the introduction of a similar scheme to the Carbon Trading regime but in this case focused upon the emission of NOx.

Under the current market regime the saving to the system would not manifest itself as funds for energy storage. However, without energy storage there would be a need for new plant capacity driven by the requirement for 'Security of Supply' and the capital would be needed.

7.4.3 Transmission and Distribution Losses
An attempt to quantify the losses experienced during transmission and distribution of electrical power was identified in Chapter 5 and the costs and benefits of local energy storage were examined in Chapter 6. If the benefits of the energy stores were to be financially rewarded for reducing these power losses, there would be further revenue contributions towards their capital funding.

In order to achieve some measure of the impact of storing energy adjacent to the customer, it will be necessary to measure and account for the power flows with respect to time across the whole network. Without such measurements it will be difficult to identify the optimum locations for the energy stores and to quantify the gains achieved.

Until the current process of 'Cost Pass Through' to the customer is ended and some form of realistic charging for these power losses is established, nothing is likely to change. The role of local energy storage could provide an attractive solution if it can be successfully integrated into the system.

7.5 Renewable Sources of Energy and Embedded Storage
The principle sources of renewable energy in the UK are unable to provide a secure source of power (wind & solar power). This characteristic together with their variable output will limit the final capacity, that may be integrated into the system described in chapter 2.
In the case of wind energy the best locations for the turbines are located in the north west of the UK (much of this will be found offshore) whilst the major load is towards the south-east. The losses, which will occur as the power is transmitted, will be amongst the highest in the UK especially during periods of peak demand.

Solar power also has major limitations, the power is only available when the sun is visible and varies with the seasons of the year and the amount of cloud cover.

Tidal power is predictable but as identified in Chapter 2, the power is variable both with respect to time during the tidal cycle and due to the variations that occur across the period between spring tides and neap tides. Although the variation due to the tidal rise and fall may be reduced as the periodicity of the tide varies around the coastline, the technologies for capturing this source of energy restrict the locations where the energy may be extracted. A barrage requires an estuary to contain the water, and the tidal stream devices require geographical features where the speed of the tidal flow is accelerated.

The only method of dealing with some of these power variations to make the power output from these sources more valuable to the market is through energy storage, bringing five major benefits:

1) Power would be available on demand
2) Renewable energy sources could demonstrate their ability to respond to the ancillary services (i.e. security of supply)
3) Balancing power currently supplied from fossil fuel stations would be reduced thereby increasing their efficiency of operation with the consequent reduced fuel usage, reduced CO₂ and NOX emissions.

In addition, in the case of wind power and power tidal (depending upon where the storage was located) power losses during transmission and distribution could be reduced if the excess power generated during the low demand periods was stored adjacent to the customer.

Where power is stored adjacent to the renewable energy source, capital investment and environmental impact could be reduced by the use of lower capacity transmission lines.
(e.g. Where the energy storage is located adjacent to the power source such as the wind turbines the power lines would not be required to convey the full output of the wind farm as the maximum output only occurs for a very small period of time. Power could be released in a controlled fashion to match market requirements over the short term).

### 7.6 Characteristics of Renewable Energy Sources

**Solar power** would benefit from local storage, as it would be possible to span some of the periods when no generation is possible. But it would not address the issue of the very significant variation of solar radiation and hence the power produced across a 12-month period.

**Tidal power** presents two issues, the dwell period between tides and the variation between spring tides and neap tides. Storing power could well accommodate the dwell period, which occurs approximately every 6 hours across the high tide and low tide periods. Again it would allow tidal energy to claim a degree of power supply security in the short term (24 hours). But it would not solve the very large power output differences, which occur between spring tides and neap tides. Without the use of very large energy storage facilities designed to smooth the output over a period of 14 to 28 days, it would not be practical to solve this issue. Tidal power will only be able to provide a limited but predictable power output of base load capacity.

### 7.7 Nuclear Energy and Energy Storage

The nuclear power plants are best suited to supplying base load. Any thermal cycling of the reactor core to match the market demand causes problems. Firstly, the fuel rods are not suited to thermal cycling and their life is reduced where this occurs. Secondly, the thermal inertia of the plant does not allow the generating unit to change the generating output of the plant with the necessary speed of response. Whilst a certain amount of short-term change in output can be achieved by flashing steam in the system, this provides minimal increase in output for a very short period.

The nuclear stations are best employed supplying a continuous constant output. If there was sufficient energy storage built into the electricity supply chain these plants would be
able to supply a higher proportion of the power demand. By charging the energy stores at night they could provide, both electricity to meet the daily variations from the customers and provide power to make good shot falls in supply from the renewable energy sector.

In theory, the combination of renewable energy and nuclear power with sufficient energy storage embedded in the distribution system could provide very low gaseous pollution levels. It would deliver the problem of significantly increased amounts of spent nuclear fuel to be disposed. Until there is an agreed method of dealing with this material the dream of all electricity production being free of CO₂ emissions is unlikely to be realised.

7.8 Environmental Impact of Embedded Energy Storage

There are two separate elements of the environmental impact of local energy storage:

(1) the potential to contribute to reduce of pollution from major fossil fuelled power stations and power losses occurring in the transmission and distribution network.

(2) the impact on the immediate environment of the local energy stores.

This section of the thesis will discuss item 2 and the potential restrictions which could apply these stores if places in urban areas.

7.8.1 Noise

The local energy stores would need to be designed to meet the national and local planning regulations with respect to the noise emissions.

The principle guidelines require that noise emitted by new equipment should be less that 48 dB (A) at the nearest receptors. It would also be necessary for any single emitted noise frequency to be restricted to less than 3 dB above the normal background noise [76]. As the energy storage operation would take place every night between 00.00hours and 05.00hours it is unlikely that any special concessions would be allowed even during the start-up period when electric motors in particular can emit high noise levels.
7.8.2 Visual Impact
The visual impact of the energy storage units would be required to meet the requirements of the planning authorities and the local population. The outline profile, the colour and the physical size of the store would be important factors in obtaining the necessary permissions.

Where such energy stores can be integrated with or adjacent existing electricity substations, the visual impact is likely to be more acceptable by comparison with new stand-alone installations.

7.8.3 Emissions to the Environment
All emissions to the environment whether liquid, solid or gaseous would need to be authorised by the Environment Agency. Potential accidental emissions would require special measures of containment and any possible contamination of the aquifers would require special prevention measures where poisonous material might reach the watercourses.

As gaseous releases are sensitive issues for the general public, local energy stores would cause concern. If it were thought that the atmosphere might be contaminated by unpleasant or poisonous gases or chemical, the resistance to new proposals would be a significant factor in gaining planning permission.

7.8.4 Electromagnetic Radiation
The subject of electromagnetic radiation from overhead transmission lines has been an emotive subject amongst the general public with the possible link to childhood leukaemia. It has been a significant issue where high voltage lines are concerned and caused several major project planning permission delays as public enquiries have been held.

One of the benefits of local storage rests upon the fact that all the storage would be at low voltage (11kV and 415vots) and therefore cause less concern. Where the storage was placed within a local electricity substation it would most likely be seen as an extension of existing equipment on a 'Brown Field' site which has been acceptable to-date.
7.8.5 Local Energy Storage life cycle and Maintenance requirements.

If acceptance is to be achieved amongst the local residents, the energy store should cause the minimum of local interference. It must be constructed quickly, need little or no maintenance and have a long life.

The installation should have a continuous life expectancy of more than 20 years, be operated remotely from the site with a minimum of activity for maintenance and adjustments.

7.9 Summary of the General and Technical Requirements

An ideal local energy storage facility should therefore:

(a) Be silent in operation
(b) Operate for many years (+20 years) with a minimum of attendance
(c) Be operated remotely
(d) Present an acceptable visual impact to the public
(e) Emit no detectable noise or smells
(f) Present no health hazards with respect to solids, liquids or gases
(g) Cause no concern with respect to electromagnetic radiation
(h) Should not cause concern about reduced the residential property values near the site
(i) Be built on a brown field site where possible
(j) Be incorporated within existing local electricity substations where possible
(k) Be quick and easy to install with a minimum of noise, dust and inconvenience

Technical Requirements

If a local energy store is to be technically successful it must have a number of essential characteristics:

(a) The Turn Round efficiency of the device should be equal to or better than 80% to make it economic for application in the distribution system where the average loss is average power loss is experienced at the 11kV and 415 volt level.
(b) It must be capable of storing the full capacity of the energy store within 4 hours (i.e. between 01.00 and 05.00 each 24 hour cycle).
(c) It must be able to discharge the full capacity of the store within a 2 hour period (i.e. between 0.6.30 and 0.6.30 hours and between 16.30 and 18.30 hours each day).

(d) It must be able to respond to help correct frequency deviations on the system according to the National Grid Code specifications.

(e) It must respond to correct local voltage deviations and to supply reactive power when requested.

(f) It must be controlled remotely and be equipped with automatic synchronising equipment.

(g) The power output must not exceed the capability of the local circuit. (This will require the system to respond to local customer demand to avoid overloading any local circuits).

(h) When acting as a generator it must be protected from external faults with sufficiently fast acting instrumentation and circuit breakers.

(i) When acting as an energy store it should cause a minimum of local interference in respect of voltage reductions or transformer overload due to the start-up current demand.

(j) It must be capable of continuous power output with a minimum of power loss during the quiescent periods when fully charged but not regenerating power.

7.10 Energy Storage Technology not suitable for Embedded Applications

Although there are a number of proven energy storage methods available, not all are suitable to apply to the task of storing energy in the urban environment on the low voltage distribution circuits.

Using the review of all the major methods of energy storage developed in Chapter 4 above it is possible to eliminate some of the established methods as being unsuitable to provide the local storage duties.

7.10.1 Pumped Storage

Pumped Storage requires special geographical features for it to provide the head of water necessary to store the energy. As these physical features do not exist in most urban locations, it may therefore be eliminated as a potential contender.
7.10.2 Superconducting Magnetic Energy Storage (SMES)

Superconducting Magnetic Energy Storage (SMES) is a possible contender but it requires a relatively large foot-print and where the bulk of the equipment is located underground it requires significant civil engineering construction work.

The technology is best suited to providing short-term power back-up services. It is therefore not suitable to provide a continuous power supply over several hours. It also suffers from the requirement of storing power in the form of high current flows in coils of copper wire at very low temperatures involving high magnetic fields. The electromagnetic radiation caused by the high current flows would be seen as an environmental hazard by the general public which could become a major factor when seeking planning permission for such projects.

7.10.3 Compressed Air Energy Storage (CAES)

Compressed Air Energy Storage (CAES) is another technology, which requires special conditions. In this case it is associated with boosting the output of a CCGT power plant and suitable geological features where compressed air may be stored. As neither of these requirements is likely to be available in urban areas, it is also not suitable to store energy in small quantities.

7.10.4 Super-Capacitors

Super-Capacitors can store energy in small quantities. However, they are only suitable to provide pulses of power and hence are limited to providing a service during voltage drops and short term interruptions. They are not suitable for supplying a constant power output over a period of several hours.

7.10.5 Flywheels

Flywheels can store very small quantities of energy. They are best suited to supplying power for a short duration. They are mainly used to correct power drops or short term power outages where it is essential to provide power to ensure an ordered shutdown of vital plant. They are not suitable to supply power over an extended period of several hours.
7.11 Energy Storage Technologies with potential as Embedded Stores

The remaining technology for storing energy is focused upon the electrochemical battery. This range of chemical energy storage technologies has expanded considerably in recent times. Whilst some methods show specific potential as potential contenders to perform the duties of local energy stores others may be eliminated at the outset.

7.11.1 The Lead–Acid battery

The lead acid technology is mature and relatively cheap to install. Some notable examples of its use can be found in remote areas such as Alaska where a continuous power supply is vital [77].

Unfortunately, it may be eliminated on several grounds, namely:

- It requires a large land area to store the energy
- The storage capacity is limited (25 – 45 Wh/kg)
- The life cycle is relatively short (200 – 3,500 cycles) depending upon the depth of discharge
- A variable range of turn round efficiency (65 to 95%)

The life cycle is effected by the charge / discharge cycle employed. In cases where the depth of discharge is greater than 70% the life cycle would be less 500, equivalent to approximately 1.4 years of service. When the depth of discharge is reduced to 80% the life cycle is extended to approximately 3,500 cycles or 9.5 years at the expense of increased capital cost and the physical size of the installation to accommodate the increased volume.

7.11.2 The Sodium Sulphur Battery

The sodium sulphur battery is capable of delivering bulk power but it has a number of disadvantages. It has to operate in the liquid phase at a temperature in excess of 300°C which requires thermal lagging making the installation physically large.

As the chemical compounds represent a hazard the environmental restrictions may be difficult to accommodate in urban areas and cause local objections. The life cycle (2,500 cycles) represents a life of approximately 7 years, which would require refurbishment on a
regular routine. The battery has a high turn round efficiency of ~90% but there is a parasitic loss due to the requirement for heat to keep the system at the correct temperature.

7.11.3 The Nickel Cadmium Battery
The nickel cadmium has high power potential, an output of +10MW but an efficiency of only 70%. The life of the battery system would require to be replaced after approximately 2,500 cycles.

The turn round efficiency is approximately 70% and the potential for leakage into the environment are of concern. The disposal of the units at the end their life cycle due to the cadmium present is more expensive than the lead acid battery.

7.11.4 The Sodium Nickel Battery
The sodium nickel bromide battery has similar limitations to the Sodium Sulphur battery. Limited to an output of ~300kW it requires a source of heat to keep the unit at the correct temperature. The life is limited to 2,500 cycles before refurbishment. It is therefore unsuitable to store power locally in an urban area.

7.11.5 The Lithium-ion Battery
Lithium-ion batteries have very high efficiencies of ~95% with a potential long life of up to 10,000 cycles before a refurbishment is required. The capacity of the system is limited to ~200kW which together with the high cost of the unit makes it unsuitable for storing energy locally.

These batteries have a high energy density which has made them applicable to providing the small portable electronic devices with rechargeable storage units. Further development of this technology may deliver units which are suitable to supply the bulk power for electric traction in vehicles and energy storage for renewable energy smoothing and load shifting in an urban environment.

7.11.6 Flow Batteries
The flow battery offers the best potential for bulk energy storage. Its development has been centred upon three different electrolyte constituents, Vanadium, Zinc bromide and polysulphide bromide (Regenesy).
Chapter 7 Distributed Energy Storage

They are potentially attractive as they offer high energy content (kWh) to power (kW) ratio. The capacity of each battery is dependent upon the size of the storage capacity for the electrolytes. The most ambitious attempt to-date to store significant quantities of energy (The Little Barford Experiment UK), where 120MWh of storage capacity was installed has been discontinued. The project summary report [78] indicates that difficulties were encountered with failure due to

- Module sealing (leaks of bromine and H2S)
- End bipole failures
- Electrode Fracture

If or when these difficulties are overcome, this technology offers potential bulk energy storage suitable for urban locations. A comparison of the turn round efficiencies and the life cycles claimed for flow batteries is shown in table 7.1

However, the current designs require land areas similar to those illustrated in Table 7.2 for the VRB vanadium flow battery [81].

Table 7.1 Flow Battery performances Sources:[79], and [80].

<table>
<thead>
<tr>
<th>Flow Battery</th>
<th>Turn Round efficiency</th>
<th>Life cycle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vanadium</td>
<td>70 - 75</td>
<td>15,000</td>
</tr>
<tr>
<td>Zinc Bromide</td>
<td>70 - 75</td>
<td>1,500-2,500</td>
</tr>
<tr>
<td>Polysulphide bromide</td>
<td>60 - 75</td>
<td>NA</td>
</tr>
</tbody>
</table>

Table 7.2 The Vanadium flow battery foot print area (m²)

<table>
<thead>
<tr>
<th>Storage duration hrs</th>
<th>4 hrs</th>
<th>6hrs</th>
<th>8hrs</th>
<th>10Hrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>kW rating</td>
<td>m²</td>
<td>m²</td>
<td>m²</td>
<td>m²</td>
</tr>
<tr>
<td>50</td>
<td>11</td>
<td>16</td>
<td>21</td>
<td>26</td>
</tr>
<tr>
<td>100</td>
<td>21</td>
<td>32</td>
<td>42</td>
<td>53</td>
</tr>
<tr>
<td>200</td>
<td>46</td>
<td>46</td>
<td>46</td>
<td>57</td>
</tr>
<tr>
<td>500</td>
<td>60</td>
<td>90</td>
<td>120</td>
<td>140</td>
</tr>
<tr>
<td>1000</td>
<td>120</td>
<td>170</td>
<td>139</td>
<td>172</td>
</tr>
<tr>
<td>10000</td>
<td>622</td>
<td>933</td>
<td>995</td>
<td>1291</td>
</tr>
</tbody>
</table>
Chapter 7 Distributed Energy Storage

From the above tables it can be seen that three factors may limit the flow battery applications for local energy storage duties:

1) The turn round efficiency is low (nominally 70% to 75%)
2) The long term sustainability at this level remains to be proved.
3) The current designs indicate that the land area required may also place a limit on the use of these devices in urban areas. Finding suitable areas near electricity substations may be difficult and as the land is often expensive it would add significantly to the capital cost where such land is available.

The environmental impact will be an important consideration. The visual appearance will be substantial by comparison with local buildings and the potential leakage of various dangerous chemicals would require special attention to protect the local population and the aquifers from contamination.

7.12 Chapter Summary

The results of the review completed in this chapter indicate that many of the storage technologies currently in use are unsuitable for the purposes of embedded energy storage within the electricity supply chain.

Whilst some of the benefits to be gained from storing energy will attract financial reward, there are other benefits which will not be rewarded including the following:

Savings achieved by energy stores located at points in the transmission and distribution system where the power losses are equal to or above the declared average level.

The benefits delivered at the fossil fuelled power plants;

- Better fuel consumption / unit delivered to the customer
- Lower emissions (CO₂ and NOX) emitted per unit delivered.
- Better utilisation of capital investment in generating plant, electrical transmission and distribution equipment and the gas transmission network.
- Reduced operating and maintenance costs at the generating station
- The greater penetration of renewable energy sources (Group 2 & 3) through:
Chapter 7 Distributed Energy Storage

• Reduced volatility of supply.
• The storing of excess power when not immediately required by customers.
• Storing power generated by nuclear power stations thereby lifting their contribution above the base load demand.

The most suitable technology to store energy in relatively small quantities (say 100kWh to 1000kWh) is the ‘Flow Battery’. The advantages are:

• The operational life of the batteries is purported to be in excess of 10,000 cycles.
• The capacity can be designed to match local requirements
• The operational costs are low
• The capacity can be extended by adding extra storage capacity for the electrolyte
• The response characteristics are capable of delivering the operational requirements
• The environmental impact is low

The disadvantages of the flow battery to be overcome include:

• A relatively large land area required for storage which would be expensive in many urban areas.
• A low turn round efficiency of 70% when converting from an AC supply to DC for storage and finally he back to AC for final use by the customer
• A relatively high capital cost.
Chapter 8
Local Energy Storage using
The Flow Battery

8.1 Introduction

The most suitable energy storage technology currently available to provide local energy storage is the Redox flow battery. A number of different electrochemical reactions have been examined but the current commercialised systems are based on a vanadium electrolyte. It does not offer the highest cell voltage but it is claimed to be the most suitable for unattended operation with the current state of flow battery development.

8.2 The Vanadium Cell

The energy is stored by changing the chemical species of vanadium dissolved in a solution which becomes the working fluid to be pumped from a set of storage tanks to the membrane cell. The basic operation is illustrated in Figure 8.1.

Gaterall et al [82] were the originators of the mechanism and the interaction with the Electrodes. They used platinum electrodes. The equations included in the script are taken from their paper [82]. They acknowledge helpful discussions with Miake [83]. The reaction that occurs at the electrodes in the cell is shown below:

At the positive electrode

\[ \text{V}^{4+} \rightleftharpoons \text{V}^{5+} + \text{e}^- \]

At the negative electrode

\[ \text{V}^{3+} + \text{e}^- \rightleftharpoons \text{V}^{2+} \]

The potential difference between the electrodes is reported to be 1.257V theoretically but in practice it is found to be marginally higher at approximately 1.4 V [82]. The required output voltage may be achieved by simply connecting a group of cells in series. As this...
technology operates in Direct Current (DC) mode, when it is incorporated into the national supply, it requires a rectifier in the circuit to convert from Alternating Current (AC) to DC and during the charge cycle and an inverter when in the discharge cycle when converting from AC to DC. Both cycles cause small quantities of heat to be liberated during the conversion process, which result in a loss of power.

Fig 8.1 The Vanadium Redox Battery

8.3 Vanadium Battery Performance

The performance of the flow battery may be examined for a number of desired characteristics which would be essential if it is to provide an energy storage service operating within the national transmission and distribution systems.

8.3.1 Turn Round Efficiency

The energy storage losses that occur during the storage process play a very large part in determining the economic viability of each potential application. The Vanadium Flow battery is reported to have a turn round efficiency of between 65 and 75% depending upon the design and the application, [84]. Where the device is connected to an AC system, a
transformer, rectifier and inverter are required to operate in conjunction with the battery and all produce energy losses when in the circuit.

8.3.2 The Characteristics of a Modern Vanadium Flow Battery

Now the Vanadium battery is becoming more commercially available, the performance of these units is proving to be suitable for a whole range of applications. Table 8.1a illustrates the performance achieved by a VRB Power Systems Company, 5kW (DC to DC) energy store [85].

<table>
<thead>
<tr>
<th>Current Output</th>
<th>5kW (112A) X 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Output Voltage range (VDC)</td>
<td>42-56</td>
</tr>
<tr>
<td>Approx. Dimensions (W x D x H, in)</td>
<td>34 x 86 x 80</td>
</tr>
<tr>
<td>Approx. Weigh (Full, lbs)</td>
<td>7,000</td>
</tr>
<tr>
<td>Approx. DC-DC Efficiency round trip</td>
<td>75%</td>
</tr>
<tr>
<td>Performance vs Temp.</td>
<td>Flat response over temperature range</td>
</tr>
<tr>
<td>Containment</td>
<td>Double containment of electrolyte</td>
</tr>
<tr>
<td>Lifetime (discharge cycles)</td>
<td>10,000+</td>
</tr>
<tr>
<td>Depth of Discharge</td>
<td>From Full to 20% state of charge</td>
</tr>
<tr>
<td>Recharge Time</td>
<td>4 hours (optional 1:1 charge/discharge ratio)</td>
</tr>
<tr>
<td>Speed of response</td>
<td>1 ms</td>
</tr>
<tr>
<td>Overload capacity</td>
<td>2 X normal rating</td>
</tr>
<tr>
<td>Maintenance</td>
<td>Annual inspection if desired</td>
</tr>
</tbody>
</table>

Table 8.1a A VRB Power Systems 5kW energy storage unit. Source: [85]

A more recent Vanadium Flow Battery array has been purchased for storing the power from a wind farm in Éire, [86]. The specification of this device is shown in Table 8.1b. This specification was subsequently increased to deliver 2MW with a storage capacity of 12MWh.
Table 8.1b The 8MWh Vanadium flow battery specification destined for installation adjacent to the Sorme Hill wind farm. Source: [86]

<table>
<thead>
<tr>
<th><strong>8MWh VRB - ESS™</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Load Output Power Rating</strong></td>
</tr>
<tr>
<td><strong>Energy Storage duration</strong></td>
</tr>
<tr>
<td><strong>Input Voltage (rms):</strong></td>
</tr>
<tr>
<td>- Nominal Supply Voltage V nominal</td>
</tr>
<tr>
<td>- Maximum Supply Voltage V nominal</td>
</tr>
<tr>
<td><strong>Nominal Frequency</strong></td>
</tr>
<tr>
<td><strong>Output Voltage:</strong></td>
</tr>
<tr>
<td><strong>Voltage Regulation</strong></td>
</tr>
<tr>
<td><strong>Reactive Energy Compensation</strong></td>
</tr>
<tr>
<td><strong>DC Bus Voltage</strong></td>
</tr>
<tr>
<td><strong>Transient Performance - Load</strong></td>
</tr>
<tr>
<td><strong>Load Terminal Overvoltage</strong></td>
</tr>
<tr>
<td><strong>Short Circuit Capability</strong></td>
</tr>
<tr>
<td><strong>Minimum Efficiency (Power Out/Power In) PCS</strong></td>
</tr>
<tr>
<td><strong>Maximum Overload Capacity &lt; 10 minutes</strong></td>
</tr>
<tr>
<td><strong>Maximum Overload Capacity &lt; 3 seconds</strong></td>
</tr>
<tr>
<td><strong>Reliability</strong></td>
</tr>
<tr>
<td><strong>Harmonic Performance</strong></td>
</tr>
<tr>
<td><strong>Voltage Unbalance at Input Terminals</strong></td>
</tr>
<tr>
<td><strong>Communications Protocols</strong></td>
</tr>
<tr>
<td><strong>Communication Connection Interfaces</strong></td>
</tr>
<tr>
<td>Environmental</td>
</tr>
<tr>
<td>---------------------------------------</td>
</tr>
<tr>
<td>Mass kg - Storage Tanks (With Electrolyte)</td>
</tr>
<tr>
<td>- Stacks</td>
</tr>
<tr>
<td>- Power Converter and Controls</td>
</tr>
<tr>
<td>Dimensions 8MWH</td>
</tr>
<tr>
<td>Noise Levels dB (A Weighted)</td>
</tr>
<tr>
<td>Life of System Before Replacement of Membranes</td>
</tr>
<tr>
<td>Annual Operations &amp; Maintenance Costs</td>
</tr>
</tbody>
</table>

The experiences to date with the Vanadium batteries suggest that there will be no degradation of the electrolytes and each unit should be capable of 10,000 cycles of operation with minimal maintenance costs. Availability of the plant is claimed to be greater than 98% [85].

The operating performance described in tables 8.1a and 8.1b meets many of the requirements when operating in parallel with the national electricity supply, such as the speed of response of 1ms or 0.05 of a cycle for a 50Hz power system. There is also no detriment to performance over a wide changes in the ambient temperature from -5°C to 40°C, but certain factors will place some limits upon its general application. The depth of discharge which may be extracted between each recharge is declared at 100% to 20%. This implies that 20% more energy is placed in the store at the commencement of the project than will be extracted and the working range will always require a residual amount of energy to remain in the store.

### 8.4 Physical Dimensions and Plant Layout

The physical size of the plant is determined by the maximum output required and the amount of energy to be delivered and quantity of energy to be stored between recharging periods. The larger the output (MW) the larger the physical size of the power electronics.
and the number of reaction cells required. The greater the amount of energy to be delivered (MWh) the greater the need for electrolyte storage within the complex.

### 8.5 Demonstration Applications

A number of demonstration projects have been installed around the world. The capacity of the energy stored has ranged from 5kWh to 2MWh designed to meet a number of potential future markets. Some these projects are reviewed below.

#### 8.5.1 Voltage Support and Line Load levelling

Figure 8.2 illustrates the layout used to deliver up to 3MW of line voltage support for 1.5 seconds up to 20 times per year and 1.5 MW for one hour to help keep the load on the transmission line in balance and within its operational specification every day. The energy store requires a total building volume of approximately 2,500m³ and a footprint of 250m².

<table>
<thead>
<tr>
<th>Specifications</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Function</strong></td>
</tr>
<tr>
<td>(1) Voltage Sag Protection</td>
</tr>
<tr>
<td>(2) Load leveling</td>
</tr>
</tbody>
</table>

**System Layout**

Fig 8.2 Example A - A Flow Battery complex designed to deliver Voltage Sumitomo Electric Industries Ltd [83]
The physical size of the device (200m$^2$ without the transformer and rectifier and inverter [83]) will limit its use for local energy storage in urban areas where land is both expensive and at a premium.

### 8.5.2 Wind Turbine Applications

The variable power delivered by wind turbines has been discussed earlier but the application of energy storage to help smooth this output has been addressed with the application of a trial 500kW–10 hour flow battery storage unit in Japan [87].

The principle of power balancing is illustrated in figures 8.3 and 8.4. Here the resulting power flowing out to the network in the untreated method is contrasted with the application of an energy store to help soothe the power flow.

![Fig 8.3 Wind power output without and with the use of Energy storage [83].](image-url)
8.5.3 Example A 1MWh store using VBR redox Flow cell Technology

In this example a 1MWh energy store was installed to support a power plant on King Island (Australia). [87]. The extent of the plant is illustrated in Figs 8.5, 8.6 and 8.7 below.

Fig 8.4 Field test to stabilise the output from a wind turbine [83].
The storage tanks for the electrolyte take up the bulk of the space with the reaction cells placed on the first floor level above the pumps.

### 8.5.4 Line Voltage Support and Capital Postponement

A 2MWh energy store using a flow battery has been installed to cure a number of operational problems on a long feeder cable (209 miles) and to postpone capital expenditure on a new distribution circuit. The circuit was operated at 25kV with a connected load of 11MVA. The objectives included the requirement to improve the line voltage, power factor, overall reliability of supply and to be able to supply new customers.
Figure 8.9 illustrates the typical electricity demand on the circuit over a 24 hour period. During periods when the power line operates below the nominal maximum capacity, energy may be stored in the flow battery.

As the daily demand reaches a peak between 12.00 hours and 21.00 hours, the power from the battery may be injected into the circuit at a rate up to 250kW thereby avoiding line overload. The red line indicates the normal shape to the demand and the line indicates the effect of the power injection from the flow battery during the high demand period.

The flow battery installation is designed to run as an unmanned plant [85]. The benefits claimed for the system include increased line capacity, improved line voltage, reduced line losses and postponed capital investment in a new distribution system which is facing environmental impact objections from the planning process [89].

8.6 Capital Cost

The cost of the installing a vanadium flow battery may be divided into three discrete parts: The rate at which power will be consumed and produced by the installation, the quantity of
energy to be stored during each cycle of charge and discharge and items specific to individual sites.

### 8.6.1 The rate of power storage and production
The number of cells and the size of the pumps are set by the rate at which the energy store is required to produce power into the system. It also sets the capacity of the power electronics associated with the unit.

### 8.6.2 Flow Battery Capacity
The quantity of energy held within the store is set by the rate of discharge and period of the discharge required. In the case of load shifting from the night storage period to the peak cost period, two hours of continuous output would be required at the design rate of production. This sets the quantity of electrolyte required to be held in the holding tanks and hence defines the area needed for storage.

### 8.6.3 The Site Specific Charges
The cost of land, the permitting, funding, construction and commissioning of the installation all form part of the final financing package required.

Each energy store would be required to match the local electrical, network conditions. The system fault levels and the power flow patterns under both normal and under fault conditions will need to be examined and a protection system implemented.

### 8.6.4 Indicative Costs
The capital costs of a vanadium flow battery consist of a number of discrete items, the infrastructure, (the site, foundations, buildings, switchgear, electricity grid connection, design services), the power generating cells, the electrolyte and its storage.

The infrastructure cost is assumed to be approximately proportional to the generating capacity of the battery but with minor variations due to local requirements. The battery cells form the major proportion of the remaining costs being between 4 and 6 times more expensive per kW installed than the cost of the electrolyte per kWh. Hence an increase in the generating capacity from say 10kW to 20kW is 4 to 6 times the cost of increasing the storage capacity from 10kWh to 20kWh.
There are very few examples of the Vanadium Flow Battery installations across the world where the cost of the installation has been declared. Few companies are currently manufacturing these units and commercial confidentiality has inhibited this information from reaching the public domain. Without this data it is not possible to indicate whether the Flow Battery would be sufficiently competitive to provide the services required of an embedded energy store. The graph in figure 8.10 has been constructed to illustrate the changes in the capital cost of energy storage (£/kW and £/kWh) when based upon the flow battery principle.

![Flow Battery Capital Cost (100kW model)](image)

**Fig 8.10** The Estimated Shape of Capital Cost Variation of the Flow Battery with increasing kW and kWh capacities (Multiple sources)

The total capital cost per kW installed increases as the required power output increases, but it decreases per kWh as the storage capacity of a specific project increases. Hence the unit is more suitable to deliver a set amount of power for long periods of time, whilst it is more expensive when required to supply power for short periods. It might therefore be more suitable to match the storage requirements of the domestic market where a supply is required over a 12 hour period. Alternatively it might be less suitable to take advantage of the industrial storage requirements where there is only a 2 hour period each day when the maximum price differential occurs.
The Vanadium Flow Battery is becoming commercially available to suit a wide range of demands. Table 8.2 shows the list of some recently installed units in Japan.

Table 8.2 Vanadium Flow Battery installations Compiled from a number of information sheets (source: VRB Power Systems Inc [90])

<table>
<thead>
<tr>
<th>Industry type</th>
<th>Output rate / Storage capacity</th>
<th>Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sports Centre</td>
<td>30kW, 180kWh</td>
<td>Load levelling</td>
</tr>
<tr>
<td>Research Centre</td>
<td>42kW, 84kWh</td>
<td>Peak Lopping</td>
</tr>
<tr>
<td>Office Centre</td>
<td>100kW, 800kWh</td>
<td>Load Levelling</td>
</tr>
<tr>
<td>Wind Farm</td>
<td>170kW, 1020kWh</td>
<td>Output smoothing</td>
</tr>
<tr>
<td>Power Station</td>
<td>200kW, 800kWh</td>
<td>Load levelling</td>
</tr>
<tr>
<td>University</td>
<td>500kW, 5000kWh</td>
<td>Load levelling</td>
</tr>
<tr>
<td>Process factor</td>
<td>1500kW, 1500kWh</td>
<td>Load levelling</td>
</tr>
<tr>
<td>Wind Farm</td>
<td>2000kW, 6000kWh</td>
<td>Output Smoothing</td>
</tr>
<tr>
<td>Wind Farm</td>
<td>4000kW, 6000kWh</td>
<td>Output Optimisation</td>
</tr>
<tr>
<td>Wind Farm</td>
<td>2,000kW, 12,000kWh</td>
<td>Output Smoothing</td>
</tr>
</tbody>
</table>

One project (Some Hill Wind Farm installation (Erie)) has declared some details of the capital cost. This energy store will be used to smooth the output from a 32MW wind turbine installation. It was originally declared to have a value of $6.3m for a 1.5MW capacity with 8 hours of storage. However, following a detailed study of the optimum requirements for the energy store it was revised to have a 2MW capacity with 6 hour storage. The resulting capital cost has been declared as $9.4M, [91]. The total cost of the project including the engineering optimisation studies and the infrastructure costs has not been declared.

8.6.5. Future Price Projections

The Flow battery is a relatively new product and developments in the technology and the methods of production should reduce the cost of these devices. The increase in demand for the battery would lead to volume production and bring further price reductions. One manufacturer (VRB power Systems) has indicated expectations of future cost reductions (figure 8.10) but no time scale has been placed on these developments.
Chapter 8 Energy Storage via Flow Battery

Projected VRB-ESS Cost at Various Manufacturing Volumes
(as % of 2006 Cost)

<table>
<thead>
<tr>
<th>Cumulative Manufactured Volume</th>
<th>Current (2006)</th>
<th>10 MW</th>
<th>100 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total System Cost</td>
<td>100%</td>
<td>89%</td>
<td>69%</td>
</tr>
<tr>
<td>PCS and Controls</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balance of Plant</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cell Stacks</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electrolyte</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Fig 8.11 Future price projections for the Vanadium Flow Battery [92].

8.7 Chapter Summary

The flow battery based upon Vanadium electrolytes offers the best technical solution available to-date.

1. The flow battery has demonstrated many of the characteristics of performance that make it suitable as an embedded energy storage device
2. It can be made available with a wide range of storage capacities and can deliver power over wide time scales (from an hour to several days) to suit local requirements.
3. It is suitable to correct various distribution problems from line voltage and power factor correction to supplying load during peak demands.
4. It is has proved capable of balancing the variable output from renewable energy sources such as wind power and thereby increasing the potential security of supply from such sources.
The environmental impact of the Flow Battery is reported as relatively benign. There are no unmanageable issues

1. The electrolytes do not represent a pollution hazard
2. Potential noise radiated by the pumping system may be easily suppressed if necessary in sensitive locations.
3. No gaseous emissions are expelled from the plant and therefore there are no air pollution or smells to cause a problem.
4. Where necessary the visual impact can be architecturally treated to match local requirements.
5. The operational temperature of the flow cell (-5°C to 40°C) should not present its exclusion from most geographical location.

The disadvantages identified during the review include:

1. The relatively low turn round efficiency (70% for ac to ac circuits).
2. The physical size of the plant, which requires a significant land area per MWh stored. This may add significant expense and or exclusion from some inner city areas.
3. The current high capital cost may exclude a number of potential applications especially for small scale applications (e.g. at domestic level). The device becomes less expensive per MWh stored as the capacity increases.
4. The size of specific installations will require careful matching to the application.
Chapter 9
A Potential New Energy Storage Technology for Urban Locations

9.1 Introduction

Storing energy by compressing gas has been employed in a number of applications such as hydraulic presses, absorption springs etc. Most of these applications have stored energy on a very small scale for short periods. The one exception is the CAES project (Chapter 2) where large volumes of air are stored in underground caverns before being exhausted into a gas turbine. This technology is not applicable to small local energy storage applications as it requires the correct geological conditions and a link to a relatively large combined cycle gas turbine power station. A new approach is required if energy is to be stored in an Urban Location.

It is proposed that energy may be stored in relatively small quantities (25 kWh to 1000 kWh) by compressing a gas to a relatively high pressure. It could then be used to provide packages of stored energy for conversion to electrical power for the local distribution circuits at a later time. Using this method the compressed gas is allowed to expand under controlled conditions as it delivers hydraulic fluid to a hydraulic motor / alternator set. Conversely, when energy is stored, the hydraulic fluid is forced back into the compression chamber using a motor / pump set, ideally the same equipment, working in reverse, (i.e. electric motor / hydraulic pump). In this way it should be possible to meet two of the important criteria identified in Chapter 7, namely: the requirement that such devices should require a small area of land (footprint) and present a minimum visual impact. The only part of the equipment above ground level would be the motor / generator set and control gear.
Fig. 9.1 The proposed Hydraulic-Pneumatic energy storage (charged)

Fig. 9.2 The proposed Hydraulic-Pneumatic storage phase (discharged)
The storage device is illustrated in Fig.9.1 and Fig.9.2. It consists of a long cylindrical vessel, mounted vertically and located beneath ground level. The hydraulic fluid is exhausted into a reservoir at atmospheric pressure during the generation cycle and pumped back into the compression vessel during the storage phase. This low pressure reservoir is in the shape of a concentric tank placed around the compression chamber.

### 9.2 Model Analysis

Here an analysis is undertaken to evaluate the principle parameters of the hydraulic energy store and to establish the optimum dimensions when the maximum gas pressure in the store is varied over a wide range (350bar to 800 bar). The architecture of the model used in Chapters 9 and 10 is illustrated in Fig.9.3. The arrows denote the data links used.

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**Fig 9.3 The integrated model (Chapters 9 & 10)**
Chapter 9 Potential New Energy Store

The technical analysis was carried out using the following assumptions:

(a) The energy is stored over a period of 4 hours during the low cost period at night time. Any heat generated will be small and will leak into the surrounding environment; hence the compression will take place under isothermal conditions. Likewise, as the power will be returned to the system over a period of 2 hours during the expensive peak demand period during the evening period, the expansion of the gas will be isothermal.

(b) The gas is compressed and expanded according to the ideal gas laws.

(c) The hydraulic fluid is incompressible.

(d) None of the gas is absorbed by the hydraulic fluid.

(e) The dimensions of the vessel remain constant during the complete cycle.

(f) The hydraulic fluid exhausts into atmospheric pressure.

9.2.1 Technical Model

The analysis is based upon calculating the quantity of hydraulic fluid required to generate the required power output during each time interval as the gas pressure reduces during the power generation cycle.

Phase 1 of the model follows the process illustrated in Fig. 9.4

Using the relationship for a hydraulic motor:

\[ P_o = \frac{(Q \times p)}{600} \quad (kW) \]  

(9.1)

Where:

- \( P_o \) = Power output to be delivered (kW)
- \( Q \) = The fluid flow rate during the initial time interval (Litres/Min)
- \( p \) = The initial gas pressure in the compression chamber (bar)

Let:

- \( \Delta t \) = time interval selected (min)
- \( V_o \) = Initial volume of gas
- \( \Delta V \) = Incremental change in gas volume during time \( \Delta t \)
- \( T_o \) = start of generation cycle
- \( T_x \) = end of generation cycle
- \( p_o \) = Initial gas pressure
\[ \Delta p = \text{Incremental change in gas pressure during time } \Delta t \]

Applying the ideal gas laws equations of state

\[ P_o \times V_o = (P_o - \Delta P)(V_o + \Delta V) \]

\[ \Delta V = Q \]

\[ (P_o - \Delta P) = (P_o \times V_o)/(V_o + \Delta V) \]

\[ (P_o - \Delta P) = (P_o \times V_o)/(V_o + Q) \]

Rearranging equation 9.1

\[ Q_x = (P \times 600)/p_x \quad \text{(litres/min)} \] (9.2)

\[ P_x = (P - \Delta p) \]

\[ Q_x = (P_o \times 600)/(P - \Delta p) \]

The total volume of fluid required to deliver the stored energy is given by during the period \( T_o \) to \( T_x \).

\[ \sum_{T=T_o}^{T=T_x} Q_x = (P_o \times 600)/p_x \quad (9.3) \]

The above equations have been used in the calculation process shown in Appendix 6.

The model (Appendix 6) has the following inputs

- Power to be stored: \( 1 \text{MWh} \)
- Starting gas pressure: Varied from 350 to 800 bar

In the calculation process the model first calculates \( Q \), the fluid flow per min. Next the new gas pressure is determined and used to determine the next fluid flow rate. The calculation is performed for 60 increments. A series of calculations were performed to evaluate the cylinder volume required to deliver One MWh over the cycle. The starting pressure in the cylinder was varied from 350 bar to 800 bar in increments of 150 bar.
9.2.2 Case 1 350 bar Initial Cylinder Pressure

The model was used to seek the minimum volume of the compression cylinder required to store energy equal to 1MWh as the volume of the initial gas volume at the beginning of each cycle was varied. As the generation cycle proceeds, the pressure in the cylinder is reduced with the expansion of the gas. In order to maintain a constant power output, the hydraulic fluid flow to the motor increases.
Fig. 9.6 Cylinder pressure change during the generation cycle for different gas starting volumes.

The energy stored per cubic meter, as the starting volume is varied, is illustrated in Fig. 9.7 and Fig. 9.8 which clearly identifies the initial conditions for maximum energy storage per unit of capacity when the maximum cylinder pressure is set at 350 bar. Here the optimum occurs with an initial gas volume of 102,000 litres and a total volume (Fluid plus Gas) of 277,000 litres.

Fig. 9.7 Cylinder volume required to store 1MWh
Fig.9.8 Energy stored per cubic meter for different starting gas volumes

1MWh model

9.2.3 Initial Cylinder Pressure and Energy Stored

The model was subsequently employed to explore the consequences of increasing the initial maximum pressure in the cylinder, to determine the quantity of energy which could be stored (per unit volume).

The starting pressure was increased from 350bar to 800bar in increments of 150 bar (Appendix 6 sheets 1 to 4 and the consolidated results are shown in sheet 5). Fig.9.9 illustrates the results obtained. It can be seen that the energy stored per unit volume increases as the cylinder pressure increases and the optimum gas starting volume decreases. The total compression cylinder volume, which is required at the start of the generation cycle to store the maximum energy density for each pressure range is shown in Table 9.1 and illustrated graphically in Fig.9.10
Table 9.1 Minimum Compression Cylinder volume (1MWh stored) / Starting Pressure

<table>
<thead>
<tr>
<th>Maximum Cylinder pressure bar</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum Cylinder volume cu m</td>
<td>277.3</td>
<td>194.1</td>
<td>149.3</td>
<td>121.3</td>
</tr>
</tbody>
</table>

The starting conditions, which result in using the minimum volume of gas at the beginning of each cycle over the range of gas starting pressures investigated (350 bar to 800 bars), are shown in Table 9.2 & illustrated graphically in Fig. 9.11.
Chapter 9 Potential New Energy Store

Fig. 9.10 Optimum cylinder volume for each pressure range

Table 9.2 Hydraulic Fluid fill & Gas Fill for optimum energy storage (1MWh)

<table>
<thead>
<tr>
<th>Maximum Cylinder pressure</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>bar</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydraulic Fluid Volume/m³</td>
<td>177.3</td>
<td>129.8</td>
<td>94.3</td>
<td>76.3</td>
</tr>
<tr>
<td>Starting Gas Volume /m³</td>
<td>100.0</td>
<td>64.3</td>
<td>55.0</td>
<td>45.0</td>
</tr>
</tbody>
</table>

Fig. 9.11 Hydraulic fluid and Gas volumes at the start of the generation cycle for optimum cylinder volume (1MWh stored)
The maximum energy stored per cubic meter of the compression cylinder is summarised in Table 9.3 and illustrated in Fig 9.12 below.

<table>
<thead>
<tr>
<th>Maximum Cylinder pressure bar</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Stored kWh /cu m</td>
<td>3.61</td>
<td>5.15</td>
<td>6.70</td>
<td>8.24</td>
</tr>
</tbody>
</table>

![Energy Stored per m³ - Cylinder starting pressure](image)

Fig 9.12 Energy stored per m³ - Cylinder starting pressure

### 9.3 The Compression Cylinder

#### 9.3.1 Dimensions & Weight

In order to restrict the footprint of the energy store on the surface and to work within the current limits of high pressure steel piping, it was decided to limit the maximum diameter of the cylinder to 36 inches.

Length of cylinder \( L_c = \frac{V_c}{\pi r_c^2} \)

Where
- \( L_c = \) length of cylinder
- \( V_c = \) total volume of cylinder
- \( r_c = \) cylinder radius
Note: The Imperial measurement system has been used in part of this analysis as it continues to be used in the manufacture of steel pipes across the industry. However, where relevant, the measurements have been converted to the SI system for reporting results.

If the maximum outside diameter of the cylinder is set at 36 inches, it is necessary to correct the calculations for both cylinder wall thickness and the grade of steel employed (i.e. the 'X'- grading). (The pipes are designated an X factor to indicate the yield strength of the pipeline material (kilo pounds per square inch).

Hence the corrected length of the cylinder is given by:

\[ L_{cc} = V_{cc} / [\pi (36/2 - (r_{c} - W_{t}))] \] (9.4)

Where

\( L_{cc} \) = corrected cylinder length
\( W_{t} \) = wall thickness

The cylinder wall thickness is given by;

\[ W_{t} = P_{\text{max}} \times D_{od} / (2 \times \text{Steel grade factor} \times \text{Design factor}) \] (9.5)

Where

\( P_{\text{max}} \) = Maximum pressure in cylinder
\( D_{od} \) = Outside diameter of the cylinder

The calculations of wall thickness required at the various maximum pressures (Appendix 6 (sheets 1 to 4)) are shown in table 9.4 and illustrated in Fig 9.13. The most suitable specification of steel currently available for the construction of the compression cylinder is the X-120 grade (Asahi et al [93] and Hillenbrand et al [94]). (The calculations of the necessary wall thicknesses are shown in appendix 6.)

<table>
<thead>
<tr>
<th>Maximum gas pressure (bar)</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wall thickness (inches)</td>
<td>0.76125</td>
<td>1.0875</td>
<td>1.41375</td>
<td>1.74</td>
</tr>
</tbody>
</table>

The required depths of the cylinder for the different operating pressures after correcting for the differences in wall thickness are shown in Table 9.5.
The total length of the compression cylinder (including gas volume and fluid volume) adjusted to allow for the varying wall thickness due to the maximum pressure applied is shown in Table 9.5.

Table 9.5 Length of cylinder (m) for 36 inch diameter tube

<table>
<thead>
<tr>
<th>Maximum Cylinder pressure (bar)</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length of Cylinder required (m)</td>
<td>460.4</td>
<td>334.9</td>
<td>267.8</td>
<td>226.4</td>
</tr>
</tbody>
</table>

The graph (Fig 9.14) shows the depth (m) of the bore hole required if the cylinder is to be accommodated below ground level. It is apparent that the higher the initial operating pressure, the shorter the length of the cylinder required. The optimum cost of the system would be achieved by the careful selection of the maximum operating pressure, the equipment and the materials from commercially available equipment. If the higher pressures are selected (650 bar and 800 bar) it is likely that each unit in the system would require a tailor made model for the duty.
9.3.2 Cost of Steel Cylinder

The volume of the steel required represents the major cost of this energy storage proposal. The quantity of steel varies depending upon the specific steel specification selected. The grade X-120 has been chosen for the following calculation.

The weight of steel per ft run of the cylinder is given by:

\[ M_{\text{cyl}} = 10.69 \times (r_c - W_t) \times W_t \]  

(9.6)

where

\[ M_{\text{cyl}} = \text{Weight of the cylinder lbs/ft} \]

The weight/ft run and the total weight for each cylinder for the pressure range (350 to 800 bar) are listed in Table 9.6 and graphically Fig.9.15.

Table 9.6 Compression cylinder weights (lbs/foot run and tonnes)

<table>
<thead>
<tr>
<th>Maximum gas pressure bar</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Weight of cylinder tonnes</td>
<td>196</td>
<td>202</td>
<td>208</td>
<td>215</td>
</tr>
<tr>
<td>Wall Weight lbs/ft run</td>
<td>287</td>
<td>406</td>
<td>523</td>
<td>637</td>
</tr>
</tbody>
</table>
Fig.9.15 Compression Cylinder weights (lbs/ft run & tonnes total weight)

The results indicate that total weight of the cylinder over the complete pressure range is virtually identical. But as the wall thickness for the higher pressures is progressively thicker, the length of the cylinder at the higher pressures is proportionately greater which has a marked impact upon the cost of the vessel.

The cost of the cylinder as a finished item is dominated by the price of steel in its final form. The cost of steel piping has been estimated (2006 prices) at $1550 / tonne. At current exchange rates of £/$ = 1.88 the cost of a tonne of steel has been taken as £824.

The cost of the compression cylinder for each pressure duty described above is shown in Table 9.7 (see Appendix 6 sheets 1-5)

Table 9.7 Estimated cost the compression cylinders / working pressure. (1MWh model)

<table>
<thead>
<tr>
<th>Maximum gas pressure (bar)</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of cylinder steel (£/cylinder)</td>
<td>158371</td>
<td>163017</td>
<td>167906</td>
<td>173080</td>
</tr>
</tbody>
</table>
The cost of drilling the bore hole to accommodate the cylinder has to be taken into account.

9.3.3 Composite Materials
The compression cylinder is a dominant factor in the capital costs of the energy store. The wall thickness necessary to contain the high pressures and hence the weight of the cylinder is also a major consideration in the site construction. Any method where by these factors can be reduced is therefore an advantage.

Recent work on composite materials offers a possible solution which could replace the steel pipes used in the above analysis. One such composite which is currently being developed by iTi Scotland Ltd (equivalent to steel grade X-200) is known as the Helipipe [97]. It represents a significant advance in the pressure which can be contained in a pipe line of a given thickness. Constructed of high strength materials to reduce the weight, it uses a geometrical shape described in [95, 96, 97] to obtain higher second moment of area and increased hoop stiffness. The final pipe is assembled using a proven adhesive technology. By using a number of layers of the material it should be possible to develop compression cylinders suitable to operate at significantly higher pressures than currently achieved. Fig 9.17 illustrates the claimed advance achieved where the pipe strength claimed is approximately 60% greater than the X-120 steel pipe.
Fig 9.17 The maximum strength of pipe line materials available (1960 to 2006)

Fig 9.18 The Helipipe construction [96].

9.4 Hydraulic Fluid Receiving Tank

The receiving tank for the hydraulic fluid after it leaves the hydraulic motor will need to be placed adjacent to the high pressure cylinder. If it is placed below ground level to minimise
visual impact, it will require to be designed to offer the minimum surface area in order to keep the land requirement as small as possible.

It is therefore proposed that it is accommodated as a concentric tank around the high pressure cylinder as shown in Figs, 9.1, 9.2. & 9.19.

The actual surface area may be adjusted to suit the land available by varying the outside radius of the tank and adjusting the depth of the vessel in the ground as indicated in Table 9.8 where the depth of the tank has been calculated for a tank with outside diameters of 2.0 meters and 3 meters. (i.e. a total surface area of approximately 3.1 m² and 7 m² respectively)

<table>
<thead>
<tr>
<th>Cylinder Maximum Pressure</th>
<th>350</th>
<th>500</th>
<th>650</th>
<th>800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (m) (OD=2m)</td>
<td>77.9</td>
<td>45.3</td>
<td>32.9</td>
<td>26.6</td>
</tr>
<tr>
<td>Depth (m) (OD=3m)</td>
<td>28.6</td>
<td>19.1</td>
<td>13.9</td>
<td>11.2</td>
</tr>
<tr>
<td>Depth (m) (OD=4m)</td>
<td>15.2</td>
<td>10.6</td>
<td>7.7</td>
<td>6.2</td>
</tr>
</tbody>
</table>
Fig. 9.19 Schematic of the receiving tank
Fig 9.20 illustrates the variation of the depth of the receiving tank with starting pressure.

9.5 Micro Energy Storage

The opportunity exists to store smaller quantities of energy within the local electricity network within the light industrial and domestic circuit levels. The electricity tariff structures potentially rewards customers at this level for extracting power during the night time period and charges much higher prices during other times.

If energy storage is to find a role within this market, the quantity of power stored would need to be in the range 10 to 250 kWh, with a routine of storing power each night and regenerating it on demand when required.

Currently, there would be no case for such customers to export power to the local network as the price paid for such power is very low. Hence careful regulation of the device would be required to ensure that only sufficient power was regenerated to meet the needs of the household.

The physical and operating parameters to store energy at the 10kWh and 25kWh have been computed using the same model used above. Table 9.9a and Table 9.7b indicate the data
computed for two cases where the maximum cylinder pressure was 350 bar and 500 bar respectively using steel grade X-120 for the construction of the cylinder. Further data are available in Appendix 6 for a range of energy storage capacities from 10kWh to 1000kWh, maximum cylinder pressures from 350 bar to 800 bar using steel grades X120 and X200.

Table 9.9a Micro Energy Storage (Maximum Pressure 350 bar)

<table>
<thead>
<tr>
<th>Maximum Cylinder pressure</th>
<th>350bar</th>
<th>Steel GradeX-120</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stored Energy kWh</td>
<td></td>
<td>10kWh 25kWh</td>
</tr>
<tr>
<td>Minimum Cylinder volume cu m</td>
<td></td>
<td>2.760 6.909</td>
</tr>
<tr>
<td>Fluid Volume for Min cu m</td>
<td></td>
<td>1.7 4.3</td>
</tr>
<tr>
<td>Gas Start Volume for Min cu m</td>
<td></td>
<td>0.973 2.432</td>
</tr>
<tr>
<td>Length of Cylinder required m</td>
<td></td>
<td>4.58 11.473</td>
</tr>
<tr>
<td>Weight of cylinder tonne</td>
<td>1.96</td>
<td>4.90</td>
</tr>
<tr>
<td>Volume of atmospheric tank cu m</td>
<td>1.71</td>
<td>4.28</td>
</tr>
<tr>
<td>Energy stored kWh/cu m</td>
<td>3.623</td>
<td></td>
</tr>
</tbody>
</table>

Table 9.9b Micro Energy Storage (Maximum pressure 500 bar)

<table>
<thead>
<tr>
<th>Maximum Cylinder pressure</th>
<th>500bar</th>
<th>Steel GradeX-120</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stored Energy kWh</td>
<td></td>
<td>10kWh 25kWh</td>
</tr>
<tr>
<td>Minimum Cylinder volume cu m</td>
<td></td>
<td>1.93 4.83</td>
</tr>
<tr>
<td>Fluid Volume for Min cu m</td>
<td></td>
<td>1.25 3.13</td>
</tr>
<tr>
<td>Gas Start Volume for Min cu m</td>
<td></td>
<td>0.68 1.702</td>
</tr>
<tr>
<td>Length of Cylinder required m</td>
<td></td>
<td>3.33 8.34</td>
</tr>
<tr>
<td>Weight of cylinder tonne</td>
<td>2.01</td>
<td>5.04</td>
</tr>
<tr>
<td>Volume of atmospheric tank cu m</td>
<td>1.25</td>
<td>3.14</td>
</tr>
<tr>
<td>Energy Stored kWh/m³</td>
<td>5.18</td>
<td></td>
</tr>
</tbody>
</table>

Table 9.10 Contrasts the model findings for an energy store of 10kWh capacity with varying maximum cylinder pressures using X-120 grade of steel. These results are illustrated graphically in Fig.9.21
Table 9.10 The parameters for an Energy store of 10 kWh (for a range of maximum cylinder pressures, cylinder dia; 18 inches)

<table>
<thead>
<tr>
<th>Model Results</th>
<th>350 bar (bar)</th>
<th>500 bar (bar)</th>
<th>650 bar (bar)</th>
<th>800 bar (bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Cylinder pressure</td>
<td>X120</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stored Energy kWh</td>
<td>10 kWh</td>
<td>10 kWh</td>
<td>10 kWh</td>
<td>10 kWh</td>
</tr>
<tr>
<td>Minimum Cylinder volume cu m</td>
<td>2.760</td>
<td>1.93</td>
<td>1.5</td>
<td>1.20</td>
</tr>
<tr>
<td>Fluid Volume for Min cu m</td>
<td>1.7</td>
<td>1.25</td>
<td>1.0</td>
<td>0.79</td>
</tr>
<tr>
<td>Gas Start Volume for Min cu m</td>
<td>0.973</td>
<td>0.68</td>
<td>0.52</td>
<td>0.42</td>
</tr>
<tr>
<td>Length of Cylinder required m</td>
<td>4.58</td>
<td>3.331</td>
<td>2.662</td>
<td>2.24</td>
</tr>
<tr>
<td>Weight of cylinder tonne</td>
<td>1.96</td>
<td>2.01</td>
<td>2.07</td>
<td>2.13</td>
</tr>
<tr>
<td>Volume of atmospheric tank cu m</td>
<td>1.71</td>
<td>1.25</td>
<td>0.96</td>
<td>0.75</td>
</tr>
<tr>
<td>Energy stored kWh/cu m</td>
<td>3.62</td>
<td>5.18</td>
<td>6.74</td>
<td>8.32</td>
</tr>
</tbody>
</table>

Fig 9.21 A 10 kWh energy store dimensions & fluid fill for a range of maximum cylinder pressures.

Further results contrasting the dimensions and fluid volumes for energy stores with capacities of 25 kWh, 250 kWh and 1000 kWh are recorded in Appendix 6, Sheet 5.
Chapter 9 Potential New Energy Store

Energy Stored 10kWh, Length of Cylinder
Steel grades X120 & X200

Fig. 9.22 A 10 kWh energy store cylinder length using different steel grades

10kWh Model Weight of Cylinder-Max Cylinder pressure
(Steel grades X120 & X200)

Fig. 9.23 Cylinder weight using different grades of steel
Chapter 9 Potential New Energy Store

Fig. 9.24 Energy stored kWh / m³ - Cylinder pressure

Fig. 9.25 Gas Volume & Cylinder Volume (10kWh energy Store)
Table 9.11 Fluid Flow rates at start and end of the generation cycle

<table>
<thead>
<tr>
<th>Ration (End Fluid Flowrate / Start Fluid Flow rate)</th>
<th>Maximum Starting pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Stored 1000kWh</td>
<td></td>
</tr>
<tr>
<td>Start Fluid Flow rate l/min</td>
<td>350 bar 500 bar 650 bar 800 bar</td>
</tr>
<tr>
<td>End Fluid Flow rate l/min</td>
<td></td>
</tr>
<tr>
<td>Start Gas Pressure 350 bar, 500 bar, 650 bar &amp; 800 bar</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ration (End flow rate / Start Fluid Flow rate)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2.70 2.73 1.49 1.50</td>
</tr>
</tbody>
</table>

Table 9.11 Fluid Flow rates at start and end of the generation cycle

Fig 9.16 Fluid Flow rate at start of discharge cycle

9.6 Depth of Discharge

The depth of discharge is approximately 100%, apart from a residual amount to hydraulic fluid which would be required to remain in the cylinder to provide a buffer between the gas and the fluid to prevent the gas from escaping through the hydraulic motor.
There should be no degradation effect upon the system by cycling the energy store between 100% and 0% storage for an indefinite period. This is in direct contrast to the most electric battery storage systems (with the exception of the Flow Battery), which suffer a significant reduction in their operational life if they are subjected to depths of discharge deeper than 10% (i.e. from 100% to 90%) of their full capacity nominal capacity.

9.7 Component Parts of the Energy Store

(a) Besides the compression cylinder describes above the other component parts include;
(b) A hydraulic motor generator set
(c) An electric drive-hydraulic pump set
(d) Hydraulic control elements and logic controller and safety equipment
(e) An electric circuit breaker
(f) Electric control systems and external electric links
(g) Electric safety equipment
(h) Hydraulic fluid
(i) Atmospheric hydraulic fluid receiving tank
(j) Environmental protection equipment (acoustic noise protection, hydraulic fluid and gas leak detection)

9.7.1 Hydraulic and Electrical Equipment

The principle components of the system are the Hydraulic pump/motor and the electric motor/alternator.

As the energy store is required to deliver power at (50Hz) when synchronised to the distribution network, the generator must operate continuously at this speed with falling hydraulic pressure driving the hydraulic motor during the regeneration cycle. The drive requirement is best provided by the variable displacement hydraulic motor coupled to a synchronous alternator. Likewise when energy is being stored, the alternator must operate as a synchronous motor and the variable displacement motor as a hydraulic pump. (In the event that combined motor/generator/pump sets are unavailable at certain power levels, separate sets may be required during the storage and regeneration cycles)
The availability and cost of suitable hydraulic equipment will be one of the important parameters in the economic success of this type technology. Whilst the smaller capacities of the hydraulic motors and pumps are mass produced for the lower operating pressures and priced accordingly, the larger capacity and higher pressure systems are designed and built to meet specific duties at much higher costs.

Pressures up to 500 bar and capacities up to 100kW may be regarded as standard industrial units, but any device bigger than this would require bespoke design specifically tailored for the energy storage duties.

Figure 9.27 illustrates a typical hydraulic drive / alternator set commercially available with capacities from 3.5 kVA to 70 kVA. This equipment may be used in reverse as a motor / pump set, and figure 9.28 shows an hydraulic motor-powered alternator installed in an excavator.

DYNASET HG 6,6 kVA 400V - 33 IP 54 with an electric box.

Electric box includes:
- Automatic voltage regulator
- Terminal board
- V-meter
- Earth leakage relay
- Automatic circuit breaker
- Single phase socket, 2 pcs
- 3-phase socket

Fig 9.27 A combined hydraulically driven electric generator and electric [98, 99].
9.7.2 Control System

The proposed design is based on an open-circuit variable displacement hydraulic drive which can operate as a motor or pump. It is coupled to an electric generator / motor as indicated in figure 9.29. The response of the system to load changes is claimed to be within 0.1s using electronic control coupled to the stator windings. The hydraulic open circuit system proposed for the duties of the energy store is illustrated in figure 9.30.
Fig. 9.29 schematic view of the energy store operating in regeneration and storage mode.
As prices for exporting power back to the distribution system are very low, even during peak demand periods, it is essential that no energy from the store is spilled into the network. This means the power regenerated from the energy store must be carefully regulated to ensure that the power flow across the synchronising circuit breaker is always equal to or greater than zero in the direction from the distribution system. It will be necessary to adjust the power flow from the energy store to the beneficiary automatically.

Further logic systems will be necessary to ensure the electric generator is protected from electrical faults on the distribution network. Firstly, should an electrical short circuit occur between the customer circuit breaker and the nearest distribution network protection device, it will be necessary to isolate the generator feeding the fault. As the sub-transient reactance of the generator will be approximately 20% the potential fault current could be
approaching five times the full load design current of the machine. The local circuit breaker must be capable of rupturing this current to prevent damage to the equipment.

Secondly, when there is a power outage on the distribution network, the local energy store would be isolated and operating as an 'islanded' system. As soon as power is restored to the network perhaps by an automatic re-closing circuit breaker on the distribution network there would be a real danger of the two systems being out of synchronism. In this situation, large fault currents can flow, the protection system would need to detect the condition and prevent the islanded system being reconnected whilst out of synchronism.

9.8 Potential Applications

The proposed hydraulic system for energy storage could find a number of cost saving applications beyond energy storage for local consumption when prices are high.

The Half Hourly (HH) measured industrial customer would be able to avoid Triad charges by regenerating stored energy during each Triad warning period. It would also be possible for the same customer to offer demand management to the National Grid system controller by producing power during peak periods. Not only would the customer earn an income from this service, but it could also be achieved without the necessity of load reduction within the premises, Hence there would be no loss of productivity which can presently occur when the incoming power is reduced.

The good dynamic response of the energy store to transient changes on the network should make it capable of providing many of the ancillary services required to keep the power supply chain stable.

If a number of these energy stores across distribution system were operated in tandem, a significant amount of power would be available to correct the impact of power demand changes. Energy could be injected or withdrawn from the system to correct frequency and voltage variations and provide the equivalent of spinning reserve. Such a service would provide an important contribution as it would remove a proportion of the fossil fuel power plant capacity being operated below optimum conditions with consequent savings of fuel
and gaseous emissions and in the case of the CCGT plants possible damage to the gas turbines.

Figure 9.31 illustrates the possibility of grouping a number of compression cylinders together in a common shaft to provide a larger reserve of power at locations where there is a substantial load.

The land area required for such systems could be small with most if not all the equipment being housed below ground level. If it were possible to construct such installations into new building developments during the construction period, the land area required could be effectively reduced to zero.

This type of energy storage could provide a real service if it was placed in the centre of a city where there is no possibility of locating a power plant and where the load demand from commercial and administrative operations places a large variable load on the system during the working week.

The integrating of such energy storage facilities into the supply chain would require an integrated approach to the overall control of power flows. Figure 9.32 illustrates the degree of complexity which would be introduced if such systems were adopted. It would require active management of the distribution network working closely with the current active management of the national transmission system.
The smaller energy storage devices could provide services to domestic housing at remote parts on the distribution system where the heating losses are high or where the current network is inadequate to give the correct cover to meet peak demands.

There is also a potential for energy stores (where the excitation of the alternator can be adjusted) to provide reactive power (kVAR) to correct a lagging power factor within parts of the network.

Fig.9.31 A potential multiple compression cylinder energy store
9.9 Capital Cost Estimate

In order to place a provisional cost on the compressed gas energy store a number of companies have been approached for indicative costs of individual components.

The compression cylinder costs have been considered (sections 9.22 & 9.23). The nominal cost of the steel was obtained from a major oil company as they have very wide experience purchasing and using special high grade steel. The potential cost of the composite material (x-200) was estimated in conjunction with the company developing the material.

The cost of the hydraulic and electrical drives has been investigated with two companies who manufacture this equipment.

The cost of the equipment can be divided into two clearly defined groups,

1) Equipment suitable for the small energy stores (i.e. up to 70 to 100 KVA and below
500 bar maximum pressure applications)

2) The larger drives above 100KVA equivalent

It also became apparent during general enquiries to the possible suppliers that the cost of single unit costs was higher than those for volume orders, with prices often 40 to 50% lower for bulk orders.

The hydraulic and electrical control and safety equipment would require specific designs to regulate the response of energy stores matched to each type of application (e.g. individual households through to major stores for industrial purposes). Control systems are available to regulate frequency, voltage control, automatic synchronisation with the public electricity supply etc) but would not meet the complete requirement. Estimates have been included to cover these costs.

As the atmospheric hydraulic fluid receiving tank could be manufactured from several different materials (steel, plastic etc) an estimated cost has been made using prices for tanks of similar volume and derived on a price / cubic metre basis.

Hydraulic fluid is a major cost in each system (second only to the compression cylinder). The cost of this material is volume dependent on a strictly competitive basis. An indication of the cost has been obtained from an experienced purchaser of this material and included in the overall estimates. The bore hole drilling costs are site specific: they are principally determined by the geology of the selected area, the ease of access for the equipment and the number of bore holes drilled. The estimated costs are based upon discussions with two international drilling companies experienced in both large and small diameter drilling.

No cost has been included for the land required as it ranges widely and it is assumed that any initial applications of this type of energy store would be on land already in the ownership of the user.

Two examples of the installed capital costs are itemised in tables 9.12 and 9.13.
Table 9.12 is an example of the estimated costs for an energy store designed to deliver 25kWh suitable for domestic applications. Table 9.13 estimates a store suitable for industrial purposes delivering 250kWh.

Costs for the remaining cases considered are recorded in Appendix 6. They include estimates for energy stores with maximum compression cylinder pressures up to 800 bar and for cylinders built from the new x-200 composite material.
Table 9.12 Estimated cost of 25kWh Energy Store (Max pressure 350 bar)

<table>
<thead>
<tr>
<th>Case 2a</th>
<th>25kWh case X-120, 350 bar</th>
<th>Steel Grade</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Length m</td>
<td>X-</td>
</tr>
<tr>
<td>Compression Cylinder</td>
<td>11.5</td>
<td>120</td>
</tr>
<tr>
<td>Weight of cylinder tonnes</td>
<td>4.90</td>
<td>806</td>
</tr>
<tr>
<td>Volume of Tank m³</td>
<td>4.28</td>
<td>150</td>
</tr>
<tr>
<td>Hydraulic fluid</td>
<td>4.28</td>
<td>0.6</td>
</tr>
<tr>
<td>Motor / Generator set (note: energy delivered over 2 hrs) 12.5 kW (output)</td>
<td>1000</td>
<td></td>
</tr>
<tr>
<td>Pipe Work</td>
<td>5kW - 10kW</td>
<td>150</td>
</tr>
<tr>
<td>Instrumentation &amp; Local Control</td>
<td>Domestic</td>
<td>100</td>
</tr>
<tr>
<td>Logic &amp; External controller Domestic</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Metering &amp; Telecoms Domestic</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Land</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Site Work &amp; Installation</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Shaft Drilling + Liner Depth m</td>
<td>Cost /m £</td>
<td></td>
</tr>
<tr>
<td>25kW model</td>
<td>11.35</td>
<td>300</td>
</tr>
<tr>
<td>Installation of Compression Cylinder &amp; Receiving tank Domestic</td>
<td>500</td>
<td></td>
</tr>
<tr>
<td>Fitting of Motor / Gen set etc</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td>Commissioning</td>
<td>Total</td>
<td>12125</td>
</tr>
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</table>
Table 9.13 Estimated Costs of a 250kWh Energy Store (Max pressure 350 bar)

<table>
<thead>
<tr>
<th>Case 3a</th>
<th>250kWh case X-120</th>
<th>350 bar</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steel Grade</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Compression Cylinder</strong></td>
<td>Length m</td>
<td>X-</td>
<td>£</td>
</tr>
<tr>
<td></td>
<td>114.80</td>
<td>120</td>
<td>39392.62</td>
</tr>
<tr>
<td></td>
<td>weight of cylinder tonnes</td>
<td>Cost/tonne</td>
<td>£</td>
</tr>
<tr>
<td></td>
<td>48.99</td>
<td>806</td>
<td></td>
</tr>
<tr>
<td><strong>Hydraulic Receiving tank</strong></td>
<td>Volume of Tank m³</td>
<td>Cost/m³ £</td>
<td>4110.75</td>
</tr>
<tr>
<td></td>
<td>42.88</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td><strong>Hydraulic fluid</strong></td>
<td>£</td>
<td>42.88</td>
<td>0.6</td>
</tr>
<tr>
<td><strong>Motor / Generator set</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(note: energy delivered over 2 hrs)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>125 kW (output)</td>
<td></td>
<td>10000</td>
</tr>
<tr>
<td><strong>Pipe Work</strong></td>
<td>500kW - 1000kW</td>
<td></td>
<td>5000</td>
</tr>
<tr>
<td><strong>Instrumentation &amp; Local Control</strong></td>
<td>250kW - 1000kW</td>
<td></td>
<td>1000</td>
</tr>
<tr>
<td><strong>Logic &amp; External controller</strong></td>
<td>250kW - 1000kW</td>
<td></td>
<td>10000</td>
</tr>
<tr>
<td><strong>Metering &amp; Telecoms</strong></td>
<td>250kW - 1000kW</td>
<td></td>
<td>5000</td>
</tr>
<tr>
<td><strong>Land</strong></td>
<td><strong>Site Work &amp; Installation</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Shaft Drilling + Liner</strong></td>
<td>Depth m</td>
<td>Cost/m £</td>
</tr>
<tr>
<td></td>
<td>250kW model</td>
<td>114.52</td>
<td>600</td>
</tr>
<tr>
<td><strong>Installation of compression cylinder &amp; receiving tank</strong></td>
<td>250kW model</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>5000</td>
</tr>
<tr>
<td><strong>Fitting of Motor / Gen set etc</strong></td>
<td><strong>Commissioning</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>5000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td>178951.03</td>
</tr>
</tbody>
</table>
9.10 Environmental Impact

Before any industrial project may be installed in an urban or rural location it would need 'Planning Permission' from the local authority in order to make sure it met all the national and local conditions for construction and operation. It would further require to meet the national standards administered by the Environment Agency and the Health and Safety authority.

An energy store such as the one proposed here would be evaluated for the environmental impact it would have on the local area.

Although in this case the major part of the device would be located below the surface, there would be a minor visual impact if the motor – generator set was above ground level. However, as the equipment would need to be protected from the weather and external interference, it is anticipated that a suitably designed cover would suffice.

Two specific environmental hazards would need special attention: namely, noise radiation from the motor – generator system and hydraulic fluid leakage from the compression cylinder, atmospheric receiving tank and the associated pipe work and control equipment.

9.10.1 Noise Radiation

The noise radiated from the Motor/Generator set would be most noticeable during night time when noise from other sources is at a minimum. Each potential site for the store would require a noise survey to establish the current noise level of the background during a quite night when there was no wind noise. If the new equipment is to meet current standards (British Standard BS 4142, 1990) are not to be exceeded, it will be necessary to keep the noise level increase below 5dB(A) higher than the existing Background Noise Level (BNL). As the equipment is designed to operate at night time to take advantage of the lower prices at these times, further noise restrictions may apply.

The World Health Organisation issued a guidance note (1980), which recommended that internal room noise level should not exceed 35 dB(A) to preserve the restorative process of sleep. It assumed that a noise level reduction of 10 to 15 dB would be achieved by a
building of normal construction standards and that a free-field noise level of 37 to 47 dB $L_{Aeq}$ would be an acceptable limit.

It is therefore necessary that the operation of the energy store should not emit noise radiation above these levels. The manufacturer’s specification for the hydraulic Motor / Generator set for the smaller range of devices indicates that the maximum noise levels are 90db(A) at one metre.

It is possible to use sufficient noise absorbing material in the design of the protective housing that encapsulates the system above ground level to stop any nuisance. As each site is likely to be unique with respect to the background noise level, it will require care to match the protection provided to the site conditions.

Noise created during the construction phase is also a regulated factor. Where the construction is limited to day time operations, the BS Standard states that the noise level outside the nearest occupied room should not exceed 75 dB(A) in urban areas and 70 dB(A) in rural and suburban areas taken as being façade $L_{Aeq}$.

It is anticipated that the installation period would be achieved over a short period and that even where major drilling equipment may be required for the larger scale energy stores, the radiated noise could be contained within the required limits.

9.10.2 Leakage of Fluids into the Environment
Potential leakage of fluids or gasses into the environment would be restricted to those caused by accidental discharges.

Damage (either random or during maintenance work) to the pipe work, control valves, fluid seals or hydraulic motors could release fluid. Corrosion within the vessels and pipe work could also allow fluid to escape. The careful selection of the hydraulic fluid to ensure little or no corrosion should minimise this potential danger.

The gas used in the compression cylinder could be selected so that any releases would be benign if it escaped. However, as this gas could be at very high pressure during particular
periods in the storage cycle special provision would be required to protect against any releases from the system.

9.10.3 Life Span of the Equipment and Decommissioning

Most of the equipment employed in the proposed energy storage system is proven technology and of mature development. Examples of such equipment working in harsh conditions for long periods indicate that a long trouble free operation could be expected.

The elements most at risk of failure are the seals within the hydraulic motor and control valves. With a planned maintenance programme and adequate oil filtration facilities the basic equipment should have a life of 25 to 40 years.

When the plant comes to the end of its economic life, there should be no expensive operations to remove that element of the device above the surface.

Should it be necessary to remove the underground elements (compression cylinder) there would be expensive demolition charges especially in the case of the deeper cylinder models. However, if the same conditions apply to this form of construction as currently apply to wind turbine installations where the below ground construction works are allowed to remain, the decommissioning process should be simple cheap and present no risks to health to the environment.

9.11 Chapter Summary

This chapter examined the potential of storing energy by compressing a gas. It uses hydraulic fluid as the compressive medium to store the energy and subsequently to retrieve it via a motor generator set. The findings suggest that:

(1) Relatively high pressures are required if significant quantities are to be stored in a small volume suitable for urban applications.

(2) Energy may be stored in single units with capacities of 10kWh to 1000kWh (or even larger).

(3) The energy could be stored in long cylinders and placed vertically under ground thereby requiring a very small area of land.
Suitable materials and hydraulic equipment are available to construct the store. Off-the-shelf equipment can be obtained for the hydraulic motor and pumps (up to 500 bar and the electrical equipment involves standard motors, generators and control equipment. Where gas compression above 500 bar is envisaged the hydraulic equipment would require bespoke designs.

The variation in the hydraulic fluid flow from initial gas pressure to final gas pressure is within the practical variable rates available for pumps and motors.

The depth of discharge (a limitation on many other forms of energy storage) is not an issue with this proposal.

The minimum size of compression vessel has be determined for each pressure range and storage capacity studied.

A potential new composite material (the Helipipe) has been selected as a potential material for the compression cylinders which is stronger, cheaper and lighter than the selected steel option.

The operational characteristics should meet most of the technical requirements required to perform the duties identified for an embedded energy storage facility.

The environmental impact of the proposed technology has been examined and should pose little or no problems. The radiated noise can be suppressed and any leakage of hydraulic fluid should be contained within the confines of the atmospheric tank.

Gas leaks can be vented to atmosphere and will not present an environmental hazard with the careful selection of the gas used.

The working life of the equipment should far exceed the currently available technologies for local energy storage with an estimated life time of 25 to 40 years.

The use of energy stores embedded within urban areas with a high density of commercial activity may offer particular opportunities to contribute to overall fuel and gaseous emissions when integrated with active management of the distribution system.
Chapter 10
An Economic Evaluation of The Embedded Energy Storage

10.1 Introduction

The preceding chapters have examined a number of issues which influence the power supply and demand for electricity. In the light of the variability of customer demand and the unpredictable nature of power generated from renewable energy sources require the fossil fuel plants to balance demand and supply second by second.

We have also seen that energy storage could make a valuable contribution to solving some of the consequential problems of wasted fuel, inefficient generation, wasted capital resources, transmission equipment and increased carbon releases caused by the variable power output from generating plant.

The variation of the power losses across the transmission and distribution networks and the potential extent of these losses in remote areas and at the end of long supply lines have been estimated, with the objective of identifying the best locations to place energy storage (Chapter 5). This study has indicated that the most attractive point for storage to be installed is embedded deep within the distribution system and it follows that the power demand at such locations would be relatively small. Hence the storage capacity to meet local requirements would be relatively small. As a consequence most of the proven energy storage technologies are not suitable to perform the duties.

This chapter evaluates the potential profitability of local energy storage of the selected devices using three different approaches.

- The first study examines the potential earnings of energy storage embedded within the distribution system for a number of different owners, from individual
households and light industrial and commercial units to large electricity users when considering only the published tariffs.

- The second study considers the savings that accrue by combining the benefits identified in the first study with the benefits gained by operating the power plants continuously at their optimum performance.
- The third study speculates how embedded energy storage may be used to expand the contribution from renewable energy sources and nuclear generating capacity whilst providing some ancillary services.
- The final study examines the potential economic benefits of two potential energy storage technologies suitable for embedded applications (i.e. The energy flow battery and the pneumatic / hydraulic accumulator).

The work described here also suggests there is an urgent need to make fundamental structural changes to the existing electricity tariff and regulatory systems if the wide panoply of benefits to be gained from ‘Local Energy Storage’ are to be made available to fund the capital and operating costs.

10.2 Analysis of Energy Storage Earnings from Tariff Payments

The cost of power delivered along the electricity supply chain is determined by a number of factors. Several of these factors are time dependent and determined by the supply tariffs. Adjustments must be made in order to arrive at the true cost of power.

The charges are applied by depending upon the:

- Time of day
- Day of week / weekend
- Month of year

Some factors such as the price of fuel and carbon certificates depend upon market driven forces.

Hence the actual annual cost of power follows the general equation:

$$\sum_{n=Dec}^{Jan} \sum_{D=24h}^{D=0h} \sum_{T=24h}^{T=0h} C_c = \sum C_g + \sum C_f + \sum C_d + \sum C_s + \sum C_{CO2}$$

(10.1)

Where

$$C_c = \text{Cost of power to the customer}$$
Chapter 10 Economic Evaluation of Energy Storage

\[ C_{CO2} = \text{Cost of carbon emissions (where applicable)} \]
\[ C_g = \text{Cost of generation} \]
\[ C_T = \text{Cost of transmission} \]
\[ C_d = \text{Cost of distribution} \]
\[ C_s = \text{Costs of supplier} \]

Each sector of the industry (generation, transmission, distribution and supply) may be owned and operated by different organisations.

Carbon certificates are traded within the European Carbon Trading scheme and as such are an element to be considered in the generation sector. The allocation and the use of these certificates may be either represented as a cost or a benefit to the generator depending upon individual annual allowances and the annual production profile over a period of one year.

The costs associated within the supply chain may be further identified.

Costs of Generation

\[ \sum C_g = \sum C_k + \sum C_f + \sum C_o + \sum C_m \quad (10.2) \]

Where
\[ C_k = \text{Cost of capital} \]
\[ C_f = \text{Cost of Fuel over one year} \]
\[ C_o = \text{Cost of operations and fixed overheads for one year} \]
\[ C_m = \text{Cost of plant maintenance for one year} \]

Costs of Transmission

\[ \sum C_T = \sum C_e + \sum C_t \quad (10.3) \]

Where
\[ C_e = \text{Cost of entry charge} \]
\[ C_t = \text{Cost Triad charge (exit charges)} \]

Costs of Distribution

\[ \sum C_d = \sum C_f + \sum C_s \quad (10.4) \]
Where

\[ C_t = \text{Cost of line loss factors} \]
\[ C_u = \text{Cost of DNsos/ unit} \]

Costs of the supply company

\[ \sum C_s = \sum C_p + \sum C_a + \sum C_s \]  \hspace{1cm} (10.5)

Where

\[ C_p = \text{Cost of power purchase} \]
\[ C_a = \text{Cost of administration} \]
\[ C_s = \text{Cost of power sales} \]

### 10.2.1 Price Projections and the long term cost of Capital

As the life time of the capital equipment is likely to be in excess of 25 years it was necessary to make an estimate of price projections for electrical power with respect to general price increases (i.e. RPI) and the long term cost of capital (i.e. the bank rate).

During the period from 1990 to 2000 the industry prices for electricity declined as the impact of privatisation drove prices down. At the end of the period the methods of selling power changed with the replacement of the original 'Electricity Pool' with a market based system. Further issues of fuel price rises following supply difficulties and political factors in the supplying countries and changes in industry regulation by individual governments increased the concerns in the market and prices have risen dramatically. Figure 10.1 illustrates the volatility of electricity contract prices for forward contract dates with market price currently declining with respect to the RPI.

This type of volatility of fuel and electricity prices has been the pattern over a number of decades which makes the measurement of the likely financial return on any investment in major projects difficult. Figure 10.1 illustrates the price changes since 1970.

The price changes experienced during the period 2004 to 2006 are shown in figure 10.2 where it can be seen that the volatility is typical of the price movements over time. Hence there is a variable nature of the return on financial investments in major projects. The price change over the period 2004 to 2006 (Q2) was 33.6 percent in real terms (including the
Climate Change Levy (CCL)) during a period when the UK RPI rose by 2.9 % year on year.

It is possible to purchase power forward of the current date at fixed prices as shown in figure 10.3 where it is indicated that the future prices are falling. The cost of power two years ahead is significantly cheaper than currently contracted. The prediction of the potential income stream from any power producing plant over a twenty five year period is therefore a very unreliable parameter and best accommodated by a sensitivity test to establish the possible risk due to price variations. In practice most commercial agreements include protection clauses whereby the price paid for electricity is index linked to a basket of escalators. These escalators may include a proportion of the fuel price from the Petroleum Price Index (PPI), the cost of capital (bank rate) and the base inflation rate, (Retail Price Index (RPI) or Consumer price Index (CPI)).
Fig. 10.2 Fuel prices 2004 to 2006 deflated by the implied GDP deflator.
Source: Dukes tables [100]

Fig. 10.3 The Forward Market electricity prices Jan 2004 to Sept 2006 [101].

10.2.2 Cost of Capital
The cost of capital is an important element when evaluating the viability of a project. For the purposes of nominating a discount factor in the Internal Rate of Return (IRR)
calculations, it has been assumed that the energy storage devices are technically proven and the occurrence of unforeseen risks of failure is low. This should place a risk premium of some 1.5 to 2% above UK bank rate on the senior debt leaving the equity input to carry the full impact of any difficulties. The current bank rate during 2006 (4.75 – 5.00 %) has been adopted as the base rate, which places a rate of 7.25 to 8.0% on the major element of the capital required if the funds are raised through the ‘Project Finance’ method. The bank rate has been volatile during the last 15 years (Fig.10.4) reaching values as high as 15% during 1990, but rates have been relatively benign for the last five years.

The project finance route is mostly available to fund projects using proven technology where the lending agents (i.e. the investment banks) can gain a clear understanding of the technical risks involved and the potential forward stream of earnings which will be produced. Where modern CCGT plants have been project financed during the 1990s and early 2000s they have been funded on an 80% senior debt (i.e. bank capital) 20% equity input from the developers. This type of funding will be considered as one of the potential source of funds whilst evaluating the potential for local energy storage technology, however, until the technology is developed and proved over a period of time, it is doubtful if such a funding route would be available for new technology.

Base Rate Data (1985 - 2007)

Fig 10.4 UK bank base rate 1985 to 2006, Source: Bank of England, [102]
If all the capital is raised within the investing company, the hurdle rate will be set by competing capital projects within that company. The actual return on investment required will be individually set by each company depending on their particular circumstances (e.g. their perception of the risk involved and their desire to enter a new market).

Initial development of the energy storage technology must be considered to have a high risk of failure. Therefore, only if a company or organisation considered the opportunity to be a strategic element of its business future would it choose to make such an investment.

The economic potential of local storage will be evaluated assuming it was proven technology in order to compare and contrast the benefits which may be expected should the process be successful. If a mature reliable technology emerged, it might reasonably be predicted that the capital and overhead costs would be minimised by the economies of volume production and engineering developments.

10.3 Commercial Integration of Embedded Energy Storage
Under the complex tariff arrangements that apply to the transport, distribution and supply of electrical power to commercial and domestic customers, the financial benefits to be gained from local energy storage would depend upon:

(a) how the stores were operated;
(b) how the facility owner may claim particular revenues and savings;
(c) who owns the storage facilities (customer, supplier, trader);
(d) the geographical location;
(e) the capacity of the energy store.

In order to evaluate these issues raised above, five different operational strategies have been formulated, namely:

Study 1
- Domestic customers
- Industrial customers
- Power suppliers
- Power traders
10.3.1 The Domestic Customers (Case 1)

The domestic customer model assumes that the power is imported during the night time (Economy 7 tariff) and used within the household during the daytime when a higher tariff applies. An energy store would be installed on individual premises and sized to supply the total amount of storage energy required for each daytime period day without re-exporting power to the grid system where prices are low. It would be controlled automatically.

A corollary of this model is an expansion of the storage capacity to a co-operative project where a number of households combine together and operate one local store as illustrated in figure 10.5. One would expect, in this case, potential benefits of capital and operational savings.

The levels of energy storage were set at 10kWh / 24 hours for a single household and 25 kWh for multiple household projects. The rate of regeneration of power could be set to suit
a range of demands from 3kW to 10kW or greater if there was potential for the export of power to the locality from the co-operative.

It is assumed that the energy would be purchased at night using the current ‘economy 7’ tariff offered by most power suppliers.

In the case of the single household, as long as all the stored energy was used during the daytime tariff period, the full benefit of the price difference (less storage losses) would be captured. Likewise, the co-operative project would require each household to feed power to the common store at night and retrieve it during the daytime. An agreement between the various households would be necessary which made provision to allocate the costs and payments. However, such a store would be more likely to capture the full benefits over the 365 days if it was sized correctly to ensure that all the stored energy was used every day.

The power flows are illustrated in figure 10.6. No allowance for any savings which may have been avoided in the transmission and distribution circuits has been included, as there is no recognition of these losses in the tariffs either for the average losses or the actual losses due to the geographic position of the store.

The cost savings follow the simple relationship:

\[ C_r = (C_d - C_n) \times T_e \]

Where,

- \( C_r \) = Cost reduction per unit \( \text{p/kWh} \)
- \( C_d \) = Cost of power per unit at daytime rate \( \text{p/kWh} \)
- \( C_n \) = Cost of power per unit at night time rate \( \text{p/kWh} \)
- \( T_e \) = Turn round efficiency of energy store \( \% \)
10.3.2 The Industrial / Commercial model (Case 2)

The industrial customer is charged for power against a different set of tariff schedules to those that apply to the domestic customer. The power intake is measured over each Half Hour (HH) period which is used to set a number of tariffs including the price per unit, the maximum demand (Triad Charge) and the use of system charges set by the supplying DNO. The power supply chain for the industrial customer is illustrated in Fig. 10.7.
This case assumes that the customer is supplied on a HH metered tariff at high voltage and is subject to Triad charges.

The unit charge varies according to geographic location of the power off-take, the time of the year and the time of day. The charges illustrated in table 10.1 are representative of those paid by a typical industrial customer in central England (2006).
Table 10.1 Cost of power for a typical industrial customer (2006) and the daily maximum energy price difference

<table>
<thead>
<tr>
<th>Daily Prices</th>
<th>Price pence / Unit</th>
<th>Time of year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day time (weekdays)</td>
<td>6.75</td>
<td>Summer &amp; Winter</td>
</tr>
<tr>
<td>Day time (Peak time)</td>
<td>12.5</td>
<td>November to February</td>
</tr>
<tr>
<td>(16.30 to 18.30)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day time (weekends)</td>
<td>5.53</td>
<td>Summer &amp; Winter</td>
</tr>
<tr>
<td>Night time</td>
<td>4.54</td>
<td>All year</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Daily price differences</th>
<th>Maximum Price Differential</th>
<th>Time of year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum to Minimum</td>
<td>Pence / unit</td>
<td></td>
</tr>
<tr>
<td>Day time (weekdays)</td>
<td>1.21</td>
<td>Summer &amp; Winter</td>
</tr>
<tr>
<td>Day time (Peak time)</td>
<td>7.94</td>
<td>November to February</td>
</tr>
<tr>
<td>(16.30 to 18.30)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day time (weekends)</td>
<td>1.00</td>
<td>Summer &amp; Winter</td>
</tr>
</tbody>
</table>

The difference between the cost of energy stored per and the price of energy at the maximum level each month may be expressed as follows;

Weekdays

\[ C_{rx1} = (C_{max1} - (C_{min1} \times T_e)) \times D_{m1} \]  \hspace{1cm} (10.6)

Weekends

\[ C_{rx2} = (C_{max2} - (C_{min2} \times T_e)) \times D_{m2} \]  \hspace{1cm} (10.7)

Where

- \( C_{rx1} \) = Cost reduction for a specified day \( \text{p/kWh} \)
- \( C_{rx2} \) = Cost reduction for a specified weekend \( \text{p/kWh} \)
- \( C_{max1} \) = Maximum Cost of Power for weekdays \( \text{p/kWh} \)
- \( C_{max2} \) = Maximum Cost of Power for weekends \( \text{p/kWh} \)
- \( C_{min1} \) = Minimum cost of power for weekdays \( \text{p/kWh} \)
- \( C_{min2} \) = Minimum cost of power for weekends \( \text{p/kWh} \)
- \( D_{m1} \) = Number of days weekdays / month
- \( D_{m2} \) = Number of weekend days / month

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Hence the annual saving from storing and regenerating one unit of power may be computed:

$$\text{Annual Savings} = \sum_{\text{Dec}}^{\text{Jan}} C_{x1} + \sum_{\text{Jan}}^{\text{Dec}} C_{x2}$$  \hspace{1cm} (10.8)

The maximum and minimum charges that occur in any one twenty four hour period (according to the EDF Energy Networks plc tariff 2006, [103]) are illustrated by figure 10.8 which illustrates the changes in the level of this charge depending upon the time of day, the day of the week and the month of the year the power is consumed. The bars illustrate the time of day the charge applied and the colour indicates the level of the charge. (Red bars show the times of maximum charge and green bars the times when the minimum charge applies whilst the solid bars indicate the week day charge period and the cross hatched bars apply to the weekend periods). It will be noted that, during the months of November to February each year, there are very restricted times when it is possible to import power at the minimum price and to use it during the highest price thereby reducing the Maximum Demand charge.
### Economic Evaluation of Energy Storage

#### Fig 10.8 The Maximum and Minimum prices for energy delivered / (kWh)

<table>
<thead>
<tr>
<th>Time of day</th>
<th>Max. price</th>
<th>Max. price</th>
<th>Min. price</th>
<th>Min. price</th>
</tr>
</thead>
<tbody>
<tr>
<td>00.00</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
</tr>
<tr>
<td>06.00</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
</tr>
<tr>
<td>12.00</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
</tr>
<tr>
<td>18.00</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
</tr>
<tr>
<td>24.00</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
<td>Weekday</td>
</tr>
</tbody>
</table>

The graph shows the maximum and minimum prices for energy delivered for each month, with separate lines for weekdays and weekends.
10.3.3 Adjustments for Distribution System Losses

The industrial tariff carries an adjustment to each price level to correct for the nominal power losses incurred in transporting the power from the GSP to the customer’s premises. These ‘Line Loss Factors’ are multiplied by the customer meter readings to arrive at the new value. As they are charged according to the time of day and month of the year each daily price must be computed according to the published schedule. Table 10.2 records these Line Loss Factors and figure 10.9 shows the variations charged by the hour, the day and the month of the year.

<table>
<thead>
<tr>
<th></th>
<th>Period 1</th>
<th>Period 2</th>
<th>Period 3</th>
<th>Period 4</th>
<th>Period 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Voltage network</td>
<td>1.071</td>
<td>1.088</td>
<td>1.095</td>
<td>1.101</td>
<td>1.079</td>
</tr>
<tr>
<td>Low Voltage Substation</td>
<td>1.054</td>
<td>1.062</td>
<td>1.066</td>
<td>1.069</td>
<td>1.057</td>
</tr>
<tr>
<td>High Voltage</td>
<td>1.030</td>
<td>1.042</td>
<td>1.045</td>
<td>1.048</td>
<td>1.036</td>
</tr>
</tbody>
</table>

Table 10.2 The distribution charging times for an industrial tariff (2006), HH customers (Source:[103])

Table 10.3 illustrates the maximum difference that occurs between line loss factors in any 24 hour period during each month of the year.
Table 10.3 The periods when the maximum and maximum and minimum differential Loss Factors occur.

<table>
<thead>
<tr>
<th>Low Voltage Network</th>
<th>Maximum Differential between daily loss Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Maximum</td>
</tr>
<tr>
<td></td>
<td>period</td>
</tr>
<tr>
<td>January</td>
<td></td>
</tr>
<tr>
<td>weekdays</td>
<td>P4</td>
</tr>
<tr>
<td>weekends</td>
<td>P4</td>
</tr>
<tr>
<td>February</td>
<td></td>
</tr>
<tr>
<td>weekdays</td>
<td>P4</td>
</tr>
<tr>
<td>weekends</td>
<td>P4</td>
</tr>
<tr>
<td>March</td>
<td></td>
</tr>
<tr>
<td>weekdays</td>
<td>P3</td>
</tr>
<tr>
<td>weekends</td>
<td>P5</td>
</tr>
<tr>
<td>April</td>
<td></td>
</tr>
<tr>
<td>weekdays</td>
<td>P2</td>
</tr>
<tr>
<td>weekends</td>
<td>P5</td>
</tr>
<tr>
<td>May to September</td>
<td></td>
</tr>
<tr>
<td>each days</td>
<td>P5</td>
</tr>
<tr>
<td>October</td>
<td></td>
</tr>
<tr>
<td>weekdays</td>
<td>P2</td>
</tr>
<tr>
<td>weekends</td>
<td>P5</td>
</tr>
<tr>
<td>November</td>
<td></td>
</tr>
<tr>
<td>weekdays</td>
<td>P4</td>
</tr>
<tr>
<td>weekends</td>
<td>P2</td>
</tr>
<tr>
<td>December</td>
<td></td>
</tr>
<tr>
<td>weekdays</td>
<td>P4</td>
</tr>
<tr>
<td>weekends</td>
<td>P2</td>
</tr>
</tbody>
</table>

Once again, the weekday periods are different from the weekend periods and have to be treated separately for some of the months of the year. As the line loss factor has a significant impact upon the number of units of power charged for during each 24 hour period, these adjustment factors have being illustrated graphically in figure 10.9.
Fig 10.9 The time periods when the Line Loss factors each hour, day and month of the year
Although these charges are an attempt to reflect some of the losses incurred, it neither represents the real loss in supplying a specific site nor does it reflect the real cost in supplying that lost energy. It is merely, a method of charging out on a shared basis an approximation of the possible average loss.

The impact of the Line Loss Factor on the cost of the energy stored must be calculated on a daily basis to correct for the day of the week and the month of the year. Only then can the difference in the annual charge for power via the energy store be compared with the charge which would have been applicable for energy supplied direct to the customer over each 24 hour period.

\[ C_{\text{rx}}L1 = (C_{p_{\text{max}1}} \times L_{i_{\text{max}1}}) - (C_{p_{\text{min}1}} \times L_{i_{\text{min}1}} \times T_e) \]  \hspace{1cm} (10.9)

\[ C_{\text{rx}}L2 = (C_{p_{\text{max}2}} \times L_{i_{\text{max}2}}) - (C_{p_{\text{min}2}} \times L_{i_{\text{min}2}} \times T_e) \]  \hspace{1cm} (10.10)

\[ C_{\text{rx}}l(m) = (C_{\text{rx}}L1 \times Y_{wd}) + (C_{\text{rx}}L2 \times Y_{we}) \]  \hspace{1cm} (10.11)

Where (Line Loss adjusted):

\[ C_{\text{rx}}L1 = \text{Cost differential of weekday of power (p/kWh)} \]

(Line Loss adjusted)

\[ L_{i_{\text{max}1}} = \text{Maximum Line Loss factor weekday} \]

\[ L_{i_{\text{min}1}} = \text{Minimum Line Loss factor weekday} \]

\[ C_{\text{rx}}L2\_e = \text{Cost differential of weekday of power (p/kWh)} \]

\[ L_{i_{\text{max}2}} = \text{Maximum Line Loss factor weekend} \]

\[ L_{i_{\text{min}2}} = \text{Minimum Line Loss factor weekend} \]

\[ C_{\text{rx}}l(m) = \text{Cost saving (per unit) for one month} \]

\[ Y_{wd} = \text{Number of weekdays / month} \]

\[ Y_{we} = \text{Number of weekend days / month} \]

The resulting annual cost difference following the Line Loss Factor adjustment is therefore given by:
\[
C_{\tau_y} = \sum_{\tau=0}^{\tau=\bar{\tau}} C_{\tau}(m)
\]  \tag{10.12}

This calculation is shown in Appendix 6, Sheet 9

### 10.3.4 Distribution Use of System Charges (DNuos Charges)

The delivered units of power are subjected to a further adjustment. Each recorded unit is multiplied by a factor to pay (in part) for the distribution system, which is often owned and operated by a third party (a DNO). This factor again depends upon the time of day and day of the year.

| Period 1 | between 00.00 and 07.00 all days of | 0.135p |
| Period 2 | between 16.00 and 20.00 Monday to Friday November to February inclusive of | 1.965p |
| Period 3 | between 0.700 and 16.00 Monday to Friday, November to February inclusive and between 07.00 and 20.00 Monday to Friday in March of | 0.827p |
| Period 4 | between 0.700 and 20.00 Monday to Friday June to August inclusive of | 0.224p |
| Period 5 | all other times of | 0.707p |

Source: EDF Energy Networks (EPN) plc Industrial Tariff for Electrical Power 2006, [103].

The tariff is illustrated in figure 10.10 where it can be seen that there are four months of the year where the maximum DNuos charge is applied during a relatively narrow time slot (16.00 to 20.00) each day. In order to achieve the maximum benefit during these time slots, it would be necessary to discharge the energy store, even during the weekend periods.

The DNuos charge is applied to the metered power consumed on the premises and not the power adjusted for the line loss factor.
Fig. 10.10 The DNuos charges [103]
Chapter 10 Economic Evaluation of Energy Storage

The maximum cost difference per unit of power consumed between the daily maximum and minimum DNuos charges:

\[ Dc_1 = Dc_{\text{max}1} - Dc_{\text{min}1} \]  
\[ Dc_2 = Dc_{\text{max}2} - Dc_{\text{min}2} \]  

Where:

- \( Dc_1 \) = Cost of DNuos differential for weekdays
- \( Dc_{\text{max}1} \) = Maximum DNuos charge for weekday
- \( Dc_{\text{min}1} \) = Minimum DNuos charge for weekday
- \( Dc_2 \) = Cost DNuos charge for weekend
- \( Dc_{\text{max}2} \) = Maximum DNuos charge for weekend
- \( Dc_{\text{min}2} \) = Minimum DNuos charges for weekend

These charges are multiplied by the meter reading of power supplied to the site and added to the monthly charges.

The final differential cost of power between the maximum prices that apply and the minimum prices paid for energy stored including an allowance for a turn round efficiency within the store of 20% is given by:

\[ C_{rs}L_y = \sum_{m=1}^{\text{Dec}} \left( C_{rs}I(m) + (Dc_1 \times Y_{wd}) + (Dc_2 \times Y_{we}) \right) \]  

The calculations are shown in Appendix 6, Sheet 9.

**10.3.5 Cost Savings**

Using the published 2006 industrial tariff of EDF Energy networks plc, the cost savings which may be obtained by storing energy during the lowest tariff and re-generating the power during the highest tariff period each day have been calculated.

The computation assumes that 20% more power must be stored on each occasion to compensate for the turn round efficiency of the store. The cost of energy is first computed
for each day (appendix 6). As the tariffs are different during weekdays and those at the weekend, it was necessary to show the totals for a specific month as separate items.

Figures 10.11 and 10.12 illustrate the price changes month by month and the differences across the week.

**Fig 10.11, Weekday prices for energy [103].**

**Fig 10.12, Weekend prices for energy [103].**
A line Loss Factor is applied to each unit purchased at the customer’s site to compensate for energy dissipated within the distribution system. These adjustments are applied to the energy recorded on the site meter and are time of day and month of the year dependent. Figure 10.13 illustrates the Line Loss factors during the maximum and minimum charge periods. The periods when the line loss factor maximum and minimum occur do not match exactly the periods of maximum and minimum energy charges but, by careful selection, there is sufficient overlap between the two tariff periods to use the maximum and minimum charges of both tariffs to import power and re-generate it.

The line loss adjustment, changes the applied of the costs per month are shown in figure 10.14.
Chapter 10 Economic Evaluation of Energy Storage

The Monthly Energy Costs
(post Line loss Adjustment)

<table>
<thead>
<tr>
<th>Month</th>
<th>Maximum</th>
<th>Minimum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>3.50</td>
<td>3.00</td>
</tr>
<tr>
<td>Feb</td>
<td>3.00</td>
<td>2.50</td>
</tr>
<tr>
<td>Mar</td>
<td>2.50</td>
<td>2.00</td>
</tr>
<tr>
<td>Apr</td>
<td>2.00</td>
<td>1.50</td>
</tr>
<tr>
<td>May</td>
<td>1.50</td>
<td>1.00</td>
</tr>
<tr>
<td>Jun</td>
<td>1.00</td>
<td>0.50</td>
</tr>
<tr>
<td>Jul</td>
<td>0.50</td>
<td>0.00</td>
</tr>
</tbody>
</table>

Fig 10.14 The monthly Line Loss adjusted energy cost per kWh imported during the maximum tariff and minimum tariff conditions.

The final adjustment is applied due to the overall calculation by adjusting for the Distribution Network use of system charges (DNuos). These charges vary from DNO to DNO and are agreed with Ofgem each year. The charges are once again, time of day and month of the year dependent.

Duos Charges (max & min during the year)

<table>
<thead>
<tr>
<th>Month</th>
<th>Weekday maximum</th>
<th>Weekday &amp; Weekend Minimum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Feb</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mar</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Apr</td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jun</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jul</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aug</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sep</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oct</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dec</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Fig 10.15 The maximum and minimum DNuos charge during the year [103].

Figure 10.15 illustrates the DNuos charges within the EDF Energy Networks plc sector.
These charges are applied on the customer’s meter reading and added to the total bill. The maximum and minimum charge periods are applicable to the system during the maximum and minimum periods of the respective Energy Price and Line Loss Factor adjustments.

There are further charges to be billed to the customer but as they are fixed by the size of the power importing facilities and by operating with an adverse power factor, they are customer specific. They have been excluded from the calculation of the annual savings achievable by using an energy storage facility.

The final difference between the annual charge of one kWh imported during the combined maximum tariff period and the minimum tariff period can be computed.

The actual cost difference due to the use of an energy store is illustrated in figure 10.16. Here the cost of delivering 1 kWh per month via the energy store with an allowance for the lost power during the storage process of 20% (i.e. a turn rounds efficiency of 80%) is contrasted with the cost of importing that power during the maximum price period. It can be seen from figure 10.16 that the major gains are made via the energy store during the winter months whilst the store is still operating with a gain during the remainder of the year.

![Cost Difference £ / kWh / Month](image)

Fig 10.16 The cost difference of importing 1 kWh at the maximum price and regenerating the power from an energy store with a turn round efficiency of 80%
10.3.6 Triad Payments

Industrial customers also pay an annual Triad charge, related to their individual maximum demand recorded during the declared Triad periods (note, the triads apply during the months November to February only. If the demand during these periods is reduced to zero (or significantly lower than the normal demand) at these times, the annual Triad charge is either zero or a smaller amount than would have otherwise have been charged.

Typical Triad charges are determined by the location of the GSP supplying the customer. Currently, these fees are levied at rates which range from £10,000/MW to £23,000/MW. They are set by NGC depending on the nominal distance to the centre of power generation in the country and the amount of generation capacity in the locality. A customers actual Triad charge upon a customer is determined by computing the average demand during the three nominated half hour period declared for a specific year.

An energy store could be employed to reduce these Triad charge if it was arranged to deliver power during these times. As the peak power demand and the high unit price for electricity invariably occur at the same time, it should be a routine task to use the power from the store to achieve this saving.

10.4 Case Analysis

10.4.1 The Energy Supplier (Case 3)

The potential benefits of energy storage apply to the energy supply company and the energy trader in a similar fashion to the industrial customer described above.

The energy supplier purchases power from the power station and delivers it to the customers using the services of the National Grid and the Distribution Network Operators figure 10.17. The power is purchased by the ‘Supplier’ to match their collective customer demand profile. The cost of power depends on their customer demand profile. Continuous power demand over a twenty four hour cycle is available at significantly lower rates than supplies which are purchased for shorter periods.
The supplier with a large portfolio of customers and a mix of power demand profiles would be in an ideal position to install a number of energy storage units around the network in the most advantageous locations to:

1) Store energy over night and deliver during the peak demand periods
2) Provide Ancillary Services to the Grid Operator
3) Provide Voltage regulation Power Factor correction and power supply back-up services to a DNO
4) Support DNOs where the distribution circuits become overloaded during the peak demand.

The financial returns would be generally in line with those described for the industrial customer above, but with added advantages of load shifting to supply their domestic customers and power to relieve overloaded circuits.

Any further benefits may come from commercial negotiations with power station where the bulk purchase of power continuously over a 24 hour period would be attractive to the power plant operator for reasons explained in Chapter 3. It is currently unclear what TNuos and DNuos charges would be levied on power retrieved from an embedded energy store and delivered to adjacent customers.
10.4.2 The Energy Trader (Case 4)
The Energy Trader buys and sells quantities of electricity for delivery over relatively short periods of time. In some cases this can be as short as 30 minutes; seldom does it extend beyond several hours. The position of the Energy Trader in the contractual system is illustrated in figure 10.18. It is a service offered 24 hours a day to balance the variations in supply and demand and is used by generators and suppliers to accommodate excess or shortfalls in power delivery contracts in the ‘Half Hourly’ supply market.

The Energy Trader can also take a speculative view of forward market prices. In this example the trader relies upon the marginal cost difference between the purchase price and
the short term future sale to generate a profit. Figure 10.19 illustrates two separate periods (i.e. A to B and C to D) during one twenty-four hour period where it would have been possible to purchase power allowing for an 80% turn round efficiency in the energy store and still remained profitable by selling the stored power within 3/4 hours of storage.

Fig 10.18 illustrates HH wholesale electricity price and the potential for the trader.

---

**The Role of Energy Storage and the Electricity Trader**

- **Power Flow**
  - **Power Plant**
  - **Energy Store**
  - **Energy Trader**
  - **Supply Company**
  - **Power Supply Contracts**
  - **Industrial Customers**
  - **Domestic Customers**

---

Fig 10.18 The Role of the Energy Trader and the integration of Energy Storage
It would be possible to physically purchase energy at advantageous prices several hours before a commitment to supply and store it anywhere on the network. It does not matter where the power is injected in the network apart from the Use of System charges.

If it became practical to measure and hence to charge realistic supply chain costs for the flow of each discrete package of power transferred, it would be necessary to optimise the location of the store.

Such an arrangement would mirror the current move by Gas Traders who are currently taking steps to physically store gas for short term periods before delivering it back into the gas transmission network. In the case of the electricity supply analogy, energy storage could additionally improve the all-round performance of generating stations.

### 10.4.3 Integrated Power Generation and Energy Storage (Case 5)

Another possible method of obtaining the benefits of the lowest costs of power supplied to the final customer within the current commercial regime (i.e. tariffs, use of system charges, line loss factors and grid system entry and exit (Triads) charges) would be the integration of the power generator and the embedded energy store. It may be necessary, in order to
comply with current regulations, to isolate commercially the power plant business from the storage facility. By establishing an Energy Storage Company and an Energy Supply Company within a holding group the necessary commercial confidentiality could be established, which may satisfy the legislation (figure 10.20). The contractual arrangements would require each company to operate independently when purchasing and selling power.

![Possible Group company structure](image_url)

Fig 10.20 Possible Group company structure

Such an arrangement would allow the generating company (Gen Co) to supply power under optimum operational conditions whilst minimising the costs identified in chapter 3, assuming it could match the price of power from competing generators who would also have access to the storage facility. The power flows from and to the various contracting parties are illustrated in figure 10.21. In this illustration no power is physically delivered to 'Supply Co', its role is solely contractual.
For the purposes of the following analysis and to present examples of the potential gains, two different power plant operational routines will be considered. These are illustrated in figures 10.22 and 10.23. (These profiles have been constructed around the scenario 3b and 4a described in Chapter 6).

The first ‘Case A’ in each scenario assumes that the power plant starts up each day (in hot start mode) and then delivers either a constant full load output for 13 hours (figure 10.22 or a modulated output figure 10.23).

The second case (case B) assumes that the plant is operated continuously under optimum conditions (24 hours per day 7 days per week) and that all the power produced during the period 22.00 hours to 06.00 hours each day is supplied to embedded energy stores for regeneration into the networks during the period 16.30 to 18.30 hours each day when the
electricity price is at its maximum. It is assumed also that there is sufficient storage capacity spread around the distribution networks to absorb any power produced by ‘Gen Co’ during this time.

The duty of ‘Gen Co’ to meet the statutory requirements under the National Grid Code for ancillary services of frequency response would be passed to the energy stores where
possible, to ensure minimum operating damage to the gas turbines in the event of major incidents.

Likewise any calls for maximum generation (MAX GEN) on the part of the National Grid Operator would first be met by Store Co. preventing overload to occur on the main gas turbine generating plant.
However, the benefits have not been included when quantifying the financial benefits of storage.

### 10.4.4 Potential Savings available to the Group of Companies

The electricity supply chain illustrated in figure 10.24 identifies the major links in the chain where benefits are shown. Some of these benefits may be captured within the tariff system, some from operational benefits within the power plant and some from the reduction of CO₂ certificates purchased (where applicable).

![Diagram of Integrated Power Plant & Energy Storage](image)

**Fig 10.24, Benefits which could result from an integrated Power Plant and an Energy Storage facility**
With the exception of power plant cost reductions, the savings which accrued to the industrial customer in section 10.22 will apply equally to the combined power generator and energy storage operation as they are all linked to the supply chain. Common elements in each case are;

1) The line loss factors.
2) The DNuos charges.
3) The Triad charges.
4) The sale of stored energy during peak prices

The financial savings generated when operating at optimum performance compared with operating under various different modulating patterns of power production (chapters 3 and 6) may be added to transmission and distribution savings when delivering power via an energy storage facility.

The relevant items and associated savings per unit are listed below:

1) Reduced Fuel costs per MWh
2) Reduced Maintenance costs per MWh
3) Reduced Operational and Fixed Costs per MWh
4) Reduced capital costs per MWh
5) Reduced CO₂ emissions (and Cost of Carbon Certificates per MWh)
6) No Grid Entry charges (see section 10.42 below)

The total costs of electrical power at the Grid Entry Point to the transmission system for case A and case B have been compared.

As Base B is represented by the continuous operation of a CCGT plant, it is possible to extract the cost of power directly and table 10.4 has been compiled using the data from the scenarios analysed in Chapter 6 and recorded here in table 6.12.
Table 10.4 Generation Costs for different operating modes.
(note: No cost of carbon certificates is included)

<table>
<thead>
<tr>
<th>Differential Production Costs</th>
<th>Cost of Power Generation Ex Generator</th>
<th>Cost of Power Generation Inc Cost of Carbon</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operational Mode</td>
<td>£/MWh</td>
<td>£/MWh</td>
</tr>
<tr>
<td>Constant Operation</td>
<td>39.98</td>
<td>43.7</td>
</tr>
<tr>
<td>Scenario 3b (chapter 6)</td>
<td>50.01</td>
<td>55.56</td>
</tr>
<tr>
<td>Scenario 4a (chapter 6)</td>
<td>62.47</td>
<td>75.27</td>
</tr>
</tbody>
</table>

The cost variances above the optimum cost of generation are recorded in table 10.5. Here the cost of carbon certificates has been set at £20 (i.e. €30) per metric tonne; however, the cost of these certificates has varied from a low of 1 Euro to 30 Euros per tonne since their introduction 2005. If the system of European Carbon Trading is implemented fully during phase 2 of the scheme and the need for a 3% reduction in the quantity of CO₂ emissions authorised each year is implemented, the price of these certificates will rise unless the use of fossil fuel is curtailed.

Table 10.5 The cost variances operating below optimum conditions.

<table>
<thead>
<tr>
<th>Generation Cost Variances above Optimum Case</th>
<th>Cost Increase above Constant Operation (No Carbon Charge) £/MWh</th>
<th>Cost Increase above Constant Operation (Inc Carbon Charge) £/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 3b</td>
<td>10.03</td>
<td>11.86</td>
</tr>
<tr>
<td>Scenario 4b</td>
<td>22.49</td>
<td>31.57</td>
</tr>
</tbody>
</table>

If the Group Company considered here, owned sufficient energy storage capacity to operate the power plant under optimum conditions continuously, the savings identified above may be added to those which would accrue from the savings identified for the industrial customer (i.e. Energy charges, DNuos charges, Line loss factors, and Triad Charges).
10.4.5 National Grid Entry Charges

The TNuos charges paid by a large power plant for entry to the transmission system is set by the maximum power export from the plant recorded during a period of 11 months (April to February). Table 10.6 illustrates the level of these charges for 2005/2006 where it can be seen that a very wide spread applies to power plants connected to the system across the country.

The annual charge for an 800MW power plant will depend on its geographic location. The potential TNuos charges could range from a payment of £16m per annum in the North of Scotland to an income of £4 to 5m per annum in an area which currently is devoid of power generation such as central London.

Table 10.6 National Grid generation charges TNuos Charges (2005/2006) [104].

<table>
<thead>
<tr>
<th>Zone No.</th>
<th>Zone Name</th>
<th>Zonal Tariff (£/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Peterhead</td>
<td>18.162</td>
</tr>
<tr>
<td>2</td>
<td>North Scotland</td>
<td>20.930</td>
</tr>
<tr>
<td>3</td>
<td>Skye</td>
<td>23.095</td>
</tr>
<tr>
<td>4</td>
<td>Western Highland</td>
<td>18.920</td>
</tr>
<tr>
<td>5</td>
<td>Central Highlands</td>
<td>15.361</td>
</tr>
<tr>
<td>6</td>
<td>Cruachan</td>
<td>15.852</td>
</tr>
<tr>
<td>7</td>
<td>Argyll</td>
<td>13.442</td>
</tr>
<tr>
<td>8</td>
<td>Stirlingshire</td>
<td>12.611</td>
</tr>
<tr>
<td>9</td>
<td>South Scotland</td>
<td>11.820</td>
</tr>
<tr>
<td>10</td>
<td>North East England</td>
<td>8.091</td>
</tr>
<tr>
<td>11</td>
<td>Humber, Lancashire &amp; SW Scotland</td>
<td>4.906</td>
</tr>
<tr>
<td>12</td>
<td>Anglesey</td>
<td>6.123</td>
</tr>
<tr>
<td>13</td>
<td>Dinorwig</td>
<td>8.706</td>
</tr>
<tr>
<td>14</td>
<td>South York &amp; North Wales</td>
<td>3.120</td>
</tr>
<tr>
<td>15</td>
<td>Midlands &amp; South East</td>
<td>1.323</td>
</tr>
<tr>
<td>16</td>
<td>Central London</td>
<td>-5.710</td>
</tr>
<tr>
<td>17</td>
<td>North London</td>
<td>-0.221</td>
</tr>
<tr>
<td>18</td>
<td>Oxon &amp; South Coast</td>
<td>-0.699</td>
</tr>
<tr>
<td>19</td>
<td>South Wales &amp; Gloucester</td>
<td>-2.552</td>
</tr>
<tr>
<td>20</td>
<td>Wessex</td>
<td>-4.951</td>
</tr>
<tr>
<td>21</td>
<td>Peninsula</td>
<td>-8.045</td>
</tr>
</tbody>
</table>

These charges apply whether the plant has delivered power for a very short period of the year or has exported 24 hours / day continuously.
The additional power generated and exported via the National Grid can therefore be regarded as adding no further TNuos charges to the plant operations.

The power generated by embedded energy store is small by comparison with the power plant output. It will enter the distribution system and should come under the regulations of embedded generation for the purposes of the exclusion from TNuos charges.

10.4.6 Conditions for power flow into and out of the Energy Store
In order to gain a measure of the potential income that would be earned by the Holding Company ("Power CO") when supplying power from the energy stores, it has been assumed that all the electrical power would be supplied either during the peak domestic period or during the peak industrial tariff period and supplied to the store during the lowest market prices.

Using the tariff differentials for both the studies where the power is stored on the domestic or industrial premises, (i.e. EDF Energy Networks plc tariff 2006), it has been assumed that the same Line Loss Factors, DNuos and Triad charges will apply to the power delivered to Store Co and that it does not apply when power flows from the store to the user.

10.5 Economic Evaluation of the Embedded Energy Store
This section attempts to place an economic value on the potential contribution that could be made by an embedded energy store could make based upon both the Hydraulic Accumulator and the Flow Battery technologies.

It was necessary to estimate the capital cost of the installed equipment for a number of different storage capacities. In the case of the Hydraulic Accumulator estimates have been made from 10kWh to 250kWh for domestic purposes and up to 1000kWh for industrial models. Cost estimates for the Flow batteries have been taken from a manufacturer estimates and extrapolated to cover three nominal capacities (5kW -20kWh, 100kW - 400kWh and 1000kW - 2000kWh).

The estimates for the hydraulic accumulator have been compiled from a number if industrial sources, including hydraulic equipment manufactures, steel users, drilling
companies and electrical manufactures. As a store using this principle has yet to be built, the costs have been assembled assuming unit equipment prices and estimated construction costs only (chapter 9). However, they do not include the cost any work necessary to develop and prove the device and must be regarded as a guide price only. In the example selected from the previous work, the evaluation has been restricted to maximum hydraulic pressures of 350 bar and 500 bar using X-120 steel as all the equipment is available from commercial sources.

Table 10.7 lists the common costs applied to each estimate across the range of capacities selected. The cost of land and the cost of obtaining the statutory permission to proceed with an installation has not been estimated as they will vary considerably from site to site.

An example of the capital cost estimate compiled for a domestic energy store with a capacity of 25kW, 25kWh hydraulic accumulator is listed in table 10.8. Further estimates for a range of energy storage capacities, and compression cylinder pressures and steel specifications are shown in Appendix 6, sheet 6.

The Vanadium Flow Battery costs have been taken from the data presented in Chapter 8 and used in the analysis exhibited in Appendix 6, sheet 12.

10.5.1 Evaluation Method
The Internal Rate of Return (IRR) has been selected as the instrument to measure the potential financial success or failure of the cash flows over a 40 year cycle for each proposal. All costs are assumed to increase in-line with general inflation (CPI) with the exception of the cost of energy (fuel and electricity) which may be set in the models to exceed CPI. In the results reported here it has been assumed to increase at 2% above the general rate.

In the first operational year of each project the construction time is deducted from the revenue streams (i.e. 20 days for domestic site installation and 60 days for industrial sites). The tariffs and the TNuos charges, which were operational during 2006, were selected to set the costs of both domestic and industrial electricity supplies in the models. The 'Turn Round' efficiency of the energy stores has been set at 80% for the hydraulic accumulator
storage units and at 75% for the Flow Batteries although this figure may be modified as required to match the characteristic of each technology.

Table 10.7 Hydraulic Accumulator Cost Estimates—Base Data

<table>
<thead>
<tr>
<th>General Cost</th>
<th>Estimates</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steel Price £/tonne</strong></td>
<td>806</td>
<td>confidential</td>
</tr>
<tr>
<td>Atmospheric Tank Price £ / m³</td>
<td>150</td>
<td>Phoenix Hydraulics</td>
</tr>
<tr>
<td>Hydraulic Fluid £/l</td>
<td>0.6</td>
<td>Phoenix Hydraulics</td>
</tr>
<tr>
<td><strong>Hydraulic M/G sets</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2kW</td>
<td>1000</td>
<td>Dynaset OY</td>
</tr>
<tr>
<td>5kW</td>
<td>1000</td>
<td>(Finland)</td>
</tr>
<tr>
<td>10kW</td>
<td>1500</td>
<td></td>
</tr>
<tr>
<td>25kw</td>
<td>2000</td>
<td></td>
</tr>
<tr>
<td>50kW</td>
<td>10000</td>
<td></td>
</tr>
<tr>
<td>100kW</td>
<td>20000</td>
<td></td>
</tr>
<tr>
<td><strong>Pipe work</strong></td>
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<tr>
<td>Domestic models</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 kWh</td>
<td>£</td>
<td>350</td>
</tr>
<tr>
<td>25 kWh</td>
<td>£</td>
<td>750</td>
</tr>
<tr>
<td>Industrial models</td>
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<tr>
<td>250 kWh</td>
<td>£</td>
<td>size dependent</td>
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<tr>
<td><strong>Instrumentation</strong></td>
<td></td>
<td>estimate</td>
</tr>
<tr>
<td>Local Domestic unit</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>Central Domestic unit</td>
<td>500</td>
<td></td>
</tr>
<tr>
<td>Industrial Local unit</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Industrial Telecoms unit</td>
<td>500</td>
<td></td>
</tr>
<tr>
<td><strong>Ground Work</strong></td>
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<td></td>
</tr>
<tr>
<td>Shaft / hole</td>
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<td></td>
</tr>
<tr>
<td><strong>Domestic sites</strong></td>
<td></td>
<td>estimate</td>
</tr>
<tr>
<td>price /m</td>
<td>200</td>
<td></td>
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<tr>
<td>Industrial</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deep bore hole</td>
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<td></td>
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<tr>
<td>price /m</td>
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<tr>
<td><strong>Commissioning</strong></td>
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<td></td>
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<tr>
<td>Small domestic (10/25 kW)</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td><strong>Industrial sites</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Site work</td>
<td>5000</td>
<td></td>
</tr>
<tr>
<td>plant commissioning</td>
<td>10000</td>
<td></td>
</tr>
</tbody>
</table>
Table 10.8. Estimated capital cost for a 25kW, 25KWh Model Store

<table>
<thead>
<tr>
<th>Case 2a 25kW, 25KWh Model</th>
<th>350 bar</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Length m</td>
</tr>
<tr>
<td></td>
<td>11.47</td>
</tr>
<tr>
<td></td>
<td>weight of cylinder tonnes</td>
</tr>
<tr>
<td></td>
<td>4.90</td>
</tr>
<tr>
<td></td>
<td>Volume of Tank cu m</td>
</tr>
<tr>
<td></td>
<td>4.28</td>
</tr>
<tr>
<td></td>
<td>4.28</td>
</tr>
<tr>
<td></td>
<td>Hydraulic fluid £</td>
</tr>
<tr>
<td></td>
<td>4.28</td>
</tr>
<tr>
<td></td>
<td>Motor / Generator set</td>
</tr>
<tr>
<td></td>
<td>6 kW (output)</td>
</tr>
<tr>
<td></td>
<td>1000</td>
</tr>
<tr>
<td></td>
<td>Pipe Work</td>
</tr>
<tr>
<td></td>
<td>5kW - 10kW</td>
</tr>
<tr>
<td></td>
<td>150</td>
</tr>
<tr>
<td></td>
<td>Instrumentation &amp; Local Control</td>
</tr>
<tr>
<td></td>
<td>Domestic</td>
</tr>
<tr>
<td></td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>Logic &amp; External controller</td>
</tr>
<tr>
<td></td>
<td>Domestic</td>
</tr>
<tr>
<td></td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Metering &amp; Telecoms</td>
</tr>
<tr>
<td></td>
<td>Domestic</td>
</tr>
<tr>
<td></td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Land</td>
</tr>
<tr>
<td></td>
<td>Domestic</td>
</tr>
<tr>
<td></td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Site Work &amp; Installation</td>
</tr>
<tr>
<td></td>
<td>Shaft Drilling</td>
</tr>
<tr>
<td></td>
<td>Depth m</td>
</tr>
<tr>
<td></td>
<td>25kW model</td>
</tr>
<tr>
<td></td>
<td>Installation of Compression cylinder &amp; receiving tank</td>
</tr>
<tr>
<td></td>
<td>Domestic</td>
</tr>
<tr>
<td></td>
<td>Fitting of Motor / Gen set etc</td>
</tr>
<tr>
<td></td>
<td>Commissioning</td>
</tr>
<tr>
<td></td>
<td>150</td>
</tr>
<tr>
<td></td>
<td>Total</td>
</tr>
</tbody>
</table>

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10.5.2 Domestic Model Analysis

The revenue stream for the domestic model is from the difference between the price difference of the cost of power supplied to the energy store and the final cost to the customer. The cost of power purchased by the energy store must be corrected to include the 'Turn Round' efficiency of the unit.

Hence the cost of the power purchased is given by:

\[ P_s = P_N \times S_c \times \frac{1}{T R_e} \]  

(10.16)

Where

- \( P_s \) = Cost of power stored
- \( P_N \) = Cost of power at night rate
- \( S_c \) = the storage capacity (kWh)
- \( T R_e \) = the Turn Round efficiency

The cost of the energy purchased corrected for the increased cost of energy above inflation;

\[ P_s' = \frac{P_{s(t-1)} \times E}{1 - E} \]  

(10.17)

Where

- \( P_s' \) = the cost of power purchased during year \( t \)
- \( P_{s(t-1)} \) = the cost of power purchased during previous year
- \( E \) = the energy differential inflation factor

Likewise the final price of energy to the customer ex the store:

\[ P_e = S_c \times P_d \]  

(10.18)

\[ P_e' = \frac{P_{e(t-1)} \times E}{1 - E} \]  

(10.19)

Where

- \( P_e \) = the cost of energy purchased during year \( t \)
- \( P_{e(t-1)} \) = the cost of energy purchased during previous year

The annual net revenue \( R_1 \) is given by:

\[ R_1 = P_{e(t)} - P_s \]  

(10.20)

And year \( t \)

\[ R_t = \left( P_{s(t-1)} - P_{e(t-1)} \right) \times E \]  

(10.21)
Chapter 10 Economic Evaluation of Energy Storage

The project internal rate of return (IRR) is given by:

\[
\sum_{t=0}^{n} \frac{R_t}{(1+r)^t} - C = 0
\]  

(10.22)

\[
\frac{R_1}{(1+r)^1} + \frac{R_2}{(1+r)^2} + \ldots + \frac{R_n}{(1+r)^n} - C = 0
\]  

(10.23)

where

- \( R_t \) = the net annual return (profit)
- \( C \) = the original investment
- \( n \) = number of years
- \( r \) = IRR

The sensitivity of the IRR to the capital invested in each project was tested by varying the capital charge above and below the initial estimate and the results presented in graphical form.

Result for the Domestic Hydraulic Accumulator Storage (Tariff based benefits only)

The calculations are recorded in Appendix 6 sheet 7, for a number of different storage capacities (10kWh, 25kWh, 250kWh and 1000kWh). The IRR for stores constructed for a maximum compression cylinder pressure of 350 bar using X-120 steel are illustrated in table 10.9 and figure 10.25.

Table 10.9 IRR & Estimated Capital Cost for the Hydraulic Accumulator storage using domestic tariff benefits

<table>
<thead>
<tr>
<th>Domestic Supply Case 350bar X-120 steel</th>
<th>IRR %</th>
<th>Capital Estimate £</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage Capacity kW/kWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10kW/10kWh</td>
<td>6.00%</td>
<td>5977</td>
</tr>
<tr>
<td>25kW/25kWh</td>
<td>10.27%</td>
<td>10989</td>
</tr>
<tr>
<td>250kW/250kWh</td>
<td>5.68%</td>
<td>156046</td>
</tr>
<tr>
<td>1000kW/1000kWh</td>
<td>7.05%</td>
<td>520319</td>
</tr>
</tbody>
</table>
The lower IRR for the larger stores can be attributed principally to the proportionately higher costs incurred due to the deep bore hole required to accommodate the extended cylinder length.

When the maximum pressure of the gas and fluid in the compression cylinder is increased in steps from 350 bar to 500 bar, 650 bar and 800 bar there are savings to be made at each step in the dimensions of the cylinder, the steel used and the drilling costs associated with the reduced length of the shaft. This has been translated into financial savings and the IRR estimated for the larger storage capacities (250kWh and 1000kWh models). Table 10.10 and figure 10.26 illustrate the order of improvement which might be expected. (Appendix 6, Sheet 8)

Table 10.10 The estimated IRR to be gained by increase Cylinder pressure

<table>
<thead>
<tr>
<th>Domestic Supply Case X-120 steel Storage Capacity kW/kWh</th>
<th>IRR % 500 bar</th>
<th>IRR % 650 bar</th>
<th>IRR % 800 bar</th>
</tr>
</thead>
<tbody>
<tr>
<td>250kW/250kWh</td>
<td>6.55%</td>
<td>7.31%</td>
<td>7.65%</td>
</tr>
<tr>
<td>1000kW/1000kWh</td>
<td>8.91%</td>
<td>9.72%</td>
<td>11.11%</td>
</tr>
</tbody>
</table>

Fig 10.25 IRR of return for the Hydraulic Accumulator using domestic tariffs
Comparative IRR% (X120 steel)
(250kW & 1000kW models)

Fig 10.26 The IRR for 250kWh and 1000kWh storage unit for increased cylinder pressure

Similar results are available (appendix 6, sheets 7 and 8) for cylinders constructed of composite steel X-200. Confidence in these results depends upon the future successful development of the composite construction method and upon the capital savings it may ultimately deliver, figure 10.27. The information is intended as a guide to the potential benefits if or when such material become available.

Potential Comparative IRR % (x-200 composite steel)
(250 kW & 1000kW Models)

Fig 10.27, Potential benefits from high pressure composite material (e.g. x-200)
10.5.3 Industrial Model Analysis

The analysis has been executed on two models with maximum cylinder pressures of 350 bar and 500 bar where much of the required commercial equipment is well developed and proven.

The financial benefits due to the tariff gains produced by the energy storage have been computed. These gains are presented in Appendix 6, sheet 9 where both the X-120 steel and the x-200 composite material have been used as the construction material for the compression cylinder.

The financial returns (IRR) for each analysis (Appendix 6, sheet 10) are illustrated in Table 10.11 and Figure 10.28 for the X-120 steel models) and Table 10.12 and Figure 10.29 for the X-200 composite material models.

Table 10.11 IRR for Energy Storage using Industrial Tariffs (X-120 steel models).

<table>
<thead>
<tr>
<th>Industrial / Commercial Supply Case 350bar X-120 steel</th>
<th>350 bar</th>
<th>500 bar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage Capacity kW/kWh</td>
<td>IRR %</td>
<td>IRR %</td>
</tr>
<tr>
<td>250kW/250kWh</td>
<td>7.17%</td>
<td>8.38%</td>
</tr>
<tr>
<td>1000kW/1000kWh</td>
<td>8.85%</td>
<td>11.15%</td>
</tr>
</tbody>
</table>

Comparative IRR% (X120 steel) (250kW & 1000kW models))

Fig 10.28 IRR Energy Storage from Industrial tariff gains (x-120 steel models)
Table 10.12 IRR for Energy Storage using Industrial Tariffs(X-200 Composite models).

<table>
<thead>
<tr>
<th>Industrial / Commercial Supply Case 500 bar X-200 Composite</th>
<th>350 bar</th>
<th>500 bar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage Capacity kW/kWh</td>
<td>IRR %</td>
<td>IRR %</td>
</tr>
<tr>
<td>250kW/250kWh</td>
<td>8.28%</td>
<td>8.38%</td>
</tr>
<tr>
<td>1000kW/1000kWh</td>
<td>11.07%</td>
<td>13.79%</td>
</tr>
</tbody>
</table>

Fig 10.29 IRR Energy Storage from Industrial tariff gains (X-200 Composite material models)

10.5.4 The Integrated Power Generation and Tariff Based Analysis

This model has been constructed to evaluate the potential benefits that could be achieved if a power plant and an energy storage plant were co-ordinated to deliver power to a market with a variable demand. The analysis uses the two test cases following the model section 10.4.4 above and attempts to place an economic value upon the combined operations described together with testing the sensitivity to the capital cost of the energy storage plant.

The analysis simply consists of adding the savings (£/MWh) generated at the power plant, when operating at the optimum level rather than that when generating at a lower level, to the benefits generated by the tariff system. The cash flows generated are evaluated using the IRR method. In order to demonstrate the argument, two storage capacities have been selected both employing the X-120 grade of steel for the compression cylinder (i.e. 25kW,
250kW model for the domestic tariff and the 250kW model for the industrial tariff). The results of the two possible solutions are tabulated below in Tables 10.13a and 10.13b.

Table 10.13a The IRR for the 25kW case Domestic Tariff

<table>
<thead>
<tr>
<th>Domestic Tariffs</th>
<th>Tariff benefits (only)</th>
<th>Tariff+ Case 3b</th>
<th>Tariff+ Case 4a</th>
</tr>
</thead>
<tbody>
<tr>
<td>25kW, 25kWh Model</td>
<td>8.342%</td>
<td>9.591%</td>
<td>10.863%</td>
</tr>
</tbody>
</table>

Table 10.13b The IRR for the 250kW case Domestic Tariff

<table>
<thead>
<tr>
<th>Domestic Tariffs</th>
<th>Tariff benefits (only)</th>
<th>Tariff+ Case 3b</th>
<th>Tariff+ Case 4a</th>
</tr>
</thead>
<tbody>
<tr>
<td>25kW, 250kWh Model</td>
<td>5.6%</td>
<td>8.7%</td>
<td>9.6%</td>
</tr>
</tbody>
</table>

10.5.5 The energy storage in stand alone mode

The energy storage operating in cooperation with the power plant under scenario 3b i.e. the power plant shuts down each day but operates at its optimum output when generating power. The energy storage operating in cooperation with the power plant under scenario 4a (i.e. the power plant shuts down each day and operates below optimum whilst balancing the market demand when on generating power).

The results are illustrated in table 10.13a for the 25kW storage capacity and table 10.13b for the 250kW storage capacity generated by the domestic tariff price differences alone.

As an indication of the potential additional benefits, should the new steel composite materials such as X-200 realise their original promise, the IRR of each case above would increase by approximately 20% above the returns projected for the X-120 steel case. The results of this analysis are presented in tables 10.14a and 10.14b and illustrated in figures 10.29a and 10.29b. These illustrate an approximately increase of 10% in IRR for each rise in the maximum cylinder pressure of 150bar. (See Appendix 6 Sheet 8).

Table 10.14a IRR Increasing Cylinder Pressure (X-120 steel) Domestic Tariff case

<table>
<thead>
<tr>
<th>Summary Chart X-120 steel</th>
<th>IRR % 500 bar</th>
<th>IRR % 650 bar</th>
<th>IRR % 800 bar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic Supply Case X-120 steel Storage Capacity kW/kWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>250kW/250kWh</td>
<td>6.55%</td>
<td>7.31%</td>
<td>7.65%</td>
</tr>
<tr>
<td>1000kW/1000kWh</td>
<td>8.91%</td>
<td>9.72%</td>
<td>11.11%</td>
</tr>
</tbody>
</table>
Table 10.14b IRR Increasing Cylinder Pressure (X-200 composite) Domestic Tariff case

<table>
<thead>
<tr>
<th>Domestic Supply Case</th>
<th>X-200 composite material</th>
<th>Storage Capacity kW/kWh</th>
<th>IRR % 500 bar</th>
<th>IRR % 650 bar</th>
<th>IRR % 800 bar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Composite steel</td>
<td></td>
<td>250kW/250kWh</td>
<td>7.79%</td>
<td>8.85%</td>
<td>9.39%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1000kW/1000kWh</td>
<td>10.86%</td>
<td>12.49%</td>
<td>13.59%</td>
</tr>
</tbody>
</table>

Fig 10.29a Comparative IRR for increasing cylinder pressure (X-120 Steel)

Fig 10.29b Comparative potential increase IRR for increasing cylinder pressure. (X-200 Composite)

The structure of the Industrial tariffs produces a number of different possibilities.
The computation of the nominal cost savings due to the tariff benefits follow the logic described above (10.20) and executed in Appendix 6, sheet 9 based upon storing power during the lowest priced periods and re-exporting it during the highest price periods.

Two energy storage capacities have been analysed, 250Kwh and 1000kWh units using X-120 steel for the compression cylinder operating at the 350 and 500 bar pressures. Table 15 and figure 10.30 record the results of the financial analysis for these energy stores where it is seen that the same general picture emerges which was found for the domestic tariff model except that the returns are lower. (See Appendix 6, sheet 10)

Table 10.15 The IRR for the Industrial Tariff model (250kWh and 1000kWh storage units)

<table>
<thead>
<tr>
<th>Industrial / Commercial Supply Case 350bar X-120 steel</th>
<th>350 bar IRR %</th>
<th>500 bar IRR %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage Capacity kW/kWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>250kW/250kWh</td>
<td>7.17%</td>
<td>8.38%</td>
</tr>
<tr>
<td>1000kW/1000kWh</td>
<td>8.85%</td>
<td>11.15%</td>
</tr>
</tbody>
</table>

![Fig 10.30 The IRR for the Industrial Tariff Model (250kWh and 1000kWh energy stores)
10.5.6 Capital Cost Sensitivity

The viability of the Energy Stores as their capital cost changes was measured by observing the change in IRR for different levels of investment.

The three modes of analysing the investment potential (i.e. tariff alone, scenario 3b and scenario 4a) were analysed separately as the capital cost was varied above and below the original capital cost estimate. (Appendix 6, sheet 11). Tables 10.16a and 10.16b compare the results for the 25kWh energy store operating in the domestic sector whilst the capital cost is varied between £12k and £6k for each case.

Table 10.16a 25kWh energy store for the stand alone tariff and the combined power generation scenario 3b and Tariff benefits.

<table>
<thead>
<tr>
<th>Capital Injection</th>
<th>IRR % Tariff only</th>
<th>IRR% Tariff + 3b</th>
</tr>
</thead>
<tbody>
<tr>
<td>12000</td>
<td>7.58</td>
<td>8.75</td>
</tr>
<tr>
<td>10000</td>
<td>9.21</td>
<td>10.56</td>
</tr>
<tr>
<td>8000</td>
<td>11.57</td>
<td>13.23</td>
</tr>
<tr>
<td>6000</td>
<td>15.46</td>
<td>17.74</td>
</tr>
</tbody>
</table>

Table 10.16b 25kWh energy store for the combined power generation scenario 3b and Scenario 4a with the Tariff benefits.

<table>
<thead>
<tr>
<th>Capital Injection</th>
<th>IRR% Tariff + 3b</th>
<th>IRR % Tariff + 4a</th>
</tr>
</thead>
<tbody>
<tr>
<td>12000</td>
<td>8.75</td>
<td>9.93</td>
</tr>
<tr>
<td>10000</td>
<td>10.56</td>
<td>11.94</td>
</tr>
<tr>
<td>8000</td>
<td>13.23</td>
<td>14.97</td>
</tr>
<tr>
<td>6000</td>
<td>17.74</td>
<td>20.17</td>
</tr>
</tbody>
</table>

The results of the capital sensitivity tests are illustrated in figures 10.31a and 10.31b. It can be seen that there is a progressive improvement in the IRR with the inclusion of the generation benefits with the tariff benefits.

The increasing improvement in the IRR with capital reduction illustrates the potential which may be gained through research and development focused upon cost reduction.
Chapter 10 Economic Evaluation of Energy Storage

Fig 10.31a 25kWh storage unit Capital Sensitivity test comparing the IRR for domestic tariff base (Tariff alone and Scenario 3b)

Fig 10.31b 25kWh storage unit Capital Sensitivity test comparing the IRR for Domestic tariff base (Scenario 3b and Scenario 4a)

The detailed results of the 250kWh energy store analysis applied to the domestic sector are available in Appendix 6, sheet 11.

The example chosen to illustrate the capital sensitivity in the industrial sector is the 1000kWh model. Return on capital investment improves markedly when the energy store is combined with the power plant to deliver the maximum benefit. (figures 10.32a and 10.32b).
Scenario 4a demonstrates an improvement over the continuous generation pattern of scenario 3b as may be predicted, however, it gives an indication that increased volatility of demand upon fossil fuelled plant due to the variability of renewable energy such as wind power can only increase the potential for embedded energy storage to contribute to the overall efficiency of power generation.
10.6 The Economic analysis of the Vanadium Flow Battery

The evaluation of the Vanadium Flow Battery follows the same methods used for the hydraulic accumulator. However, the absence of definitive market costs for these devices has limited the analysis to identifying the capital cost below which the investment would not be acceptable for each operational mode.

An Internal Rate of Return of 8% is suggested as the hurdle rate above which the investment may start to compete with the charge on the ‘Senior Debt’ for a project requiring bank funding (i.e. Bank rate plus a risk premium of 2%).

Three applications of the flow battery as an energy store have been chosen to illustrate the maximum capital investment allowed to achieve the 8% IRR:

Case 1 A 5kW, 20kWh model for the domestic market
Case 2 A 100kWh, 400kWh model to meet the domestic co-operative proposal
Case 3 A 1000kW, 2000kWh model to meet the industrial market

The investment performance of each model was investigated using the three modes of capturing financial benefits used in section 10.5, namely:

1) The income received from a Tariff Base income alone
2) The income received from combining the Tariff rewards with those projected under scenario 3b
3) The income received from combining the Tariff rewards with those projected under scenario 4a

The calculation of the IRR for each case will be found in Appendix 6, sheet 12. The maximum allowable investment was determined by observation of the graphical records shown below (figures 10.33a / b to 10.35a / b).
Graphical Results for Case 1

![Graph 1](image1)

Fig 10.33a Investment Return 5kW, 20kWh Model Domestic Tariff alone

Point ‘A’ on figure 10.33a is represents the maximum capital investment which may be invested to ensure an IRR of 8%.

![Graph 2](image2)

Fig 10.33b Investment Return 5kW, 20kWh Model Domestic Tariff alone
Graphical Results for Case 2

Fig 10.34a Investment Returns for 100kW, 400kWh Model Domestic Tariff

Fig 10.34b Investment Returns for 100kW, 400kWh Model Domestic Tariff plus Scenarios 3b and 4a
Chapter 10 Economic Evaluation of Energy Storage

Graphical Results for Case 3

Fig 10.35a Investment Returns 1000kW, 2000kWh Model Industrial Tariff alone

Fig 10.35b Investment Returns 1000kW, 2000kWh Model Industrial Tariff plus Scenario 3b and Scenario 4a

The results of all three cases are summarised in Table 10.17. It identifies the nominal maximum target capital expenditure which may be spent using the benefits determined for each scenario. The tariff benefits are, in part, built upon the recognition of the average transmission and distribution losses assumed for each DNO and allowed by the regulator (Ofgem).
Chapter 10 Economic Evaluation of Energy Storage

Table 10.17 Summary of three cases Maximum Allowable Capital Expenditure

<table>
<thead>
<tr>
<th>Test Case</th>
<th>Maximum Capital Investment</th>
<th>Maximum Capital Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tariff Alone</td>
<td>Tariff +Scenario 3b</td>
</tr>
<tr>
<td>Case 1</td>
<td>&lt;£9000</td>
<td>&lt;£10500</td>
</tr>
<tr>
<td>Case 2</td>
<td>&lt;£8000</td>
<td>&lt;£20000</td>
</tr>
<tr>
<td>Case 3</td>
<td>&lt;£600000</td>
<td>&lt;£800000</td>
</tr>
</tbody>
</table>

10.7 The Need for Changes to Regulation and the Tariff Mechanism

As no tariff mechanism is in place to recognise the benefits which accrue to the power generating stations, the numbers claimed in Scenarios 3b and 4a (table 10.17) are not available. They only serve to illustrate the need for change if these benefits are to be made available. They represent real saving in the amount of fossil fuel used to generate electricity, reduced CO₂ emissions and improved use of capital.

The second element which should be addressed is that of distribution losses. If it becomes possible to identify the areas of the transmission and distribution losses in sufficient detail so that locations of very high losses may be identified, it will then be practical to place energy storage at the most advantageous points. It will be necessary to place a value upon the gains achieved so the correct incentives are placed upon the service provided.

Figure 10.36 illustrates the area of interest on the loss distribution curve discussed in chapter 5 above. Until the size and shape of this distribution loss is known and the area of interest represented by the section bounded by the triangle ‘egf’ on the curve is defined, the opportunities to establish the case for energy storage will be less than optimum.

10.8 Further Application for Embedded Energy Storage

A number of functions could be provided by ‘Embedded Energy Storage. Quantifying the financial benefits is often site specific and therefore must be considered at the time when the opportunity arises. Other applications are market driven and depend upon the prices for
transient parcels of power which must be acquired through the market bidding process. Some of these opportunities include:

* Load Shedding
* Power Trading
* Provision of Ancillary Services
* Line Voltage correction
* Reactive Power correction
* Emergency Power standby

![Standard Normal Distribution](image)

Fig 10.36 The area of potential high energy losses on the distribution curve of the Transmission and Distribution networks.

10.8.1 **Embedded Energy Storage and Nuclear Power Generation**

**Fission**

Any replacement nuclear capacity for the plant being retired in the UK will still use the old fission process. Although the new plant will be required to have the facility to vary its output unlike the existing plants, the modulation will be limited to +/- 5%.

The addition of energy storage dedicated to allowing these plants to operate at their maximum capacity could allow them to contribute a higher proportion of the overall
demand. If sufficient capacity was available it could reduce the total number of plants required hence reduced capital expenditure, higher productivity etc.

The location of such storage would need to be judged on the losses sustained in the transmission and distribution system before any role might be assigned to embedded storage.

**Fusion**

The ITER project (the study of extracting heat from the fusion process) follows the successful JET project which proved the fundamental process [105]. It is planned to harness up to 500MW of power from the fusion reactor by 2030.

At the present time it is not obvious how the power output from an ITER installation could be modulated to meet varying power demands when it is used to generate electricity other than through a current proposal to convert surplus energy to hydrogen.

Whilst it is anticipated that the process could offer limitless power supply, if it is to deliver the product to a variable demand, the storage of energy in a form suitable to regenerate power on demand would appear to offer the best solution.

**10.8.2 Energy Storage and Wind Power**

The number of wind turbines installed in northern Europe is growing substantially year on year. The problems with the volatile nature of this source of power are also increasing [107] as power surges across international boundaries cause network control instability. The European Transmission Operators are actively seeking solutions to deal with the issues which include substantial expenditure on increases on the transmission line system.

In Ireland energy storage is to play a new role in reducing the impact of variable power production. A 2MW, 6MWh Flow Battery system is to be installed adjacent to a 32MW wind farm. It is claimed that the £9.4M project will produce a 17.5 % IRR on the investment from revenue streams generated in the Irish Market,[91].

It is too early to project if embedded storage adjacent to the consumer or at the source of generation will have a role to play in expanding the role of variable renewable power
generation. Detailed studies will be required to establish the best economic location for small storage units within the distribution networks.

10.9 Chapter Summary

This chapter attempted to examine the financial return that might be achieved by an energy storage facility embedded within the distribution system.

It was assumed that the revenue would only be available through the current tariff system and within the existing regulations regarding the use of the national grid and the distribution systems.

A number of different financial / company structures were explored to evaluate the best method of extracting the value from embedded storage installations. The study considered:

1) Standalone storage facilities for the domestic supply
2) Stand-alone storage facilities for the industrial customer
3) Energy storage owned and operated by the Energy Supplier
4) Energy storage owned and operated for the Energy Trader
5) An integrated power generating and energy storage company where benefits would accrue to the group at the storage facility and at the power plant.

The flow battery and the pneumatic / hydraulic accumulator could both supply the function of embedded storage as both devices could be unmanned and remotely controlled. They would be funded through the tariff system, storing power at night for use during the daytime when prices are significantly higher.

It was determined that savings achieved through increased efficient operation at the power station (due to continuous operation under optimum conditions) would not flow directly to the storage facility. Such benefits could only be extracted either by a change in regulations or possibly by the creation of a special commercial arrangement such an independent holding company.

In the domestic tariff system two possible commercial arrangements were considered, energy storage within individual households and collective household units.
When applied to the industrial customer, there are three important income generators, the day / night differential pricing of energy, the use of distribution network charges and the energy loss charges. A fourth item is based upon the avoidance of Triad charges. The benefits which may be claimed by embedded energy storage depend upon the ownership. Amongst all the potential owners, which include the final customer, the local DNO, the NGC, the energy supplier and the energy trader, the final customer would appear to best placed to gain the most.

If the energy storage was owned by Energy Supply Companies or by Energy Traders, it would allow both to hedge their power purchases, in a way not possible at the present time. It would add another dimension to their operation. The benefits would depend upon the methods by which each company chose to integrate the energy stores.

The Energy Supplier could be in a position to avoid Triad charges and reduce use of distribution charges whilst selling into the high prices daytime market. The company structure best suited to taking advantage of most of the benefits generated by an energy store is the integrated energy generation and storage company. A power station could gain all the financial benefits identified, if it was associated with energy storage embedded within the distribution system.

The one area of benefits which cannot be claimed by any of the market players under the present tariff structure is that of energy losses which occur at the extremities of the transmission and distribution. Until these losses are measured and a tariff system devised to reward the “True Economic Value of strategically placed storage, the opportunities to make the saving of fossil fuels, CO₂ emission, increase capital and operational productivity gains will be lost.
Chapter 11
Conclusions and Recommendations for Future Work

The main purpose of the research work was to explore the impact of sources of renewable energy upon the electricity supply chain and to consider the potential benefits which may be obtained through introducing energy storage.

The work entailed developing and analysing potential alternative methods of storing energy embedded into the electricity distribution system.

In order to maximise the detailed financial return of embedded energy storage it was necessary to develop a number of commercial arrangements which could operate within the current electrical regulations and tariff systems.

11.1 The Main Findings and Conclusions

Renewable sources of energy can be usefully divided into 3 groups. The most variable and unpredictable source Group 3 (e.g. Wind power) is the most likely to provide the bulk of the renewable energy contribution in the foreseeable future. There are times when an anticyclone is centred across the whole of the UK which causes there to be no power available from the wind. As the wind turbine capacity increases significantly, it will be necessary to build new power plants with secure sources of power or retain old inefficient fossil fuelled plants to provide the emergency back-up, [107].

The consequences of supplying variable power output from a modern CCGT power station were measured under a number of different production patterns. It was shown for the first time that as such power plants depart from their optimum operating conditions; fuel used increases, pollution increases together with the cost of operation and maintenance. When these consequences are quantified it is possible to place an overall cost on providing a balancing service necessary to accommodate the variable power supply from Group 3
renewable sources of energy. One solution to accommodate both the variable power input from renewable sources of energy and the variable demand from customers would be the storage of energy.

In Chapter five it was revealed that the current practice of storing energy using pumped storage in remote locations was the least efficient option. The most effective location would be provided by embedding the energy stores adjacent to the customer. The analysis of the losses that occur along the supply chain showed that not only is there a significant lack of information concerning the extent of these losses, but also that there may be points in the distribution chain where the actual losses are extremely high. The practice of estimating the annual power lost in the system and making it a ‘Pass-Through’ cost to the customer per unit of power consumed is presently hiding the extent of the problem.

The benefits of embedded energy storage when working in conjunction with a fossil fuelled power plant were explored in detail. Significant improvements could be obtained if the power plant was operated under ‘Optimum Conditions’ whilst the energy stored in the system is used to match both variable demand and variable supply. The selection of high power loss sectors within the distribution system would be the most rewarding locations for embedded storage.

Following a review of current energy storage technologies it was concluded that few available offer suitable characteristics to make them a practical option as embedded storage devices. The electrical storage battery is the only proven device which may make a contribution for this application. Of the available technologies in this sector the chemical battery has been rejected as it fails to offer the necessary economic and environmental advantages for long term success. The flow battery has the potential to deliver the most suitable solution. Several different electrolytes have been proposed and tested and the most promising form of flow battery is based upon the vanadium electrolyte. It has been applied to a number of applications but in its’ current form has a low overall efficiency of 70% and requires significant land area to store the electrolyte which would make it an expansive option in urban locations. It does however, offer suitable depth of discharge, low operational costs, low environmental impact and an extended life cycle (≥ 10,000 cycles).
In exploring other technical options for storing energy in small quantities, an enhanced version of the hydraulic accumulator was examined. This work suggests that there is the possibility of developing such a device and that it has the potential of competing with the flow battery.

It would involve high pressure compression of a gas with the potential of delivering an acceptable ‘Turn Round’ efficiency and using proven items of hydraulic and electrical equipment. The environmental impact would be acceptable for application in an urban location with a useful life cycle (≥10,000 cycles) and the requirement for a small land area to accommodate the equipment on the surface. Materials for the compression cylinder present a challenge and recent developments in composite materials for high pressure applications may deliver a real solution. A configuration of the plant was proposed that would make it more suitable for application in densely populated urban areas where land prices are high.

An examination of the financial viability of embedded energy storage was carried out. The study was confined to revenues which might be earned within the current (2006) regulations and complex tariff systems. The capital costs of the two methods of storage considered (the flow battery and the pneumatic/hydraulic accumulator) were based on estimates using published data wherever possible and reference to professionals in the field. Reluctance to divulge the specific costs for vanadium batteries of varying capacities led to the use of generally applied rules from the manufacturer. In the case of the pneumatic/hydraulic accumulator where possible discrete component costs were obtained and estimates made for the remaining items.

It was shown that the potential financial case for embedded energy could produce a modest return both for domestic and industrial customers. The best case was delivered by the Integrated Power Company where the benefits could be gathered locally within the tariff system for the energy storage operation and at the power plant through lower operational and capital costs. These returns would be independent where the store was placed within the low voltage distribution network, no matter whether the actual distribution loss was below the average value incurred or not.
A tariff system which rewarded the storage unit based upon the actual savings contributed would enhance the earnings thereby encouraging the development of the technology and would offer potential savings in environmental pollution when applied in the correct locations. It could form part of the thrust to reduce the concentration of atmospheric CO₂ in the coming decades and might, therefore attract politically motivated incentives.

11.2 Recommendations for future work

The following recommendations are made for future research work with respect energy losses in the whole electricity supply chain:

The data analysed in the research work was carried out on an existing very efficient commercial power generating plant. It would increase the understanding of the real consequences if similar analysis was performed on other less efficient units especially those which use coal as their primary source of energy.

The declared losses on the electricity national grid transmission and the DNOs distribution systems are only declared as ‘Average Losses’ If embedded energy storage is to be placed in the network where it can deliver the maximum benefits, it will be necessary to identify and quantify the circuits where the highest losses are incurred.

The energy lost in the system represents wasted fuel, higher pollution and increased costs of the actual power delivered to the final customer.

If the focus was placed on the cost of the energy delivered to the final customer and charged accordingly, a more efficient power generation and supply system could evolve. The true cost of power would encourage the development of more innovative ways of supplying the customer. It may involve an actively managed distribution system (rather than the passive systems currently employed) to route power flows via the lowest cost route and minimise losses or to store power in different locations for subsequent delivery during peak load periods. It may involve the commissioning of generating plants to supply continuously whilst the storage of power and the emissions trading of CO₂ certificates becomes part of the actively integrated operation.
As renewable energy expands its contribution to the total power generated, there will be increasing concerns over the effective integration and security of supply. Where this energy is delivered from variable and intermittent sources of energy it will present particular problems. As wind power is likely to provide the major source of energy in the immediate future, there will be a significant issue during periods when an anticyclone is centred over the UK. Only part of the deficit (i.e. short term fluctuations) could be accommodated by energy storage.

The source of replacement power during these periods will have to come from fossil fuelled plants. As these plants will deliver progressively less and less of the total annual demand, this source of back-up power will become increasingly expensive. The real costs of making provision for sufficient standby fossil fuel capacity should be determined and added to the costs of the renewable source of energy if the integrated supply chain is to be correctly operated to minimise both atmospheric pollution and cost.

Energy Storage technology offers some solutions for the efficient operation of power supply networks. It is recommended that new technologies should be specifically developed to meet the requirements of storing energy in relatively small quantities deep within the final distribution circuits. Both the current proposals (the flow battery and the pneumatic / hydraulic devices) may provide an answer. However, further work is required to complete the development and to analyse the best methods of integrating them into the system for maximum advantage. In the case of the proposed pneumatic / hydraulic energy store a physical model is required to demonstrate the process and measure the potential characteristics of performance.

It is recommended that new tariff systems be designed to encourage the use of embedded energy storage. Such systems would need to reward the installation of storage which reduced losses in locations identified as causing high power losses. They may have the greatest initial impact if they were designed to target the Distribution Network Operator (DNO) as they currently own and operate the network and are in the best position to deliver effective solutions.

The nuclear industry contributes little or no atmospheric pollution from CO₂ but it is restricted in contribution by the inability to vary power output to match the system variable
supply and demand. If sufficient energy storage was made available the position would change and improve the competitiveness of nuclear generation. The capital cost of the nuclear plant is high but the energy costs are low when compared with the fossil fuelled plants. Hence a true analysis of the marginal cost of power delivered to the customer is required to examine the case for integrating nuclear generation and embedded energy storage.

Finally, this study has been focused on UK power generation. Similar situations exist across the world and it is recommended that the global opportunities which may exist for embedded energy storage technology should be investigated. It is anticipated that many of the electricity distribution systems in other countries supply a customer base which is more widely spread over larger geographic areas. The potential losses in such networks may well be higher than those in the UK where relatively short distances of transmission and distribution lines are involved.
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