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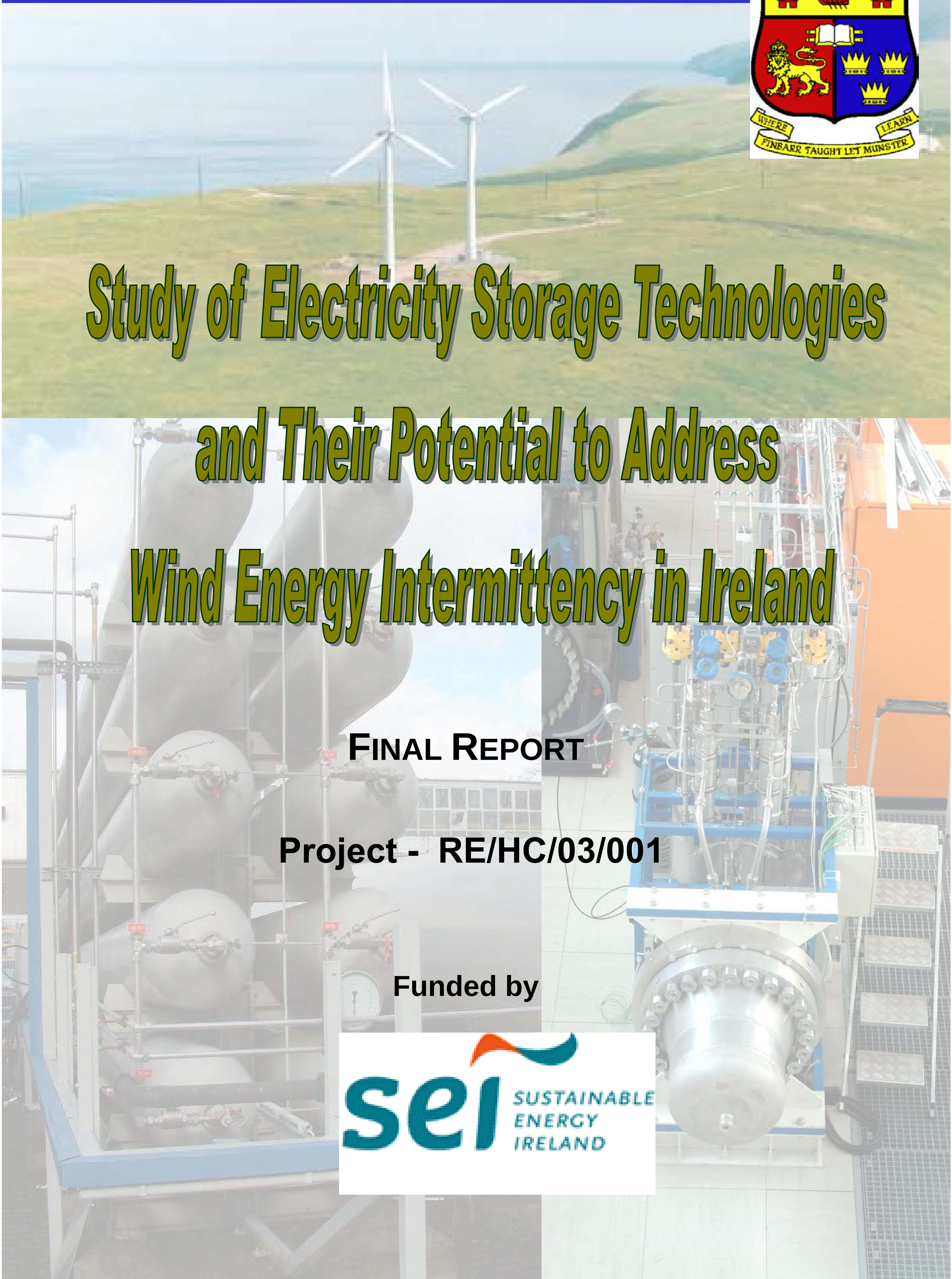

Study of Electricity Storage Technologies and Their Potential to Address Wind Energy Intermittency in Ireland

FINAL REPORT

Project - RE/HC/03/001

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Study of Electricity Storage Technologies and Their Potential to Address Wind Energy Intermittency in Ireland

Final Report

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EXECUTIVE SUMMARY

Context

Wind energy deployment in Ireland is due to accelerate very rapidly in the short term. Until recently, the rate of wind energy deployment in Ireland has been relatively modest at approximately 20MW installed capacity, on average per year, since 1997. The deployment rate increased since 2003 and the total amount of wind power installed by May 2004 was 190MW, with a further 44MW nearing final connection (CER 2004).

Adding to this the amount of wind power not yet installed but with signed connection agreements raises the 190MW to 823MW, with a further 749MW within the process and an additional 627MW for which applications were being checked in May 2004. This represents a cumulative total of 2199MW, although it is unclear how many of these wind farms have secured planning permission and the necessary finance to enable construction. A survey carried out in 2004 (CER 2004) concluded that 661MW would be likely to connect to the system by mid 2006, bringing the total installed wind capacity to 851MW. This represents 14% of projected total generation capacity in 2006 (ESBNG 2003).

Despite the recent dramatic increase in activity, it is almost certain that the target in the Green Paper on Sustainable Energy will not be met. The target set was for an additional 500MW of renewable generated electricity to be delivered by 2005, i.e. before January 1 2005. Excluding AER III wind farms that fell outside this target, 92MW has been delivered to date and based on the timeframe envisaged for connections (ESBNG 2003), an additional 308MW will be connected by the end of 2004, delivering thus 400MW of the 500MW total. Based again on accepted connection offers, it is envisaged that an additional 186MW of wind energy capacity will be installed during 2005. This assumes that the wind farms with connection agreements will be backed financially and will not encounter unforeseen circumstances that might delay or even prevent completion.

One of the difficulties in accommodating wind energy intermittency in Ireland relates to the nature of the electricity network. The design of the network evolved along the conventional approach, where large scale thermal plant feed into a transmission network through to a distribution network and supply to final customers. The structure and operation of the network does not readily accommodate decentralised embedded generation such as wind farms. This problem is common to other European electricity networks but Ireland faces an additional challenge in accommodating wind energy due to the lack of adequate scale and interconnection.

As electricity demand has grown in the past decade, the transmissions system has become strained, prompting the urgent need for system upgrade. A major refurbishment and expansion programme running from 2001 to 2005 is underway. This programme increases annual capital expenditure on the transmissions and distribution networks by a factor of three, contributing to the recent electricity price increases. Over €2.6 billion is being invested in the high voltage and low voltage networks, particularly in the counties along the southern and western coasts. Over

€820 million will be spent on transmission, over €1 billion on distribution renewal (including conversion of 50% the 10 kV network to 20 kV), and over €665 million on distribution reinforcement.

This upgrading of the electricity networks will improve the system and thereby facilitate the accommodation of increased wind energy penetration. However, this upgrading programme should now be reviewed to take account of the anticipated accelerated deployment of wind energy outlined above in line with the recommendation of the Renewable Energy Strategy Group (2000). This should be done within the framework of an integrated sustainable energy policy for Ireland.

This is separate from the financial mechanism for grid connecting wind farm clusters, which has been examined by the Steering Group for Grid Upgrade Development Programme and adopted by CER.

ESB National Grid, the Irish Transmission System Operator has expressed a number of concerns at the amount of wind energy projects currently possessing (together with those seeking) signed connection agreements. These concerns relate primarily to the inability to ride through faults and the impacts on the stability of the system. In the absence of dynamic models for wind turbines intending to connect, the nature of some of these impacts is unclear.

There are other concerns (associated with reserve requirements) that relate to the intermittency of wind energy and the high level of variability in the output of each wind farm. The primary focus of this study is the role of energy storage in addressing the these concerns.

There is much debate as to how much intermittent wind energy an isolated grid like Ireland’s can support without impacting negatively on system security and stability. For ESB National Grid, penetration levels of 5 – 7% are acceptable compared with views expressed by industry of over 30%, the latter under assumptions of adequate interconnection and well developed enabling technologies such as dynamic load levelling and short term wind forecasting.

In addition to the impacts on penetration levels of wind, intermittency also has a key bearing on the value placed on wind generated electricity. This is particularly apparent in liberalised electricity markets, where wind farm developers are not guaranteed a fixed feed in tariffs for the output of their plant (as is the case for example in Germany and Denmark). The degree to which intermittency affects the financial value of the electricity will depend to a large extent on the trading rules that apply in each electricity market. The proposal by CER, for example, that all generators pay for the cost of reserves in line with a ‘causer pays’ principle will typically mean a higher charge for wind generators due to the additional reserve requirements attributable to intermittency.

Electricity storage

Energy storage is not a new concept in the electricity sector. Utilities across the world have built a number of pumped-hydro facilities in the last few decades, resulting in a storage component of roughly 5% the capacity of all the European countries, 3% in the US, and 10% in Japan.

These pumped-hydro plants, and to a lesser extent compressed air storage systems, have been used for load levelling, frequency response, and voltage control. Likewise, storage facilities based on other technologies such as lead-acid batteries have been installed by a number of utilities to fulfil a variety of functions. At a different scale, energy storage is also commonly used at the user level to ensure reliability and power quality to customers with sensitive equipment. Another traditional application is the electrification of off-grid networks and remote telecommunications stations, mostly in connection with renewable sources.

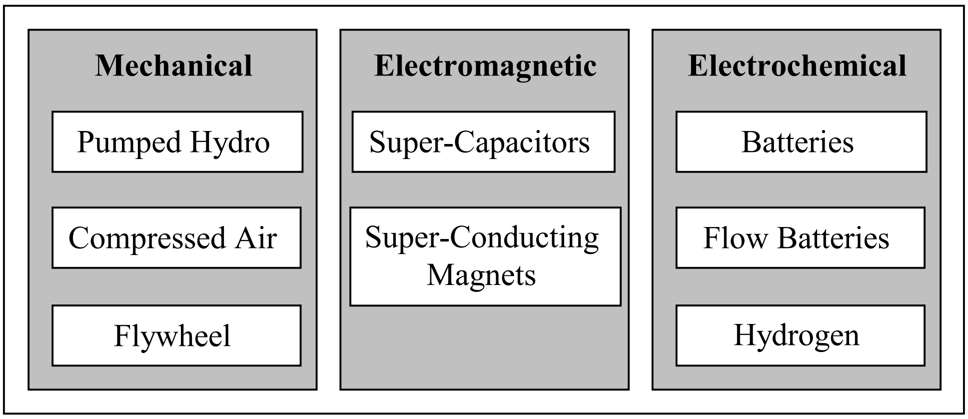
The applications for electricity storage technologies can be grouped as:-

- load management (load levelling, ramping and load following);
- spinning reserve (fast response and conventional);
- system stability and voltage regulation;
- deferral of system and plant upgrading;
- renewable energy applications;
- end use applications (UPS, peak shaving and emergency back-up).

Traditionally, electricity storage technologies have been used for the technical benefits they bring to electrical systems. With the arrival of liberalised electricity markets, a new application for energy storage has presented as price arbitrage (buying at low price, storing and selling at a high price). The key characteristics of storage technologies that determine which applications they are most suited for are :

- discharge duration;
- power rating;
- energy storage capacity;
- response time
- costs in the context of benefits.

Electricity storage systems can be categorized as **mechanical**, **electromagnetic** and **electrochemical** storage devices as follows.



Mechanical	**Electromagnetic**	**Electrochemical**
Pumped Hydro	Super-Capacitors	Batteries
Compressed Air	Super-Conducting Magnets	Flow Batteries
Flywheel		Hydrogen

Wind intermittency and storage

Many of the problems associated with wind energy intermittency can be addressed using appropriate electricity storage technologies. Different problems are associated with

- short duration fluctuations (seconds) – leading to power quality problems;
- hourly variations – primarily market related (including payment for reserve);
- longer term variations (days) –affecting the requirements for backup and the 'firmness of wind energy'

The key electrical storage technologies that are appropriate for each of these problems are :-

Power Quality	**Market Related**	**Long term fluctuations**
flywheels	pumped hydro	pumped hydro
hydrogen	hydrogen	hydrogen
batteries	batteries	batteries
flow batteries	flow batteries	flow batteries
	compressed air	compressed air

It is important to note that these technologies are at varying stages of technological maturity.

- **Pumped hydro energy storage** (PHES) is a mature and familiar technology and has been utilised within electricity systems for many years. It is the most widespread energy storage system currently in use on power networks, operating at power rating up to 4,000 MW and capacities up to 15 GWh. PHES uses the potential energy of water, transferred by pumps (charging mode) and turbines (discharge mode) between two reservoirs located at different altitudes. Currently, the overall efficiency is in the 70-85% range although variable speed machines are now being used to improve this. The efficiency is limited by the efficiency of the deployed pumps and turbines (neglecting friction losses in pipes and water losses due to evaporation). Plants are characterized by long construction times and high capital costs. One of the major problems related to building new plants is of an ecological/environmental nature.
- **Compressed air energy storage** is also a mature technology but much less deployed than pumped hydro. The electricity is stored by compressing air via electrical compressors in huge storage facilities, mostly situated underground in caverns created inside appropriate salt rocks, abandoned hard-rock mines, or natural aquifers. Recovery takes place by expanding the compressed air through a turbine, but the operating units worldwide incorporate combustion prior to turbine expansion in order to increase the overall efficiency of the system. Hence CAES can be regarded as peaking gas turbine power plants, but with a higher efficiency, thanks to the decoupling of compressor and turbine, and much lower overall cost. Deployment is often dependent on the availability of suitable underground reservoirs but custom built high pressure storage tanks can be utilised.
- Kinetic energy may also be used to store energy in the form of the inertia of a **flywheel**. Flywheels have been used in hydro power stations with synchronous

generators for many years. With the advent of advanced composite materials with high tensile strength, and the development of stable magnetically suspended bearings, flywheels may now be made with significantly higher operational speeds. All reciprocating engines contain flywheels to smooth the pulsed output of the pistons and provide stable power. Flywheels storage systems are particularly suitable for power quality control. They can provide ride-through power for the majority of power disturbances, such as voltage sags and surges, and can bridge the gap between a power outage and the time required to switch to long-term storage or generator power with excellent load following characteristics.

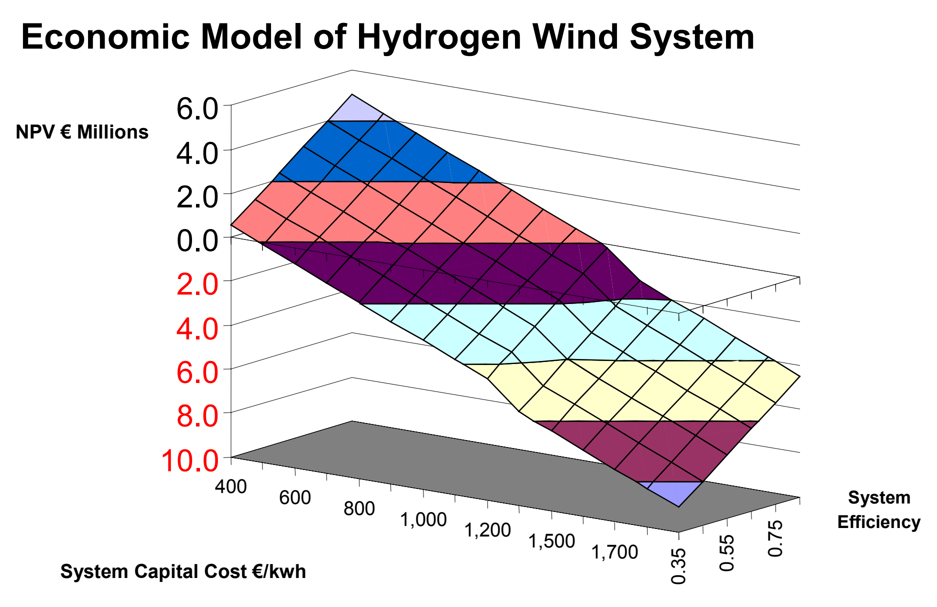
- Capacitors store energy by way of separating the charge onto two facing plates. They are widely used in electronic devices for power smoothing after rectifying. Typically, these applications require very small energy amounts. In order to increase the energy density, the so-called '**Super-Capacitors**' (or even 'Ultra-capacitors', if their capacitance exceeds 1000F) have been developed. They use polarized liquid layers at the interface between a conducting ionic electrolyte and a conducting electrode, which increases the capacitance. Super-Capacitors Energy Storage (SCES) offers extremely fast charge and discharge capability, albeit with a lower energy density than conventional batteries can provide and can be cycled tens of thousands of times without degradation.
- In a **Superconducting Magnet Energy Storage** (SMES) device, a coil of superconducting wire allows a DC current to flow through it with virtually no loss. The current creates a magnetic field that stores the energy. On discharge, special switches tap the circulating current and release it to serve a load. To set the coil in a superconducting state, it has to be cooled down either to 4.2°K (low-temperature superconducting) or 77°K (high-temperature superconducting). Technical improvements and a better knowledge of dealing with and controlling cryogenic systems have allowed SMES to penetrate the market and compete with more common storage systems. The dynamic performance of SMES is far superior to most other storage technologies. Response times down to milliseconds are possible and the energy can be transferred very quickly. SMES are most suitable for high value/low energy applications, where the storage requirement is for less than a few seconds, with power requirements up to 1 or 2 MW.
- **Batteries** are the most common devices used for storing electrical energy. Traditionally they have been used for small scale applications but there is growing awareness amongst manufacturers of the potential applications for larger scale energy storage in the context of liberalised electricity markets. As battery cells have a characteristic operating voltage and maximum current capability, battery systems normally consists of several cells, linked in line or parallel dependent on the required power and energy rating. Batteries exhibit a fast response to changes in power demand. Their efficiency varies among technologies, and also depends on the application and the operation regime. The most mature technology, **flooded lead-acid (LA)** batteries and **valve regulated lead-acid (VRLA)** batteries, have been in service in electric power applications for two decades according to Butler (2002). **Nickel-cadmium (NiCd)** batteries have also reached an important maturity degree. Advanced battery technologies such as **sodium-sulphur (NaS)** and **lithium-ion** are quickly becoming commercially available. **Lithium-polymer (Li-polymer)** and **nickel-metal hydride (NiMH),** which have been developed mainly for automotive use, and **metal-air,** are also candidate storage media.

- **Flow Batteries** (FB), also known as Regenerative Fuel Cells or Redox Flow Systems are a new class of battery that has made substantial progress technically and commercially in the last years. Flow Batteries Energy Storage (FBES) systems have features that make them especially attractive for utility-scale applications. The operational principle differs from classical batteries. The latter store energy both in the electrolyte and the electrodes, so to speak. Flow batteries, however, store and release energy using a reversible reaction between two electrolyte solutions separated by an ion permeable membrane. Both electrolytes are stored separately in bulk storage tanks, whose size defines the energy capacity of the storage system. The power rating is determined by the cell stack. Therefore the power and energy rating are decoupled, which gives the system designer an extra degree of freedom when designing the system. Many different electrolyte couples have been proposed for use in flow batteries. Current developments are based on **vanadium redox, sodium polysulphide / sodium bromide and zinc / bromine.**
- Hydrogen is an immature technology but envisaged as a promising means of electrochemical storage attracting huge interest and research funding in Europe and the USA particularly. In a **Hydrogen Energy Storage** (HES) system, the charge takes place when the electrical energy is used in an electrolyser to split water into hydrogen and oxygen. The oxygen is usually vented to the atmosphere. And the hydrogen can be stored in different ways. The discharge, providing the energy release, can take place in a fuel cell or in an internal combustion engine. One significant advantage of hydrogen as a storage option is that the energy storage capacity input power rating and output power rating are completely decoupled. Most aspects in the hydrogen-related technology, including generation, storage and utilisation in fuel cells, need further development. The most severe problem that burdens HES is the low round-trip efficiency. There are losses in the electrolyser, storage and fuel cell. Technological breakthroughs will improve the efficiency, but it will still remain considerably behind other competing technologies. Despite the concerns that hydrogen arouses, hydrogen does not pose more safety problems than other fuels. Being the lightest gas, hydrogen quickly disperses into the environment in the event of leakage, making it less of a fire hazard than gasoline.

Economic viability

The viability of energy storage was examined using a financial model, which considered the variable inputs for cost and prices. The key cost inputs are the capital and operational costs associated with constructing a storage system. The costs associated with construction of wind farms were not included in this analysis. Similiarly, the key benefit considered was the improvement of price in the market. In the absence of detailed information on the market support mechanism post 2005, proportions of green benefits were also included considering the combined price of a traded UK Renewable Obligation type certificate and carbon taxes. Other key inputs include the efficiency for each stage of the storage/discharge process, operating hours per day (of charge and discharge) and cost of capital.

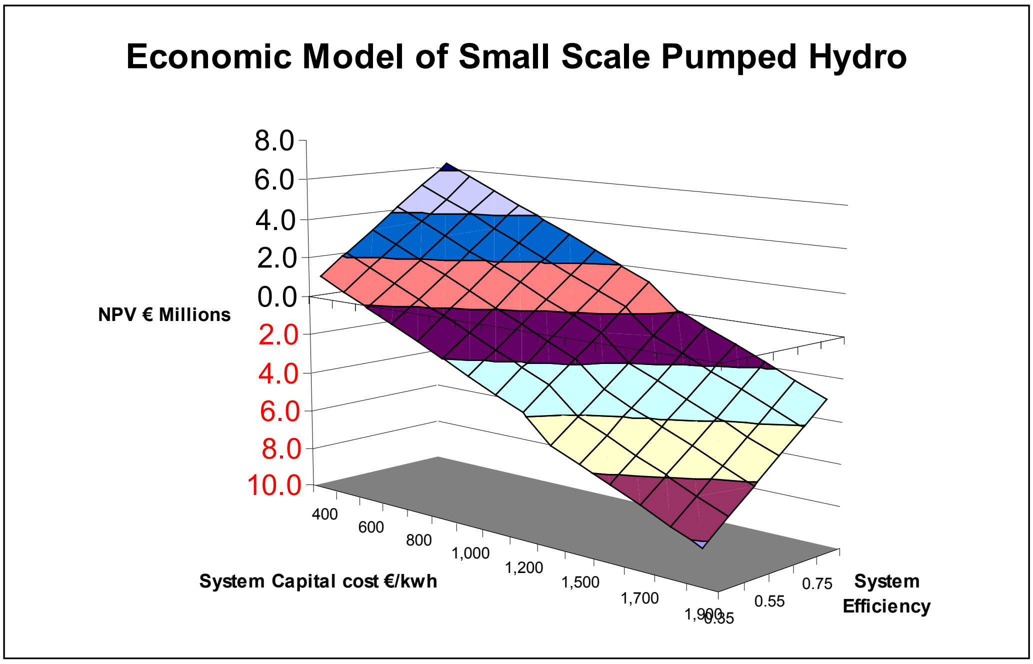
The model output gives the likely revenue enhancement and net present value for systems within a range of sizes, and configurations. Figure 1 below gives the output from the economic model as a viability surface, where NPV of a hydrogen wind system is given in terms of variance in system capital cost and system efficiency. These two variables are the most easily influence by a concerted drive to develop this technology. Typically with capital cost at or around €1,200/kW and system efficiency at approximately 40%, the system becomes profitable in current market pricing conditions.



Notes: 1. Key static inputs: 5 MW Electrolyser, with ICE Turbine Gensets, or Fuel Cells, Advanced storage medium, or full buffer
2. Input cost of wind power €0.0/MW (marginal cost), output price €40/Mwh (Nogales)
3. ICE engine uses electrolyser output at ambient pressure, output diverted for 10 hours per day (40MW/day)
4. Equipment cost from (Pritchard, Liu and proc. EERE)
5. Financing cost 7% pa., lifetime 20 years

Figure 1 Economic model of wind hydrogen systems

The results for pumped hydro are shown in figure 2. Again the key inputs to the model are capital cost, revenue enhancement potential and system efficiency. Lower capital costs for pumped hydro seem to be attainable, if a lower rating system is designed for 10-50 Megawatts, rather than the 200+MW systems which require construction of receiving reservoirs. Similarly advanced pumping and generation technologies allow for high efficiencies in both smaller and larger plants, (greater than 60%).



Notes: 1. Size data : 11 MW rated facility
2. Assumed output at 10 hours per day
3. Attained price enhancement of €30 per megawatt
4. Financing cost 7% pa., lifetime 20 years

Figure 2 Economic model of wind – pumped hydro

Analysis of the results from the model gives the following insights:

- Total system capital cost is the most important variable driver of the attractiveness of storage systems. Pumped hydro systems can be viable in certain current market environments. This refers specifically to small scale lower cost plants with favourable topographical conditions. However cost of storage capacity means that they are unlikely to fully compensate on a technical basis for the intermittency of wind. This would typically require storage capacity for up to three days of rated output

- Wind hydrogen systems are not yet economically viable, but expected improvements in capital cost and system efficiency will likely change this result over the 5-10 year term, in the context of current technology. This is based on electrolysis and gas engine technology and excludes fuel cells.

- Specifically hydrogen wind systems operating at above 40% system efficiency (product of charge and discharge efficiency), can be economically viable if the combined capital cost of the storage project is below €1,200 /kW. This applies for currently expected market and operating conditions in markets such as the UK, where the determinant variables are relatively well known.

- In the Irish context, where the variables are not yet defined, the viability of storage will be defined by the electricity price variations within any given day, and the resulting opportunities for timeshifted price arbitrage, the charges paid by wind energy generators for reserve, the converse price that will be available for the provision of reserve, and the value to be placed on the renewable benefit.

- A complete model of flow battery economics and viability will await detailed operational data. The Regenesys plant in the UK was expected to provide this in the short term but this project has been abandoned since December 2003.

Strategy and recommendations

The short to medium term strategy focuses on the utilisation of mature electricity storage technologies where performance characteristics and costs are known and understood. The longer term strategy concentrates on technologies that are not yet mature but are potentially more promising in terms of their suitability in addressing wind energy intermittency.

The strategies focus on the storage technologies themselves and how they will operate within the context of electricity network and electricity market developments.

Short to medium term strategy

The key elements of the short term strategy are :-

1. *Pumped hydro resource study*. A significant theoretical resource (up to 1,000MW) has been identified within the context of this study. A study is required to determine the practicable pumped storage potential, taking into account technical and non-technical constraints.
2. *Compressed air energy storage.* The potential for compressed air energy storage should be undertaken providing details of optimum locations close to gas generators with underground reservoirs. This will entail geological surveying and electromechanical modifications to existing or proposed gas fired generators.
3. *System modelling.* The use of storage needs to be considered in the context of an integrated approach to dealing with wind energy interactions with the electricity network, including specific focus on the technical issues causing ESB National Grid to seek a moratorium on new connection agreements. This will require the development of real time energy systems models linked to pending grid modelling studies and incorporating the use of wind energy forecasting. It should also consider the use of methods for addressing intermittency other than storage (for example open cycle gas or and East West interconnector), that fell outside of the scope of this study;
4. *Grid upgrading programme.* The current extensive grid upgrading programme currently underway should be reviewed to take account of the prolific increase and concentration in anticipated future wind energy production.
5. *Demonstration Projects.* The purpose of these projects is to link mature storage technologies with wind energy to demonstrate the technical and economic viability of the complete system. This will drive the learning curve, reduce capital costs and increase future operational efficiencies:-
    a. *Wind + Small scale pumped hydro*

    b. *Wind + Compressed air*

Long term strategy

The key elements of the long term strategy are

1. *Linking wind energy storage and the hydrogen economy*. A study will be required to detail the synergies between hydrogen production in the context of wind energy storage and the development of the hydrogen economy. In particular the anticipated advances in hydrogen fuel cell technologies will increase the value of hydrogen and as a result improve the economics of wind hydrogen systems. This study will only be meaningful when data becomes available from various detailed studies that are currently underway.
2. *Demonstration projects*.
    a. *Wind + flow battery*
    b. *Wind + hydrogen engine*
    c. *Wind + hydrogen + fuel cell*

In summary, the energy storage sector is central to the full integration of wind energy generation. There are a number of appropriate technologies, the most attractive of which from a flexibility viewpoint is wind hydrogen, because of the ability to decouple the input power, output power and storage capacity. Furthermore, wind hydrogen systems are attractive from the standpoint of achieving zero emissions energy. It has not yet matured from an economic perspective however and the overall energy efficiency remains poor.

Pumped hydro systems and compressed air systems have the advantage of technical maturity, economic viability and operational experience and are therefore viewed as a realistic and appropriate first stage in the development of an energy storage solution to wind energy intermittency.

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Chapter 1 The integration of wind energy in Ireland.

1.1 Projections of wind deployment in Ireland.

Until recently, the rate of wind energy deployment in Ireland has been relatively modest at approximately 20MW installed capacity on average per year since 1997. This rate increased more recently and the total power connected by May 2004 from wind farms was 190MW, with a further 44MW nearing final connection. The location of these wind farms is shown in figure 1.1.

However this recent acceleration rate is likely to continue as evidenced by recent data (CER 2004) on the number of signed agreements, live offers and applications for grid connections, summarised in Table 1.1

	Transmission (MW)	Distribution (MW)	Total (MW)	Cumulative Total (MW)
Connected	39	151	190	190
Signed Agreements	379	254	633	823
Live offers	0	10	10	833
Applications in process	207	532	739	1572
Applications being checked	407	220	627	2199

Table 1.1 Status of wind farm grid connection agreements May 04

This summarises the situation regarding grid connections and could be regarded as the best indicator of the future installed capacity for the next few years. Adding to the 190MW currently connected the amount of wind power not yet installed but with signed connection agreements raises the total to 823MW, with a further 749MW within the process and an additional 627MW for which applications were being checked in May 2004. This represents a cumulative total of 2199MW, although it is unclear how many of these wind farms have secured planning permission and the necessary finance to enable construction. A survey carried out in 2004 (CER 2004) concluded that 661MW would be likely to connect to the system by mid 2006, bringing the total installed wind capacity to 851MW. This represents 14% of projected total generation capacity in 2006 (ESBNG 2003).

It should be pointed out that despite the recent dramatic increase in activity, it is almost certain that the target in the Green Paper on Sustainable Energy will not be met. The target set was for an additional 500MW of renewable generated electricity to be delivered by 2005, i.e. before January 1 2005. Excluding AER III wind farms that fell outside this target, 92MW has been delivered to date and based on the timeframe envisaged for connections (ESB National Grid 2003) an additional 308MW will be connected by the end of 2004, delivering thus 400MW of the 500MW total. Based again on accepted connection offers, it is envisaged that an additional 186MW of wind energy capacity will be installed during 2005.

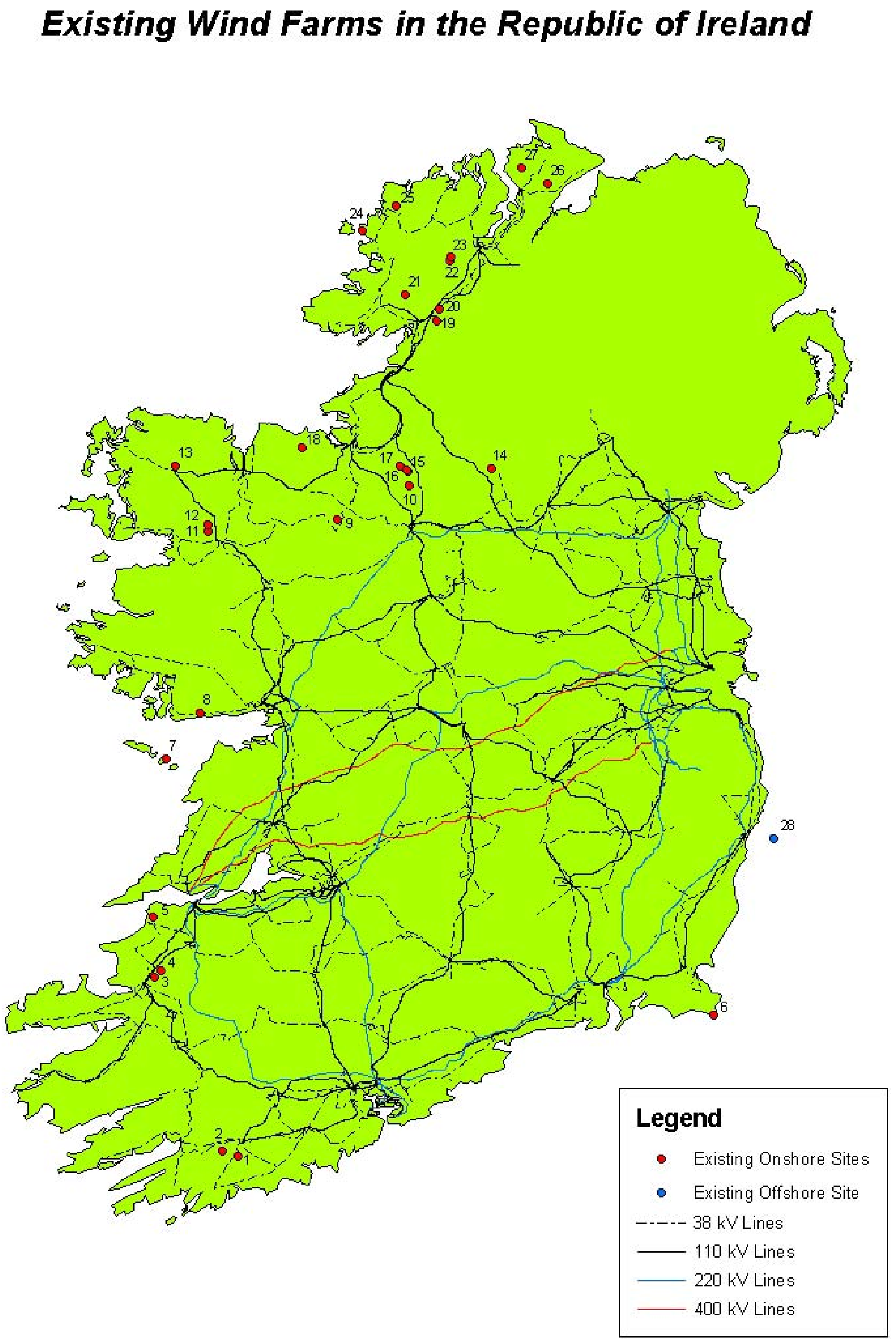
Existing Wind Farms in the Republic of Ireland

Figure 1.1 Map of wind farm sites in Ireland

Table 1.1 above does not give the complete picture of potential wind energy deployment however, as there may be wind farms that have secured a grid connection agreement but do not have planning permission, and vice versa. Table 1.2 gives the total capacity with planning permission (in November 2003) on a county-by-county basis.

County	Wind Power Currently Installed / MW	Additional Capacity with PP / MW	Portion of which under appeal MW
Mayo	27.2	326.4	323.4
Cork	10.56	247.245	6
Cavan	3	227.5	58
Donegal	65.07	206	0
Kerry	23.34	198.7	4
Galway	3.975	139.81	0
Wexford	11.9	121.3	0
Limerick	0	77.75	0
Tipperary	0	74.16	0
Clare	0	54.6	0
Carlow	0	52.5	52.5
Leitrim	9.4	48.36	0
Sligo	25	14.4	3
Meath	0	12	0
Kilkenny	0	5	0
Offaly	0	5	0
Wicklow	0	2.55	0
Roscommon	10.94	0	0
TOTAL:	**190.335**	**1813.275**	**446.9**

Table 1.2 Installed capacities of wind farms with planning permission by county

It is clear from table 1.2 that, based on the number of wind farms with planning permission, there is the potential for a cumulative installed capacity of at least 2004MW of on-shore wind, which compares well with the 2199MW total figure based on connection agreement applications (that includes on-shore and off-shore wind farms). In addition to this 2004MW, there is significant interest in developing offshore wind energy, potentially accounting for an additional 2,000MW, according to Garrad Hassan, ESBI & UCC (2003).

This highlights the need for the development of a co-ordinated wind energy strategy, which will achieve a balance between the technical constraints relating to grid integration and the contribution that can be made by wind energy to meeting national objectives arising from commitments under the Kyoto Protocol, EU Directive 2001/77/EC on the promotion of electricity from renewable energy and the drive for sustainability in the energy sector. The current consultation process on policy, targets and measures for Ireland (DCMNR 2003) will need to feed into a strategy to address the mismatch between projects with planning permission, grid connection agreements and market access as all three are necessary for a wind farm to be built. The locations of potential wind farm sites with planning permission are illustrated in figure 1.2.

The increase in the concentration of wind farms in certain locations is apparent from a comparison of figures 1.1 and 1.2 and it is important to note that wind farm concentration exacerbates the impacts of wind intermittency (RESG 2000). It should also inform grid upgrading programmes to facilitate increased wind penetration.

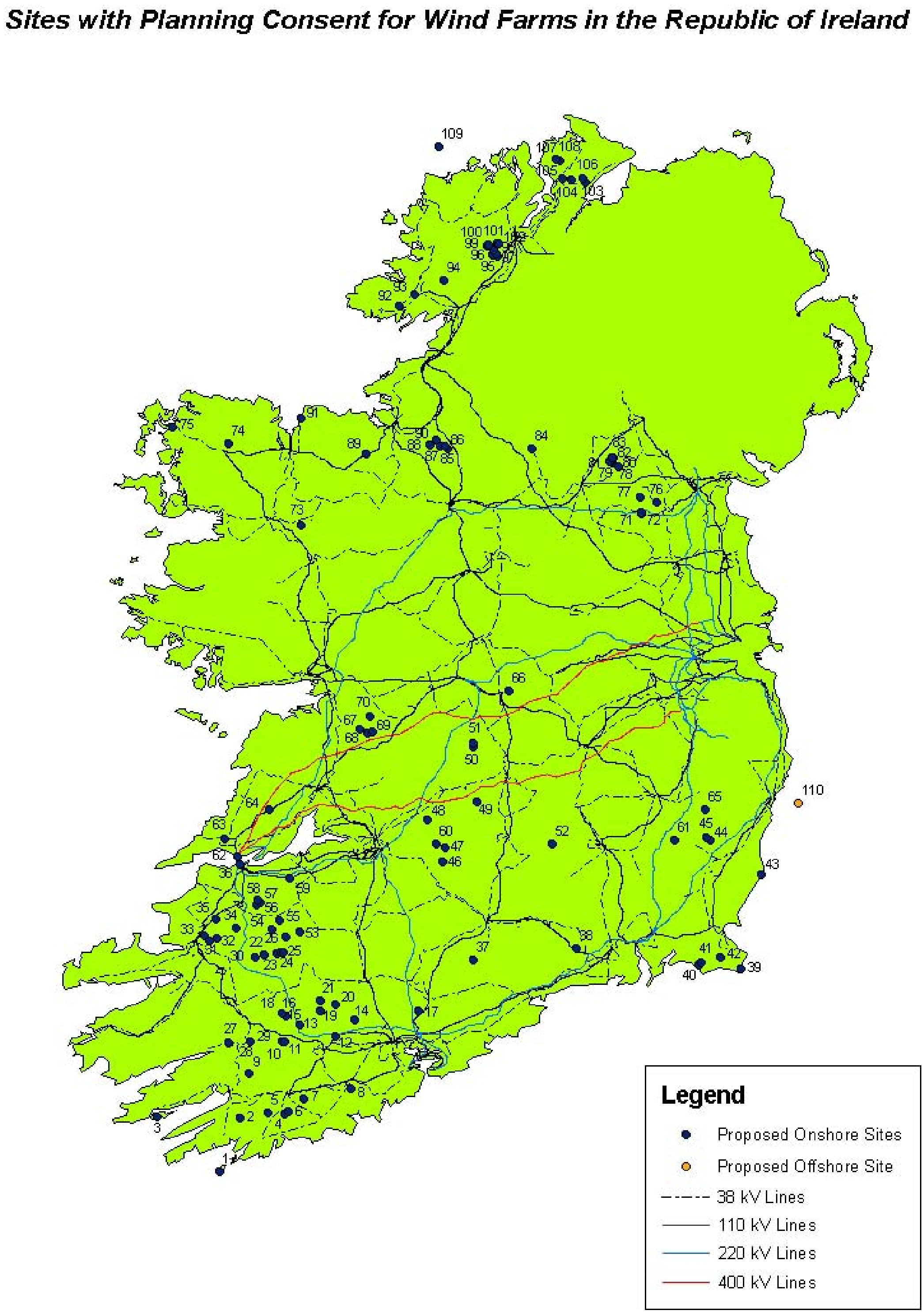

Figure 1.2 Map of wind farm sites in Ireland with planning permission

Table A.1 in Appendix 1 provides a list of all wind farms with planning permission and figure A.1 shows the locations of existing operational wind farms.

1.2 *Accommodating increasing wind capacity in Ireland.*

Garrad Hassan, ESBI & UCC (2003) reported on the impacts of increased wind penetration on the Irish electricity networks, identifying two fundamental types of limiting factors for the connection of wind to the network as follows;

Type 1 ……. Transmission planning criteria

Under existing transmission planning criteria all generation must be considered as firm i.e. it must be able to continue to operate in the event of any one of a defined set of contingencies on the transmission system. This affects wind farms as they may not connect until sufficient grid reinforcement is in place to allow for firm connection of the wind farm. The authors suggested an alternative method of dealing with contingencies that would allow wind farms to connect on a non-firm basis and thus avoid delays associated with deep grid reinforcement. The threshold at which this was deemed necessary was *well under 1000MW.*

Given that wind farms with a combined installed capacity 823MW have received connection agreements on a ‘firm’ basis without the need for significant deep reinforcement indicates that this constraint was not as significant a barrier as suggested by the authors.

Type 2 …….. Curtailment at times of low load.

A key assumption underpinning the study was that as the output of wind generation increases, the output from existing and planned fossil fuel power stations is reduced, but not shut down. There is a limit to the part-load operation of these stations for technical and efficiency reasons. Once this limit is reached, the study required that the output from wind generation be curtailed.

Additional problems associated with transient and voltage stability were also identified in the study. These have not been properly analysed at present and considerable additional dynamic grid modelling studies are required. Due to absence of understanding relating to these key issues, ESB National Grid (2003) made a request to the Commission for Energy Regulation (CER) to suspend grid further connections until the technical issues regarding security and stability of the power system are fully resolved.

CER agreed on an exceptional basis to a moratorium on connection offers until the end of 2003 and invited the wind industry to submit comments on these emergency measures. CER also proposed that ESB-National Grid host a forum to discuss the issues before the CER takes a final decision on future grid connections. The forum took place in Citywest Hotel Dublin on 17th December 2003.[1]

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[1] Presentations from this forum are available from http://www.eirgrid.com/EirGridPortal/DesktopDefault.aspx?tabid=Wind%20Forum%20Presentations%2017th%20December

Following the forum, ESB National Grid requested an extension of the moratorium until March 31st 2004. CER granted this extension, on the basis that a number of specific issues be undertaken within the 3 month extension period, namely that

- *the programme addressing the requirements of the Grid Code for Wind be accelerated and the need for interim reporting and consultation be addressed;*
- *interacting issues with the Distribution Code arising from the Grid Code for Wind review be resolved;*
- *a survey be conducted of current connection offers to the transmission and distribution systems to better assess their projected timeframes and potential impact on the system;*
- *issues regarding the constraining of wind farms be examined;*
- *the differences in the connection offer processes between the transmission and distribution systems be clarified and reconciled;*
- *a detailed programme and timetable for the modelling of wind generation plant and the impact of greater penetration of wind on the transmission system be produced;*
- *a working group containing the Commission, Transmission System Operator (TSO), Distribution System Operator (DSO) Sustainable Energy Ireland (SEI) and the Irish Wind Energy Association (IWEA) be formed to monitor progress on these and related issues;*
- *a workplan detailing the programme of work for the next three months be submitted to the Commission and published in January 2004.*

There are clear overlaps between these conditions and the recommendations made by Garrad Hassan, ESBI & UCC (2003) that;

- The TSO should define more closely their concerns about dynamic issues.
- Further work should be carried out to establish with the wind turbine manufacturers what their products can do and are expected to do in the near future. Effectively this requires that WTG's seeking connection in Ireland should be able to demonstrate compliance with Grid Codes.
- An assessment of the risk associated with the expansion of wind generation on the system is required.

In brief, Grid Codes need to be developed, the interaction of the WTG's with the grid need to be assessed and the overall dynamic performance of the system with high levels of wind penetration requires modelling.

The development of the Grid Code for Wind Energy was accelerated and consultation is currently taking place n the draft code (ESBNG 2004). Dynamic models have become available for certain wind turbines and modelling is progressing, The CER has proposed lifting the moratorium subject to a wind farms connecting to the system complying fully with the finalised code (including fault ride through provisions) and providing turbine models with the grid connection application to allow modelling of system impacts to be carried out.

1.3 The power sector framework:

Trends in the power generation market

There have been a number of significant trends in electricity generation in Ireland over the past decade, including :-

- Significant growth in electricity generation
- Increased penetration of natural gas
- Improved energy and CO_2 efficiency of generation
- Shortages of supply
- Growing influence of environmental constraints

The most significant trend has been the significant levels of growth in electricity consumption, prompting by the dramatic increase in economic growth (measured by Gross Domestic Product, GDP). According to Howley, M. & Ó Gallachóir, B. (2002) the 7.2% average annual growth in GDP during the 1990s was the primary driver for energy consumption growth. During the period 1990 – 2001, the average annual growth in final demand for electricity was 5.3%, demonstrating that electricity demand is not directly coupled to economic growth. The annual growth in electricity generation in the same period was 5.1%, indicating some improvement in reducing line losses.

Much of this increase in generation has been met by increased use of natural gas, oil and wind energy has also made a contribution. Natural gas use for electricity generation has grown by 120% between 1990 and 2001. It accounted for 35% of the electricity generation fuel mix in 2001, compared with 27% in 1990, making it the most significant fuel in electricity generation. Oil has also grown significantly, from 11% of the fuel mix in 1990 to 22% in 2001. Wind energy still contributes a small contribution to our overall electricity requirements but this is set to change dramatically in the short term, as was shown in section 1.1.

These changes in the fuel mix, in addition to technological changes (the trend towards more efficient combined cycle gas generation), have increased the efficiency of the electricity system. Defined as the final consumption of electricity divided by the fuel inputs required to generate this electricity, efficiency has increased from 33% in 1990 to 35% in 2001.

The growth in electricity consumption prompted a need for new capacity, in particular following the significant increase in the latter part of the decade (average annual growth between 1998 and 2000 was 7%). ESB National Grid (2002) reported that a 460MW combined cycle gas plant at Poolbeg had its first full year of operation in 2000 followed by the 118MW Edenderry peat plant that was commissioned in 2000. In order to address generation adequacy, ESB leased five 22MW emergency generators for winter 2000. In winter 2001, ESB procured an additional two 22MW distillate-fired emergency generators.

During 2002 two additional combined cycle gas plants were commissioned, Dublin Bay Power (408MW) and Huntstown (343MW), significantly adding to our generating capacity. Over the last few years, there has also been a number of peat fired generating plants decommissioned, at Ferbane (90MW), Rhode Island (80MW), Caherciveen (5MW) and part of the Lanesboro plant (45MW).

Looking ahead, the remaining pre 2000 plants at Shannonbridge (125MW), Lanesboro (the remaining 40MW) and Bellacorrick (40MW) are also all due to close by the end of 2004. Two new peat plants are planned to be commissioned during 2004 to replace the capacity lost, Lough Ree Power at Lanesboro (100MW) and West Offaly Power at Shannonbridge(150MW).

In addition, a number of measures have been introduced to offset anticipated shortfalls in generation including

- introduction of a Winter Peak Demand Reduction Scheme (WPDRS) from November to February – providing a winter demand reduction incentive within the new market structure, designed to reduce peak load at the time of highest demand in the year;
- the purchase 170MW capacity from the Ballylumford generation station in Co. Antrim from 2003 to 2006 through a contract between ESB and NIE;
- the CER Capacity 2005 competition, designed to facilitate the entry of up to 531MW of new, independent generation by the end of 2005. The successful bidders will enter into power purchase agreements for a maximum of 10 years with ESB.
- the installation in December 2003 of two 52MW open cycle gas fired plants in Aghada, Co. Cork and Tawnnamore, Co. Mayo. These are peaking capacity plants, to be available until the new plant built under the CER Capacity 2005 competition is delivering electricity.

The impact of environmental constraints on electricity generation is growing significantly. As DELG (2000) point out in National Climate Change Strategy, a target of 5.7 Mt CO2 per annum reduction below business as usual projections is set for the electricity supply industry. This represents more than one third of the total emission reductions (15.5 Mt). The bulk of this is to be achieved by closing the Moneypoint coal fired station and replacing it with a combined cycle gas plant (3.4 Mt) and increased penetraion of renewable energy (1 Mt).

Since this has been published the EU Emissions Trading Directive 2003/87/EC has been agreed (October 2003) that will establish a cap and trade system for greenhouse gas emissions including most thermal power plants in Ireland.

The National Emissions Ceiling Directive 2001/81/EC sets upper limits (by 2010) for the four pollutants responsible for acidification, eutrophication and ground-level ozone pollution (SO_2, NOx, VOCs and ammonia), but leaves it largely to the Member States to decide which measures to take in order to comply. Based on the provisions of the Directive, Member States are obliged to report each year their national emission inventories and projections for 2010 to the European Commission and the European

Environment Agency. They shall also draw up national programs in order to demonstrate how they are going to meet the national emission ceilings by 2010.

The Large Combustion Plant Directive 2001/80/EC focuses specifically on limiting the emissions of SO_2 and NO_x from large combustion plants, including power plants. In order to meet the provisions of these latter two Directives, ESB (2003) proposes to install Selective Catalytic Reduction (SCR) to reduce NOx emissions and flue gas desulphurisation technology to reduce SO2 emissions from the Moneypoint coal fired plant. In addition, ESB proposes to reduced use of oil and the introduction of low sulphur oil and coal into the fuel mix.

Liberalisation in the Irish electricity market

A further key policy development that impacts significantly on the power sector framework has been the introduction of electricity market liberalization, in February 2000 allowing the direct sale of electricity to customers. Liberalization in the Irish electricity market is enshrined in Electricity Regulation Act, 1999, which sets out to implement EU Directive 96/92/EC concerning common rules for the internal market in electricity. This allows independent electricity generators and/or suppliers to contract directly with designated customers for the supply of electricity.

The Directive required that approx. 28% of the market be opened up to competition in 2000, increasing to 33% by 2003 with a review of further opening in 2006. In fact, Ireland has gone further than this with approximately 30% of the market opening initially, rising to 40% in 2002 and set to increase to 56% in 2004.

Directive 96/92/EC was updated in 2003 with Directive 2003/54/EC concerning common rules for the internal market in electricity. This provided for full opening to the industrial and commercial customers by July 2004 and full market opening to all customers by July 2007. The Irish market is due to be fully open by July 2005, well in advance of the EU deadline, according to CER (2003)

The initial and current interim market is based on bilateral contracts between electricity suppliers and customers. Under the Act, large electricity consumers above a certain threshold of annual consumption can choose their electricity supplier. In addition those who supply electricity from renewable energy sources can sell directly to all final customers. As a result, brown electricity suppliers can sell only to large customers but green electricity suppliers can sell to customers of any size. Green electricity suppliers thus have had access to the sections of the market which pay most for electricity (commercial and domestic customers). This has clearly good news for wind energy, but the challenges facing the sector should not be underestimated.

The green electricity supplier will need to source green electricity to meet the demand of the customer base (which needs to be established). Already new players are entering the market to act as brokers, with the aim of buying from a portfolio of green electricity generators and selling to a portfolio of customers. Airtricity Ltd., e Power Ltd., ESB Independent Energy Ltd. and E.Co – The Electricity Company Ltd. have secured licenses to supply green electricity.

The details of market trading will change considerably with the introduction of new market arrangements from 2005. Both the current and new arrangements pose particular challenge for intermittent renewable energy sources such as wind energy, due to the half hourly trading period that is in place.

Currently the scheduling, trading and settlement are based on half-hourly intervals. Imbalances in electricity scheduled compared with that traded, are dealt with through a balancing market. In the case of a wind farm, for example, at certain times, more electricity is produced and dispatched than actually consumed by the green electricity customers it is destined for. The excess electricity in this half hour may then be sold to another generator who had a shortfall in the same period provided this is done within 7 days of the trading day. Otherwise ESB (Generation) buy this amount of electricity at the ‘spill’ price (ESB’s avoidable fuel price up to an initial tranche and thereafter the avoidable fuel cost of the best new entrant).

Equally, less electricity can be produced and dispatched from the windfarm, than was actually consumed by the customer(s). The shortfall in electricity in this half hour must then be purchased from another generator who had an excess in the same period provided this is done within 7 days of the trading day. Otherwise ESB (Generation) will sell this amount of electricity at the ‘topup’ price (which should average out over the year to the estimated full cost of a best new entrant).

Electricity from intermittent renewable energy sources relies more on the balancing market than, for example, gas generated electricity, which being more predictable, will incur less imbalances and not be as dependent on the balancing market. This affects the economics of trading green electricity and requires suppliers to incorporate this into the sale price sought for the direct sale of wind generated electricity. This is offset currently by the favorable conditions that exist for wind energy suppliers, namely access to the full market and access to unlimited top-up in a given half hour.

A further key challenge that arises for green electricity generators selling to green electricity suppliers compared to those with an AER contract is the absence of a fixed price 15 year power purchase agreement which offers significant comfort to financiers in the “AER market”. The supplier must seek customers who are willing to agree to purchase green electricity at predetermined rates for a certain time period. It seems likely that a 3 year contract would be the maximum that a green customer would sign up for. This will clearly have implications for the financial risks and the availability and cost of finance in the absence of a guaranteed sales mechanism.

The market mechanism that will replace this interim bilateral trading market will be a centralized wholesale electricity market. This new system will be a mandatory centralised pool (“the spot market”) requiring all electricity exported to or imported from the transmission system or distribution system to be sold to and bought from the SMO (System Market Operator, within ESB National Grid).

In this centralised market, all power that is generated will receive the Market Clearing Price, which may be different in different locations. Generators signal with their offers when and how much they would like to generate. The market is cleared based on these offers and dispatch instructions issued accordingly. The market clearing price is set by the highest offers accepted by the market. In a LMP (Locational Marginal Pricing) market the market clearing price is set for each node of the network.

For renewable plant reliant on intermittent power sources such as wind, offering into the market and adhering to dispatch instructions carries particular problems. The problems they face are both technical and commercial.

In order to clarify the situation with regard to renewables in the new market, CER (2003) propose that

1. wind turbines below 10MW and wind farms below 30MW will be able to register with the SMO as “not-dispatchable” and so may not be subject to dispatch instructions.
2. there be no market floor price for renewables or CHP, other then the general market price floor of negative VoLL (Value of Loss of Load). If it is required, renewables and CHP should be compensated outside of the market arrangements, through an additional support mechanism.
3. all generators be liable for the cost of reserves in line with a ‘causer-pays’ principle. These costs will be allocated in proportion to the requirements for reserves that are deemed to be due to each generating unit.

The new market poses significant and different challenges for wind energy than the current market. The use of financial tools (contracts for differences and other hedging instruments) will be very important. In addition, unresolved issues relating to Financial Transmission Rights, the detail on the operation of the reserve market and how priority dispatch for renewables will all have a key bearing on the viability of wind energy in the future.

Grid upgrading plans:

As noted by the International Energy Agency (2003), the **transmission system** comprises over 5,800 km of high voltage lines operating at 110kV, 220 kV and 400 kV. The national grid was initially established as a 110 kV network but, as the demand for electricity grew, the 220 kV and 400 kV networks were added. The transmission system also includes over 100 high voltage transformer stations where voltage is reduced fur use in the local distribution lines at voltages of 38 kV, 20 kV and 10 kV. The **distribution network** includes about 80,000 km of overhead wires and underground cables.

As electricity demand has grown in the past decade, the transmissions system has become strained, prompting the urgent need for system upgrade. A major refurbishment and expansion programme running from 2001 to 2005 is underway. This programme increases annual capital expenditure on the transmissions and distribution networks by a factor of three, contributing to the recent electricity price increases. Over €2.6 billion is being invested in the high voltage and low voltage networks, particularly in the counties along the southern and western coasts. Over € 820 million will be spent on transmission, over € 1 billion on distribution renewal (including conversion of 50% the 10 kV network to 20 kV), and over € 665 million on distribution reinforcement.

This upgrading of the electricity networks will improve the system and thereby facilitate the accommodation of wind energy. In addition, separate measures have been identified by the Renewable Energy Strategy Group (2000) to facilitate wind energy.

The Group recommended a short and medium term approach. In the short term, the absence of sufficient capacity and the financing arrangement for additional capacity were to be addressed. Specifically, the Group recommended that

1. *some funds identified in the National Development Plan should be released to finance the additional costs of delivering additional capacity at designated locations, which the Department of Public Enterprise will supervise. The extent of upgrading will depend on perceived demand and subsequent connection charges will be proportional to the capacity connected. For example, if the perceived demand is 50MW in a particular area, a 5MW wind farm would be charged 10% of the infrastructural investment instead of the 100% charge currently applied. As connections are made to the distribution and transmission networks the charge is remitted. These funds should be recycled on the same basis, so long as additional demand can be predicted under reasonable assumptions,*
2. *CER takes wind energy into account when deciding on plans to upgrade the network.*

In the National Development Plan Economic and Social Infrastructure Operational Programme, € 184.5 million is earmarked for sustainable energy initiatives.

Regarding the first recommendation, the Department of Communications, Marine and Natural Resources (2002) established a Steering Group in 1999 to oversee the implementation of the Grid Upgrade Development Programme for Renewable energy. This Group reported in September 2002 suggesting a mechanism addressing the challenge that existed for developers where they must raise the entire capital expenditure for any upgrade forming part of a potentially shared connection with money subsequently remitted as others connect to the facility. The Steering Group concluded that

- *The grid upgrades should be planned by reference to perceived demand for shared infrastructure;*
- *Perceived demand should be based on clusters with two or more projects with full planning permission intending to connect to the upgrade;*
- *The prioritisation of clusters for investment support should operate on a first come first served principle subject to compliance with minimum requirements with a fall back selection criterion in the event of simultaneous applications exceeding the available fund;*
- *The first come first served principle should apply to any project compliant with the qualifying criteria, at that time;*
- *Project developers should be charged under reasonable assumptions for the capacity reserved as a proportion of the grid upgrade built.*

CER (2003) determined that

> *in line with its duty under the Electricity Regulation Act ('the Act') to have regard to promoting the use of renewable forms of energy, to support the funding of the programme through TUoS charging. The Commission acknowledges that this proposal leads to preferential access arrangements for a number of renewable applicants. However, the Commission does not believe that this constitutes unfair discrimination.*

The scheme is not only underway, it does not require the NDP funding as it will be integrated into TuoS charging.

The Group further recommended in the short term that

> *In addition, clear positive changes have been brought about, as a result of the work carried out by the Working Group on Grid Connection Issues Relating to Renewable Energies. Further improvements can be made, and in this regard the Strategy Group endorses the following recommendation from the final report of the Working Group:*
>
> - *the four studies, detailed below, which were commenced should be completed as soon as is practicable. All test sites should be set up by mid 2000, and evaluation of the collected data should be completed by mid 2001.*
>   1. *the use of MV (medium voltage) voltage regulators with line compensation to counteract excessive voltage rise;*
>   2. *the use of high sensitivity over-voltage relays at embedded generator sites policing voltage levels during load/generation variations;*
>   3. *the testing of modern inverter technology in variable speed wind turbines to assess harmonic performance and power factor control;*
>   4. *the use of power supply monitors at generator sites recording voltage, power flows, harmonics, flicker, etc.*

The NDP funding not required for the short term strategy may now be used to deliver a key element of the medium term strategy of the Renewable Energy Strategy Group funding. The medium term strategy recommended a continuation of the mechanism described above and that

> *In addition, where strategic wind energy sites are identified which require additional transmission infrastructure then such grid upgrading should be fully funded from remaining funding available under the National Development Plan. Once built, however, this network extension will be available to all generators in a non-discriminatory fashion in line with national policy.*

There is no current publicly available information regarding progress has been made in this element of the strategy.

1.4 *Strategies addressing high wind penetration problems*

Wind forecasting

Wind forecasting does not in itself overcome the problems associated with wind intermittency. However, an accurate forecasting tool can facilitate transmission system operators to accommodate higher wind penetrations by planning for other generation available at times when it is known the wind is not available and equally curtailing other plant when the wind will be available.

There are many different wind energy forecasting techniques at various stages of development throughout Europe and the U.S. The simplest form of prediction is based on the persistence method (assuming that the current value persists) but this is acceptable only for a one hour horizon. Forecasts based on Numerical Weather Prediction (NWP) models can be used for much longer time frames of up to 48 hours but the accuracy of the predictions is extremely variable and is very dependent on the type of the prevailing weather system. Errors can range from 10 percent for 10 hours ahead to 30 percent for 48 hours during stable meteorological conditions to 200 percent during unstable conditions. One of the most recent developments is called ensemble forecasting which not only gives more accurate wind speed predictions but also quantifies the level of uncertainty associated with the given forecast. This approach recognises the fact that there are some periods when it is not possible to give an accurate prediction and this uncertainty when quantified is an important piece of additional information for the TSO. This system is being developed by the Sustainable Energy Research Group (SERG) at University College Cork and has been tested by Eltra in Denmark with very promising initial results. On the strength of these results, SERG is currently co-ordinating an EU 5th Framework supported project called *HONEYMOON (a **H**igh res**O**lution **N**umerical wind **E**nerg**Y** **M**odel **O**n- and **O**ffshore forecasting)*. The goal of the project is to develop an ensemble forecasting tool using of a numerical weather prediction model that is designed specifically for use in a real-time wind energy prediction. This system is being tested in Ireland through a collaborative SEI funded project between SERG and ESB National Grid.

Since 1999, Eon Netz in Germany has been using a forecasting tool based on artificial neural networks which was developed by ISET, the German Institute for Solar Energy Technology. These networks are collections of mathematical models that can be trained to simulate the complex weather patterns using historical data.

Wind energy forecasting has both technical and economic benefits. The main technical benefit is related to the load management of power stations which have to adjust to accommodate the level of wind power on the grid system at any given time. Advance information on the production from wind farms enables the TSO to plan production from the fully dispatchable plant and will reduce inefficiencies caused by enforced part load operation.

The economic benefits are significant in fully liberalised electricity markets where TSO's have to pay for reserve power. For example Eon Netz is required to schedule wind power as virtual base load the day ahead and they do this based on a forecast with a provision for reserve power from firm capacity to balance out any discrepancy between projected output and actual delivery. Reducing the difference between projected and actual delivery of wind power through good forecasting reduces purchases of balancing power.

Clearly wind energy forecasting will not solve the problems of associated with the variability of wind. It will reduce however, the uncertainty regarding the wind power production and facilitate more efficient power station load management. In any future system, which aims at optimising the deployment of the wind energy resource in Ireland, forecasting should play an important role integrated with appropriate energy storage technology.

Demand Side Management

One important way that electricity companies can reduce their GHG emissions is to reduce energy consumption among customers. This approach is referred to as Demand Side Management (DSM). Instead of building new power plants to respond to increasing customer demand, electricity producers can also try to reduce their customers' demand for power by offering special programs for businesses, industry, public institutions and domestic users. To determine the success of such programs, the costs and benefits of DSM opportunities, including any future financial value of greenhouse gases (GHG) emissions reductions, should be directly compared with the costs and benefits of building new power plants and transmission lines.

DSM programs aim to achieve three broad objectives:

- Energy conservation: DSM programs can reduce the overall consumption of electricity by reducing the need for heating, lighting, cooling, cooking energy and other functions. For example, adding insulation to a building can help reduce the need for heating in winter and cooling in summer.
- Energy efficiency: DSM programs can encourage customers to use energy more efficiently, and thus get more out of each unit of electricity produced. For example, energy-efficient light bulbs provide the same amount of light but use significantly less energy than conventional units.
- Load management: DSM programs allow generation companies to better manage the timing of their customers’ energy use, and thus help reduce the large discrepancy between peak and off peak demand. For example, utilities can interrupt industrial power supplies temporarily during periods of high demand, and/or store power during periods of low demand for later use, when demand is high. Although this approach does not reduce the overall consumption of electricity, it can reduce the need to build new power plants simply to serve customers during periods of peak demand. Load management can also reduce GHG emissions associated with using fossil fuels to meet those peak electrical demands.

Demand side management is well developed in the Irish situation, however it is unlikely that DSM provides a full solution to the issues around high penetration of renewable energy. Any move to institute a full DSM programme targeted improving the dispatchability of wind, and effect load levelling, to improve inherent capacity credit, should be specifically agreed with the TSO.

Changes in the generation plant mix and operation

In the Irish context one of the limiting factors affecting the non dispatchable nature of wind energy is the comparatively high baseload requirement of the conventional thermal plant. Plants such as Moneypoint have a requirement to run at significant capacity levels to be efficient and therefore cannot be easily ramped down as renewable energy comes on stream.

In pure economic terms the move to significantly more variable electricity production from CCGT plant is in the favour of wind penetration as CCGT can in fact be more variable in response to improved generation capacity from renewable sources.

Again as in the consideration of Demand Side Management any substantial move to include a revision of operating tactics and strategy for conventional generation plant should be in the context of cooperation between the TSO, conventional and renewable energy generators. Within this framework there are a number of market mechanisms which can enhance the capacity credit open to wind energy (e.g. carbon costs, PSO hand off etc.)

The diversion of traditional pumped hydro storage facilities to virtual wind energy storage devices is one obvious way for increasing the dispatchability of wind energy. This may become more compelling as the requirement to utilise pumped hydro for short term applications like power quality and load levelling is diminished both by the increased sophistication of grid operation and the increased availability of CCGT capacity, within the market context, to provide these ancillary applications.

Electrical energy storage

The fundamental issue surrounding wind energy integration and is its intermittency. As such no grid operator, especially not an isolated grid operator can accept unlimited amounts of wind energy to its grid. Strategies such as Demand side management, flexible operation of other generation plant, large interconnected grids, all provide some leeway for wind energy penetration. In some cases such as Denmark significant penetration of wind energy has been possible, because of concerted action by the Grid operators and availability of interconnects and alternative sources of energy (in Denmarks case Norwegian Hydro power is an important flexible input.)

However irrespective of load levelling and capacity sharing the fundamental requirement to improve the reliability and predictability of wind energy requires some solution which can store the energy when it is not required (and has low value) and resupply the electrical energy when needed.

Absolute limits on energy storage capacity, and high cost per kWh of storage medium installation, imply that pumped hydro (PHES) and flow battery storage (FBES), may improve the availability of wind energy, but do not address the issue of multiday unavailability of wind (meteorlogical calms often ‘blocking highs’ in a European context). Notwithstanding this, both PHES and FBES industries have made substantial progress, and the development of price arbitrage and high storage to output rating configurations by a number of companies, mean that both technologies are potentially technologically and financially viable solutions to wind intermittency in the short term. In the Irish context small scale pumped hydro seems particularly promising in combination with individual or grouped windfarms.

Wind hydrogen systems propose a fundamental decoupling of energy production, storage and regeneration. A number of early installations, and significant research activity point to a number of opportunities:

- Wind hydrogen in combination with significant storage can technically be viewed as dispatchable generation capacity on a par with other sources of generation
- Large strides have been made to address the system cost of wind hydrogen systems and the combined cost[2] and efficiency metrics of approximately €1,500/kW and 45% respectively are points where a wind hydrogen system would be economically viable
- Economic viability is driven by four important factors:
    1. The price enhancement available between variable charge cost (foregone price) and discharge attained price
    2. The average time period when the system can discharge to an ehanced revenue environment
    3. The capital cost of the facility (charging equipment, storage equipment, and discharge equipment)
    4. The efficiency of the system

Within this framework, Wind Hydrogen systems meet the technology specifications to deal completely with wind intermittency, but are still not proven to be economically viable. The interplay of market factors, price arbitrage and capacity credits may have the effect of making fully integrated Wind Hydrogen viable at present. However the potential for further economic benefit from incremental system cost and efficiency improvements highlighted.

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[2] excluding the capital costs of the wind farm

Chapter 2 ELECTRICAL ENERGY STORAGE

2.1 General issues

The electrical energy storage concept has become a controversial issue in the last years. Many questions arise in the electricity sector: Why is energy storage needed? What are the alternatives? How much do storage systems cost and how much added value does a storage system provide? Will storage contribute to the increased utilisation of renewables?

The storage issue must be viewed in the frame of a changing electricity sector.

- Restructuring of the electricity market
- Growth in new/renewable energy sources
- Increasing reliance on electricity and demand for higher quality power
- Move towards distributed generation
- More stringent environmental requirements

As part of these changes, there are growing pressures to operate the electrical network more efficiently whilst still maintaining high standards of reliability and power quality. The accommodation of renewable generation and ever more stringent environmental requirements are combining strongly to further influence electricity companies' decisions on how they should be developing their future network designs. With these driving forces as a backdrop, the rapidly accelerating rate of technological development in many of the emerging electrical energy storage technologies, with anticipated system cost reductions, now makes their practical application look attractive.

Energy storage is not a new concept in the electricity sector. Utilities across the world built a number of pumped-hydro facilities in the last decades, resulting in a storage component of roughly 5% the capacity of all the European countries, 3% in the US, and 10% in Japan. These pumped-hydro plants, and to a lesser extent compressed air storage systems, have been used for load levelling, frequency response, and voltage/reactive control. Likewise, storage facilities bases on other technologies such as lead-acid batteries have been installed by a number of utilities to fulfil a variety of functions. At a different scale, energy storage is also commonly used at the user level to ensure reliability and power quality to customers with sensitive equipment. Another traditional application is the electrification of off-grid networks and remote telecommunications stations, mostly in connection with renewable sources.

The market penetration achieved by electrical energy storage to date has been heavily constrained by its cost and the limited operational experience, resulting in high technical and commercial risk. However the presence of storage systems is growing fast owing to the circumstances mentioned above.

Benefits of storage

Storage contributes to optimising the use of existing generation and transmission infrastructure, reducing or deferring capital investment costs. It contributes to integrating RE sources (and in general distributed sources) into the system, enhances their availability and market value. The environmental benefits must be highlighted, both in terms of reduction of the emissions from conventional power plants and increase of RE sources penetration. Energy storage facilities can also help maintain transmission grid stability by providing ancillary services, including black-start capability, spinning reserve and reactive power. At the consumer level, storage improves power quality and reliability, and can provide with capability to control or reduce costs.

According to the European Commission (2002),

> *"cost-effective energy storage will be a key enabling technology for the stable operation of a liberalised energy market, for competitive energy pricing, and for the introduction of renewable energy sources".*

The EC asserts that if energy storage systems are improved further, they can contribute to EU policy objectives, such as meeting the Kyoto obligations to reduce greenhouse gas emissions, lowering consumption of primary energy, creating a sustainable supply of electricity with an increasing share of RE; and supplying low-cost reliable electricity in remote areas of Europe. Energy storage is of growing importance as it enables the smoothening of transient and/or intermittent loads, and downsizing of base-load capacity with consequent substantial potential for energy and cost savings.

However, it is acknowledged that energy storage systems will have to compete within the context of present over-capacity of power stations and power generators with short start-up times, such as open cycle gas turbines and gas or diesel motors with the appropriate emission controls. The EC concludes that the competitiveness of energy storage systems against other conventional solutions is unclear.

Barriers to the deployment of electrical energy storage

Electrical energy storage involves significant investment and energy losses, which must be weighed against the benefits and compared to other non-storage solutions.
There are a number of key barriers to a more widespread use of storage systems:

- **Immaturity of some technologies and lack of operating experience**. More demonstration projects are needed to gain the customers' confidence. Further research and development is necessary in some aspects, such as the implementation of power conditioning and control process for a multi-application energy storage system.
- **High initial capital costs**. Technological advances and large manufacturing volumes will bring these costs down.
- **Uncertainty over the quantified benefits**. This is true especially when, as usually happens, there are multiple different benefits associated with a storage system.

- **Uncertainty over the regulatory environment**. The future shape of the electricity market, not only in relation to energy trading but also to ancillary services trading, will affect decisively the viability of electrical energy storage. The use of storage systems for the provision of ancillary services currently provided by the system operator will depend on the deregulatory process.

Location of storage systems

Utility-scale energy storage systems are envisaged as forming an integral part of the future energy system. Depending on the application, they can be implemented in all the different segments of the electric system (Fig 2.1). In a liberalised market, the different segments of the electricity sector are being increasingly separated. Each segment offers different potential opportunities to energy storage applications. Correct location of the storage systems is important to maximise the benefits. Large-scale, i.e. multiMW, centralised storage could improve generation and transmission load factors and system stability. Smaller-scale, localised, or distributed storage could deliver energy management and peak shaving services, as well as improving power quality and reliability. Distributed storage would be an ideal complement to distributed generation, especially on account of the increasing levels of RE generation.

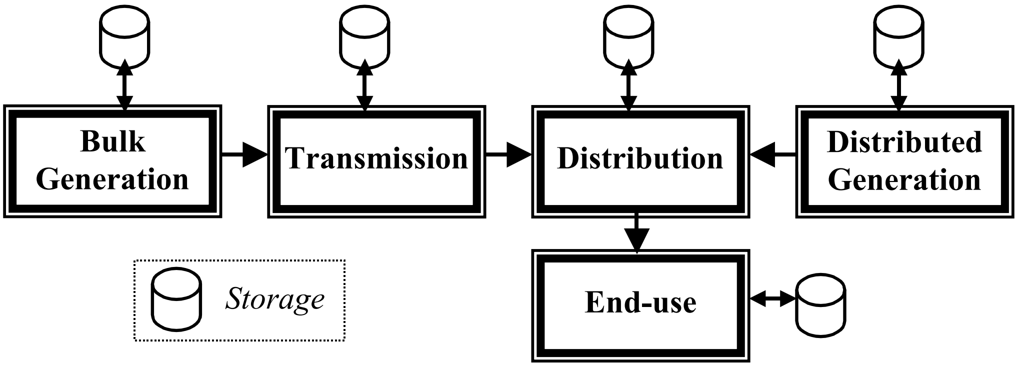


Figure 2.1. Storage locations in the electricity supply system

One of the axioms of energy storage is that storage units should be located as close as possible to the end consumer of electricity as possible. This is because the storage device can improve the utilisation of all components in the network. In order to place a storage device close to the end consumer, the device would need to be matched for both power and energy storage capacity to the requirements of the consumer. Since the specific capital cost increases as the system becomes smaller, the optimum position for a storage device in the network tends to move closer to the generation source. For this reason, Price (2000) maintains that many storage systems can, and should be located near to substations or grid distribution points. When storage systems are utlilised to facilitate renewable integration, the picture changes however, since the fluctuations of the generated power are usually greater than those of the load. As a result, the optimum location is likely to be close to the generation points, thus maximising the capacity of the transmission and distribution lines.

2.2 Applications

Applications of electrical energy storage are numerous and varied, covering a wide spectrum, from larger scale generation and transmission related systems, to smaller scale applications at the distribution network and the customer/end-use site. Even though this report deals specifically with the application of storage for RE integration, this is closely connected to other applications. Storage systems usually provide multiple benefits, and thus it is necessary to review all their possible functions. Interesting reviews of the applications can be found in Schoenung (2001), Herr (2002) and Butler (2002). Ultimately, the purposes of all these applications come down to:

- improved load management
- provision of spinning reserve
- transmission and distribution stabilisation and voltage regulation
- transmissions system upgrade deferral
- facilitating distributed generation
- facilitating renewable energy deployment
- end use applications
- miscellaneous (including ancillary services)

Load management

Load management includes the traditional **load levelling**, a widespread application for large energy storages, in which cheap electricity is used during off-peak hours for charging, while discharging takes place during peak hours, providing cost savings to the operator. In addition, load levelling can lead to more uniform load factors for the generation, transmission and distribution systems. Although load levelling was the first application that utilities recognized for energy storage, the differences in the marginal cost of generation during peak and off-peak periods for many utilities is moderate. Therefore, Butler (2002) concludes that load levelling is likely to be provided as a secondary benefit derived from an energy storage system installed for other applications that offer greater economic benefits. It requires energy storage systems on the order of at least 1MW and up to hundreds ofMW, and several hours of storage capacity (2–8 hours). For utilities without a strong seasonal demand variation, a system used for load levelling would operate on weekdays (250 days per year).

Other types of load management are **ramping and load following**, in which energy storage is used to assist generation to follow the load changes. Instantaneous match between generation and load is necessary to maintain the generators rotating speed and hence the frequency of the system. Storage systems serving this application should be able to deliver on the order of 10 to 100MW to absorb and deliver power as it fluctuates. The system would have to be able to dispatch continuously, especially during peak load times, in frequent, shallow charging and discharging that would occur. This service is usually provided by conventional generation.

Spinning reserve

The category **fast response spinning reserve** corresponds to the fast responding generation capacity that is in the state of ‘hot-stand-by’. Utilities hold it back in case of a failure of generation units. Thus, the required power output for this application is typically determined by the power output of the largest unit operating on-grid. The **conventional spinning reserve** requires less quick response. Storage systems can provide this application in competition with standard generation facilities.

Since the power plants that they would temporarily replace may have power ratings in the order of 10 to 400MW, storage systems for reserve must be in this same range. Generation outages requiring rapid reserve typically may occur about 20 to 50 times per year. Therefore, storage facilities for rapid reserve must be able to address up to 50 significant discharges that occur randomly through the year.

Transmission and distribution stabilisation and voltage regulation

Transmission and distribution stabilisation are applications that require very high power ratings for short durations in order to keep all components on a transmission or distribution line in synchronous operation. This includes phase angle control, voltage and frequency regulation.

In the event of a fault, generators may lose synchronism (difference in phase angles) if the system is not stabilised, making the systems collapse. Energy storage devices can stabilise the system after a fault by absorbing or delivering a power to the generators as needed to keep them turning at the same speed. Fast action is essential for a fast stabilisation.

Response time limitations demand an appropriate power conditioning interface design to ensure a reliable mitigation of short-duration electrical disturbances, which can range from a couple of cycles to two minutes. The portability of the storage systems might be an important factor in many cases. Some applications are temporary in nature, and Boyce (2000) points out that to transfer a storage system from site to site can significantly increase its overall value.

With the liberalisation of the electricity market there will be an increasing need to maintain and to improve the stability of the electrical grid. The risk of voltage instability, being the source of failures in automatic production centres and the base of cascading outages, will become more and more important. Many utility grids have a limited transmission capacity with which they can properly react to transient events. In case of fast changing load flow patterns or changes in the distribution of the loads or power plants among the grid, the risk of voltage instability increases.

To offset the effect of the impedance in transmission lines, utilities inject reactive power and maintain the same voltage at all locations on the line. Traditionally, fixed and switched capacitors have provided the reactive power necessary for **voltage regulation**. Storage systems deployed by transmission or distribution network operators for other primary application can provide reactive power to the system to augment existing capacitors and replace capacitors planned for future installation. Energy storage system for voltage regulation should provide reactive power on the order of 1 to 10 MVAR for several minutes, mainly during daily load peaks.

Transmission upgrade deferral

When growing demand for electricity approaches the capacity of the transmission system, utilities add new lines and transformers. Because load grows gradually, new facilities are designed to be larger than necessary at the time of their installation, and utilities under-use them during their first several years of operation. To defer a line or transformer purchase, a utility can employ an energy storage system until load demand will better use a new line or transformer.

The power requirement for this application would be on the order of 100s of kW or several hundred MW. Butler (2002) states that the energy storage system should allow for one to three hours of storage to provide support to the constrained transmission facility.

Distributed generation

The growing presence of distributed sources opens a new market for storage systems, which can assist in transient conditions of generation units such as microturbines and diesel engines, with a slower dynamic response and thus limited capability to adjust to load changes. In this way, storage can increase the distributed generation capacity that can be embedded on a distribution network and avoid cost-intensive reinforcements.

A less demanding application of storage technologies in distributed generation is **peaking generation**, which can also avoid reinforcement of distribution lines. Areas with temporarily high demands, e.g. at daytime, could be equipped with storages that supply power at peak times and are recharged through off peak hours.

These applications are often referred to as *distribution capacity deferral*. An energy storage system to defer installation of new distribution capacity requires power on the order of 10s of kW to a few MW, and must provide 1 to 3 hours of storage.

Renewable energy applications

Electrical energy storage is very promising as a means of tackling the problems associated with the intermittency of RE sources such as wind and solar energy. The applications will cover a wide range of power and discharge duration. With increasing market penetration of RE these applications are more and more likely to gather momentum within future energy systems, as conventional generation utilities ability to even out the intermittent RE production is limited.

There are a variety of denominations in the technical literature for the use of storage in connection with renewable applications. Butler (2002) states that some authors call it *renewable integration* or *renewable energy management*. Schoenung (2001) identifies only one utility-scale application under the term **renewable matching**, referring to the use of storage to match renewable generation to any load profile, making it more reliable and predictable and hence more valuable. This does not seem to be applicable to the storage of RE at off-peak times to be delivered at peak times.

Herr (2002) however, broadens the scope of **renewable matching**, by referring to applications making renewable electricity production more predictable throughout the day and bring RE closer to demand profiles, especially providing high power outputs at peak hours. Baxter & Makansi (2002) identify four categories within RE storage: distributed generation support, dispatchable wind, base-load wind, and off-grid applications.

Storage systems with a longer discharge duration can cover longer mismatches (up to several hours). In the longer term, a utility with a significant percentage of renewable power may require storage capacity of days to ride through periods with windless days. In Table 2.1, a number of short and long discharge renewable matching applications are included. Both will be referred to later as **renewable integration**. Indeed, a broader scope can be given to renewable integration, including short-time applications that also contribute to tackling the problems associated with intermittent sources.

The storage system required for either application would need to provide from 10 kW to 100MW. According to Butler (2002), the storage system would need response time in the fractions of seconds if transient fluctuations are to be addressed. The cycling of the storage systems coupled with wind energy will be rather unpredictable, and could range from one hundred to one thousand cycles per year or more.

In remote locations not connected to the grid, it may be useful to include energy storage to minimise the generation capacity. This is especially attractive in RE-based supplies. **Renewable back-up** applications should be capable of substituting RE production when this is not available for time lengths that could go up to a week. The power rating would depend on the corresponding power output of the RE system.

End-use applications

The primary end-use application for energy storage is power quality. Outages and power quality phenomena are an important concern for many business sectors –a survey estimated losses between $119 billion and $189 billion only in the US economy. Energy storage systems are being successfully installed to provide reliable and high quality power to sensitive loads. **Transit and end-use ride-through** are applications requiring very short durations combined with very quick response times. They cover electric transit systems with remarkable load fluctuations and customer power services like voltage stabilisation and frequency regulation to prevent events that can affect sensitive processing equipment and can cause data and production losses. The demand of quality power is growing within industry and is becoming a matter of concern also for electricity suppliers, which may also install systems at the distribution level to improve the power quality. **Uninterruptible Power Supply (UPS)** devices provide protection against electricity supply downtimes. Primarily they prevent production losses, however, if the serving systems have very short response times they can also be used for power quality assignments (protection against voltage sags, power surges, frequency regulation etc). UPS systems often consist of a storage device which usually acts during a short time until a generation set takes over. Although the provision of **UPS** is usually taken on at the user level, generation facilities can also use storage systems to remove particularly the short-term

	Application	**Power rating**	**Discharge duration**	**Storage capacity**	**Response time**	**System location**
Fast discharge	Transit and end-use ride-through	< 1MW	seconds	~2 kWh	< ¼ cycle	End-use & Distribution
	Transmission & distribution stabilisation	up to 100's MVA	seconds	20 – 50 kVAh	< 1/4 cycle	Transmission & Distribution
Short to long discharge	Voltage regulation	up to 10 MVAR	minutes	250 – 2,500 kVArh	< 1/4 cycle	Transmission
	Fast response spinning reserve	10 – 100MW	< 30 m	5,000 – 500,000 kWh	< 3 s	Generation
	Conventional spinning reserve	10 – 100MW	< 30 m	5,000 – 500,000 kWh	< 10 min	Generation
	Uninterruptible power supply	< 2MW	~ 2 h	100 – 4,000 kWh	seconds	End-use
	End-use & transmission peak shaving	< 5MW	1 – 3 h	1,000 – 150,000 kWh	seconds	End-use & Distribution
	Transmission upgrade deferral	up to 100'sMW	1 – 3 h	1,000 – 500,000 kWh	seconds	Transmission
	Renewable matching (short discharge)	< 100MW	min – 1 h	10 – 100,000 kWh	< 1 cycle	Generation
Long discharge	Renewable matching (long discharge)	< 100MW	1 h – 10 h	1,000 – 100,000 kWh	seconds	Generation
	Load levelling	100'sMW	6 – 10 h	100 – 10,000MWh	minutes	Generation
	Load following	10 – 100'sMW	several hours	10 – 1,000MWh	< cycle	Generation & Distribution
	Emergency back-up	< 1MW	24 h	24MWh	seconds	End-use
	Renewables back-up	100 kW – 1MW	days	20 –200MWh	sec – mins	Generation & End-use

Table 2.1Applications of storage systems with different discharge times

fluctuations from their supply. The attractiveness of the investment will depend on any penalties imposed on generating units that fail to provide a quality supply.

There are other customer uses such as **end-use peak shaving** that can avoid demand charges by reducing demand peaks. **Emergency back-up** at customer site requires power ratings of approximately one MW for durations up to one day. Presently, most of these applications are served by reciprocating engines.

Miscellany

The provision of ancillary services by storage systems can also include **black start** capability, which consists of the supply of electricity for the start up of generators after a network failure. It is usually performed by relatively expensive diesel engines. Some storage options also need an auxiliary electricity supply, but several can start without an electricity source. Once again this service can be provided in addition to other applications listed

A number of different lists and different descriptions of the storage applications can also be found in the literature. Some authors include *deferment of new capital equipment* as a separate category. This is in fact simply an aggregation of some of the applications already quoted, which can be performed by conventional equipment such as peaking plant, new lines, substations, etc. The installation of storage systems on the transmission and distribution grid in order to expand the grid capacity, decouple generation and load, and thus reduce congestion, has already been included as a separate application (transmission upgrade deferral). The use of storage systems to improve transmission stability also reduces or defers the need for transmission upgrades. Likewise, storage units for load levelling, spinning reserve or peak shaving delay the need for new generation capacity.

Other authors refer also to the *improvement of power plant efficiency* as a category, but this is rather a driving force for applications such as load management and spinning reserve.

Environmental benefits is also sometimes quoted as an application, but it is rather a consequence derived of the application of storage systems as spinning reserve, peak shaving and others, which results in the cut of emissions that conventional technologies cause. Energy storage can enhance the environmental performance of a network in a number of ways:

- Conventional generating units used to provide spinning reserve and other ancillary services can be replaced by energy storage.
- Generators which operate best at constant load can be combined to provide ramping and peaking duties.
- Grid upgrades can be avoided.
- System control issues arising from intermittent RE sources can be mitigated, thus increasing the proportion of renewable generation that the system can absorb.

2.3 Technical requirements of storage applications

The many applications can be characterised by their technical requirements, i.e. power level, energy storage capacity, and response time. There are other possible requirements which may be relevant in some applications and in some cases, such as portability and limited footprint. This may be an important issue for transmission capacity deferral purposes, but will be irrelevant in applications involving large energy capacity.

The discharge time, which is basically determined by the power/energy ratio, influences to a great extent the design of the storage system and the technology selection. Whereas some applications demand an energy discharge burst lasting only a few seconds or even less (power quality and stability), others require the energy to be available for long periods of time, up to a few hours or even days (load management) as illustrated in figure 2.2.

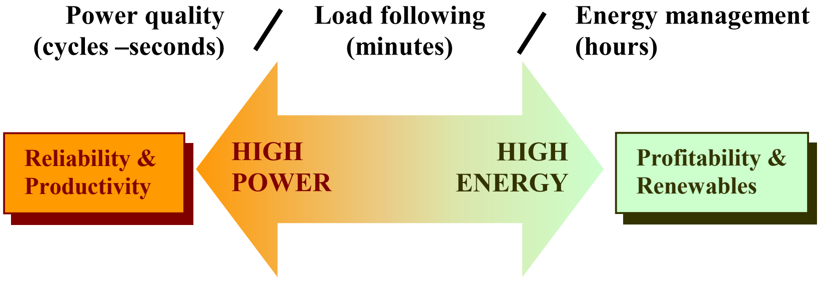


Figure 2.32 Discharge timeframes of different storage applications

The power/energy ratio will dictate to a great extent the design of the storage system and the technology selection as figure 2.3 illustrates.

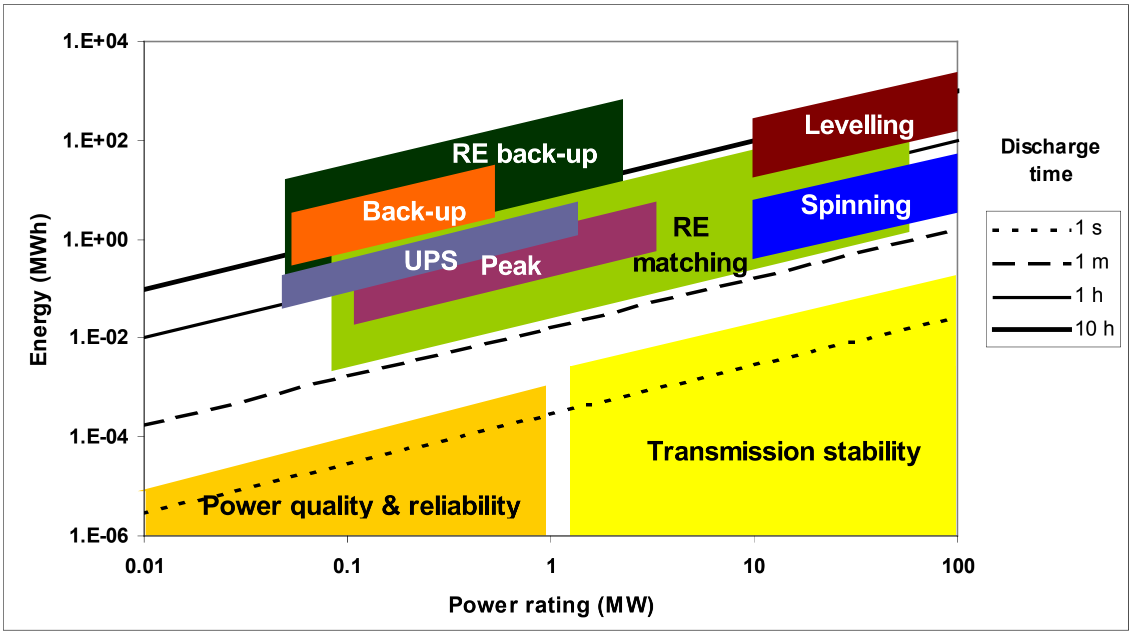


Figure 2.3 Energy and power ratings of storage applications

Response time is another relevant factor, which becomes critical in stabilisation and power quality applications. Table 2.1, based mainly on Schoenung (2001), shows the requirements of the different storage applications. Since storage systems are likely to perform more than one function to achieve a better economic viability, the requirements for multifunctional systems will obviously be more stringent.

2.4 Market potential of storage applications

Electrical energy storage will clearly only penetrate the market if it proves the most cost-effective solution. The decision to use an energy storage system depends both upon the requirements of the application and the cost of competing solutions.

Power quality applications currently show the best cost-benefit quotient. As production lines become more and more automated, small instabilities are proving to be increasingly costly to industry. Some studies indicate very significant production losses in sectors such as the semiconductor and pharmaceutical industries as a consequence of short interruptions. As a result, certain applications could be regarded as imperative, e.g. the maintenance of power quality, voltage stability, generation adequacy, and so forth. Storage systems for power quality are already being used at the customer level in many factories where power quality is a critical issue, however, in today's ‘digital economy’, customers demands of a more reliable and high-quality supply will progressively become more intensive.

Baxter (2002) points to a US-based study showing that transmission applications would have the greatest economic impact in US ($129.9 billion). End-use power quality and reliability would have an impact of $31.2 billion, whereas generation-based applications (load levelling, load following, spinning reserve) would have a more modest impact of $10.6 billion in the US market.

There is controversy over the viability of storage in the integration of renewables. Boyes (2000) points out that some studies suggest that the operating savings associated with the implementing of storage systems in connection with intermittent renewable energies can be four to six times greater than those from adding storage to a utility system without RE.

The growth of intermittent RE sources will enlarge the potential for energy storage far beyond the traditional levels. The competitiveness of storage against non-storage solutions will be influenced by a number of factors, such as the scale of renewable penetration in an electricity system, which could make other options unfeasible. The possible internalisation of environmental effects of conventional generating technology could also tip the balance in favour of storage.

2.5 Renewable energy storage applications

The focus of this report is the integration of wind energy and energy storage, or, how storage technologies can overcome the problems arising from the intermittent nature of wind energy.

The two categories of storage applications identified previously as associated with renewable integration (matching and back-up) are merely adhering to a convention. Storage systems can support intermittent RE in many issues related to its integration in the network. In the classification above these applications have been distinguished from renewable integration. In short, whereas in a system without intermittent RE sources the only uncertainty is the demand (apart from failures risks) the presence of fluctuant generation adds a new source of uncertainty, which becomes more dominant as the renewable penetration increases. The possible benefits are thus widespread and may be grouped under the headings *energy trading* and *network services.*:

Energy trading

- Load levelling, benefiting of the on-peak/off-peak price differential
- Avoidance of penalties on power exchanges due to predictable electricity deliverance
- Avoidance of wind energy curtailments

Network services

- Voltage regulation, reactive compensation.
- Transmission and distribution stability
- Frequency control
- Avoidance or deferral of transmission and distribution upgrading
- Provision of spinning reserve
- Black start capability

These applications can also be condensed into three: *time shifting generation, control,* and *reserve*. The different applications are linked to the durations of wind variations. Short-time fluctuations (over a few seconds) demand services such as stabilisation and frequency regulation. Longer fluctuations (hourly, daily or longer) are associated with energy trading applications. A combination of short and long-time energy storage enhances the economic viability of renewables according to Collinson (1999).

The provision of reserve has to do with the limited capability of intermittent sources to displace generation plant capacity. System operators will need to schedule more reserve as the amount of RE on an electricity system increases and adds to the uncertainty in balancing supply and demand. This is a key issue in the context of the Irish electricity market as the provision of reserve will be carried out under a bidding system and charging for reserve will be carried out on the basis of the *causer pays principle.* The impacts of increased wind penetration on operating reserve requirements is currently the focus of an SEI funded study being led by UCD.

Although the provision of reserve alone with storage systems is unlikely to prove viable, systems serving other applications can also increase the capacity credit of intermittent sources and reduce their loss of value. A flexible and fast-response system is ideal for this purpose. Storage allows dispatch to follow load curves or to be held in reserve.

Ingram (2000) asserts that storage can optimise the transmission of renewable electricity, and hence maximise the use of the existing grid capacity. Wind farms are often located at the end of long transmission lines with little or no available capacity during high load hours. Even if sufficient transmission capacity is available, in some markets renewable generators face the cost of grid-based transmission rights and losses. Purchases of transmission based on peak output have a worse impact on fluctuant sources owing to the low capacity factors.

Practically all energy storage facilities are expected to perform a number of support functions. Storage facilities providing load levelling can also maintain the stability of the system and provide reserve capacity.

Scale and location of the storage systems

The selection of suitable storage technologies and the sizing of the systems will depend on the functions which will be fulfilled, as well as the location of the system in the network. In this context, it is useful to draw distinctions between the following categories :-

- large-scale generation
- distributed generation
- off-grid

The fast growth of intermittent renewable sources in many countries, like Ireland, prompts expectations for the potential of **large-scale** storage systems, which would participate in the wholesale market. Large storage system can play a key part in a strategy to minimise the total cost of power delivered. The power rating could range from some hundred kilowatts to over a hundred megawatts.

Storage can help in the integration of RE in the **distribution** network, especially in weak grids, where the capacity to accommodate intermittent sources, especially wind, may be strongly constrained. Local loads can be partially met with stored energy at times when the RE source is unavailable. In short, the installation of distributed RE in connection with storage can defer the upgrade of distribution lines according to ORNL (1997). Connected to a particular wind farm, storage can help to meet the connection regulations and avoid connection charges. The size of storage systems connected to a distribution network will be smaller than in the wholesale market, depending on the amount of embedded renewable generation.

The size of **off-grid** systems ranges from small residential or telecommunication systems to medium size isolated networks. The presence of intermittent sources in an isolated system makes storage much more important than in a highly interconnected network. Such is the case of the island of Crete, the largest off-grid system in the world. 624MW of wind energy are predicted in Crete for 2010, as well as 213MW of pumped storage units within the *Action Plan for Large Scale Deployment of Renewables*. Ireland has only a low-capacity link with other electricity systems, and thereby it is in a way similar to the Crete system, where significant wind curtailment is necessary at times.

Off-grid applications are usually to be found in the electrification of small systems. Many off-grid locations are in environmentally sensitive areas. Renewable energy and storage can obviate the need for the fossil technology with its accompanying supply infrastructure. This usually requires large storage capacities to offset long periods of renewable unavailability. Therefore, fossil fuel support is usually necessary; storage can however, achieve great savings in the fuel consumption and reduce largely the cycling of the generators. The ultimate benefits are the same as in utility-scale storage –efficiency of the system and cost reduction–. There is very little market for off-grid systems in Ireland, probably limited to some very small applications, and therefore they fall beyond the scope of this study. It should be noted however, that the development of expertise and technology in this area could benefit Ireland from the perspective of export potential.

2.6 Research and investment in electrical energy storage

The growing interest in electrical energy storage has prompted an increase in research and investments worldwide.

European Union research

The European Commission's 5th Framework Programme of the included a target action on energy storage, which provided a strategic focus on the medium to long term needs for research on storage.

In the 6th Framework Programme, stationary energy storage is included among the research activities having an impact in the short to medium term. It is acknowledge that short-term research on the large-scale integration of RE sources into energy supplies is needed in support of the EU's commitments to increase the percentage of renewables in its supply mix. Electricity storage is among the areas in which the EU envisages support in particular, including 'advanced batteries, hydrogen, and other electricity storage devices for balancing variations in renewable electricity supply'.

Proposals for *Integrated Projects* have been invited for the topic **Advanced energy storage systems for RES,** with the objective is to develop technologies and systems for the storage of electricity for grid-connected applications enabling the increased penetration of renewable and distributed generation of electricity in new distributed electricity networks. R&D should also consider the analysis of storage system performance (in terms of lifetime, system lifetime cost, reliability, safety and recyclability of materials), the benchmarking of technologies and pre-normative research. One of the *Specific Targeted Research Areas* is: ***Electricity*** – **innovative energy storage technologies for grid-connected applications** (new concepts for energy storage technologies, where applicable exploiting the synergies with transport applications).

A current project funded by the EC is the **Investire Network** (Investigation on storage technologies for intermittent renewable strategies). The objectives are to review and assess existing storage technologies in the context of renewable energy applications to facilitate exchange of information. In Europe, there are few countries in which actors are capable of developing to a significant level more than two storage technologies, when so many technologies are claimed to be potential candidates to the various renewable energy applications. The project seeks to exchange R&D information, disseminate experiences and increase the markets, for example HES from Scandinavia, FES from UK, short-term storage for wind systems from Denmark, and so on.

International Energy Agency

The R&D programme Efficient Energy End-Use Technologies of the IEA contains 14 different Implementing Agreements of which one is ‘Energy Conservation through Energy Storage’ (ECES IA). According to the IEA (2003a)

> “*The overall objective is to develop and demonstrate various energy storage technologies for applications within a variety of energy systems and to encourage their use as a standard design option. Energy storage technologies can improve the utilisation of renewable energies, in particular solar and wind and the greater utilisation of waste heat energy storage technologies should be implemented in all countries with significant energy storage market potential*’’ .

At present, the ECES IA contains 17 different Annexes, some of which have been terminated. Most of the them are related to thermal energy storage. Relevant to electrical energy storage are the Annex IX, entitled ‘Electrical Energy Storage Technologies for Utility Network Optimisation’, and the recently proposed Annex XV, entitled ‘Electrical Energy Storage and the Integration of Renewables’.

Annex IX had the task of examining the potential role of electrical storage technologies in optimising electricity supply and utilisation. It also sought to identify barriers to widespread adoption of electrical energy storage technology.

The project has produced several reports, including a case study report of energy storage systems and a project definition report, which defines the framework for two potential demonstration projects (one for a power quality application and one for a utility-scale bulk storage project). A computer model for evaluating power quality applications has been developed and a requirement specification has been produced for the definition of a network applications model.

Annex XV is a natural development borne out of Annex 9. The aim is to develop a firm understanding of the technical issues and commercial implications of applying electrical energy storage technologies to the integration of RE and to develop awareness of the capabilities and uses of existing and developing energy storage systems as applied to RE (IEA. 2003). One objective is to move storage systems towards commercial market implementation, via the mechanism of technological and applications demonstrations.
The basic proposed activities focus on:

- the need for storage from a renewables perspective
- modelling of network/renewables/storage interaction
- implementation strategies for storage-based solutions
- the costs of storage
- the benefits of storage
- alternatives to storage

The conferences on Electrical Energy Storage Applications and Technologies (EESAT) provide an opportunity for dissemination of results from the Annex IX activities and to discuss issues related to the market, the applications and the technologies. So far there EESAT conferences have been held, in the years 1998, 2000 and 2002. Further information can be obtained from www.iea-eces.org/

United States

US have been leaders in the research and development of electrical energy storage. The main driver is the Energy Storage Systems Program of the US Department of Energy. This programme, conducted by Sandia National Laboratories involves systems integration, component development, prototype testing and systems analysis. Many projects are performed in collaboration with private sector organizations.
www.sandia.gov/ess/
www.eere.energy.gov/
www.eere.energy.gov/EE/power_energy_storage.html

Other useful links

The **Electricity Storage Association (ESA)** is an industry trade organization founded by eight electric utilities in 1990 that perceived a viable role for energy storage in electric power applications. Originally focused on battery energy storage, the organization was founded as an informal association as the Utility Battery Group, and later incorporated as the Energy Storage Association. The ESA is now a membership trade association that has the mission of fostering development and commercialisation of competitive and reliable energy storage delivery systems for use by electricity suppliers and their customers.
www.electricitystorage.org/

EA technology is a British utility consultant with considerable expertise on energy storage, and participated in the Annex IX of the ECES IA.
www.eatechnology.com/utilities_business/storage.cfm

The American consultant **Zaiginger Engineering Company**, Inc. has participated in many studies relating to distributed generation, renewable energies and storage systems.
www.zecoconsulting.com/distributed_gen_&_storage.htm

US Energy Storage Council
http://www.energystoragecouncil.org/

Chapter 3 STORAGE TECHNOLOGIES

Storage systems generally comprise three key elements, namely *Storage Subsystems, Power Conversion Systems (PCS) and Balance of Plant Systems (BOP)* as illustrated in figure 3.1. Depending on the storage system, certain elements within the scheme may be unnecessary, e.g. pumped hydro and compressed air energy storage do not need a rectifier and inverter, as pumps and compressors operate using alternative current (AC).

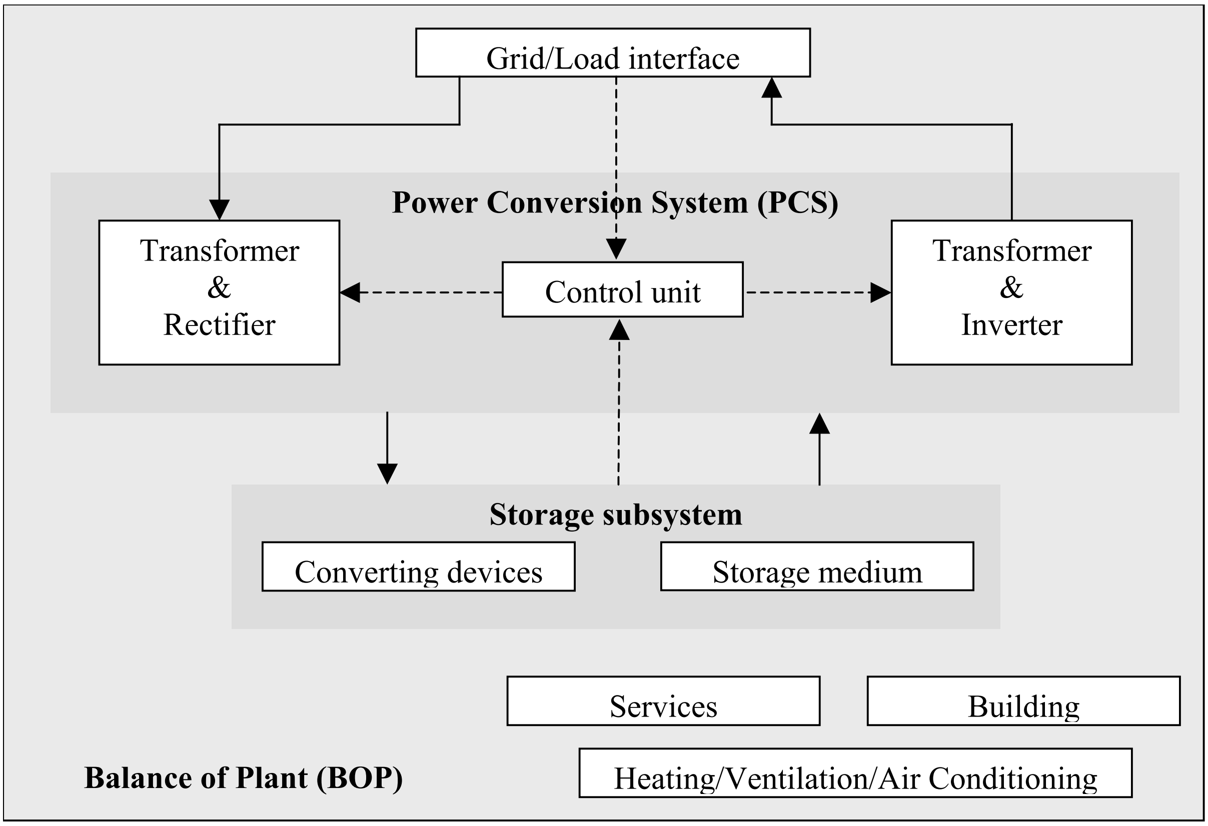


Figure 3.1 Scheme of a storage system

There is a wide range of energy storage technologies at utility scale that are at various stages of development. Each technology has different features which make it more or less desirable for the various applications. Table 3.1 provides an overview of possible selection criteria.

The relevance of the different features varies largely depending on the application which is going to be served. Fundamental criteria for any technology will be the **power capacity** (including the reactive power capacity for some purposes), the **energy capacity/discharge time**, and the **reaction time**. Some applications, like grid support, require discharges to commence less than a second after beginning; others, like power sales, can be scheduled allowing for a reaction time of a few minutes.

Design	Operating	Financial	Others
• Power rating • Storage capacity/ discharge duration • Response time • Energy density per unit area (footprint) • Energy density per unit volume and weight • Maturity of technology • Reliability • Modularity • Siting requirements • Portability • Synergies with other energy applications	• Overall cycle efficiency • Lifetime/maximum number of charge-discharge cycles • Parasitic losses	• Capital cost per energy stored • Capital cost per power rating • Fixed O&M cost • Variable O&M cost • Replacement cost • Disposal cost • Commercial risk	• Health and safety aspects • Environmental impacts • Synergies with other sectors

Table 3.1. Criteria for the selection of a storage technology

Ideally energy storage technologies should:

- be low capital, operating and maintenance cost
- have a long lifetime
- be flexible in operation
- have a high efficiency
- have a fast response
- be environmentally sustainable

There is a notable absence of available detailed technical information about storage technologies. This is surprising, given the growing need and opportunites for storage technologies. Somewhat superficial reviews can be found in Gandy (2000); Schoenung (2001); Swaminathan (1997); Ter-Gazarian (1994) and Herr (2002).

Electricity storage systems can be technically categorized by their inherent physical principles into **mechanical**, **electromagnetic** and **electrochemical** storage devices.

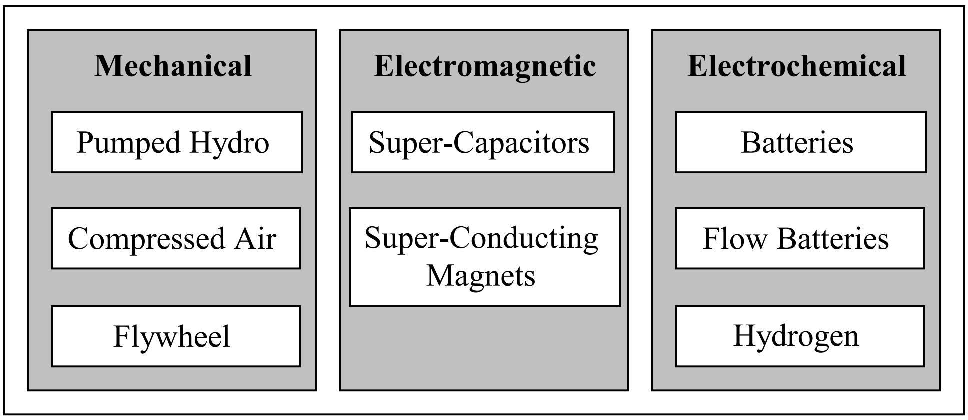


Figure 3.2 Storage technology categories

3.1 Pumped hydro

Shoenung (2001) acknowledges the role of Pumped Hydro Energy Storage (PHES) as the most widespread energy storage system currently in use on power networks, operating at power rating up to 4,000MW and capacities up to 15 GWh. PHES uses the potential energy of water, swapped by pumps (charging mode) and turbines (discharge mode) between two reservoirs located at different altitudes. Currently, the overall efficiency is in the 70-85% range although variable speed machines are now being used to improve this. The efficiency is limited by the efficiency of the deployed pumps and turbines (neglecting friction losses in pipes and water losses due to evaporation).

Plants are characterized by long construction times and high capital costs. One of the major problems related to building new plants is of an ecological/environmental nature. At least two water reservoirs are needed. Some high dam hydro plants have a storage capability and can be dispatched as a pumped hydro. A relatively new concept of pumped hydro employs a lower reservoir buried deep in the ground. A good example of underground pumped storage is the Dinorwig plant in UK, commissioned in 1982, which includes Europe's largest man-made cavern under the hills of North Wales. Open sea can also be used as the lower reservoir –a seawater pumped hydro plant was first built in Japan in 1999.

Pumped hydro facilities are available at almost any scale with discharge times ranging from several hours to a few days. PHES can be designed for fast loading and ramping, allowing frequent and rapid (<15 sec) changes among the pumping, generating and stand-by spinning modes (Gordon, 1995). The Dinorwig plant can go from 0 to 1890MW (full capacity) in only 16 seconds. PHES is best suited to load levelling, storing energy during off-peak hours for use during peak hours, and spinning reserve. They can provide energy to meet peak demands, and in the pumping mode, they serve as the source of load for base-load during off-peak periods, helping to avoid cycling these units and improving their operating efficiency. PHES systems can provide other benefits, including black start capability (they can begin generating without an external power source) and frequency regulation.

There is over 90 GW of pumped storage in operation world wide in nearly 300 plants, which is about 3 % of global generation capacity. In 1998 10% of Japan's total instantaneous energy requirement came from pumped hydro (Tanaka, 1998). Table 3.2 contains some of the most representative pumped-hydro plans in the world. The 292MW Turlough Hill Pumped Storage station (representing approx 5% of installed capacity) is the only bulk electrical energy storage facility in Ireland. Its construction was completed in 1974 and involved the construction of a huge cavern in the heart of the mountain, in which the generation plant and controls are housed. A pumped storage system allows for the use of excess electricity capacity during non-peak hours to pump water from the lower to the upper lake at Turlough Hill and then the release of the water in the reverse direction to create electricity in times of maximum demand.

Unit prices for pump/turbines have levelled out as the technology has matured. Thus, costs are typically around $600/kW. Reservoir costs can vary from almost nothing to more than \$20/kWh according to Gordon (1995). Schoenung places that cost at \$12/kWh.

Developers / Suppliers: MWH, GE Hydro, First Hydro Company.

Country	Location	Date	Max Power (MW)	Hours of discharge	Plant cost
China	Tianhuangpin	2001	1800		$1,080 M
Germany	Goldisthal	2002	1060		$700 M
Japan	Kazunogowa	2001	1600	8.2	$3,200 M
Taiwan	Mingtan	1994	1620		$1,338 M
UK	Dinorwig	1994	1890	5	$310 M
USA	Northfield	1973	1080	10	$685 M
USA	Bad Creek	1991	1065	24	$652 M
USA	Bath County	1985	2700	11	$1,850 M

Table 3.2 Some of the largest pumped-hydro facilities in the world

3.2 Compressed air

Compressed Air Energy Storage (CAES) systems are used, like PHES, for storing large amounts of energy, though they are much less employed worldwide. The electricity is stored by compressing air via electrical compressors in huge storage facilities, mostly situated underground in caverns created inside appropriate salt rocks, abandoned hard-rock mines, or natural aquifers, as discussed in Schoenung (2001). Recovery takes place by expanding the compressed air through a turbine, but the operating units worldwide incorporate combustion prior to turbine expansion in order to increase the overall efficiency of the system. Hence CAES can be regarded as peaking gas turbine power plants, but with a higher efficiency, thanks to the decoupling of compressor and turbine, and much lower overall cost. The savings come from the fact that, unlike conventional gas turbines that consume about 66% of their input fuel to compress air at the time of generation, CAES pre-compresses air using the low cost electricity from the power grid at off-peak times and utilizes that energy later along with some gas fuel to generate electricity as needed. The electricity/fuel ratio is an important design criterion for CAES plants.

Since CAES uses two energy sources – natural gas and electricity – it is difficult to specify efficiency in a meaningful way. Based on the efficiency of compression and expansion, Herr (2002) gives an efficiency of 64% for large systems.

Size limitations are driven mostly by the size of the gas turbines available. Currently, units as small as 20 kW are available. Large size units are limited by the reservoir size, as well as the grid capacity.

CAES offers an alternative to PHES for the storage of a large amount of power, most usefully for load levelling. It can also provide ancillary services, including reactive power. CAES plants can ramp faster than simple-cycle gas-fired plants because they are not restrained by compression requirements. Zink (1997) points to studies concluding that CAES is competitive with combustion turbines and combined-cycle units, even without attributing some of the unique benefits of energy storage.

However, few projects have been successfully completed globally, and so it remains a technology of some potential but little experience. The site-specific nature, coupled with the modest demand for long-duration storage, has limited the market entry of CAES. Owing to the limited operational experience, the technical risk is considered high by many utilities according to Gordon (1995). Price (2000) points out that the recently announced proposals for micro CAES using small gas turbines and pipelines as air receivers may reverse this trend. Micro CAES could be conveniently located near to load centres and become a useful distributed resource.

The first commercial CAES system was a 290MW unit built by ABB in Huntorf, Germany in 1978 (Figure. 3.3). This plant, now decommissioned, was operational for 10 years with 90% availability and 99% reliability according to Breeze (1998). The storage reservoir was a 300,000 m^3 underground cavity in a natural salt deposit, where air was stored at 70 bar. The system was charged over an eight-hour period, and could delivered 300MW for 2 hours.

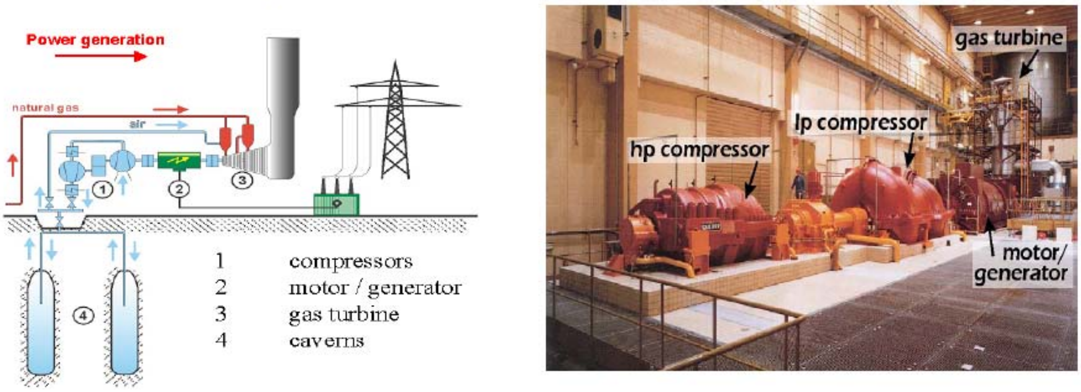


Figure 3.3 290MW CAES plant in Huntorf

The second commercial unit was a 110MW unit built by Dresser-Rand in McIntosh, Alabama in 1991. The construction took 30 months and cost $65M (about $591/kW). Semadeni (2003) reports that the plant has since generated over 55 GWh during peak demand periods. It comes on line within 14 minutes and can supply the nominal power for 26 h according to Price (2000).

The third commercial CAES plant, the largest ever (and larger than any energy storage plant in US, including pumped hydro), is a 2,700MW plant that is being developed in Norton, Ohio, by CAES Development Company. Van der Linden (2002) explains that this 9-unit plant will compress air to 104 bar in an existing limestone mine some 670 m under ground, with a capacity of 9.5 million m^3. Also in progress is the 540MW facility in Markham, Texas, being developed by Ridge Energy Storage. There are additional CAES plants built or planned at Sesta in Italy (25MW), in Japan (35MW, 6 h), Israel (300MW) and Russia (1050MW).

The features and limitations of CAES are similar to those of PHES. The need for geologically suitable locations for underground storage acts as a significant constraint to the deployment of this technology. Salt caverns are created by drilling a conventional well to pump fresh water into a salt dome or bedded salt formation. The salt dissolves until the water is saturated, and the resulting salt water is returned to the surface. This process continues until a cavern of the desired volume and shape is created. It can take about 1.5 to 2 years to create such a cavern. Detailed studies of underground storage caverns are essential before excavation and are very expensive. Taylor (1999) notes that hard-rock caverns are more costly to mine (60% higher) than salt-caverns for CAES purposes. Smaller on-site plants may be built using aboveground man-made reservoirs, possibly posing special safety or permitting challenges. Another possibility is the use of fabricated high-pressure tanks. Because of the expense of such tanks, only several hours worth of storage has been proposed for this concept according to Nakhamkin (1999).

In contrast to other storage technologies CAES is dependent on supplies of primary fuel in addition to an electrical supply. Air emissions (from combustion of gas) and most safety issues are very similar to other gas turbine-based generation plants.

Ridge Energy designs standard compression train blocks of 100MW each and standard generation blocks of 135MW. In generation mode, the plant can start up from 0 to 100% in less than 10 minutes. A normal ramp up from 10 to 100% load is 4 minutes, while in emergency it can be done in 2 minutes. Ramping from 50% to 100% can be accomplished in less than 15 seconds. As for the compression, the full load is reached in less than 10 minutes, and the 50% - 100% ramp in less than 10 seconds. They are capable of black start.

Schoenung (2001) and Gordon (1995) project capital costs to range between $425 and $480/kW for advanced designs if expected commercialisation occurs and expected experience is gained. Energy related costs are estimated between $3/kWh by Schoenung (2001) and $10/kWh by Gordon (1995). Costs depend largely on special requirements related to geologic reservoirs. The O&M costs (excluding fuel) will also be heavily affected by the reservoir characteristics.
Developers / Suppliers: CAES Development Company, Ridge Energy Storage, Dresser-Rand.

3.3 *Flywheels*

Kinetic energy may also be used to store energy in the form of the inertia of a flywheel. Flywheels have been used for centuries to flatten intermittent input in such applications as windmills. Nowadays all reciprocating engines contain flywheels to smooth the pulsed output of the pistons and provide stable power. With the advent of advanced composite materials with high tensile strength, and the development of stable magnetically suspended bearings, flywheels may now be made with significantly higher operational speeds. This in turn opens a new field of opportunities for Flywheel Energy Storage (FES).

Most modern flywheel energy storage systems consist of a massive rotating cylinder (comprised of a rim attached to a shaft) that is substantially supported on a stator by magnetically levitated bearings that eliminate bearing wear and increase system life. To maintain efficiency, the flywheel system is operated in a low vacuum environment to reduce friction. The flywheel is connected to a motor/generator mounted onto the stator that, through some power electronics, interact with the grid. The basic diagram of a FES system is shown in Figure. 3.4. Some of the key features of flywheels are rapid dynamic response, little maintenance, long life (20 years or 10s of thousands of deep cycles) and environmentally inert material.

The design of the flywheel itself has been the subject of much research. In order to maximise the energy stored, mass, radius and angular velocity of the flywheel must be increased, but this poses challenges to the materials strength. In general, flywheels can be divided into low-speed and high-speed units. The former are made of steel, and the latter, which reach speeds up to 100,000 rpm, of low-density composite materials such as fibre-reinforced carbon, aramid and glass fibres. The choice is based on the system cost, weight, size, and performance.

Flywheels storage systems are particularly suitable for power quality control. They can provide ride-through power for the majority of power disturbances, such as voltage sags and surges, and can bridge the gap between a power outage and the time required to switch to long-term storage or generator power with excellent load following characteristics. In comparison with lead-acid batteries providing ride-through and UPS, flywheels have a longer lifespan, lower maintenance, faster charge/discharge, take up relatively little space and pose no environmental hazards. In these applications, the need for a rapid load following, very frequent cycling and high power draws negatively impact battery life.

Flywheels are therefore contemplated now only for a range of short-term applications up to a size of severalMW, although not only for quality power and UPS. Despite the moderate storage capacity, some interest has been shown for the use of FES in renewable generation applications, basically to smooth out the power output and thus help improve power quality, and in stand alone systems in conjunction with batteries.

Butler (2002) asserts that steel rotor FES have limited promise for the entire array of applications but is well suited to hybrid FES/battery power quality applications. He also states that composite-rotor FES has potential for broader applicability but will require significant development to compete with other, more mature technologies. A number of technical hurdles will need to be overcome and the level of the technology will need to mature before flywheels become more widespread. High initial costs have slowed adoption of these units, although life-cycle costs can be already lower than for battery systems, especially in demanding operations. Research on flywheels focuses on improvements in the materials and manufacturing processes to achieve long-term mechanical stability, better low-loss bearings and cost reduction.

Beacon has developed a 250 kW/25 kWh flywheel. A matrix containing 10 units could deliver 2.5MW during 5min, or 0.5MW during 30min. The most powerful referenced flywheel is from the University of Texas, which is able to discharge 3MW for 2½ minutes according to Taylor (1999).

Headifen (1994) examined flywheels used for load-levelling in conjunction with 300 kW wind turbines (to smooth out power variations) gave a detailed cost breakdown for a 300kW/277kWh flywheel, resulting in a total installed cost of $220,000 or about $800 per kWh. The manufacturer Beacon, however, expects composite flywheels to break even with steel machines at 2-6 kWh, and is aiming at $500/kWh in composite units of 25 kWh. Other developers estimate long-term costs as low as $200/kWh according to Akhil (1997). Schoenung (2001) gives a cost estimate of $200-300/kWh for low-speed flywheels, but, surprisingly, the cost estimated for high-speed systems soars to 25,000/kWh. This wide range of cost estimates is typical for a technology in its early stages of development. In any case, composite flywheels are progressively becoming competitively priced, especially in applications requiring high power rating. Costs are expected to drop with increasing energy, but so far, only modest sizes have been reached. It must be borne in mind that the long life span and low O&M costs make the lifetime cost much more affordable. Although flywheel banks have been proposed to reach higher energy capacities, this solution does not avail of economy-of-scale effects. The operating costs of large units, dominated by vacuum pumping, are expected to be very low according to Gordon (1995).

As Manwell, McGowan & Rogers (2003) point out, some variable speed pitch regulated wind turbines use rotor speed controls to improve power quality in wind turbines. During gusts, the generator power is maintained at a constant while the rotor speed increases. The increased energy in the wind is stored as kinetic energy in the rotor. If the wind speed drops, the reduced aerodynamic torque results in a deceleration of the rotor speed while the generator power is kept constant. This principle of energy storage as kinetic energy in the rotor is similar to the principal underpinning flywheel energy storage.

Developers / Suppliers: Beacon, Active Power, AFS Trinity Power, Urenco Power Technologies, Flywheel Energy Systems, ASPES AG, Pentadyne Power Corporation, Piller, Regenerative Power and Motion.

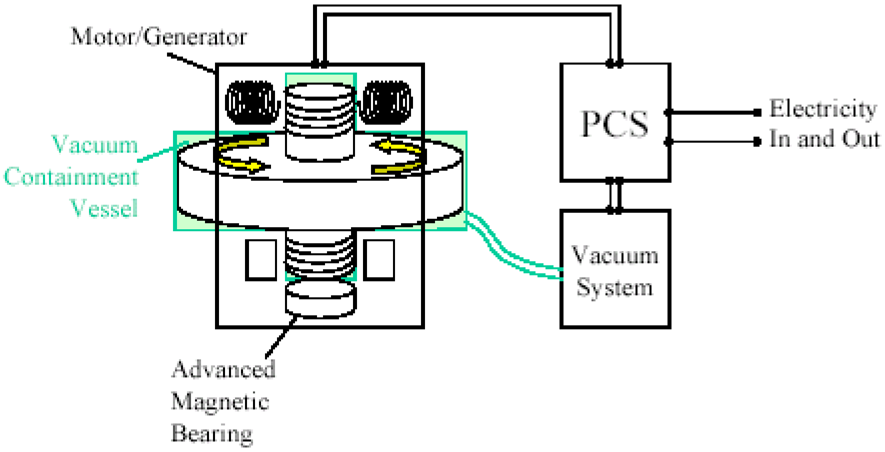


Figure 3.4 Basic diagram of a FES system

3.4 Super-capacitors

Capacitors store energy by way of separating the charge onto two facing plates. They are widely used in electronic devices for power smoothing after rectifying. Typically, these applications require very small energy amounts. In order to increase the energy density, the so-called ‘Super-Capacitors’ (or even ‘Ultra-capacitors’, if their capacitance exceeds 1000F) have been developed. They use polarized liquid layers at the interface between a conducting ionic electrolyte and a conducting electrode, which increases the capacitance. The bipolar configuration lends itself to versatility in

connecting individual cells in series or parallel. Energy densities of 20 to 70 MJ/m^3 are usually reached. The efficiency is approximately 95% (Gordon, 1995).
Super-Capacitors Energy Storage (SCES) offers extremely fast charge and discharge capability, albeit with a lower energy density than conventional batteries can provide and can be cycled tens of thousands of times without degradation.

The interest in automotive applications and telecommunications has stimulated the development of the technology. SCES will probably be linked to batteries in these realisations. By combining a supercapacitor with a battery-based uninterruptible power supply system, the lifetime of the battery is extended. The batteries would provide power only during the longer interruptions, reducing their cycling duty on the battery. Small supercapacitors are commercially available to extend battery life in electronic equipment, but large supercapacitors are still in development.

SCES is still at an early stage of development, as an energy storage technology for electric utility applications. Small-scale power quality (<250 kW) is considered to be its most promising utility use. The units under development target applications where pulse power is needed for duration in the millisecond to second time range, mainly to by-pass voltage sags. Supercapacitors with discharge times up to 1 minute are feasible.

In any event, their use for large energy storage is not contemplated in the medium term. Since the number of capacitors needed is directly proportional to the stored energy, there is no economy of scale. This, together with the relatively low energy densities, makes them little attractive for large energy (or long duration) applications.
Gordon (1995) reports that capital costs of SCES were estimated by Pinnacle Research Institute at $12,960/kWh, with O&M 5% of the capital cost per year. Nevertheless, Schoenung (2001) estimates the energy-related costs at $82,000/kWh. Further research has to concentrate on cost, manufacturing process and the lowering of internal resistance.

Developers: SAFT, NessCap, ESMA, Maxwell, ABB, ELIT.

3.5 Superconducting magnets

In a Superconducting Magnet Energy Storage (SMES) device, a coil of superconducting wire allows a DC current to flow through it with virtually no loss. The current creates a magnetic field that stores the energy. On discharge, special switches tap the circulating current and release it to serve a load. For setting the coil in state of superconducting, it has to be cooled down either to 4.2°K (low-temperature superconducting) or 77°K (high-temperature superconducting). Technical improvements and a better knowledge of dealing with and controlling cryogenic systems have allowed SMES to penetrate the market and compete with more common storage systems according to Sels (2001).

The dynamic performance of SMES is far superior to most other storage technologies. Response times down to milliseconds are possible and the energy can be transferred very quickly (limited normally by the cost of the power conversion components). Another key feature is the virtually unlimited number of charge/discharge cycles. Sels

(2001) places the overall efficiency at over 90%, while Schoenung (2001) states it can be as high as 95%. The losses are mostly dictated by the cooling system.

SMES are most suitable for high value/low energy applications, where the storage requirement is for less than a few seconds, with power requirements up to 1 or 2MW. Although research is being conducted on larger SMES systems in the range of 10 to 100MW (with storage times of minutes), recent focus has been on the smaller micro-SMES devices in the range of 1 to 10MW for the power quality market, which are becoming commercially available. A commercial product for example provides approximately 1MW for 1s. Buckles (2000) reports that the discharge rate can be easily controlled and thus the available bridging time becomes longer as the load is smaller. The size is an obvious limitation to large systems. One estimate of the radius of a coil supporting a load of 5,000MWh, 1,000MW is 150-500m, depending on the peak field and the ratio of the coil height to diameter, while Breeze (1998) states that a 5,000MW unit would need a coil of radius 800 m.

SMES technology provides an efficient protection against voltage sags (supplying reactive power to the system) or momentary outages. They can be used for smoothing fast changing loads at a small scale like factories or at a bigger-scale at the distribution and transmission level according to Yurek (1999).

The projected capital cost and, to a lesser extent, the high energy consumption by the cryogenics and refrigeration systems, make SMES unattractive for competitive diurnal storage applications such as generation and transmission deferral, load levelling, peak reduction and renewable applications concludes Swaminathan (1997). In continuous mode operation, the system is constantly cycled and the parasitic losses are proportionally less. In diurnal storage applications, however, these parasitic losses are proportionally large, thus reducing overall system efficiency according to Akhil (1997).

Table 3.3 shows an estimation of the costs of a 1MW unit in 2001 and the expected evolution in 5 and 10 years from Sels (2001). The cost increases as the bridging time becomes longer. The O&M costs are not very well established, but are expected to be around $8/kW-y, including refrigeration according to Gordon (1995). The specific costs of SMES facilities fall as the size increases.

	discharge time		
	1 s	30 s	60 s
2001	865	1388	943
2006	224	403	540
2011	178	344	464

Table 3.3 Estimated cost for a 1MW SMES unit (×€1,000)

The deployment of SMES demands a reduction of costs, possibly achieved by the design of high-temperature super-conducting materials and low-temperature power electronics. Siemens completed an evaluation and conceptual design of a 2MWh/50 MW SMES for use in providing frequency stabilisation to the electric system, but Prescher (1995) reported that it may be too expensive compared to other storage technologies. The PCS represents more than 60% of the total cost, but decreases significantly with increasing rated power and decreasing bridging time. Another problem that must be addressed is the stability of the superconducting coil, which is very sensitive to small temperature deviations (Sels, 2001).

Figure 3.5 Distributed SMES at a substation

American Superconductor is commercialising the system D-SMES, with a power rating of 1MW, to provide grid stabilisation and support (Price, 2000). These units can provide up to 3MW of instantaneous real power and up to 8 MVAR of reactive power from the converters. The energy capacity is 3 MJ, which means at full power the discharge lasts 1 s. The charge is carried out in less than 90 s. Six of these units are being used to stabilise a 115kV transmission grid in Wisconsin, avoiding grid upgrades.

3.6 Batteries

Batteries are the most common devices used for storing electrical energy. Battery Energy Storage (BES) can be seen as the 'standard' storage system. There are a number of different technologies with their own reactions, materials and electrical characteristics. This wide variety of attributes leads to tremendous diversity in battery types and uses. Some of these technologies are presently applied in electric power applications, including utility-scale energy storage facilities. Despite the interest of utilities in BES, end-users continue to be the largest market for batteries.

As battery cells have a characteristic operating voltage and maximum current capability, battery systems normally consists of several cells, linked in line or parallel dependent on the required power and energy rating.

Batteries exhibit a fast response to changes in power demand. Their efficiency varies among technologies, and also depends on the application and the operation regime.

Applications

BES shows the broadest application range. Their response time is suitable for virtually all applications while modular build-up ensures great flexible and enlargement. The flexibility of batteries is illustrated in the range of applications for which they have been used, from the 10MW / 40MWh installation in Chino to the sub-kW/kWh UPS systems available for computer applications.

BES has been receiving considerate attention from the utility industry. During the eighties they were considered a viable option for large-scale load levelling applications. However, there is an increasing controversy as to whether they can be viewed as energy supply technology, serving applications such as load levelling and capacity deferral, as the economics mitigate against operating in this manner. The cost structure of BES makes them less competitive for applications that require high power (MW scale) for long durations (> 1h). Large installed BES systems have typically power-to-energy ratings resulting in a discharge durations from ½ hour to 4 hours. Although there are systems with longer discharge times, the competitiveness against non-storage technologies is progressively dubious. Swaminathan (1997) found that this trend could be observed in the 90's, with installations which have large power ratings but are designed to operate for durations typically < 1 hour. Lower discharge time limits are set by the discharge characteristics of the battery.

Utilities do see key roles for batteries especially in areas such as distributed generation and power quality, but Akhil (1997b) notes that they still express their concern about costs, life span, maintenance, and energy density. It must be stated however, that although battery technology is mature, stationary battery systems are not. System costs still need to be reduced, and it is anticipated that this can be achieved through optimised integration and mass production.

BES systems are also widely used in small off-grid renewable back-up applications. They can also be seen as an option for renewable energy integration, increasing the reliability and dispatchability of renewable sources.

Battery energy storage systems must be optimised to give the best possible performance for a given application. This optimisation may include the actual design of the battery cell and so it is important to understand the different parameters affecting battery design. These include:

- power requirements
- energy requirements
- charge/discharge rates
- number of discharge cycles

Classical vs. advanced batteries

The most mature technology, **flooded lead-acid (LA)** batteries and **valve regulated lead-acid (VRLA)** batteries, have been in service in electric power applications for two decades according to Butler (2002). **Nickel-cadmium (NiCd)** batteries have also reached an important maturity degree.

Lead-acid batteries have a very high efficiency and all other electrical storage technologies have to compete with them. However their low power and energy density and other drawbacks have encouraged much research to develop new battery technologies. The advanced battery technologies offer improved power and energy densities, as well as lower maintenance, but Gyuk (2002) found that they do not have such a proven track record and tend to be expensive for large-scale applications. They are being used mostly in vehicles and for power quality and backup purposes at manufacturing plants.

Advanced battery technologies such as **sodium-sulphur (NaS)** and **lithium-ion** are quickly becoming commercially available. **Lithium-polymer (Li-polymer)** and **nickel-metal hydride (NiMH),** which have been developed mainly for automotive use, and **metal-air,** are also candidate storage media, but are just emerging in pilot scale systems according to Butler (2002).

Good battery management and well-optimised operational regime are important for the financial viability. Not all batteries are the same and so care should be taken in the application requirement specification to ensure that the requirements placed on the battery storage media are well matched to the battery specifications (number of anticipated discharges, depth of discharge, rate of discharge, etc.).

The costs vary a lot between technologies. Based only on the initial costs, the least expensive is lead-acid followed by NiCd. Advanced battery technologies are currently more expensive, but costs are expected by Collinson (2000) to fall as the volume of sales increases. O&M costs hold an important share of the life-cycle costs in most technologies.

Some batteries involve environmental hazards. Lead and cadmium, for instance, are highly toxic elements.

Information about battery manufacturers and other related issues may be found at www.basytec.de/links_e.html.

Lead-acid batteries

The majority of operating energy storage worldwide in both utility and non-utility applications is in the form of flooded lead-acid (LA) and valve regulated lead-acid (VRLA) battery technology. This success is founded on its maturity, relatively low cost and long lifespan. Due to the fast response and reasonably low self-discharge rate, they offer a very flexible solution for energy storage, ranging from short-term applications (seconds) to long duration storage (hours). A major disadvantage is the low performance quotient in terms of energy and power densities, which may pose a problem in applications where space is a serious constraint. The other major drawback is the high O&M requirements. Furthermore, there is very little cost reduction margin for lead-acid batteries in the future. However, due to their current costs and the familiarity of industry with them, they will always be an option for less taxing applications.

Although it is anticipated that incremental performance improvements will continue to be made with conventional lead-acid battery technology, Collinson (1999) maintains that future advances in system performance will probably come from developments in system operation, control and design optimisation, including the energy storage systems that can provide multiple benefits.

VRLAs use the same basic electrochemical technology as flooded LA batteries, but they are closed with a pressure-regulating valve, so that they are essentially sealed. Therefore there is no venting of hydrogen and oxygen, and no ingress of air into the cells. In addition, the acid electrolyte is immobilized, which eliminates the need to add water to the cells to keep the electrolyte functioning properly, or to mix the electrolyte to prevent stratification. They can be used close to people and sensitive equipment. The major advantages of VRLAs over flooded lead-acid cells are the dramatic cut in the maintenance and the reduction in weight and size. The drawbacks are their higher cost and lower lifetime. The battery subsystem may need to be replaced more frequently than with the flooded lead-acid battery, increasing the levelised cost of the system. VRLAs have become popular for standby power supplies in telecommunications applications, where they are perceived as maintenance-free and safe, and for uninterruptible power supplies in situations where special rooms cannot be set aside for the batteries.

There is a significant body or research attempting to address the durability and charge/discharge rate deficiencies of LA and VRLA batteries. The international Advanced Lead-Acid Battery Consortium has developed a technique to significantly improve storage capacity and recharge the battery in a few minutes rather than hours. In US, a related technique appears to have extended cycle life by three or four times.

In general, lead-acid batteries, both flooded and valve-regulated, are a popular storage choice for power quality, UPS and some spinning reserve applications. Its application for energy management, however, has been very limited due to its short life cycle. They have been used in a few commercial and large-scale applications. The largest one is a 10MW /40MWh system in Chino, California, built in 1988 and shown in figure 3.6. The LA battery system operated by PREPA in Puerto Rico since 1994, which provides spinning reserve as well as voltage and frequency control for the island's grid, has a larger power (20MW), but a lower energy capacity (14MWh). This facility provides spinning reserve in case of a generator outage –its quick response time enables the system to maintain a smaller spinning reserve capacity– and contributes to frequency regulation for the San Juan metropolitan area. The economic and technical success of this system has resulted in a decision to double the capacity of the system. However, premature aging of the batteries, initially projected to last for 10 years, suggests a cycling rate that is too demanding for the batteries.

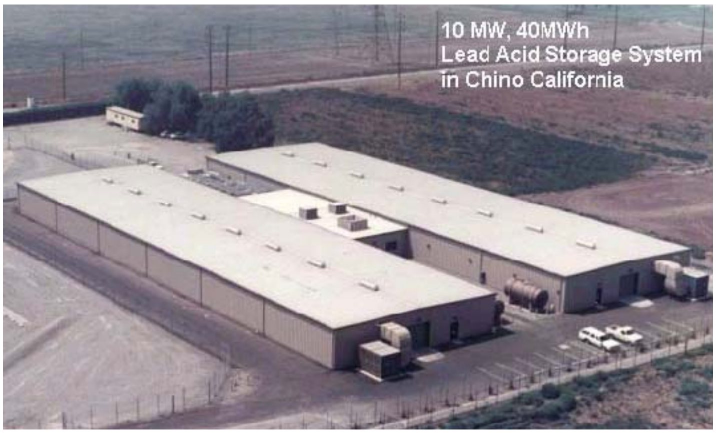


Figure 3.6 10MW/40MWh Lead-Acid storage system in Chino, California

The 1MW/1.4MWh VRLA plant in Metlakatla Island (Alaska) supports minigrid stability. Berlin Power and Light (BEWAG) operates an 8.5MW/8.5MWh and a

17.5MW/5.7MWh plant in a combined spinning reserve and frequency regulation mode. The 3MW/4.5MWh VRLA plant at Vernon provides back-up power to critical loads and peak shaving to a factory.

Table 3.4. lists and compares some lead-acid (including VRLA) storage systems larger than 1MWh. Since some plants have a greater energy capacity or a greater discharge rate, Akhil (1997) warns that it is difficult to compare the cost of batteries on a $/kW or a $/kWh basis. The Chino battery, which is three times larger than PREPA and 9 times larger than Vernon, appears to have benefited from economies of scale with a cost of $201/kWh.

				Battery system alone		Total cost of the storage system*	
Plant	Year of installation	Rated Energy (MWh)	Rated Power (MW)	Cost in $1995 ($/kWh)	Cost in $1995 ($/kW)	Cost in $1995 ($/kWh)	Cost in $1995 ($/kW)
CHINO California	1988	40	10	201	805	456	1,823
HELCO Hawaii (VRLA)	1993	15	10	304	456	777	1,166
PREPA Puerto Rico	1994	14	20	341	239	1,574	1,102
BEWAG Germany	1986	8.5	8.5	707	707	n/a	n/a
VERNON Calif. (VRLA)	1995	4.5	3	305	458	944	1,416

* Includes Power Conditioning System and Balance-of-Plant

Table 3.64 Largest LA and VRLA batteries installed worldwide

The total cost of a BES for large storage applications generally range from $1,200 to $1,500/kW for a 1-2 h system, whereas the specific cost of a system for power quality applications is around $450/kW. Akhil (1997) estimates a cost reduction potential of around 20%. At any rate, the costs are driven by a combination of power and energy ratings. Schoenung (2001) gives a power-based specific cost of $250/kW, and an energy-related cost of $225/kWh, which can be as low as $100/kWh for power quality applications.

Wagner (1999) points out that utility-scale lead-acid batteries can be also installed in connection with renewable energy plants, such as the multifunctional 1.2MWh plant installed in combination with a 2MW wind farm in Bocholt (Germany), which is used for UPS, improvement of power quality and peak-load shaving.

Developers / Suppliers: GNB Industrial Power/Exide, East Penn, Trojan, Crown Battery.

Nickel-cadmium batteries

A nickel-cadmium (NiCd) battery uses an alkaline electrolyte, usually potassium hydroxide (KOH) or occasionally sodium hydroxide (NaOH), which act as an ion-conducting medium. NiCd batteries cost more than LA but have many advantages. They exhibit higher specific energy and longer lifetime, require less maintenance, endure more extreme conditions, and can withstand full discharge without compromising the battery life and efficiency. An important concern is the toxicity of cadmium, which causes severe problems for the disposal of the batteries. Cadmium might even be banned in the future. Other drawbacks include high rates of self-discharge and 'memory' effect, which reduces the storage capacity available.

A 40MW NiCd plant comprising 13,760 cells from SAFT is under construction for voltage support on a long power line to Fairbanks, Alaska. Although these batteries are not common for large stationary applications, resistance to cold may have been among the deciding factors in this case. The system, completed in September 2003, is able to supply 46MW for 5 minutes, but will typically provide 27MW for 15 minutes. The cost of the facility was $35M.

Lithium-ion batteries

The main advantages of Li-ion batteries, compared to other advanced batteries, are their high energy density (four times that of lead-acid batteries), very high efficiency (near 100%), and long life cycle (3,000 cycles at 80% depth of discharge).

High energy density enabled Li-ion to take over 50% of small portable market in a few years, but there are some challenges in upscaling to large-scale batteries. The main hurdle is the high cost (above $600/kWh) due to special packaging and internal overcharge protection circuits. Several companies are working to reduce the manufacturing cost of Li-ion batteries to capture larger energy markets, mainly the auto industry but also multi-kW, kWh sizes for residential, commercial, and renewable markets. However, only power quality applications and short-duration peak shaving seem to be feasible in the medium term according to Boyes (2000).

Major Li-Ion battery manufacturers include SAFT, Sanyo Electric Company, and Hithachi.

Sodium-sulphur batteries

A special case among advanced batteries is the NaS battery. Developed in Japan, this battery operates at high temperatures. The electrodes are liquid –molten sodium for the cathode and molten sulphur for the anode– and the electrolyte solid –alumina ceramic. The assembly has to be maintained at 300ºC to keep the electrodes molten. Extensive tests have demonstrated safe containment under extreme conditions. They were first developed for automotive applications and are now being successfully applied to large commercial buildings and utility power stations to provide power quality and load levelling functions. Some utilities have also begun investigating this technology for deferring substation upgrades.

This type of batteries is characterized by long cycle life, good energy efficiency (up to 86%), high specific energy (3–4 times a lead-acid battery), and very low self-discharge rates. NaS batteries have a pulse power capability over six times their continuous rating (for 30 seconds). This attribute enables the NaS battery to be economically used in combined power quality and peak shaving applications. The continuing high cost is a major barrier for a greater market penetration.

The high operating temperature necessary for NaS batteries makes them more efficient when serving applications in which the battery cycles frequently and the thermal effects of cycling contribute to the maintenance of the operating temperature of the unit. They could also serve applications with long periods of inactivity if the same battery system also served a frequent cycling application reports Butler (2002).

Some 38 systems totalling approximately 20MW and 124MWh have been installed in Japan. The largest of these installations is a 6MW, 8h unit for Tokyo Electric Power company shown in figure 3.7, which is used for long-term electricity storage (load-levelling and load management). It also can supply active and reactive power to mitigate voltage sags and frequency fluctuations. The peak power is up to six times the continuous rating. The batteries of this plant alone exhibit efficiencies of 86% according to the developers. The entire system, including the AC/DC converters, has an efficiency of about 75%. A second system of the same characteristics was commissioned subsequently. Outside of Japan, operation of a 500kW demonstration unit has been installed in the US to be used for load levelling or as an UPS according to Gyuk (2002).

Figure 3.7 6MW, 8h NaS battery storage system

Prospects for this technology are focused on the retail market for energy management and power quality. Combined power quality and peak shaving applications is an important potential market. Commercial production of the basic building block –the NaS 50kW, 360 kWh module– is the initial target.

Developers / Suppliers: NGK

Metal-air

Potentially the cheapest batteries are metal-air batteries, which, along with their very high energy density, explains why a good number of companies including Evonyx, AER Energy Resources, Metallic Power, Chem Tek, Power Zinc, Electric Fuel, Alupower and Aluminium Power are developing them. Anodes contain commonly available metals, like zinc, aluminium, lead and even iron, placed in a liquid or polymer impregnated electrolyte of potassium or other conducting hydroxide. The cathodic material is oxygen from ambient air. Metal-air batteries are inherently safe and environmentally benign. But while high energy, controllable discharge and low cost could suit them to many primary battery applications, the only known rechargeable unit so far available, a zinc-air system, has a very short cycle life and a charge/discharge efficiency of only about 50%. Thereby the technology demands further research and development before it can compete with other types of batteries. Zinc-air batteries are being developed by Evonyx.

Comparison table

Table 3.5 summarises some relevant data for battery technologies comparison.

Battery type	**Energy density (Wh/kg)**	**Energy density (Wh/litre)**	**Operating temp (°C)**	**Efficiency (%)**	**Self-discharge (% loss /month)**	**Cycle life (cycles)**
Lead-acid	10-20	50-70	-10 to 40	85		variable
NiCd	30-37	58-96	-40 to 50	65	10	< 2000
NiMH	75	240	-20 to 50	65	15-25	up to 600
Li-ion	150	400	-20 to 50	95	2	3000+
Li-polymer	200	220		65		1000+
NaS	53-116	40-170	310 to 350	75-86	0	2250+
Zn-air	120-180	169-180		50		200

Table 3.5. (Source: Linden, 2001)

3.7 Flow batteries

Flow Batteries (FB), also known as Regenerative Fuel Cells or Redox Flow Systems are a new class of battery that has made substantial progress technically and commercially in the last years. Flow Batteries Energy Storage (FBES) systems have features that make them especially attractive for utility-scale applications. The operational principle differs from classical batteries. The latter store energy both in the electrolyte and the electrodes, so to speak. Flow batteries, however, store and release energy using a reversible reaction between two electrolyte solutions separated by an ion permeable membrane. Both electrolytes are stored separately in bulk storage tanks, whose size defines the energy capacity of the storage system. The power rating is determined by the cell stack. Therefore the power and energy rating are decoupled, which gives the system designer an extra degree of freedom when designing the system. The cost per kWh decreases as the energy storage capacity increases for a given power, and can reach very competitive values. Since the energy storage capacity depends exclusively on the size of the electrolytic tanks, the flow batteries do not have obvious scale limits. This makes them a promising candidate to join CAES and PHES providing large-scale energy storage.

FBs are flexible in operation, especially with respect to discharge times, which can range from minutes to many hours. Other interesting features are the fast response delivering real power (reactive power is not delivered so quickly) and the capability of withstanding overload and total discharge without any risk of damage (Sels, 2001).

Flow batteries are generally not more than between 75% and 80% efficient. This is higher than electrolysis-fuel cell systems, but still below the efficiency of most batteries. The need for pumps to circulate the electrolytes adds a parasitic loss, but at the same time makes the thermal management easier (heat exchanger in the circulation loop). Another disadvantage is the use of aggressive chemical solutions.

FBs are entering the market now, and are likely to experience sustainable growth to attain commercial-scale production in 3-5 years. Developers are positioned for mass manufacturing, are soliciting large-scale orders, and report significant interest among potential buyers (Lotspeich, 2002). Demonstration FBs have performed well in a range of applications that showcase their technical versatility and the potential economic benefits of providing multiple services and value streams. FBs are an integrative technology, serving a range of fragmented storage market niches such as load levelling, peak shaving, power reliability, and substation-based transmission support.

Many different electrolyte couples have been proposed for use in flow batteries. Present developments are based on:

- Vanadium Redox
- Sodium polysulphide / Sodium bromide
- Zinc/Bromine

Vanadium Redox Flow Battery

Vanadium Redox Batteries (VRB) store energy by employing vanadium redox couples ($V2^+/V3^+$ in the negative and $V4^+/V5^+$ in the positive half-cells). These are stored in mild sulphuric acid solutions (electrolytes). During the charge/discharge cycles, H^+ ions are exchanged between the two electrolyte tanks through the hydrogen-ion permeable polymer membrane. The net efficiency of this battery can be as high as 85%. Efficiencies over 80% have been proven, according to Blackaby (2002). Like other flow batteries, the power and energy ratings of VRB are independent of each other, which gives the flexibility to increase the system capacity by simply increasing the volume of solution. Menictas (1994) affirms they can be fully discharged (100%) without any detrimental effects. The VRB offers a very long lifetime, fast response (from charge to discharge modes in 1/1000 s) and high overload capacity (more than twice the rated power for several minutes). The technology has proven its capability for ride-through, power quality and emergency back-up.

Cells last at least 10,000 cycles, and in the laboratory 25 kW modules have exceeded 16,000 cycles according to Lotspeich (2002). The electrodes are made of inert materials. Stack service life is determined primarily by membrane longevity, and the life of pumps and other auxiliary components. The manufacturer Sumitomo Electric Industries (SEI) recommends that the stack be replaced be replaced every 10 years, reflecting an expected membrane life of 8–10 years. The electrolytes have an indefinite life, and may be reused.

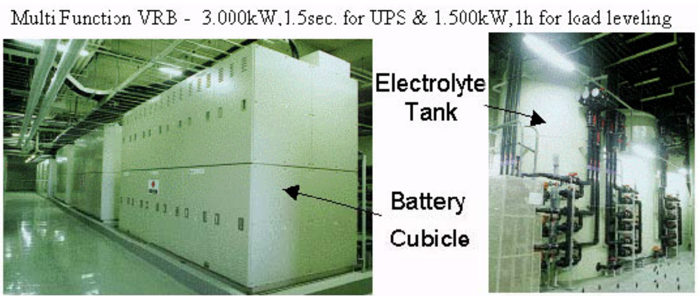


Figure 3.8 VRB at a semiconductor factory

VRB was pioneered in the Australian University of New South Wales (UNSW) in early 1980's. The Australian Pinnacle VRB bought the basic patents in 1998 and licensed them to SEI and Vanteck. Another developer is Cellenium Co Ltd. To date, the majority of the demonstrations have been on-grid load-levelling and peak-shaving applications in Japan, where storages up to 500kW, 10 hrs (5MWh) have been installed by SEI. VRBs are used for load levelling at a substation (450 kW, 900 kWh), a university (500 kW, 5MWh), and an office building (100 kW, 800 kWh), and stabilise the output of both photovoltaic (30 kW, 240 kWh) and wind generators (170 kW, 1.2MWh).

This latter plant, provided by SEI, can supply 170 kW for 6 hour and is installed with a 275 kW wind turbine. VRBs have also been applied for power quality applications – figure 3.8 shows a VRB facility installed by SEI at a Japanese semiconductor factory provides 1.5MW for load levelling, and can yield 3MW for 1.5 sec to eliminate sudden sags. The first large commercial VRB outside Japan was installed in South Africa by Vanteck (250kW, 520 kWh, ~2 hrs) for UPS ride-through, power quality and emergency back-up. PacifiCorp built recently a 2,000 kWh (8 h) system in a remote area in Utah, the first in North America, to provide peak power and end-of-line voltage support, deferring the need for a new substation. VRBs are scalable to MW sizes, and Lotspeich (2002) points to studies on feasible systems up to 100MW.

Developers / Suppliers: Pinnacle, Sumitomo Electric Industries, Vanteck Technology Corp & Telepower Australia, Cellenium Company Limited.

Polysulphide bromide flow battery

Polysulphide Bromide Batteries (PSB), also known as Sodium/Bromide, are a regenerative fuel cell technology based on a reversible electrochemical reaction between two salt solution electrolytes – sodium bromide and sodium polysulphide. PSB electrolytes are brought close together in the battery cells where they are separated by a polymer membrane that only allows positive sodium ions to pass through. Cells are electrically connected in series and parallel to obtain the desired levels of voltage and current. A 100 kW module for instance comprises a stack of 200 cells, and sixteen m^3 of each electrolyte is needed for each MWh of storage, according to Lotspeich (2002).

Lotspeich (2002) states that the net efficiency ranges from 55–60% to about 75% depending on its operational mode, including power conversion and energy losses due to auxiliary equipment such as pumps. It operates ideally between 20–40°C, but tolerates a wider temperature range. The energy density is 20 to 30 Wh per litre, which is about 30% of a normal lead-acid battery. Therefore they are relatively large and heavy.

This flow battery was developed during the 1980s–90s by the British firm Regenesys Technologies Ltd., owned by Innogy, in turn owned by its German parent RWE. The patented name of the flow battery is Regenesys®.

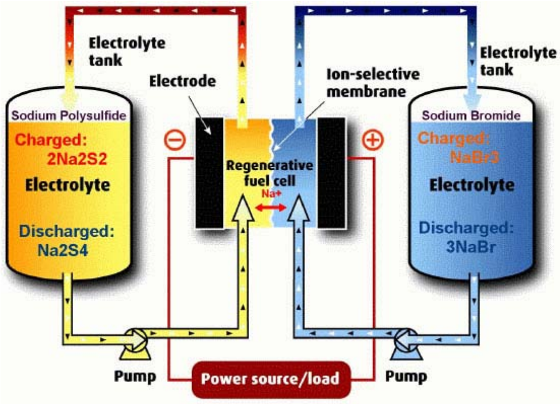


Figure 3.79 Scheme of a Polysulphide Bromide Battery

The power conditioning system and controls linking Regenesys® to the grid allow ‘cold’ start up in less than 10 minutes. Lotspeich (2002) reports that if held in standby mode with charged electrolyte in the stacks, the system can respond in fraction if a second (reportedly within 20 milliseconds) to supply more than 10MW. It is designed to be automated and run remotely, with biweekly removal of sodium sulphate crystal by-products.

In the year 2000, Regenesys Technologies began building a 15MW, 120MWh energy storage plant (the largest battery in the world) at Innogy's Little Barford Power Station in the UK, following the success of a four-year, 1MW demonstration at Innogy's Aberthaw power station. It was expected to come into operation in 2003 and to last for at least 15 years with overall cycle efficiency predicted at 60-65%. The purpose was to provide a combined-cycle gas turbine power station of the same power with black start in the event of a grid supply outage. Other duties of the plant included frequency response and voltage control, as well as energy management in the UK’s electricity market.

The use a RFB in parallel with a power plant was expected to increase the overall efficiency by avoiding inefficient partial loads. At the same time, expensive start-up and shutdowns of other plants could be delayed. It was also hoped to use the plant at Little Barford in conjunction with wind power generation according to Price (2000b).

The facility cost was approximates at €21-million, that is €1400/kW or €175/kWh. The system was anticipated to reach full charge or discharge power in 0.1s, asserts Price (2000b). This, for a first commercial scale plant, would be very encouraging, as costs should fall significantly with volume and further development. The O&M costs were estimated to be relatively small, according to Semadeni (2003). The facility, which includes two tanks of 1800 m^3, covers an area of nearly 5000 m^2 as shown in figure 3.10).

Figure 3.10 Drawing of the 120MWh planned Regenesys plant at Little Barford

Tennessee Valley Authority (TVA) ordered a 12MW, 120MWh Regenesys® unit (USA) to be operational in Mississippi in late 2004 (shown in figure 3.11), at a total cost of $25 million. The expected operational life of the plant was 15 years and the purpose was to reduce the need to build additional power lines and power plant for peak generation. TVA also felt it would enhance the reliability and improve power quality by eliminating momentary interruptions in service and maintaining voltage levels. TVA assessed the economic viability of a storage system against the installation of low capacity factor peak generation, as well as grid upgrades to prevent interruptions (TVA, 2001). However, in 2002 TVA cancelled plans for a second Regenesys plant, which was to be associated with a 20MW wind farm.

Figure 3.11 Electrolyte tanks of the TVA Regenesys plant under construction in Mississippi

In response to a query from the report authors in 2003, the Regenesys Technologies Marketing Manager confirmed there were some international orders in various stages of negotiation. Lotspeich (2002) states that systems of up to 500MW capacity are feasible in its current configuration. Regenesys Technologies were targeting the renewable generation market, with the conviction that the system can be economically feasible in enabling better use to be made of intermittent sources, availing of the differential between peak and off-peak rates. Innogy planned MW-scale support for wind farms in Denmark and elsewhere, and reports customer interest in installations ranging from 12–100MW according to Lotspeich (2002).

Despite the positive signals, Innogy abandoned its Regenesys electricity storage project in December 2003 according to The Guardian Newspaper, after its German parent, RWE decided against investing the money need to commercialise the plant. This system seemed very suited to addressing the intermittent nature of wind energy in Ireland and the reasons for the abrupt cessation in development are currently unclear.

Developers / Suppliers: Regenesys Technologies Limited (ceased in December 2003)

Zinc bromine flow battery

ZnBr batteries are also FBs, but their design and electrochemistry differ from the PSBs and VRBs. A Zn-Br electrolyte flows through two half-cells divided by a microporous membrane, with a Zn^- electrode and a Br^+ electrode. Unlike other FBs and to an extent similar to conventional batteries, the electrodes serve as substrates for the reactions and their performance capacity can be degraded if the battery is not completely and regularly discharged according to Lotspeich (2002).

During charge, zinc is electroplated on the anode and bromine is evolved at the cathode. An agent in the electrolyte is used to reduce the reactivity of the elemental bromine by forming a polybromide complex, thus minimising the self-discharge of the battery. The complexed bromine is then removed from the stacks via the flowing electrolyte and is stored in the external reservoir. On discharge, the complexed bromine is returned to the battery stacks and reduced to bromide on the cathodes, while zinc is oxidized to zinc ions on the anodes.

The battery has a lifetime of up to 2000 cycles, and can be repeatedly deeply discharged (100%) without noticeable performance deterioration. The system’s net efficiency is about 75%.

The ZnBr battery was developed by Exxon in the early 1970's. Over the years, many multi-kWh ZnBr batteries have been built and tested. A 1MW/4MWh system was implemented at Kyushu Electric Power in 1991. The primary developer is the U.S./Australian firm ZBB Energy. ZBB combines 25 kW, 50 kWh standard modules with PCS and controls into containerised 250 kW, 500 kWh turnkey units; Lotspeich (2002) states that power output can be doubled with appropriate PCS. These systems are suitable for industrial energy storage, or may be combined into larger multi-megawatt sizes for utility applications. Zinc-bromine batteries are thus available off the shelf, although Gyuk (2002) points out that integrated power electronics are essential to successful applications. U.S./Austrian developer Powercell sold 100 kW, 100 kWh modules, but shut down in April 2002.

Installations have been made in several countries, providing facility-scale UPS and load management and supporting microturbines and solar generators as well as substations and T&D grids. The plants installed include several remote villages in Malaysia, powered by hybrid off-grid systems. Systems have been demonstrated on trailer-mounted mobile systems at both 1.8MW, 1.8MWh and 200kW, 400kWh scales. ZBB's baseline turnkey product is a 500kWh system. In December 2003, ZBB secured a contract to supply four 500kWh systems to Pacific Gas and Electric Company.

Figure 3.12 Containerised 200 kW, 2.5 h ZnBr battery

The technology is modular, as shown in figure 3.12. Modules can be linked electrically but not hydraulically. Hermetic electrolyte tanks isolated within each module limit economies of scale in larger installations of aggregated modules. ZBB sizes PCS and control systems to serve the number of modules in each application.

ZnBr batteries are viewed as a candidate for renewables backup. Transportability, low weight, and flexible operation are advantageous when compared to lead-acid batteries, and can outweigh the somewhat lower electrical efficiency.

ZBB is targeting the renewable integration market with a module especially designed to operate in connection with renewable sources. ZnBr batteries can be used to smooth out the wind farm fluctuations and hence help to control the frequency fluctuations. The company is in negotiations with Apollo Energy Corporation to provide 30 ZnBr batteries to back up a 20MW wind farm for several minutes. The goal is to keep the wind farm operational for the 200+ hours each year when erratic winds would otherwise force operators to shut down some turbines.

Developers / Suppliers: ZBB Energy Corp

3.8 Hydrogen energy storage

Hydrogen is envisaged as a promising means of electrochemical storage. In a Hydrogen Energy Storage (HES) system, the charge takes place when the electrical energy is used in an electrolyser to split water into hydrogen and oxygen. Although oxygen has an economic interest, it is usually vented to the atmosphere. Hydrogen can be stored in different ways. The discharge, providing the energy release, can take place in a fuel cell or in an internal combustion engine (ICE).

One advantage of hydrogen storage systems, compared with the others discussed, is that the energy storage capacity and input/output power rating are completely decoupled. For many electrical energy storage applications, this advantage is significant. This notwithstanding, it is the expected use of hydrogen in the future as a fuel for transport and other applications that provides the greatest appeal for hydrogen as a means of storage.

Hydrogen energy storage systems have many drawbacks. Most aspects in the hydrogen-related technology, including generation, storage and utilisation in fuel cells, need further development. HES appear as an option for the long run on account of the current modest scale and relative immaturity of the components, and the consequent present high costs. A lot of research is still necessary to make storage through hydrogen attractive for utility-scale storage.

The most significant challenge facing HES is the low round-trip efficiency. There are losses in the electrolyser, in storage and in the fuel cell. Technological breakthroughs will improve the efficiency, but it will still remain considerably behind other competing technologies. Future estimates of electrolyser and fuel cell efficiencies vary quite a lot among the different literature sources. The hydrogen storage option chosen will also influence the efficiency. It is therefore not easy to provide accurate estimates of the efficiency and its likely evolution. This notwithstanding, a reasonable efficiency range is of the order of 34-40% for FC-based systems and 29-33% for those using ICEs for discharge.

Swaminathan (1997) reports on a study carried out in 1997 by the US Department of Energy, in which hydrogen was identified as a candidate for long duration storage applications such as load management, peak shaving and transmission & distribution capacity deferral. However, HES was compared to batteries both in a current and future scenario, and despite the optimistic projections used for the hydrogen storage component costs and the more than optimistic round trip efficiency of 50% projected in the long term, HES was only find to break even with batteries for applications requiring 5.4 hours or more.

Due to the modularity and availability of small-scale components, and the decoupling of power and energy capacity, HES is particularly attractive for long-term storage in renewable-based stand-alone systems. This may in fact be the first market that HES will penetrate.

Despite the concerns that exist regarding safety, hydrogen does not pose more of a problem than other fuels. Being the lightest gas, hydrogen quickly disperses into the environment in the event of leakage, making it a lower fire hazard than gasoline. Extensive research has been carried out to simulate consequences of hydrogen releases in confined and unconfined spaces. So far this has not revealed any issues that are considered to be unacceptable or which represent unmanageable risk.

Components of a HES

Electrolyser

Generation of hydrogen via electrolysis is a well-known and established technology. It is mostly used when moderate amounts of high-purity hydrogen are required. Due to the high cost of electrical energy, only a very small proportion of the worldwide hydrogen production comes from electrolysis, but the foreseen changeover to the hydrogen economy indicates an ever-growing demand of electrolysis-generated hydrogen, especially using renewable power.

Electrolysers serving in electrical storage applications will operate with fluctuating input power, and must be designed to meet the following requirements:

- high efficiency
- good dynamic performance
- possibility of operating over a wide input power range with high current yields and sufficient gas purities
- durability under frequently changing conditions of operation

These features must be attained at the lowest cost possible. Electrolysis technology in general has experienced some advances during the last years, achieving higher efficiencies –up to 85% based on the Higher Heating Value (HHV) of hydrogen– and longer-lasting stacks. Cognisant of the great potential market for renewable electrolysis, manufacturers have managed to enhance the performance of their electrolysers under conditions of variable power input.

Electrolysers are inherently modular devices, since the production capacity is proportional to the number of cells that make up the stack. The specific cost declines as the size increases. The largest commercial systems can produce 485 Nm^3/h, which corresponds roughly to an input power of 2.5MW. Larger customer-tailored electrolysers can also be produced, although the cost rises.

Electrolysis has been traditionally based on an alkaline technology, but Proton Exchange Membrane (PEM) stacks are now coming to the forefront. Figure. 3.13 shows an example of a PEM electrolyser and storage vessel. Higher hydrogen purity, faster dynamic response, lower maintenance and increased suitability for pressurisation are among the advantages of PEM technology. Efficiencies are not currently very high however, and only small units are commercially available.

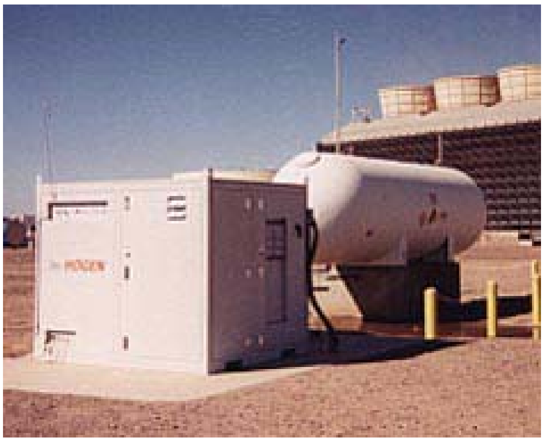


Figure 3.813 PEM electrolyser and storage vessel

Since the most likely storage solution, at least in the medium term, is pressurised gas, another challenge to perform the electrolysis at a high pressure. If pressure can be provided in the electrolyser and thus hydrogen delivered at high pressure, expensive and unreliable compressors may be omitted. Commercial units rarely surpass some tens of bars (~30 bar), whereas some prototypes have reached up to 120 bar (Meurer, 1999).

The cost of electrolysers varies significantly among different manufacturers and different scales. Divergent estimates can be found in technical literature. A specific cost of 1,100 €/kW may be a rather optimistic estimate at present, especially in the low power range, but realistic for large-scale systems (several megawatts) in the medium term. In fact, specific costs might drop sharply in the future down to 600 €/kW or even 300 €/kW according to the most optimistic predictions (Krom, 1998). Annual maintenance costs are approximately 3% of the capital cost. Lifetime is difficult to predict on account of the limited field experience of electrolysers operating under fluctuant conditions. The stack may last from 5 to 10 years, while the rest of the system has a longer durability (20 years).

Developers / Suppliers: Nosrk Hydro Electrolysers, GHW, Hydrogen Systems, Stuart Energy, Proton Energy, Casale Chemicals.

Power generation: fuel cells

There are two competing technologies for power generation from hydrogen: **internal combustion engines (ICE)** and **fuel cells (FC)**. ICE appears as a transition technology while fuel cells are improved and costs are brought down. The modifications that must be introduced in gas engines to be adapted to hydrogen are not very significant.

FCs are more efficient and reliable than ICEs, and need less maintenance (no moving parts). While ICEs give rise to some NOx emissions, fuel cells are virtually emission-free when fuelled directly with hydrogen. Expected life spans range from 15-20 years, although current realisations show much more premature aging of the electrochemical cells, which can be replaced independently. It is anticipated that costs will become competitive, when economies of scale are achieved. Fuel cells are expected to play a major role in future energy supply. The current level activity in FC research and development is significant, mainly driven by the transport sector but also for stationary applications.

Fuel cells have efficiencies at partial loads higher than at rated power. This makes FCs very attractive and efficient for applications with highly variable loads. One of the characteristics of FC systems is that their high efficiency is little affected by size. This, together with their modularity, low emissions and low noise level, makes them very suitable for distributed generation. As a result, initial stationary plant development has been focused on several hundred kW to low MW capacity plants.

It is clear that all FC costs at present – and these are estimated at anything between 500 and 8,000 €/kW are high because they are representative of an emerging technology.

There are a number of different FC technologies, differing in the type of electrolyte. These are described in more detail in Gonzalez and Ó Gallachóir (2003). High temperature FCs have a significant thermal inertia. Since fast dynamic behaviour is an important requirement in electrical energy storage applications, low temperature fuel cells are more suitable. This market segment is likely to be dominated by **Proton Exchange Membrane Fuel Cells (PEMFC)**, as shown in figure 3.14, which operate at temperatures <90ºC.

Figure 3.814 1MW power plant in Alaska (5 PEMFC 200 kW units in parallel)

PEMFC is the technology being focussed on in the transport sector, not only because of the dynamic response and rapid start-up but also the high current densities and low weight. This will hasten as well the deployment of hydrogen-fuelled PEMFCs for stationary applications, in which there are less stringent requirements on overall cost, space and hydrogen storage.

Systems of up to 300 kW are currently under development and have started to be commercialised. Costs are high, in part due to the high catalyst loading (Pt in most cases) required for both the anode and cathode, but the high manufacturing volumes required for transport applications, together with technological breakthroughs, is expected to result in lower capital costs in the long term. Efficiencies are in the 40-45% range when directly supplied with hydrogen.

Among the high-temperature fuel cells, **Solid Oxide Fuel Cell (SOFC)** are making great advances. Current systems fuelled with natural gas achieve efficiencies from 50% to 60%, clearly superior to PEMFC. The operation temperature ranges between 600ºC and 1000ºC, which places severe constraints on materials selection, resulting in difficult fabrication processes, and gives rise to sealing difficulties. SOFCs are very promising, however, on the crucial issue of cost. SOFC components are potentially cheaper and easier to manufacture that their PEM counterparts, and notable achievements have already been made in reducing costs according to Cropper (2001).

The dynamic response of SOFC is evidently far slower than PEMFC however, which limits to a large extent the range of applications where SOFCs can be employed.

Depending on the location of the fuel cell systems, the waste heat produced by the fuel cell can be harnessed to improve overall efficiency and make them more cost effective.

Developers / Suppliers: Although there is a host of smaller players in the market, PEMFC major developers include Ballard, UTC Fuel Cells, Plug Power and Nuvera, In the SOFC sector Siemens is developing units of several hundred kilowatts.

Reversible fuel cells

Since electrolysers and fuel cells are very similar devices operating in opposite ways, it is technically possible to combine them in a single unit. The advantage of the so-called reversible fuel cell is obviously lower capital cost. However, this must be compared against the drawback of lower efficiency, increased corrosion and other technical hurdles. This technology, mostly associated with the PEM concept, is still in an early stage of development, but without any doubt is the very attractive for the future of electrical storage systems.

Storage and compression

There are several hydrogen storage technologies, at different stages of development. Research in this field is primarily driven by the transport sector. **Compressed gas** storage is a relatively simple technology, which has the major disadvantage of low energy density and the problems associated with mechanical compression. **Liquefied hydrogen** storage is currently used for distribution, has a track record on safety, and has moderately good volume and weight storage densities, as shown in table 3.15. Issues regarding this technology include losses (up to 2%/day) and high energy costs of liquefaction. **Metal hydrides** exhibit high volume density and are being developed for on-board storage in vehicles, but is still an immature and expensive option. **Carbon-based absorption** can achieve higher volume densities, but the costs are even higher and there is a lack of system demonstrations. Other innovative solutions are being investigated. Millennium Cell has developed a system in which hydrogen is bound in a liquid chemical compound ($NaBO_2 + 4\ H_2 \rightarrow NaBH_4$) easy to store and transport, which would release hydrogen again when required reversing the reaction. A different approach binds hydrogen with liquid organic hydrocarbons (Scherer, 1999).

	Volume ratio [kWh/m^3]
Pressurised H_2	**80 – 1000**
Liquid H_2	**2000 – 2800**
Metal hydride	**2000 – 2400**

Table 3.6 Energy density of hydrogen storage technologies

The storage efficiency is highly dependant on the choice of storage technology. It must be borne in mind that metal-hydride and carbon-based absorption do not use mechanical but thermal energy, releasing and absorbing it with certain losses. The thermal energy needed could be drawn from the waste heat of other processes.

For electrical energy storage, gas pressurisation is the simplest and least costly solution provided that enough space available. Hydrogen can be stored in **pressure vessels,** or, in large-scale systems requiring long-duration storage, **underground reservoirs**.

Pressure tanks are used already in the gas business, are available in a wide range of sizes and are a well-established technology. Weight is not a concern, thus aluminium containers can be ruled out, due to their higher cost. Therefore the vessels are made of steel. The size of these tanks will depend on the storage requirements and the pressure. Higher storage pressures result in smaller tanks, but in higher operating costs. Figure 3.15 shows the energy density of hydrogen as a function of the storage pressure.

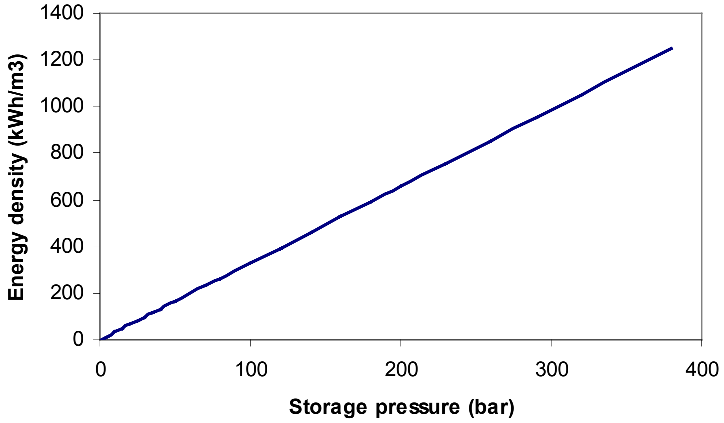


Figure 3.15. Compressed hydrogen energy density

Schoenung (2001) estimates energy-related costs of a storage system, that is, the cost of the pressure vessels, at $15/kWh. Other authors use a lower estimate of €11/kWh, notably Meurer (2000). For underground storage costs in large systems, cost drop dramatically as low as $2/kWh according to Padro (1999).

Reciprocating **compressors** are most commonly used for hydrogen applications. Large double-action units have efficiencies in the 65%-70% range. Hydrogen compressors can be electricity-powered of air-driven. The latter are safer, but a compressed air facility is needed. The former are not readily available in the market and are expensive.

Compression is traditionally one of the weak points of hydrogen systems (unreliability, maintenance, lifetime of the components…). For this reason, the future points to pressurised electrolysis, delivering hydrogen at high pressure and thus avoiding the need for further compression. This also leads to energy savings. Figure 3.16 shows how the energy consumption of hydrogen compression varies depending on the pressure ratio.

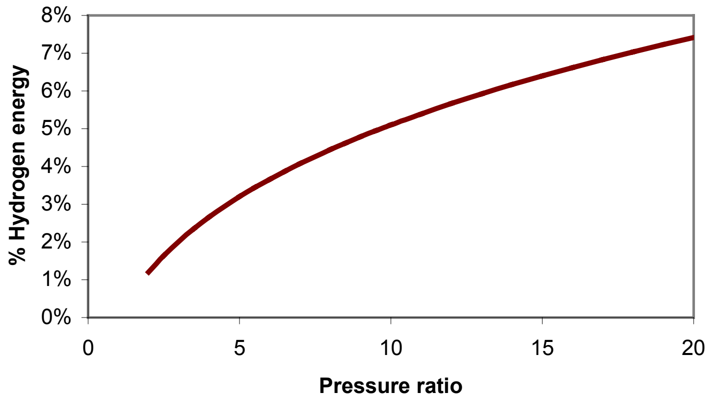


Figure 3.816. Energy required for hydrogen compression

Power electronics

Currently electrolysers and fuel cells have their own power conversion systems, with a rectifier in the electrolyser and the fuel cell having an inverter. In an integrated hydrogen storage system the two PCS can easily be integrated into one optimised system. This would be particularly true for a reversible fuel cell.

Synergy: The hydrogen economy

Hydrogen is anticipated to play a prominent role as a fuel in the future, and could eventually substitute fossil fuels completely. This is what is termed 'the hydrogen economy'. The reasons for this fuel changeover relate to environmental concerns, depletion of fossil fuels, supply security, etc.

The most important property of hydrogen is that it is the ‘cleanest fuel’. Emissions are virtually zero if fuel cells are used for energy conversion. As a solution for transport, batteries have not been demonstrated as an ideal option. Hydrogen is the most common element in the universe, but does not exist in nature as an unbound compound, and therefore is a secondary **energy carrier** –not a source– that must be derived from other energy sources. Although in the transition to a hydrogen-based economy, fossil fuels will constitute a major source for hydrogen production, the full benefits of hydrogen as a clean and sustainable energy supply will only be realised when produced from renewable energies. Water electrolysis using solar and wind power is a sustainable hydrogen source.

Hydrogen can replace fossil fuels basically in all their applications. Hydrogen use is expected to increase rapidly for transport and electricity generation applications, as industry commercialises advanced technologies such as fuel cells and as costs decline.

Public and private investments on hydrogen research and development have grown sharply during recent years. There are very ambitious hydrogen programs in the EU (lead by Germany) USA and Japan, with many other countries showing an increasing interest in hydrogen. Iceland is on the way to become the first 'hydrogen country' in the world, producing hydrogen from surplus renewable energy and progressively converting the transport infrastructure from fossil fuels to hydrogen.

Car manufacturers, electric utilities, oil companies and firms specialised in hydrogen technology began the race to commercialise the technology a number of years ago. All major car manufacturers have programs in place for the development of hydrogen vehicles and infrastructure. Although the hydrogen economy is driven in first instance by the transport sector, stationary applications will be an essential part of it.

Figure 3.17. Refuelling a hydrogen car

With all this in consideration, the attractiveness of hydrogen as a storage option lies on its multi-functionality. Stored hydrogen can be either converted back into electricity or used as a 'zero emissions' fuel for other applications, such as transport. Since the final goal of the hydrogen economy requires its production from renewable sources, the HES market will be chiefly linked to renewable energy applications. In this way, hydrogen will extend the scope of renewable energies to the transport field.

As the production of hydrogen from renewables requires the existence of a market for hydrogen and the appropriate infrastructure, this is an option envisaged for the long-term. The need to build a new energy and fuel infrastructure is seen as a main task for the future. The route towards a hydrogen-based economy remains unclear and the necessary investments are huge. The infrastructure required includes production, distribution and fuelling stations. The automotive industry and energy companies are engaged in setting up a strategy for the progressive introduction of hydrogen into the transport sector. Currently, the step from single prototypes to fleet demonstration activities is being accomplished. These activities are accompanied by industrial efforts in the field of regulations and standardisations.

The replacement of fossil fuels with hydrogen will be therefore gradual. If the hydrogen consumed in the first hydrogen fleets comes from renewable energies, the public perception of the hydrogen economy is likely to be more enthusiastic than if produced from natural gas. It is envisaged that the changeover to a hydrogen economy will not be fully realised in less than fifty years from now, but important amounts of hydrogen will start to be used far sooner.

Projects

So far, the focus of HES has been renewable-based stand-alone systems and the production of hydrogen from renewables. A number of demonstration projects have been carried out [as described in Dutton (1996); Barthels (1996); Galli (1997); Szyszka (1998); Abaoud (1998); Friedland (1999); Agbossou (2000)], in most cases using solar energy rather than wind as the intermittent source. Many of these plants were in connection with the International Energy Agency Hydrogen Implementing Agreement, and more precisely, the Task XI – Integrated Systems [see Schucan (2000)]. The scale of these test systems is modest, a few tens of kilowatts at most.

In order to prove the technical viability of wind-hydrogen systems, it is necessary to undertake demonstration projects coupling wind turbines and electrolysers in a larger scale. Norsk Hydro Electrolysers is leading a project to provide the Utsira Island (Norway) with a wind-hydrogen system. Also in Norway, the utility Statkraft plans to connect an electrolysis unit to a large wind turbine. P&T Technologies and Siemens are completing the installation in Germany of the first plant following the development of a wind-hydrogen system patent, which includes an ICE as the regeneration device instead of a fuel cell. The recently formed Wind Hydrogen Limited (UK) is seeking the development of large-scale wind-hydrogen schemes and has now two major projects under development in UK. HyGen, which is a company formed in 1996 by firms that participated in the Clean Air Now! solar-hydrogen project in California, is undertaking a pilot multi-megawatt commercial renewable hydrogen generating facility and hydrogen distribution network. The facility will be using PV as well as wind for the generation of electricity. There are also ambitious schemes in Alaska, like a stand-alone wind-hydrogen system including an electrolysis unit of 160 kW [see Rambach (1999)].

3.9 Power conditioning subsystem and balance-of-plant

Apart from the storage subsystem, an electrical energy storage system comprises a power conditioning subsystem (PCS) and the balance-of-plant (BOP). It is crucial for the viability of storage to design the power converter interface between the AC power bus and the energy storage to be efficient, reliable and robust. A poor PCS design will constrain the performance of the full system.

In storage technologies which need DC supply, the PCS rectifies AC line power to DC during charge, and inverts the DC power back to AC during discharge. The PCS controls the rate of discharge and the switching time of the system. The power switches are typically either GTO (gate turn off) or the newer, more flexible IGBT (insulated gate bipolar transistor) semiconductors. IGBT semiconductors have fewer requirements for driver circuitry, making inverters more compact and modular. IGBTs are currently used to overcome problems of poor power factor and high current harmonics and are employed in a number of wind turbine designs.

Additional PCS components may include transformers as needed for voltage matching and isolation, and a controller for operating the system and interfacing with the supervisory system.

The requirements placed on the PCS will depend on the applications that the system is going to be used for. In application requiring a fast response, fast-acting power conversion and control systems are as crucial as the dynamic behaviour of the storage subsystem.

PCS for large-scale systems are not off-the-shelf components. The concept of modular PCS is now being promulgated as a way to drive PCS costs down. Modular PCS is comprised of many small converters that are networked in parallel to achieve the same power rating of a single large converter, but benefit through the economies of mass production. The individual units, if designed to operate with a sufficient degree of autonomy, can be resealed dynamically. This offers the advantage of redundancy high efficiency at low power rates, because only the minimum required number of power converters need to be energized.

The balance-of-plant includes structural and mechanical equipment such as the protective enclosure, heating/ventilation/air conditioning (HVAC), and maintenance/auxiliary devices. Other BOP features include the foundation, structure (if needed), electrical protection and safety equipment, metering equipment, data monitoring equipment, and communications and control equipment. Other cost such as siting, permits, project management and training may also be considered here.

The system control is a key part of an electrical energy storage system, especially when it is configured to match several different application concurrently. It must be designed in a way that permits the realization of all these functions. An obvious important consideration here is to ensure that the target applications do not impose mutually exclusive demands on the storage system and when conflicting demands are placed on the system that the highest priority need is met as Collinson (2000) points out.

3.10 Costs

Table 3.7 contains a breakdown of all the possible expenditures of an electrical energy storage system, including operation and maintenance.

Utility-scale storage systems are not at present off-the-shelf products (with the exception of some power quality systems), and are custom-sized. The incidental costs particular to tailored systems has added considerable cost to each of the systems now in operation. Collinson (1999) stresses that modularity and standardisation of system assemblies will reduce costs, improve reliability, and diminish the demands on system designers and engineers.

The initial costs of an electrical storage system can be calculated by the sum of a not-linear cost function of the power rating, a non-linear cost function of the energy capacity, and a fixed cost:

Initial cost: F(energy) + F(power) + Fixed cost

Schoenung (2001) groups the costs under three main headings:

- storage media cost (as a function of cost per kWh)
- power conditioning unit (as a function of cost/kW)
- balance-of-plant (as a function of cost/kWh)

Collinson (2000) follows a very similar line, although giving the BOP cost as a function of the power rating (cost/kW). Indeed Schoenung acknowledges, that in some cases it may be proportional to the installed power or even a fixed cost.

This approach provides a very rough basis for approximation. Although for some technologies and applications the storage subsystem cost is clearly dominated by energy-related costs, it is more a combination of energy-related and power-related costs. This is especially true for PHES, CAES, FBES and HES, in which the charge and discharge devices are independent from the storage media. In a HES system, for instance, the electrolyser and fuel cell costs are function of the power ratings. Even for technologies in which there is not physical decoupling of power and energy capabilities, such as BES, FES and SMES, the cost can be dominated by power-related costs in systems with a high power/energy ratio.

Storage subsystem	
Interfaces to AC Load and Source	▪ New lines to serve installation ▪ Transformer between utility voltage and battery system AC voltage ▪ Protection devices (e.g. switches, breakers, fuses)
Power Conversion System	▪ AC switchgear/disconnect ▪ Rectifier/inverter ▪ DC switchgear/disconnect ▪ Protection devices (e.g., switches, breakers, fuses)
Auxiliary Systems and Accessories	▪ Mechanical: racking/physical support, watering/heating/air and fluid pumping systems ▪ Safety equipment (e.g. ventilation, fire equipment, detectors, respirators, spill troughs) ▪ Cryogenic refrigeration, vacuum system
Monitors & Controls	▪ Monitors/diagnostics: storage media, power conversion, subsystems (bearings, cryogenics, vacuum) ▪ Controls: storage media, protection devices, power conversion, subsystems
Facilities	▪ Foundation and structure ▪ Materials ▪ Lighting/plumbing ▪ Access road and landscaping ▪ Grounding/cabling ▪ Heating, ventilation, air conditioning
Labour Costs	▪ Construction ▪ Installation and start-up testing ▪ Operations ▪ Project management
Operation and maintenance	▪ Service contract: inspection, service costs, component replacement ▪ Training for operation and maintenance workers ▪ Monitoring/data acquisition[2]
Financing, taxes and permits	
Transportation	

Table 3.7. Breakdown of the costs of an electrical energy storage system

Also, for some technologies, the cost is not linear over the range of sizes, due to the economies of scale. This is not only applicable to the storage subsystem, but to the PCS and BOP as well. There are many common elements that must appear in all systems, and thus the cost does not scale linearly with size.

Operation & maintenance costs consist of fixed and variable costs. For instance, the fixed costs of a battery system include cooling and general maintenance at the site, while variable costs include recharging the batteries and periodically replacing the batteries.

The contribution of each expenditure to the total cost will depend largely on the application and technology. In general, the capital cost in power quality applications is dominated by the power conversion system, followed by the BOP. On the contrary, in utility-scale energy storage the energy storage subsystem may prevail over the PCS and BOP as illustrated in figure 3.18.

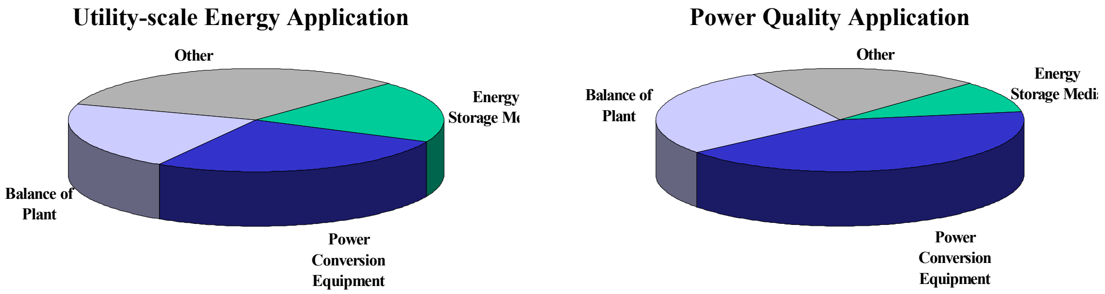


Figure 3.18 Examples of cost breakdown for different storage applications

The costs of the **PCS** can be very variable. Different outage protection features would, for example, add different costs. The costs are not linear with the size of the systems. While for a 300-500 kVA system the price of the PCS may be in the range $300-235/kW, for a smaller system 30-50 kVA the cost would be as high as $500-400/kW.

PCS has significant contribution to the overall cost, but they are becoming cheaper and more modular, and the component ratings are increasing. Progressive standardization is very important to achieve cost reductions, interchangeability from different suppliers, and ability to replace them easily.

Standardisation is also crucial to bring down the costs of **BOP**. In mature technologies, e.g. lead acid batteries, the largest potential for cost reduction is the BOP. Again the cost of BOP is highly variable, and depends on a myriad of factors, not only related the storage technology and the applications, but also the site for the installation.

By way of example, the BOP cost of a large-scale BES system may be separated into three components:

- Facilities to house the equipment: ~45%
- System design and integration: ~22%
- Transportation, finance charges and taxes: ~33%

Table 3.8 shows the contribution of the PCS and BOP in some large-scale BES systems [see Akhil (1997)].

Plant	Storage	PCS	BOP
CHINO 10MWh/40MW	44%	14% ($258/kW)	42%
HELCO 10MW/15MWh	34.5%	18.5% ($212/kW)	47%
PREPA 20MW/14MWh	22%	27% ($294/kW)	51%
VERNON 3MW/4.5MWh	32%	19% ($275/kW)	49%

Table 3.8. Cost breakdown of large-scale BES systems

3.11 Comparison of electricity storage technologies

The various storage technologies have a number of features, such as efficiency, size, dynamic behaviour, etc. which are all relevant in the selection of the most suitable system for a particular application or set of applications. Available power and energy ratings are essential criteria for any application.

The energy / power ratings in Table 3.9, also illustrated in Figure 3.19, correspond to the current realisations. Some technologies, such as the polysulphide-Br flow battery are targeting power ratings far larger. Obviously, modular technologies such as HES can theoretically reach unlimited size.

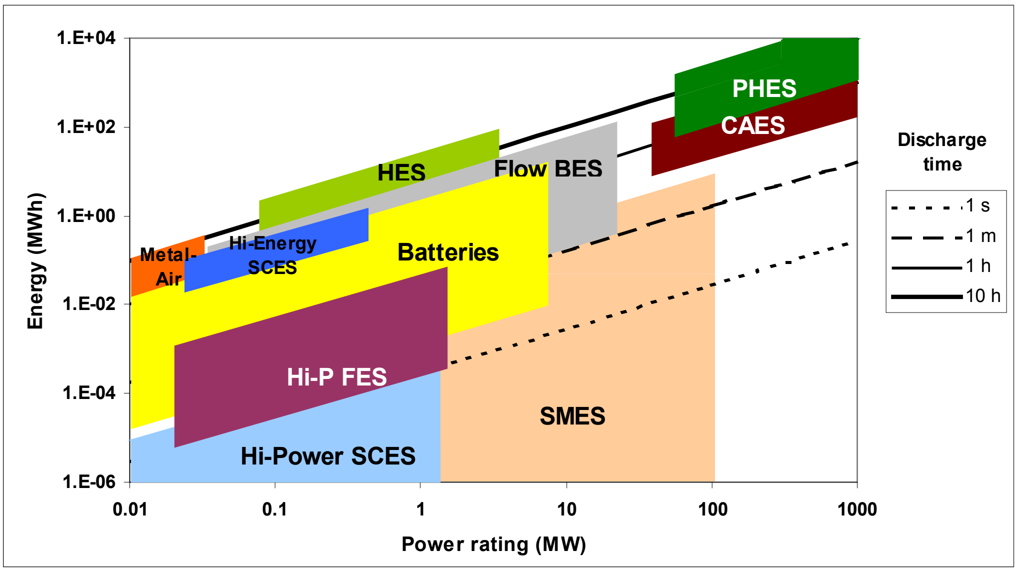


Figure 3.19 Power and energy ratings of storage technologies

Life spans are often expressed in literature in terms of years. However, the characteristics of the duty cycle affect the replacement interval of some components and eventually the service life of the whole storage device. Similarly, the nature of the duty cycle profile, its distribution and frequency also affect to some extent the performance of virtually all storage systems. While frequent cycles increase the efficiency of some storage media, they decrease efficiency of others.

Although not included in Table 3.9, the size of the systems (m^2/kWh) may be a very important parameter if space constraints exist. The portability may also be an important factor in some applications, but for large systems requiring significant energy content portable systems are not be feasible, as the size of the storage media often becomes impractical or non-economic for transport. Portability varies greatly between types of systems. SMES, battery and flywheel systems are now offered commercially as pre-packed systems that fit into trailer containers with all of their monitors, controls, and power conversion equipment for easy transportation and installation.

The efficiencies in Table 3.9 correspond to the storage subsystem unless otherwise stated. Power conditioning and parasitic losses need also to be considered.

Regarding costs, the estimates presented in the previous review are simple ratios of the total cost to the power or energy rating. However, with the specific costs given in Table 3.10, the initial cost of a system can be estimated as an addition of power-related costs, energy-related costs, and BOP costs. Estimates can vary significantly between different studies, and in most technologies costs are changing as they evolve.

	Power rating	Discharge duration	Response time	Efficiency	Parasitic losses	Lifetime	Maturity
Pumped hydro	100 – 4000MW	4 – 12 h	sec – min	0.7 – 0.85	evaporation	30 y	commercial
CAES (in reservoirs)	100 – 300MW	6 – 20 h	sec – min	0.64	-	30 y	commercial
CAES (in vessels)	50 – 100MW	1 – 4 h	sec – min	0.57	-	30 y	concept
Flywheels (low speed)	< 1650 kW	3 – 120 s	< 1 cycle	0.9	~1%	20 y	commercial products
Flywheels (high speed)	< 750 kW	< 1 h	< 1 cycle	0.93	~3%	20 y	prototypes in testing
Super-capacitors	< 100 kW	< 1 m	< 1/4 cycle	0.95	-	10,000 cycles	some commercial products
SMES (Micro)	10 kW – 10MW	1 s – 1 m	< 1/4 cycle	0.95	~4%	30 y	commercial
SMES	10 – 10MW	1 – 30 m	< 1/4 cycle	0.95	~1%	30 y	design concept
Lead-acid battery	< 50MW	1 m – 8 h	< 1/4 cycle	0.85	small	5 – 10 y	commercial
NaS battery	< 10MW	< 8 h	n/a	0.75 – 0.86	5 kW/kWh	5 y	in development
ZnBr flow battery	< 1MW	< 4 h	< 1/4 cycle	0.75*	small	2,000 cycles	in test / commercial units
V redox flow battery	< 3MW	< 10 h	n/a	70 – 85*	n/a	10 y	in test
Polysulphide Br flow battery	< 15MW	< 20 h	n/a	60 – 75*	n/a	2,000 cycles	in test
Hydrogen (Fuel Cell)	< 250 kW**	as needed	< 1/4 cycle	0.34 – 0.40*	n/a	10 – 20 y	in test
Hydrogen (Engine)	< 2MW**	as needed	seconds	0.29 – 0.33*	n/a	10 – 20 y	available for demonstration

*AC-AC efficiency

** Discharge device. An independent charging device (electrolyser) is required

Table 3.9. Characteristics of storage technologies

	Capital cost			O&M cost				
	Power-related cost ($/kW)	**Energy-related cost ($/kWh)**	**BOP ($/kWh)**	**Fixed ($/kW-y)**	**Variable (c$/kWh)**	**Cost certainty**	**Environmental issues**	**Safety issues**
Pumped hydro	600	0 – 20	included	3.8	0.38	▓	reservoir	exclusion area
CAES (in reservoirs)	425 – 480	3 – 10	50	1.42	0.01	▒	gas emissions	none
CAES (in vessels)	517	50	40	3.77	0.27	□	gas emissions	pressure vessels
Flywheels (low speed)	300	200 – 300	~80			▓	-	containment
Flywheels (high speed)	350	500 – 25,000	~1000	7.5	0.4	░	-	containment
Super-capacitors	300	82,000	10,000	5.55	0.5	░	-	-
SMES (Micro)	300	72,000	~ 10,000	26	2	▒	-	magnetic field
SMES	300	2,000	~ 1,500	8	0.5	□	-	magnetic field
Lead-acid battery	200 – 300	175 – 250	~ 50	1.55	1.0	▓	lead disposal	lead disposal, H2
NaS battery	259	245	~ 40	n/a	n/a	░	chemical handling	thermal reaction
ZnBr flow battery	1,500	200	included	n/a	n/a	░	chemical handling	chemical handling
V redox flow battery	n/a	175 –190	n/a	n/a	n/a	░	chemical handling	chemical handling
Polysulphide Br flow battery	1,200	175 –190	n/a	n/a	n/a	░	chemical handling	chemical handling
Hydrogen (Fuel Cell)	1100 – 2600	2 – 15	n/a	10.0	1.0	▒	-	-
Hydrogen (Engine)	950 – 1850	2 – 15	n/a	0.7	0.77	▓	emissions	-

▓ Price list available ▒ Price quotes available ░ Cost determined each project □ Costs estimated

Table 3.10. Cost comparison of storage technologies

Chapter 4 STORAGE TO ACCOMMODATE WIND ENERGY IN IRELAND

4.1 Selection of technologies for different storage applications

Due to the fact that many different energy storage technologies can be used in a variety of applications, identifying the technology which best matches the requirements of an energy storage application can be a difficult task. Each storage technology has particular characteristics that make it suitable in some situations, but less desirable in others. It is important to identify the key features of different storage media and to match the storage technologies with the most appropriate end-use applications, including multiple-application systems, in order to achieve an optimum cost-benefit solution. The selection process can be aided by a technoeconomic cost/benefit model Collinson (2000).

Table 4.1 shows the technical suitability of the various technologies to the different applications. It is based on a survey carried out by Schoenung (2001) with the incorporation of flow batteries, which are potentially suitable for all storage applications.

	Storage Technology	Pumped hydro	Compressed air	Flywheel	Supercapacitors	Superconducting magnets	Lead-acid batteries	Advanced batteries	Flow batteries	Hydrogen fuel cell	Hydrogen engine
Storage Application				☒	☒	☒	☒		☒	☒	
Transit and end-use ride-through				☒	☒	☒	☒		☒	☒	
T&D stabilisation and regulation						☒	☒		☒	☒	
Peak generation		☒	☒	☒			☒	☒	☒	☒	☒
Fast response spinning reserve				☒			☒	☒	☒	☒	☒
Conventional spinning reserve		☒	☒	☒			☒	☒	☒	☒	☒
Uninterruptible power supply				☒			☒	☒	☒	☒	☒
Renewable integration				☒			☒	☒	☒	☒	
Load levelling		☒	☒				☒	☒	☒	☒	☒
Load following							☒	☒	☒	☒	☒
Emergency back-up			☒				☒	☒	☒	☒	☒
Renewables back-up		☒	☒				☒	☒	☒	☒	

Table 4.1 Technical suitability of storage technologies to different applications

The analysis carried out by Schoenung (2001) [and Schoenung (2002)] provides a useful first indication of the technologies that are more suitable than others for renewable integration. The study did not include flow batteries, which are widely recognised as a technology with a significant potential for renewable integration and other applications. The costs for these storage technologies were those showed in Table 3.10. Two cost estimates have been employed for the hydrogen storage option, a low estimate based on a specific cost of $500/kW for the fuel cell and $300/kW for the electrolyser and a high estimate, in which $1,500/kW is attributed to the fuel cell and $600/kW for the electrolyser. Similarly, two different costs can be considered for the lead-acid batteries according to the range expressed in Table 3.10.

The results of this cost comparison analysis are summarised in figures 4.1 – 4.4. Figure 4.1 compares the capital costs of different technologies used for short duration (< 2 hours) storage. For applications with discharging times ranging from minutes up to 2 hours, BES and HES (low cost projection) seem to be the most competitive, with CAES also likely to play a role in this area.

Schoenung (2001) also compared hydrogen-fuelled combustion engines and fuel cells and these results are shown in figure 4.2. The engine appears a very competitive solution for applications up to a few hours due to the lower capital costs. At longer discharge times the lower efficiency begins to dominate. In addition, engines exhibit a slower dynamic response.

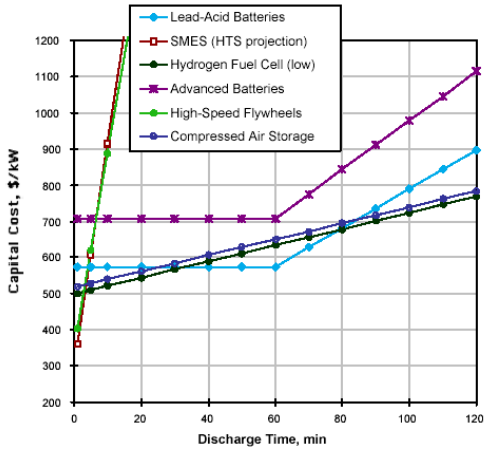


Figure 4.11 Costs of applications <2 h discharge

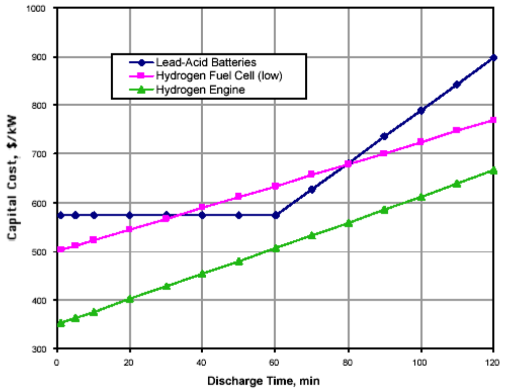


Figure 4.11 Comparison of batteries and hydrogen technologies <2 h discharge

As the discharge times increase, extending the applications to load management, the power related costs (per kW) become less important and the energy related cost (per kWh) begin to dominate, as evident from table 3.10.

Figure 4.3 compares the capital costs of storage technologies that are technically suited to long duration storage. Two traditional technologies, PHES and CAES are least costly but these do have siting limitations however. The next most attractive on a capital cost basis is the hydrogen fuel cell (low cost scenario), and then CAES storing air in tanks. Lead-acid batteries seem to lose attractiveness for long discharge applications, but this is very sensitive to cost projections.

Fig 4.4 show that HES costs exhibit a lower cost increase rate than lead-acid batteries as the energy storage capacity grows, but the latter would be still desirable if the hydrogen storage components remain expensive.

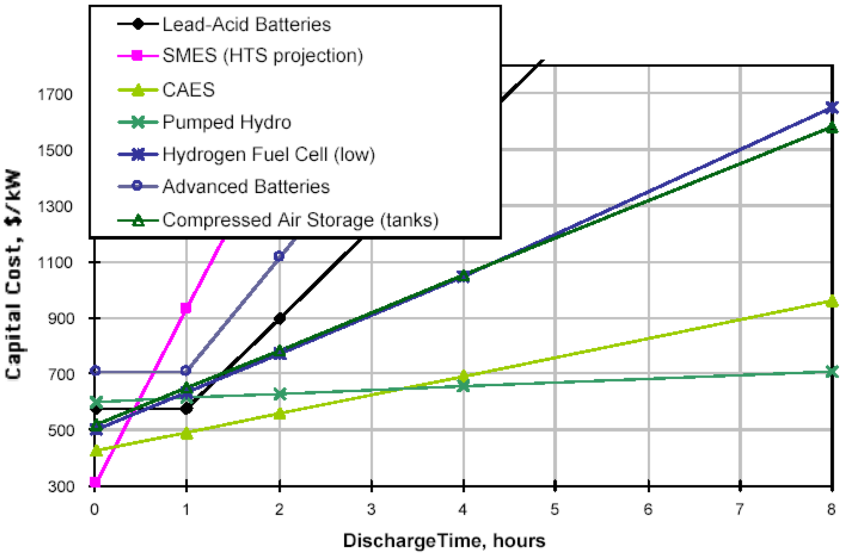


Figure 4.12 Costs of applications for long duration storage

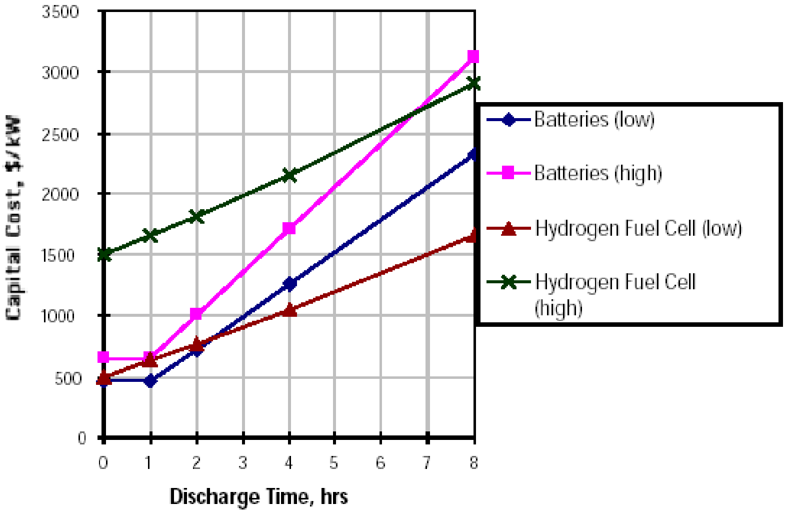


Figure 4.13 Comparison of batteries and hydrogen fuel cells. Long duration

For even longer storage time (several days), Schoenung (2001) points to PHES, HES and CAES as the most economic options. It should again be noted however, that flow batteries are not included in the study.

4.2 Experience in the use of storage for the integration of RE

There is little or no experience on the use of electrical energy storage for the integration of large-scale intermittent renewable generation on electricity systems.

In Germany, there have been some multifunctional energy storage systems used to improve the utilization of renewable energy supplies (Wagner, 1999). These systems include three different functions: UPS, improvement of power quality, and peak-load shaving. For such a multifunctional application, large lead–acid batteries with high power and good charge acceptance, as well as good cycle life was deemed appropriate. One system was installed in combination with a 2MW/1.2MWh wind farm in Bocholt. The batteries were modified according to the demand of a multifunctional application, and an appropriate power converter was designed. The use of a battery made it possible to substitute the required peak-load power with the stored power from renewable energy sources achieving high efficiency.

As previously mentioned, Tennessee Valley Authority (TVA) had plans to install a Regenesys storage system parallel to the development of a 20MW wind farm. The main reason for the initial decision of building the plant was that in the TVA's area the wind resource is most available at night during much of the year. In contrast, TVA's greatest needs for intermittent or peaking energy are during the morning in the winter, and during the afternoon and early evening in the summer. TVA was hoping that the system would meet peaking needs, improve power quality and reliability, and provide rapid response to changing power demand. TVA decided against the project in 2002 and in December 2003, RWE Innogy ceased the development of the Regenesys technology.

ZBB is targeting the renewable integration market for its ZnBr flow batteries, which can be used to smooth out the wind farm fluctuations and hence help to control the frequency fluctuations. The company is in negotiations with Apollo Energy Corporation to provide 30 ZnBr batteries to back up a 20MW wind farm for several minutes. The goal is to keep the wind farm operational for the 200+ hours each year when erratic winds would otherwise force operators to shut down some turbines.

Pumped Hydro storage systems have been proposed to increase the wind penetration in the Greek islands of Crete [Christakis (2001)] and Serifos [Theodoropoulos (2003)]. As pointed out in Section 2.4, the Crete system is the largest isolated or 'island' electricity system with wind input. Given the weakness of the interconnections in Ireland, Crete might resemble the future Irish situation more than Denmark.

The major difficulty for the system operator in Crete is that a minimum quantity of conventional generation must be kept operating, to provide frequency control and reactive power. This restriction leads to the curtailment of the wind production at times of high winds and low demand. The level of curtailment in 2001 was 6% of wind production, and was expected to rise to approximately 20% in 2002, due to additional wind farms coming onstream [see Garrad Hassan et al (2003)]. This has clearly a major effect on the economics of wind generation in Crete. Studies show that the PHES units can contribute a lot toward the minimisation of the existing thermal units energy production cost [Christakis (1996)] and the maximisation of the wind energy penetration [Christakis (1997)].

Zaininger (1997) examined the benefits and costs of installing an integrated MW-scale wind farm with battery storage to defer the upgrade of a 25 kV circuit to 69 kV for Orcas Power and Light Company in US. Although sufficient wind potential was identified, the high winds did not generally occur coincidentally with peak loads on the distribution line. A transportable 500 kW/2-hour battery was considered for use during low wind periods to defer the upgrade of the distribution line until 2000.

Enslin (2004) explored energy storage options in the context of Dutch plans to connect 6000 MW of offshore wind farms off the Dutch coast. The study considered

PHES, CAES, Regenesys and lead acid batteries and concluded that storage would not be an economically viable option, if only considered for one function and should be considered for several parallel tasks, including power balancing, grid stability, power trading and power quality mitigation solutions.

Gonzalez et al (2003) made a preliminary examination of the role of hydrogen in facilitating high wind energy penetration in Ireland.

4.3 Assessment of different technologies

In assessing technologies it is important to bear in mind that electricity market policies and regulations will influence the choice of storage technology best suited to renewable energy integration. Environmental policies will also have an impact and are likely to disfavour options posing environmental hazards. It is essential to bear in mind that future regulations could affect the chosen technologies in a positive or negative manner.

The rate at which the technologies develop is critical to their future attractiveness. The achievement of certain milestones, especially in terms of costs, can change the best option.

An ideal storage technology candidate for renewable energy applications would have the following characteristics:

- Low cost, long cycle life and little maintenance requirements
- Mature technology
- High efficiency
- Large energy storage capability
- Flexibility and adaptability to future trends in the electric sector
- Modularity and easiness of upscale
- Ability to deliver power rapidly or slowly, as desired, under full control
- Ability to operate on a reversible charge/discharge cycle. Capability of deep discharge without damage.
- Environmental sustainability and safe operation
- High energy density in some cases
- Possible synergies

None of the technologies described in section 3 meets all these requirements.

The cycling requirements depend on the functions that the system is going to fulfil. For instance, if used for load levelling, the system would typically go through a discharge/charge cycle once or twice a day, mainly during weekday peaks. If storage is used to adjust the output to the scheduled generation, the cycling would depend on the mismatches between forecast and actual renewable power output.

Pumped hydro

Even though PHES can provide high storage capacity at low cost, the application to renewables is constrained by a number of factors. A crucial limitation is the siting requirements (large water reservoirs), which inhibits further developments. PHES is normally used at large scale level by major utilities, because of the time and capital needed to construct them. The scale is not particularly suited to distributed generation. Its main applications are energy management, frequency control and provision of reserve. Its response is rapid enough in both directions for these applications but limits its deployment for renewable integration, since it cannot follow wind energy variations rapidly. In large systems where quick response is not necessarily required, it is suitable for bulk renewable storage and seasonal storage. Due to these considerations, Herr (2002) concludes that PHES is not likely to be employed in widespread renewable integration, even with the offer of low cost storage capacity.

Compressed air

CAES is the only commercially available technology other than PHES able to provide very large energy storage deliverability (above 100MWh) to use for commodity storage or other large-scale setting. Operational experience is very limited however, as only a few facilities have been installed worldwide to date. The response time is another drawback. According to Gordon (1995), CAES appears to be the most economic option for systems that require 3-12 storage hours per day.

Smaller-scale installations could have less stringent siting requirements, shorter construction times and require moderate investments, although the specific costs prove higher. These micro-CAES systems could be integrated at the distribution level.

In 2001, the US mining company Ovoca Resources announced that it had entered into a joint venture arrangement with the purpose of making a preliminary feasibility study of compressed air energy storage possibilities in Ireland. Results of this study indicated considerable potential and this led to the decision of setting up a joint venture, Optimum Energy Limited, owned by Ovoca and Mercury Holdings.

Optimum Energy has identified the storage of electrical energy for use at peak times as a highly profitable and yet undeveloped aspect of the electricity market in Ireland. In addition to the on-peak/off-peak differential, Optimum sees storage as a key component in the strategic development of wind energy in Ireland. In this regard, they claim the system to have fast reaction times and could reduce largely the need to hold hydrocarbon-powered plants on spinning reserve. The intended storage vessels for the compressed air are deep underground areas of high rock porosity (several natural gas storage plants use similar underground structures). Optimum reports that following detailed analysis of existing geologic and drilling data, a number of potential sites suitable for CAES development have been selected, although the project's full feasibility, particularly in relation to reservoir integrity and suitability, is yet to be proved. This will involve geotechnical surveys, drill testing, computer modelling, and so on. Optimum budgeted a sum of up to €1.3m for this phase.

Flywheels

FES systems are in early stages of market entry and are primarily expected to serve the customer-end power quality market. Whereas steel-rotor flywheel has very limited scope for the entire array of applications, composite-rotor FES has potential for broader applicability. However, it will require significant development to compete with other, more mature technologies and non-technology options

Application of FES to RE integration is under consideration. Although they are unsuitable when large amounts of stored energy are required and storage and discharge times grow larger, further improvements in storage capacity would make them more suitable for renewable integration. The use of a number of small units in parallel can meet large energy storage needs, but this solution does not benefit of economy of scale.

Since composite flywheels depend primarily on high speed to achieve the necessary power and energy levels, they also depend on high-strength fibres to allow for lightweight, high-speed rotation. Unless the cost of the fibre material (advanced carbon fibres) falls significantly, Butler (2002) points out that FES systems will be limited to applications with low duration discharge.

However, in weak grids FES can also help to comply with the grid requirements, avoid grid reinforcements, and facilitate higher penetration rate (improvement of power quality by dynamic absorption/injection of reactive power). In remote areas, FES can improve the power quality, the overall efficiency and the durability of hybrid systems.

In smoothing out short and medium-term variations, FES is superior to BES due to the cycling limitations of batteries. As, conversely, FES cannot compensate for long-period intermittency of the wind resource, it has been proposed that flywheels and could used in combination with batteries, each addressing different challenges associated with renewable integration. However, this increases the costs too much. Indeed costs are an important issue for FES, although the long life and minimal maintenance are compensating factors.

Most flywheels manufacturers are targeting the distributed power generation market, with special focus on renewable sources.

Supercapacitors and supermagnets

Both SCES and SMES devices are being developed primarily for grid stabilisation, uninterruptible substations and pulse power applications and their use for renewables integration is not the immediate current focus. They are unsuitable for long-duration storage due to the high capital costs per kWh. In SMES, the high energy consumption by the cryogenic and refrigeration systems is another disadvantage for long-term storage. One application where they could make their mark in time, however, is in managing the power quality of wind farms. The stabilisation of transmission and distribution lines increases the capacity of the grid to accommodate wind energy.

Batteries

Traditionally, the use of BES in utility applications has been hindered by uncertainty about lifetime, lack of understanding on how to apply battery systems, lack of operating experience, maintenance needs, reliability issues, and desire to reduce initial investment.

However, Butler (1996) reports that the experience gathered from early battery installations such as the BEWAG and Chino plants, has generated a positive reaction from the utility community. As a result, both **LA** and **VRLA** batteries are in an advantageous position. At any rate these technologies have the most field experience and can satisfy most of the defined utility energy storage applications, unless footprint is important. LA batteries have a long record as renewable buffers in small off-grid systems. Although a mature technology, still some improvement can be expected with regard to energy capacity, lifetime, and recharge times. LA and VRLA batteries, though affordable initially thanks to economies of manufacturing scale, are less so in the long term because their limited cycle lives.

As for **NiCd** batteries, the plant being built in Alaska, which will provide spinning reserve, shows the sort of scale of storage regarded as viable for some renewable applications. However, the high costs and the environmental issues related to cadmium disposal make this technology little desirable for renewable integration.

Advanced and flow batteries are considered potential candidates for all applications, but have not yet been fully evaluated, and some of the technologies are just emerging as pilot-scale systems. Lithium-based batteries, such as **lithium-ion** and **lithium-polymer** are still only available in small sizes. Scaling up of these technologies for utility applications is not likely to happen in the medium term.

NaS batteries are often considered a potential candidate in renewable application [Butler (1996)], although there are contradictory positions in this regard [Butler (2002)]. In theory, the power and energy ratings achieved in current realisations make NaS suitable for medium-scale renewable integration. However, these batteries are still at an early stage of technological maturity. Costs need to be reduced and service life extended to compete with other technologies. Another hurdle is the high temperature operation, which requires thermal management and involves parasitic losses.

Metal-air batteries may become an option in the long term on account of their potentially very low cost and high energy capacity, but they are at an early stage of development and the efficiency is very poor at the moment to consider them as an alternative.

Flow batteries

According to Collinson (2000), FBES systems are the best option for long-term storage. Their main advantage is the decoupling of power and energy ratings. The cost of additional storage capacity is limited to the active materials and storage tanks. FBs can provide both power-intensive and long discharge, and can cycle very rapidly and deeply.

Thanks to the rapid response and the low operating costs when idle, flow batteries are well suited to supply ancillary services such as voltage and frequency regulation and spinning reserve according to Taylor (2002). Therefore the versatility of FBs makes them suitable to provide a number of secondary services at the same time as matching or levelling load and generation. This offers critical advantages, but in order to improve FBES competitiveness with respect to the cheaper, proven systems such as LA and VRLA batteries, it is essential that these multiple services are commercially developed and proven in the marketplace.

The life cycle of FBs is longer than classical batteries, offering life cycle cost advantages, but this claim is based on relatively little experience. As a new and unfamiliar technology, any FB successes that build the market's confidence will benefit all FB producers. Analysts project continued FB initial market penetration over 1–3 yrs, and growth to commercial-scale production over 3–5 yrs according to Lotspeich (2002).

FB technologies are evolving as they enter the marketplace. Orders are few, current capital costs are high, and comparisons between firms and technologies are neither simple nor direct. Technical characteristics are similar, with no system offering clearly superior performance, according to Lotspeich (2002), who provides a more detailed comparison. This comparison is summarised in table 4.2 and was made before the ending of the Regensys programme in December 2003.

Commercialisation characteristics

The three major FBs have relative attributes and commercialisation pathways that help define particular markets where each might compete more or less effectively. Regenesys focuses on multi-MW systems roughly tenfold larger than typical VRB and ZnBr FBs. Each Regenesys® installation is to be built as an integrated, turnkey system, with scalable electrolyte storage. This might reflect a focus on facility scale economies of power and energy capacity. Production capacity was not determined, but Regenesys is reportedly well positioned for manufacturing according to Lotspeich (2002). VRB and ZnBr FB developers are concentrating on modular systems, typically (but not exclusively) below 1MW of power capacity. This might reflect a focus on production scale economies for FB and auxiliary system components. In 2000, VRB firms produced 10MWh compared to ZnBr production of 4.5MWh. Some VRB and ZnBr firms are also targeting larger-scale markets, where they would compete with Regenesys®. Regenesys® has the potential to compete best in multi-MW applications, e.g., power trading, large generation and transmission and distribution (T&D) grid support; VRB markets span from generation and T&D grid support to facility-scale applications, while ZnBr FBs might compete best in facility-scale and distribution- or substation-level support.

Economic comparison

Power and energy capacity costs are useful but vary considerably between different applications and systems. Life-cycle cost of ownership is arguably the most useful metric. Cost data varies and is hard to get from competing developers, but some information is available. A study carried out by the US Electric Power Research Institute (EPRI) in 2000 evaluated total costs for VRBs, Zn-Br FBs, and Regenesys®

	Vanadium redox	**Na polysulphide / Na bromide**	**Zinc / Bromine**
Net efficiency (AC – AC)	~70–85% depending on operation	55–75% depending on operation	~75%
Lifetime	Cycles: ≥10,000 Target: 10 y; 15 with O&M	Cycles: n/a Target: 15–20 y with O&M	Cycles: ≥ 1,500 cycles Target: 10–20 y with O&M
Power cost	$1,500–5,500/kW Projected: $1,000/kW	~$1,500/kW Projected: ~$750/kW	$1,500–2,000/kW? (ZBB: ≥$800/kW achievable)
Energy cost	Electrolyte: $30–50/kWh System: $300–1,000/kWh	Electrolyte: $10–20/kWh System: $160–185/kWh	Electrolyte: ≥ $10–20/kWh System: target ~$400/kWh
O&M cost	~$50,000/y for 2.5MW, 10MWh	n/a	$30,000–150,000/y for 2.5MW, 10MWh
System cost	~$11 million for 2.5MW, 10MWh	$20–25 million for 10–15MW, 100–150+MWh	~$300,000 for 100 kW, 100 kWh module; $5.8–8 million for 2.5MW, 10MWh
Representative systems	250 kW, 520 kWh; 1.5MW, 1.5MWh	12–15MW. 120MWh	50 kW, 500 kWh module; 200 kW, 400 kWh trailer
Projected capacity	50 kW, 500 kWh to 5MW, 20MWh; 50–100MW upper range; 500MW feasible	5–50MW, 100–250+MWh; 500MW feasible	300–600 kW, 300–1,000 kWh modular arrays; 4–5MW, 4–10MWh upper range (“no practical limit”)

Table 4.2 Comparison of the three FB technologies (Lotspeich, 2002)

for a large system (10+MW, 100+MWh). TVA (2001) used the study to select its Mississippi FB system, and summarized the results. Sandia National Laboratories (SNL) and Black&Veatch (B&V) (2001) surveyed Vanteck, SEI, ZBB, and Powercell to evaluate technical and cost factors for a 2.5MW, 10MWh battery demonstration project in Nevada .

POWER CAPACITY COSTS: FB cost/power ratio varies by application and discharge rate, complicating direct comparisons. The three FBs are in a roughly equivalent range of a few to several thousand dollars per kW for initial systems, decreasing towards \$1,500–2,000/kW (ZBB reports that ~\$800/kW and lower is achievable). TVA (2001) reports that EPRI concluded that Regenesys® had the lowest capital costs of the three main designs. VRBs and Zn-Br FBs developers focus on smaller, modular systems, which might reduce capacity costs faster as production volumes build over the mid- to long-term. SNL/B&V indicated that ZnBr systems offer lower capacity costs than VRBs.

ENERGY CAPACITY COSTS: As the energy capacity increases, the cost/energy ratio is more influenced by the electrolyte costs, which are not consumed during cycling. Lotspeich, (2002) points to analysts estimating electrolyte costs in the range of \$10–20/kWh for Regenesys® and ZnBr FBs, and \$30–40/kWh for VRBs. EPRI indicated that ZnBr electrolyte costs per kW were twice that of Regenesys®. Regenesys® appears to have provided the lowest system electrical energy storage cost, reportedly in the range of \$160–185/kWh per kWh in large installations. ZBB reports ZnBr FBs storage costs approach \$400/kWh with scaled-up production. Consistent values for VRBs were not determined. Apparently ZnBr systems currently offer lower electrolyte and total capacity costs than VRBs. However, VRB systems offer greater scalability of electrolyte storage, probably enabling storage cost reductions in larger installations that stacks of electrically linked but not hydraulically connected ZnBr modules cannot attain.

PCS AND CONTROLS COSTS: PCS costs are typically \$200–400/kW for smaller (~100 kW) batteries, and are roughly equivalent components for all FBs on a capacity and cost basis according to Lotspeich (2002). Although controls and PCS for energy storage technologies are widely available, FB firms are developing proprietary components, software, and integrated systems to match FBs' diverse capabilities, and anticipate cost and performance improvements. One VRB developer projects eventual PCS cost reductions of 30–50%.

O&M COSTS: Long-term operating and maintenance costs are projected as FBs are new and existing installations vary in design, capacity, and operational profile. All FB systems are designed for automated operations, but initial installations are provided with more maintenance and operational support. Regenesys® might require more regular maintenance (e.g., for removal of process by-products) than VRBs or Zn-Br FBs. Regenesys® installations target a 15 y service life, but the O&M cost to attain that was not determined. Sandia National Laboratories and Black & Veatch (2001) report average projected O&M costs for VRBs of ~\$50,000, lower than the ~\$90,000 of projected ZnBr costs for an equivalent capacity. VRBs are targeting a shorter service life (7–15 y) than ZnBr systems (10–20 y). However, SEI claims to have demonstrated cells that exceed 10,000 cycles and suggests a 10 y VRB stack service life of their VRB, while Powercell offered buyers a 5 y service guarantee and estimated only a 1,500 cycle life for its ZnBr modules.

TOTAL COST: The TVA study concluded that Regenesys® "would most likely provide the lowest cost of operation of a life-cycle-cost basis for multi-hour utility energy storage, while providing other energy storage services that have economic value to electric utilities." Zn-Br was the second choice, but the Zn-Br developer was focused only on units for "short duration, small scale discharges (25 kW for 4 hours)." The study also concluded that VRBs and Zn-Br FBs had lower power and energy ratings and higher capital costs than Regenesys®, and that Zn-Br "electrolytes that are twice the cost per kilowatt of those used for Regenesys." Table 4.2 summarises the features of the three technologies.

Activity in the RE sector

VRB in the only of the three technologies boasting a demonstration plant associated with a wind energy installation, although of modest scale. A 170 kW, 1.2MWh system is being used to stabilise the output of a 275 kW wind turbine operated by the More noteworthy, Hokkaido Electric Power Company. Hydro Tasmania has awarded recently a contract to Pinnacle VRB for the supply and installation of a VRB as part of the King Island (Australia) wind farm expansion.

The ZnBr FB manufacturer ZBB is targeting the renewable integration market with a module especially designed to operate in connection with renewable sources. Some ZnBr units have been installed in off-grid systems in connection with solar generation, but there is no experience with wind energy as yet.

As mentioned before, Tennessee Valley Association (2002) evaluated and selected a 12MW Regenesys® energy storage facility to operate in conjunction with a 20MW wind farm, principally for load levelling. However, TVA (2002) eventually abandoned the plan. Other energy storage technologies were rejected based on their life-cycle costs, environmental impacts, and energy storage capacity. TVA was at that time already constructing a Regenesys® facility in Mississippi to demonstrate its use in meeting peaking needs, in improving power quality and reliability, and in providing rapid response to changing power demand.

It is worth mentioning the reasons TVA argued to select Regenesys® in an assessment carried out in collaboration with the EPRI. TVA was seeking a technology in the process of being commercialised which could provide the lowest cost of operation on a life-cycle basis for multi-hour utility energy storage while still providing other services. TVA (2001) felt that PHES and CAES were found to require large sites that are seldom available near the point of need and have negative environmental and financial impacts. Included in this study were VRB, and ZnBr FBs. Regenesys® was identified as meeting all of these requirements. ZnBr FB ranked as the second choice, but with the drawbacks of being only developed for shorter duration (< 4 h), small-scale discharges, and a higher cost of the electrolytes. At the time of the report, the developer surveyed (probably Powercell) was focusing only on this small-scale unit with no plans for larger scale plants [TVA (2001)].

Hydrogen

Due to low round-trip efficiency, hydrogen may not be best suited for renewable integration unless very long storage durations are required.

As pointed out before, hydrogen role in the integration of RE is likely to be as a source of fuel for other applications, mainly transport. At least in the medium term, transport is believed to represent a higher market value for hydrogen than stationary electricity generation. But even for this purpose, technological advances and cost reductions are still necessary.

The production of hydrogen from wind generated electricity for transport applications alone does not provide all the possible benefits for the network. The same level of spinning reserve must to be kept, and the capability of stabilising the network is much more limited. Hydrogen production, however, does contribute to smoothing out considerably the wind power output, thus enhancing the electric system management and avoiding curtailments.

Operational penalties when the demand exceeds generation would still stand and the precise details of these in the new market arrangements are not yet fully clear, but it is unlikely that in the medium-term the penalties are high enough to make regeneration cost-effective.

The feasibility of the production of hydrogen for transport applications will be subordinated to the success in building a hydrogen supply infrastructure and commercialising hydrogen-fuelled vehicles. In that future scenario, hydrogen will have to compete against the production of hydrogen from natural gas, which is for now the most affordable process. Hydrogen is therefore an alternative envisaged for the long term. Nevertheless, the route towards the hydrogen economy will require intermediate steps, in which moderate amounts of hydrogen will be needed to supply fuel to fleets of cars.

4.4 Conclusions

PHES viability is subject to siting requirements and environmental policies. The construction of pumped-hydro facilities with enough capacity to address the growth of wind energy in Ireland could face stiff opposition, even if suitable locations are found.

CAES is a very promising solution provided that suitable underground caves exist in Ireland. Although there are positive reports, an independent study of the potential in Ireland is necessary. CAES will be probably the most cost-effective large-scale energy storage technology, at least in the short and medium term.

FES may play a role in smoothing out short-term variations of wind farms on weak distribution networks. They can also provide some services such as reactive power compensation and frequency control. FES may increase the capacity to accommodate distributed wind energy, but significant technological advances and cost reductions are still necessary. At any rate, due to the limited energy storage capacity, FES can barely address the loss of value of wind energy at high penetration, and therefore its potential to allow for a large penetration of wind energy in Ireland is very constrained. Similarly, the role of **SMES** and **SCES** would be limited to the stabilisation of transmission and distribution lines, thus also enabling the system to assimilate more wind energy.

Classical and advanced batteries would not be suitable when large amounts of stored energy are required (costs largely proportional to energy capacity). **BES** advantages over FBES seem to be limited to the greater operational experience and lower initial costs. But even these advantages are expected to fade in the near future as FBES gain market presence. BES might find applications in the short to medium term for transmission and distribution capacity deferral, as these lines become congested at times of strong winds.

Among the **FBES** technologies, the typical scales remain complementary. With the demise of Regenesys®, which had the lowest cost of ownership, and was focused on applications of at least 5MW (5 to 500MW systems were envisaged), the remaining contenders are VRBs and ZnBr FBs. ZnBr FBs apparently have lower power and ES capacity capital costs than VRBs, but VRBs offer higher efficiency and more scalable storage. Both can potentially be suited at an individual wind farm scale to addressing intermittency concerns.

As for **hydrogen**, the production of hydrogen using surplus wind energy will be of serious interest in the short to medium term Specifically benefits will accrue to wind energy producers operating in a liberalised market where they must rely on their own ability to price electricity for dispatch and confirmed supply. Ultimately the wind energy configuration of hydrogen to production of energy may become substantially decoupled. This will allow for remote hydrogen storage and energy regeneration. The key to hydrogen current viability is the nature of its solution of the intermittency problem, and the effect of this on the realised price for wind hydrogen energy.

The options that will be analysed in the next section for the integration of growing amounts of wind energy in Ireland will be: CAES, Regenesys and Hydrogen.

Chapter 5 ECONOMIC VIABILITY OF STORAGE OPTIONS

5.1 Introduction and summary

This chapter examines the economic viability of energy storage in a systematic fashion. A number of studies have examined the effects of scale and technology efficiency on the viability of energy storage systems. [Kroon (2002), Liu(2003), EA Technology (1998), EA Technology (1999) Sandia (1994) and Sandia (2002)]

Given these inputs, the preceding discussion on the appropriate technologies for addressing intermittency, it has been possible to analyse the trends in terms of research developments and economics, and to model the resulting outcomes in an outline fashion. The consensus view among researchers points to significant expected benefits from new technology developments (particularly scale, capital cost, charge time, discharge time and efficiency), which will mirror those efficiencies currently being achieved in wind energy production.

System prices for a range of energy storage solutions are likely to fall in the longer term to below € 1,000 / kW as capital cost, for charge, storage and discharge combined [Price (2000), Nakhamkin et al (2001), Baker (2001), Carnegie (2001) and Harrison (2003)]. At the same time, progress has been made in decoupling storage capacity, charge capacity and discharge capacity. Price data indicate that ideally in a liberalised market, prices will exceed € 30 /MWh for periods most days, and € 50 /MWh during high demand periods. Effective storage technologies will allow renewable generated electricity to sell into the market at these attractive prices. [Platts (various)]

Energy storage, its interaction with liberalised electricity markets, renewable energy systems, and the evolving requirements of electricity grids (allowing for simultaneously increased local distribution and regional interconnection), is a complex and fast growing research and industrial area. There are no absolutes in this field, particularly with reference to setting the limits of emerging technology, and market dynamics. [Garrad Hassan et al (2003) and ESB NG (2003a)]

Industry participants should be aware of the pace of research and development in the energy storage field. Researchers should also take care to develop a complete cost and economic profile, and to include direct, indirect and external costs in their analysis. The analysis is, by nature, inter-disciplinary and complex, but is particularly important with reference to the integration of renewable energy into power grids designed for conventional generating equipment.[Liu (2003) and Garrad Hassan et al (2003)] At the same time electricity markets are currently being liberalised (as is the case in Ireland), thus increasing the complexity of the analysis. [EA Technology(1999) and Kroon (2002)]

As discussed in chapter 4, the most likely systems to be appropriate in the Irish context are:

1. Pumped hydro
2. Compressed air storage
3. Flow batteries

4. Hydrogen systems

In monetary terms, an energy storage system, which delivers energy at a cost of 5.1c/kWh (5.1 euro cents per kilowatt hour) or less, are closest to economic viability. Energy storage systems based on pumped hydro and compressed air, can meet this requirement now. Flow battery systems are expected to meet this cost requirement in the short term, and large scale wind hydrogen systems have potential to achieve this cost basis in the medium to long term (5-10 years). Table 5.1 gives comparative measures for this target energy cost in terms of comparable primary sources:

Energy Source	Energy Density	Kgs to Provide 1MWh	Target Cost Per Kg to give € 51/MWh
Coal	5.7 kWh/kg	175	€0.3
Natural Gas	9.4 kWh/kg	107	€0.5
Oil	11.4 kWh/kg	87	€0.6
Hydrogen	39.4 kWh/kg	25	€2

Table 5.1: Comparative Target Costs per Kg for Primary Energy Sources

Typically Combined Cycle Gas Turbine (CCGT) competes with energy storage (particularly pumped hydro) in terms of ensuring power quality to a transmission grid. From a technology perspective, Compressed Air Energy Storage (CAES) complements CCGT systems and is not a competitor. Similiarly CCGT systems do not compete with energy storage in applications where the storage system targets the integration of wind energy to a transmission grid [Schoenung (2002)].

This study has analysed in some detail the challenge to provide this integration capability in a technologically sound and economically viable fashion. The fundamental report from this analysis is that large scale energy storage could be economically viable in the medium term and would be well suited to the proposed changes in the Irish electricity market, where renewable energy is not likely to be preferentially treated in the future, where the grid is isolated currently and where there is large scale potential for the development of wind energy [ESB NG (2003a), CER (2003c)].

An alternative solution to the intermittency of wind power, the provision of a 'supergrid' capability was not evaluated. A supergrid would be capable of delivering power to temporarily calm areas of Europe from windier areas. The underlying assumption that there is a low incidence of continental calms has not been tested.

Summary economic findings:

In summary the findings of a preliminary but inclusive economic evaluation bear out the following points:

1. Grid requirements for power quality, power consistency and dispatch prioritisation, for high baseload conventional plant, provide a rationale for

energy storage. The economic case for these ancillary services is well established and holds true in the absence of either a liberalised market or large scale penetration of intermittent renewable energy [Price (2002)].

2. Electricity storage technology even decoupled from renewable sources is a viable investment in an environment of a liberalised trading electricity market [Kroon (2002)]
3. Future improvements in electricity storage technology are likely to further improve energy storage's exogenous attractiveness [Baker (2001)]
4. Electricity storage technology will allow integration of renewable sources to replace conventional generation technology in an interconnected grid, thus allowing a more aggressive penetration than a 'fuel saving' only analysis could support [Garrad Hassan et al (2003) and Christakis (1996)]
5. Similarly a grid incorporating high renewable penetration and active storage technology may not have to resort to wind 'curtailment' in any but the most extreme circumstances. A corollary of this is that 'curtailment' usage such as desalination or large industrial projects will likely not be appropriate. Ultimately non-dispatched wind power will always be stored. [Liu (2003) and DOE (2003)]
6. Large scale renewable penetration, associated storage and 'curtailment' of conventional generating capacity is a technical and financial possibility. The economics of such an integrated system will likely depend on progress of hydrogen wind systems, which are the only renewable systems with long term discharge characteristics.[Liu (2003), DOE (2003)and Lyons and Voigt (2003)]
7. TSO's (transmission system operators), DSO's (distribution system operators), as well as regulators should understand the challenges and opportunities offered by a large scale development of renewable energy linked to energy storage systems.[ESB NG (2003a)]
8. The proliferation of storage systems (e.g Wind Hydrogen, CAES Hybrids, Pumped Hydro, Advanced batteries), and of systemisation technologies are an opportunity for a knowledge economy like Ireland's to win a leadership role in a new and potentially valuable emerging industry.[Dept. of the Taoiseach (2003)]

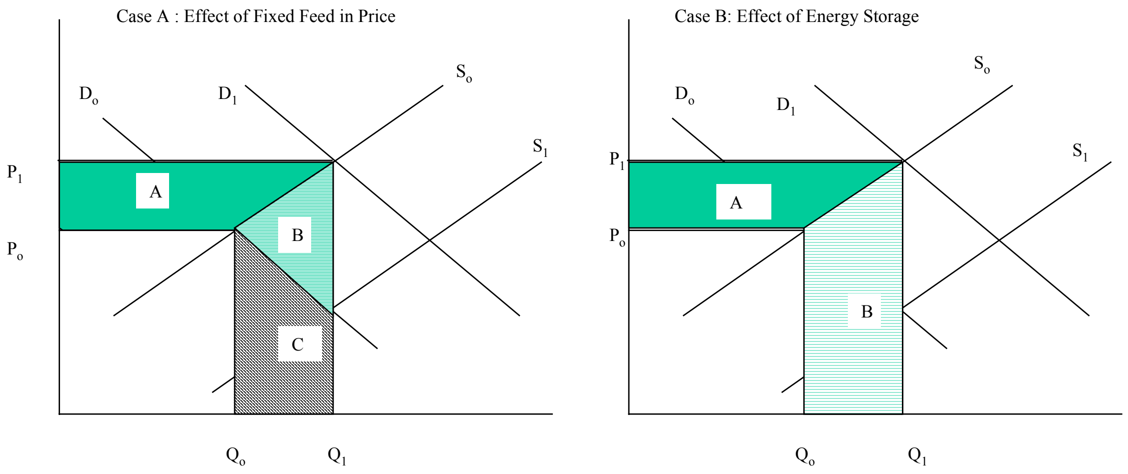
There is much interest within the EU 6th Framework Programme on energy storage. Research opportunities provided by the both EU, National and private funding should be encouraged. Ireland has produced comparatively little research to date on the subject of energy storage. Opinions have often been formed based on limited understanding of the emerging landscape, where research and development expenditures are proliferating. The comparative low cost of production and capital expense of Combined Cycle Gas Turbines (CCGT) generating equipment has further entrenched a view that energy storage is not viable. However as pointed out above this view lacks validity, as the core comparison to be made concerns the underlying feasibility of technology and investment to reduce the intermittency of wind, and to improve its dispatchability to the grid. There is need for further work on economic, regulatory, scientific and engineering sectors in this field, particularly to understand the emerging economics of the sector.

5.2 Costs: Present and Future

Economic Underpinings

In a fixed feed in tariff, or under a high AER priced contract, or similar systems in Germany and elsewhere, there is little incentive to the renewable producer to store energy. However under a system where renewable producers participate in the market periods occur when low prices make it appealing to store energy rather than to sell into the market at low or uneconomic rates. This will be the case under the proposed incorporation of renewables into the market arrangements for electricity in Ireland, and the UK approach of ROC (renewable obligation certificate trading) which will make it more, not less, attractive to invest in energy storage [Armitage and Biggs (2003)]. The ability of base load conventional plant to sell off peak at less than marginal cost (€3/kWh) further distorts the economic rationale for integration of renewables, but supports the argument for storage. This finding, which derives from point 2 in the summary findings above is illustrated in figure 5.1 (a) and (b) below.

Figure 5.1 : Improving the Attractiveness of Renewable Energy (Supply - Demand Analysis



Case A:

- Electricity Demand CurveD0, meets Supply Curve S0 to give market clearing priceP0 and quantity Q0
- Regulation in favour of renewables set renewable price at P1, effectively imposing a tarrif [P0-P1], and causing a demand shift to D1
- Excess quantity of [Q0-Q1] of renewables are produced
- Value A accrues as a premium to renewable producers
- Value B is lost by customers
- Quantify corresponding to block C, is not released because intermittency does not guarantee its availability
- Taxation effect is at least A and B

Case B:

- Electricity Demand CurveD0, meets Supply Curve S0 to give market clearing priceP0 and quantity Q0
- Electricity Demand is not constant at all times, demand shifts to Demand curve D1 for significant time periods
- Renewable originated energy, does not wish to participate at Price P0, but with stored energy particpates at price P1
- Value A accrues as a premium to renewable/ storage producers, as a supplier surplus
- Quantify corresponding to block B, is displaced as renewable originated energy now approximates conventional generating capacity
- Quantity [Q0-Q1] of renewables is produced
- In both cases a demand shift of renewables from Supply Curve S0 to S1 is desired. Case B is more likely to deliver this step change

It should be noted that similar situation can exist under fixed feed in tarrifs, but in this case the PSO (public service obligation) payment scheme may incent other producers to pay to store the energy from renewables and then release the energy at times of higher prices.

Therefore, from a purely microeconomic viewpoint, energy storage has an important role to play in liberalised electricity markets, where carbon emission constraints are being imposed. In fact markets where renewable sources are expected to be price takers, will likely have an added incentive to explore the economic viability of energy storage technologies and systems.

Potential for renewable energy dispatch

The medium term unpredictability of wind is well documented. However for significant penetration of wind and other renewable sources (20% and more), a systematic energy reserve pool is required, to ensure power quality and grid distribution integrity [Harrison (2003), Garrad Hassan et al (2003) and Nicholson (2000)].

Very few storage systems can sustain curtailment of conventional generating equipment over a longer term than say 10-12 hours. Limits apply because of absolute energy storage capacity and its link to discharge time at rated capacity. Of the storage systems only hydrogen, or wind hydrogen systems offer the potential of fully replacing conventional electricity generation, and therefore accruing a ‘capacity credit’ in their economic analysis [EA Technology (1998), Price (2000), DOE (2003) and Enslin, Knijp et al (2001)]. Economically the renewable-storage energy system becomes more attractive, as more of the economic benefits associated with zero marginal cost energy production accrue.

Storage System	Typical Output Rating (Megawatt)	Typical Storage Rating (Megawatt hours)	Physical Linkage Reqd.
Pumped Hydro	100	500- 10000	Yes
CAES	25	200	No
Battery	10	100	Yes
Hydrogen	10	Unlimited	No

Table 5.2: Discharge rating and storage capacities for typical systems[3]

So for instance in a conservative ‘fuel saver’ analysis, the greatest benefit from wind energy is the reduced fuel costs associated with some reduction in output from conventional generation plant [Garrad Hassan et al (2003)]. In a more aggressive analysis, sometimes called a ‘capacity credit’ where wind energy meets all the dispatch requirements, then fuel saving, externality costs, and capital cost comparisons become the key drivers of the analysis. The essential requirement is that hydrogen production and storage can be decoupled, and that large storage facilities for hydrogen can be constructed.

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[3] Price (2000)

If hydrogen systems do attain this potential (<5.1c/kWh integrated cost) then renewable energy sources can safely replace conventional generation on distributed and centralised grids [DOE (2003)].

An alternative approach is to develop an interconnected 'super-grid' for transmission of renewable resources on a continental or transcontinental basis. As mentioned earlier an initiative or its analysis falls outside the terms of reference of this study.

Categorisation of Costs and Prices

For purposes of analysis of economic viability a number of different categories of costs lie within the model of a storage system. Table 5.3 illustrates the most important cost categories and a description of their scale:

Costs	Viable Value Range	Comments
Capital Costs		
Charging Equipment	<€1000/kW	Scale and technology dependent
(e.g. pumping, or hydrolyser)		
Generating Equipment	<€1000/kW	The lowest capital cost plant is typically CCGT. Depending on scale this can be as low as €300/kW installed capacity
Storage Equipment Cost	<€20/kWh	Scale and technology dependent.
Variable Costs		
Generating costs variable	<€0.05/kWh	€0.00/kWh for renewables, €0.02/kWh and higher for Coal and Gas (cash costs)
Operating Maintenance costs	<€0.004/kWh	Typically decline with scale. (Note that depreciation is a non cash cost).
External Costs		
Grid Connection Costs	<€50/kW	Not a direct cost, however many grid operators may seek to recover costs of connecting new capacity (particularly in liberalised market). Both transmission and distribution grids, are broadly speaking public goods, and should be designed and managed to reflect a broad indifference to the source and destination of electricity.
Fuel Saving Cost	<€0.02/kWh	Least benefit accrued from Renewable generation
Efficiency penalty	<€0.02/kWh	Actual penalty for system inability to run without base generating load at conventional plant
Carbon Costs	<€0.02/kWh	Real costs, but paid by broader group, associated with burning of fossil fuels. Cash cost of carbon fuels reflects only, recovery and distribution costs.

Table 5.3: Overview of most important cost categories for renewable energy[4]

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[4] Price (2000) and Price and Thijssen (1999)

Many different pricing mechanisms with slightly nuanced meanings are apparent in different markets. An overview of the most important pricing considerations met in the both fields of renewable energy pricing and liberalised markets is presented in Table 5.4

Prices	Value range	Comments
Fixed feed in tariffs	<€0.14/kWh	'German' approach to encouraging wind energy and other renewable production
AER/NFFO tariffs	<€0.10/kWh	Contracted prices, similar in effect to fixed feed in tariffs, where long term price is paid to producers of wind energy (irrespective of actual price for electricity in a liberalised market)
ROC Market price	<€0.05/kWh	Traded price for a certificate specifying production of a single Megawatt Hour of renewable energy. Distributors have an obligation to either produce or purchase a mandated percentage of total electricity as ROCs
ROC Obligation (Cash in price)	€0.04/kWh	Threshold price below which a ROC can be cashed in at an issuing authority
Electricity price	<€0.14/kWh	Market price of electricity in a liberalised market, typically power producers bid in half hourly windows for actual and reserve power feeds ins. The market price is set either by pure market or a market clearing engine (MCE) as in the proposed Irish case.
LMP	<€ TBD	Location Marginal Price (LMP). Price paid at a node in the network for required power capacity
PSO tariff	<€ TBD	Difference between renewable (or other preferred source, such as peat) electricity price promised to producer and actual price attainable in a market. This is recharged to the other producers as a levy which, is often passed on to the consumer
Charge for reserve	<€ TBD	Causer pays principle will apply.

Table 5.4: Overview of most important pricing categories for renewable energy[5]

Current Capital costs

Table 5.5 shows capital costs for storage systems most likely to be associated with wind energy systems. Data is based on best available information as of 2001. There is a significant scale effect explored in many sources which as expected implies that the larger the storage system the lower the cost per kW of installed capacity

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[5] Price (2000), Schoenung (2002), European Commission (2003) and CER (2003d)

Storage Technology	Capital Cost €/kW	Life time limits	Output range rate
Hydrogen wind systems (electrolyzer/turbine /storage configuration)	€1700	Similar to conventional plant	5MW in current production. No theoretical limit on either range or output rate
Hydrogen wind systems (electrolyzer/fuel cell/storage configuration)	€2400	Similar to conventional plant	5MW in current production No theoretical limits
Pumped hydro (pump/storage/turbine)	€800 - 3000	Similar or better than conventional plants	50MWh-15000MWh total storage capacity, up to 4000MW/hour highest rates
Compressed air (storage/turbine)	€600 - €1000	Similar or better than conventional plants	Up to 1000MWh Limited by storage capacity (underground/some vessels), rate for hybrid systems up to 400MW/h
Flow batteries (NaS) (Combined charge/storage/ discharge)	€700-1500	Up to 50,000 cycles at current technology	Prototype flow batteries (e.g. UK Regenysys up to 120MWh). Rating up to 40MW/h
Lead acid batteries (Combined charge /storage/discharge)	€300-1000	Up to 20,000 cycles at current technology	Smaller applications installed, up to 40MWh with ratings of 10MW/h

Table 5.5: 2001 Capital cost (excluding wind turbine costs) comparison for appropriate energy storage technologies[6]

Operating costs and costs per discharge; [4]

Typical operating costs for an integrated energy storage system are very low, and depend to a large extent on the system integration to demand and supply functions. A good rule of thumb is to estimate 0.5 c/kWh of output, for a plant of greater than 500MWh per day output, with expected 10 hours per day discharge. Staffing and maintenance spend are a function of equipment age, type and scale, and therefore vary within a broad range for different types of storage facility.

Any increase in plant operating time produces a clear scale benefit to the storage facility. Twelve hours discharge per day is ideal for a coupled system. A hydrogen based system, may however operate up to 24 hours per day, as the energy source, storage and regeneration are all decoupled.

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[6] Schoenung (2002)

Equipment cost per discharge and depreciation, as noted earlier are not actual cash costs, so are not included in any analysis. Capital costs are explicitly included in the viability model, as an initial investment with a specified lifetime and a required economic rate of return.

Input and output energy costs: [Platts (various) and CER (2003d)]

In considering costs of input energy to a storage system, a clear decision has been taken to consider only cash costs. Broadly for a system designed to deal with intermittment supply issues, and where market prices prevail, two cost or price points present themselves:

- In a curtailment operating environment as envisioned in Ireland, where wind energy will not be preferentially dispatched the input cost of wind energy is exactly the marginal cost to produce it, that is €0.000/kWh. This price is exactly equal to the revenue foregone by diverting the energy to a storage medium
- In a market environment where renewable wind energy is dispatched or offered to be bought from a producer at a given price the cost of the input energy is exactly equal to the LMP (in the Irish case), if the wind producer turns this down. Alternatively the producer may decide to decline a Fixed Feed in Tarrif price or an AER price (in the Irish case) if one is in operation.
- In an ROC trading system, stored energy has a cost equal to the cash out cost of the ROC itself (£30/MWh in the UK). However the ROC is also 'stored' and can be resold at market prices.

Similarly output energy costs, are the direct payment that a producer can accrue for the electricity at the targeted output time. A significant body of research has been devoted to this topic, with consistent results:

- For a successful peaking strategy, average prices obtained are in the range €50-60/MWh. This is the maximum output price used as a base point in this study. Average feed in price data was typically €30-40/MWh
- For a fixed feed in tariff, clearly there is no revenue enhancement (and therefore little incentive to store renewable energy)
- In some cases (power imbalance) price spikes for electricity are experienced (although these circumstances like negative prices are actually manifestations of market failures), allowing very high prices exceeding €100/MWh to be realised

Cost improvements areas to examine [Baker (2001), Altmann, Niebauer et al (2000), Nicoletti (1995)]

From the above analysis it can be seen that substantial progress has been made to reduce the overall cost and improve the financial attractiveness of energy storage. However it is anticipated that much improvement will accrue over the next years to further improve the efficiency and cost performance of energy storage. In terms of the discussion relating to economic underpinnings, this corresponds to an expected supply side shift from a supply curve S_0 to S_1 (see Figure 5.1). Topics of current research are explained in summary below. For each field it should be noted that many researchers in academic institutions, government sponsored research and the private sector are active. The most important areas are:

- Further reduction in the capital cost of wind energy. With an increase in potential power per turbine to upwards of 2.5-5MW, and a move to offshore farming, the likelihood is that the there is potential for a continued decrease in the cost perMW. It is estimated that the total capital cost of wind energy production could fall to €800/kW over the next 10 years. Wind energy marginal production cost will continue to be zero, giving a potential cost of at least 3 cents per kWh advantage over the most competitive fossil fuel system (CCGT)

- Additional storage capacity in wind systems prior to conversion to electrical energy has not been explicitly modelled in this analysis. However flywheel, hydraulic pump potential energy storage mechanisms are being developed. However no reliable cost or operating data on these systems has become available

- Improvement in flow battery technology. In the short term it is anticipated that further electrochemical improvements will occur in the areas of safety, energy density, and storage lifetime. [private communication and Taylor and Hoagland (2002)]

- Both hydrogen wind systems and CAES Hybrids are in their infancy. A number of investigators have pointed to expected technology, learning curve, systemisation and scale benefits to be accrued over the next 5 – 10 years [Nakhamkin et al (2001) and Enslin, Knijp et al (2001)]

- Development of a systemised approach to pumped hydro distributed storage, may reduce the overall system cost significantly. Together with more efficient pumping equipment, and the potential to build plants designed specifically to combat the intermittency of renewable energy production [Christakis (1996) and Lyons and Voigt (2003)]

- Wind forecasting, particularly short term wind forecasting within the context of market bids for electricity supply is a highly important software enabling technology [ESB NG (2003a) and Lyons and Voigt (2003)]

- Development of dynamic response grid transmission and distribution software is ongoing. The incorporation of renewables is an addition of complexity, and provides opportunities in the development, maintenance and operation of appropriate system software [ESB NG (2003a)]

- Hydrogen production, storage and reuse. The development of a ‘hydrogen economy’ is particularly important in the context of decoupling the timing of renewable energy production (wind, solar and biomass) from its use. Electrolyser technology, hydrogen storage and reintegration via fuel cells, hydrogen turbines or other mechanisms is a relatively young area of dedicated research, but many important advances are already being made. [Liu (2003), DOE (2003) and Pritchard (2003)]

In summary the expectation is that improvements of the order of 50% in total system cost, for a combined wind and storage system, will be realised within the optimisation of the current technology environment.

5.3 Financial model ouputs:

Benefits in the context of a liberalised electricity market

The liberalised market provides a number of opportunities to further advance energy storage. Specifically the opportunities fall into three interlinked categories [Kroon (2002)] :

Category 1: Power quality and power management
  a) Preventing voltage dip
  b) Prevents cascading grid failures

Category 2: Tariff trading:
  c) Peak shaving arbitrage
  d) Coverage of high value power imbalance requirements

Category 3: Energy storage for the integration of renewable and distributed generation
  e) Improves dispatchability of renewable energy
  f) Allows curtailment of base load conventional generation capacity
  g) Reduces cost and complexity of integrating renewable energy to transmission, distribution systems as well as incorporating renewables into the new Market Arrangements for Electricity

The economic case for energy storage under category 1, power quality management is well established as the rationale for most older pumped hydro storage systems. Increasingly CCGT generation is seen as adequate protection against the requirement for further investment in pumped storage. It should be noted that variable costs for a CCGT system are high, (June 2003 price of 4c/kWh). Smaller scale pumped hydro schemes may be more attractive at locational marginal nodes to protect a local or distributed section of grid. Similarly explicitly utilising zero marginal cost, wind energy as the charging power for an existing large scale storage system, significantly improves its inherent profitability.

The economic case for tariff trading (category 2) is readily established. Using some historic data from a client example the arbitrage value is demonstrated to be up to €20/MWh, (input energy cost – output energy price) The net benefit means that a peak shaving battery system is viable, even when linked to conventional generation technology. The key variables affecting the viability of a grid input and output storage system are the number of charges and discharges per day. Prior to the project closure, it was anticipated that the operating data from the Regenysys system will give some insight into these essentially market driven economics. [Kroon (2002), Pritchard (2003)]

Compressed Air Energy Storage can also be used in conjunction with gas turbines to provide power management and longer term power quality security. A number of systems have been developed to utilise the compressed air to improve gas turbine efficiency to upwards of 70%. The fundamental trade off is related to cost of storage. It should be noted however that CAES systems are being built using pressure vessels as well as large underground storage facilities [Nakhamkin et al. (2001)]

Large scale energy storage for renewable applications, where the ultimate goal is to integrate renewables into the conventional grid and cause curtailment of conventional generation capacity, requires significant storage capacity. In reality the only systems which are suitable are those where the energy production and utilisation are substantially separated. Hydrogen wind systems are the most likely means to achieve this goal of conventional generation curtailment. The key cost determinants in the valuation models are:

1. Cost per MW for storage charging
2. Capital cost of equipment €/kWh
3. Cost per MWh /day for storage
4. Round trip efficiency

However on an ongoing basis, both pumped hydro and compressed air, offer the potential to significantly increase the reliability and thus the dispatchability of renewable energy. Both are limited only to the extent of the available storage reservoir. In the case of pumped hydro, smaller scale systems can be linked to individual wind farm sites, and may allow for much higher storage to discharge ratios required to ensure power availability.

Wind hydrogen system

The economic model, developed during this study, produces some important results in terms of the viability of the systems. The variables used and associated ranges are tabulated in Appendix 2. Assuming that it is technically feasible and meets the basic requirements to allow the electricity to be dispatched on equal terms to other power producers, the viability of a storage system, depends quite heavily on four factors.

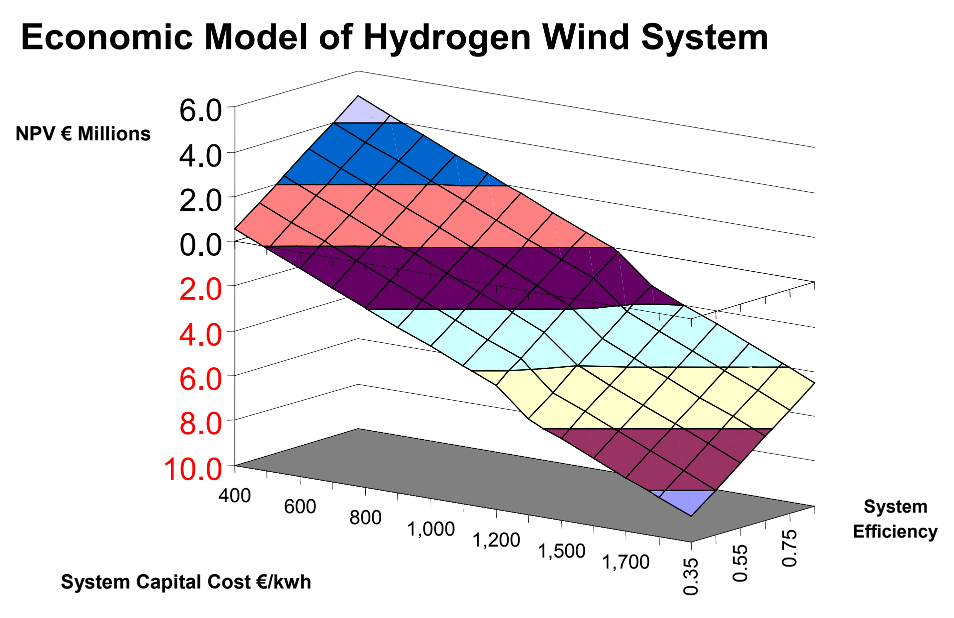
1. The price enhancement available between variable charge cost (foregone price) and discharge attained price
2. The average time period when the system can discharge to an enhanced revenue environment
3. The capital cost of the facility (charging equipment, storage equipment, and discharge equipment)
4. The efficiency of the system

In this context hydrogen wind systems are potentially viable. Because of the independence of storage from charge and discharge, these systems are the most suitable (together with battery storage) for peak shaving. However given sufficient storage, wind hydrogen can be as flexible as a methane driven CCGT. For all systems the expected realisable price enhancement is modelled as either at €30 or €40 per

MWh, depending on the time of discharge[Nakhamkin et al (2001), Baker (2001), Platts (various), Lyons and Voigt (2003), Crudden (2000), Taylor and Hoagland (2002), Sandia Lab (1994)].

The economic evaluation of wind hydrogen used a number of static and variable inputs. However the key drivers of viability are system cost, and system efficiency. Total system cost is expected to reduce significantly but current costs for an integrated production, storage, turbine/engine system are close to €2,200 per kW. Potential savings have been evaluated by a number of researchers, and these expectations have been factored into ongoing business expectations. A combined electrolyser, storage system total cost of less than €1,500 per kW may be reached in the next three years. [Pritchard (2003), CER (2003b)]

Figure 5.2 illustrates the output from the economic model as a viability surface, where NPV of a hydrogen wind system is given in terms of variance in system capital cost and system efficiency. These two variables are the most easily influence by a concerted drive to develop this technology. Typically with capital cost at or around €1,500/kWh and system efficiency at approximately 40%, the system becomes profitable in current market pricing conditions.



Notes: 1. Key static inputs: 5 MW Electrolyser, with ICE Turbine Gensets, or Fuel Cells, Advanced storage medium, or full buffer

2. Input cost of wind power €0.0/MW (marginal cost), output price €40/Mwh (Nogales)

3. ICE engine uses electrolyser output at ambient pressure, output diverted for 10 hours per day (40MW/day)

4. Equipment cost from (Pritchard, Liu and proc. EERE)

5. Financing cost 7% pa., lifetime 20 years

Figure 5.2 Economic model of wind hydrogen system

The economic viability increases for these systems if variance is allowed on hours of daily production. Because of decoupling the energy generation segment of a Hydrogen Wind system, the energy production or availability to a grid begins to resemble availability for a conventional generation facility. In fact many pumped hydro storage systems (e.g. Turlough Hill) now operate up to 16 hours a day in discharge mode. Table 5.6 illustrates the effect by way of three case examples.

Capital cost for a hydrogen turbine or hydrogen engine system will likely approach total cost for a methane (natural gas) turbine of approx. €400/kW. Future turbine systems will generate significantly less NOx pollutant than current generation turbines.

	Current case (intermittency arbitrage)	Near term case (intermittency arbitrage)	Medium term case Decoupled storage (fully dispatchable plant)
Capital cost	€2500 /kW	€1800/kW	€1400/kW
Price enhancement	€0.02/kWh	€0.03/kWh	€0.03/kWh
System efficiency	30%	36%	47%
Operating hours/day	10	10	20
NPV	(€11.2m)	(€6.9m)	€1.1m

Note: 5MW matched hydrolyser and generation equipment, storage estimated at €2/kWh capacity

Table 5.6: Large storage, long discharge hydrogen wind systems

Fuel cells are an alternative to a gas turbine, and offer the prospect of significantly higher efficiencies. However fuel cell prices are currently prohibitively expensive and not commercially available. Further this technology is still in intense development, by companies such as Ballard Power and Plug Power.

Electrolyser efficiencies of higher than 70% seem to be attainable from a number of manufacturers. However the production of hydrogen from wind energy is a relatively new market for suppliers, who have previously concentrated on hydrogen purity as the critical performance indicator of their products and systems.

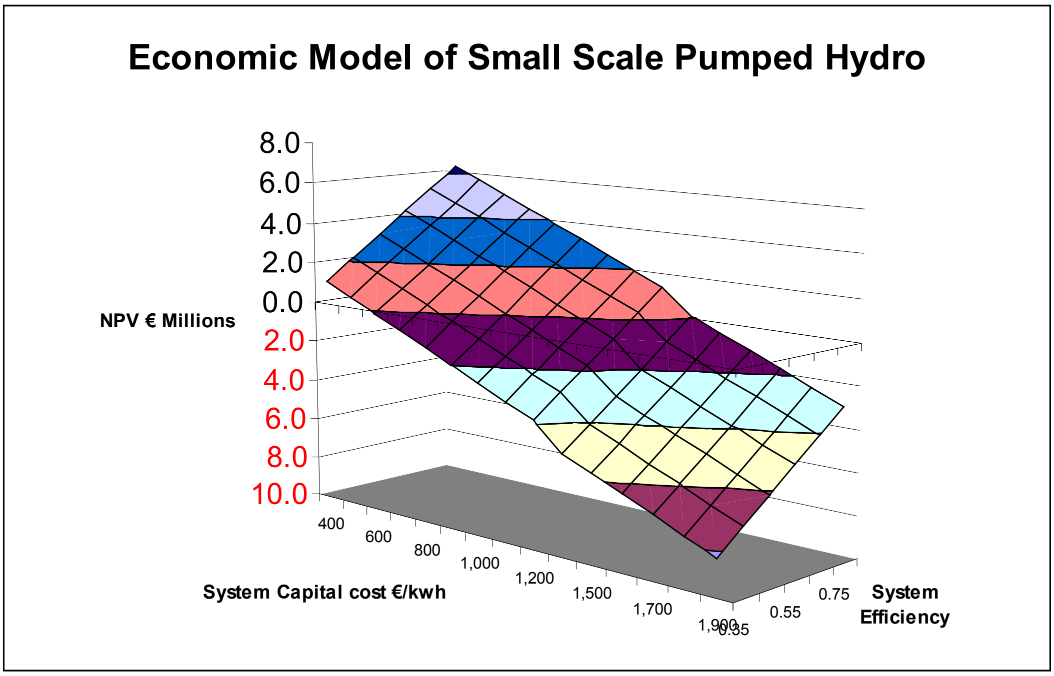
As can be seen, within current constraints the complete system struggles to be viable. However, with small incremental increases in efficiency and reductions in capital cost, both of which are expected by many experts the system becomes economically viable at relatively low hydrogen production of 8 hours per day from a connected wind farm site.

The viability becomes more compelling if a larger facility is constructed (Large Scale Wind Hyrdrogen – LSWH) with more utilisation of the expensive capital plant (33% in the analysis presented here, but potentially as high as 80% to 90%)

Wind pumped hydro system

Pumped hydro facilities have typically been constructed with a view to ensuring power quality on a transient basis in a large integrated grid. In the last ten years however, CCGT spinning reserve has become more viable and the smaller scale of incremental capacity requirements for a conventional grid can be well met from CCGT, or in extremis, oil fired generation plant.

Along with capital costs and efficiencies, the ratio of storage capacity to generating capacity is central to improving the dispatchability of renewable energy. Storage capacity equating to two days of rated reserve output from a plant, should be adequate for the wind – hydro power integrated system to participate in a liberalised electricity market on an equal dispatch paradigm. For a 10MW output plant this implies a storage capacity of 480MWhs. Interestingly storage capital costs for both pumped hydro and flow battery are expected to be higher than for hydrogen systems. This does not take into account the operational storage costs which will tend to be higher for hydrogen and battery technologies than for pumped hydro (where these costs approach zero).



Notes: 1. Size data : 11 MW rated facility

2. Assumed output at 10 hours per day

3. Attained price enhancement of €30 per megawatt

4. Financing cost 7% pa., lifetime 20 years

Figure 5.3 Economic model of wind pumped hydro system

Similar models have been constructed for other storage technologies, however the operating data on charge and discharge times for flow batteries are not sufficiently disseminated to allow for publication of this data.

Compressed air storage relies on the availability of suitable storage facilities. However some installations are currently using pressure vessels to store compressed air. The central attraction of a compressed air system is that it allows a conventional CCGT to work at higher efficiencies (up to 80%). In measurement terms, a CAES gives an reduction in cost per kWh of approximately 2cents. Running continuously a 50MW turbine will save approximately €8.4m in running cost per year, if continuously fed with compressed air.

External benefits

The external benefits of energy storage have not been explicitly modelled in the financial viability study, however there are a number of important external benefits from the integration and maturation of an energy storage capability in the Irish context.

- An integrated storage strategy improves the reliability of wind energy and removes many, and potentially all, issues around intermittency of wind energy as a primary source of energy. This then allows wind to be viewed in dispatch terms, as equivalent to conventional energy supply, thus providing the basis for higher investment and more attractive returns from wind energy.

- By allowing wind energy to be integrated to the overall energy requirement, energy storage can reduce the need for additional conventional generation in the medium and long term. Similarly given the characterisation of Ireland as the 'Saudia Arabia of Wind', there is potential for Ireland to become a net exporter of renewable energy

- Energy storage by increasing wind energy installations, allows Ireland to reach its EU and Kyoto commitments for greenhouse gas emission reduction, on time and with reduced cost. These commitments are in themselves proxies for the actual external costs attributed to fossil fuel usage.

- Development of an intellectual knowledge base in a new industry such as energy storage is valuable for Ireland, and its migration to a knowledge economy

- Energy storage linked to wind energy enables distributed transmission and distribution systems for electrical energy. At one level this will reduce the cost associated with distribution to remote areas, and at another level it will reduce the cost associated with provision of back up generating capacity (often diesel) at non grid connected sites.

Chapter 6 STRATEGY

The short to medium term strategy focuses on the utilisation of mature electricity storage technologies where performance characteristics and costs are better known and more clearly understood. The longer term strategy concentrates on technologies that are not yet mature but are potentially more promising in terms of their suitability in addressing wind energy intermittency.

The strategies focus on the storage technologies themselves and how they will operate within the context of electricity network and electricity market developments.

Short to medium term strategy

The key elements of the short term strategy are :-

1. *Pumped hydro resource study*. A significant theoretical resource (up to 1,000MW) has been identified within the context of this study. A study is required to determine the practicable pumped storage potential, taking into account technical and non-technical constraints. It is important to distinguish in this study between a) the potential for pumped hydro storage plants associated with individual wind farms, and b) the potential for pumped hydro plants that provide storage capability for a group of wind farms (data from Turlough Hill could be utilised as a reference case in this analysis). In the case of the latter, the storage plant will address the issues of wind energy intermittency associated with load levelling and back-up requirements. whereas the former has also the potential of addressing local network constraints to wind energy integration.
2. *Compressed air energy storage.* The potential for compressed air energy storage should be undertaken providing details of optimum locations close to gas generators with underground reservoirs. This will entail geological surveying and electromechanical modifications to existing or proposed gas fired generators. It may be beneficial draw on the results of Optimum Energy’s work if the publication timeframe is appropriate. The requirement to carry out a CAES feasibility study should also be considered by CER in the licensing process for new gas fired electricity generators.
3. *System modelling.* The use of storage needs to be considered in the context of an integrated approach to dealing with wind energy interactions with the electricity network. This will require the development of real time energy systems models linked to pending grid modelling studies and incorporating the use of wind energy forecasting. It should also consider the use of methods for addressing intermittency other than storage (for example open cycle gas or and East West interconnector), that fell outside of the scope of this study;
4. *Grid upgrading programme.* The current extensive grid upgrading programme currently underway should be reviewed to take account of the prolific increase and concentration in anticipated future wind energy production. This programme review is a key recommendation of the Renewable Energy Strategy Group and is separate to the agreed mechanism addressing the challenge that existed for developers where they must raise the entire capital

expenditure for any upgrade forming part of a potentially shared connection with money subsequently remitted as others connect to the facility.

5. *Demonstration Projects.* The purpose of these projects is to link mature storage technologies with wind energy to demonstrate the technical and economic viability of the complete system. This will drive the learning curve, reducing capital costs and increasing future operational efficiencies. The projects should only proceed following a detailed, fully costed technical and financial feasibility study
    a. *Wind + Small scale pumped hydro*
    This demonstration project should provide insights into the potential of small scale pumped hydro to address wind energy intermittency in Ireland. The pumped hydro plant should be situated in close proximity to the wind farm in order to assess the ability to provide reserve in addition to providing back-up for and storing the wind energy. The provision of detailed technical information should be a condition of financial support associated with the project. The funding support provided should be linked specifically to the pumped hydro storage elements of the system.

    b. *Wind + Compressed air energy storage*
    This demonstration project should provide insights into the potential of compressed air energy storage to address wind energy intermittency in Ireland. The CAES should be situated in close proximity to a gas fired electricity generation plant, and where possible, also close to the wind farm. The provision of detailed technical information should be a condition of the project. The funding support provided should be linked specifically to the CAES elements of the system.

Long term strategy

The key elements of the long term strategy are

1. *Linking wind energy storage and the hydrogen economy*. A study will be required to detail the synergies between hydrogen production in the context of wind energy storage and the development of the hydrogen economy. In particular the anticipated advances in hydrogen fuel cell technologies will increase the value of hydrogen and as a result improve the economics of wind hydrogen systems. It is crucial to investigate beyond the hype surrounding the hydrogen economy and use a sound basis for this work. It will only be meaningful to carry out this study when more data becomes available from various detailed studies on the future of hydrogen and fuel cells that are currently underway.

2. *Demonstration projects*. The purpose of these projects is to assess more flexible storage technologies that have the potential to address wind energy intermittency more completely by dealing short term fluctuations as well as providing load levelling and back-up. These technologies are not yet technically or economically proven in Ireland. It is recommended that research as well as demonstration projects be considered in this category, given the stage of development of these technologies. In addition, it is recommended that the results of EU and extra-EU projects be disseminated in Ireland as they become available.

The projects should only proceed following a detailed, fully costed technical and financial feasibility study and as in the case of the other demonstration projects proposed, the provision of detailed technical information should be a condition of the project

a. *Wind + flow battery*
Despite the withdrawal of Regenesys, flow batteries are still a strong contender as a potential storage solution to wind energy intermittency, with both VRBs and ZnBr batteries targeting wind energy projects. It is recommended that the choice of flow battery type should be made based on project proposals submitted, rather than being prescribed in advance.

b. *Wind + hydrogen engine*
While engines are less efficient than fuel cells, a wind hydrogen engine demonstration project can be seen as a transition stage to a wind hydrogen fuel cell project and can provide some valuable information on the stage of progress in electrolyser and engine technology, as distinct from fuel cell technology.

c. *Wind + hydrogen fuel cell*
The absence of detailed information from working wind hydrogen fuel cell systems is a key gap in this area. There is a lot of international focus that should reduce the costs of these systems. A demonstration project would provide clarity relating to the performance of the individual components, overall system efficiency, current costs and valuable insights into what may be required to make these systems viable.

In summary, the energy storage sector is central to the full integration of wind energy generation. There are a number of appropriate technologies, the most attractive of which from a flexibility viewpoint is wind hydrogen, because of the ability to decouple the input power, output power and storage capacity. Furthermore, wind hydrogen systems are attractive from the standpoint of achieving zero emissions energy. It has not yet matured from an economic perspective however and the overall energy efficiency remains poor.

Pumped hydro systems and compressed air systems have the advantage of technical maturity, economic viability and operational experience and are therefore viewed as a realistic and appropriate first stage in the development of an energy storage solution to wind energy intermittency.

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APPENDIX 1. WIND FARMS WITH PLANNING PERMISSION

Table A.1 Location of wind farms with planning permission

Site ID	Site Location	County	Capacity (MW)	Turbines	Under Appeal?
1	Cape Clear Island	Cork	0.035	-	No
2	Dromourneen, Deereennacno, Glanaphuca	Cork	-	21	No
3	Bere Island	Cork	0.66	1	No
4	Coomatallin	Cork	5.95	7	No
5	Lahanaght, Derryclough	Cork	4.95	3	No
6	Coomatalin, Kippagh	Cork	5.95	7	No
7	Garranure, Kilvinane	Cork	4	-	No
8	Cloghmacsimon	Cork	3	3	No
9	Cappaboy/Curraglass/Maugha	Cork	8.5	10	No
10	Milleeny	Cork	2	2	No
11	Inchamore	Cork	4.8	4	No
12	Cahernafulla, Kilberrihert	Cork	7	7	No
13	Knockraheen, Carriganimmy	Cork	-	6	No
14	Pluckanes West	Cork	2	2	No
15	Gneeves	Cork	15.6	13	No
16	Gneeves	Cork	4.8	4	No
17	Scartbarry	Cork	-	1	No
18	Coomaghcheo, Curracahill, Adrivale	Cork	-	17	No
19	Boggeragh Mountains	Cork	50	20	No
20	Esk South	Cork	7	7	No
21	Carragraigue, Charlesfield, Inchamay North	Cork	8	8	No
22	Glenlahan, Forehane, Cappaphaudeen	Cork	26	20	No
23	Glentanemacelligott, Glennakeel South	Cork	-	6	Yes
24	Taurbeg, Glasheenavargid	Cork	-	14	No
25	Taurbeg	Cork	15	25	No
26	Rockhill West	Cork	-	7	No
27	Coomagearlahy	Kerry	-	17	No
28	The Coom, Cordal	Kerry	8	8	No
29	The Coom, Cordal	Kerry	6.8	8	No
30	Knockauncurragh/Glanowen/Coom	Kerry	17.85	21	No
31	Tylagh	Kerry	-	4	Yes
32	Muingnaminane	Kerry	21	21	No
33	Tursillagh Expansion/Extension	Kerry	21.8	-	No
34	Cloghboola	Kerry	40.25	24	No
35	Pallas, Banemore, Cloghanenagleragh and Kilfeighny	Kerry	39	26	No
36	Kilpaddoge/Carhoonakineely	Kerry	23	28.5	No
37	Knockaveelish/Knocknalougha	Waterford	15.3	12	No
38	Beallough	Waterford	1.6	2	No
39	Nethertown & Shilmore	Wexford	-	1	No
40	Newtown/ Richfield/ Riesk/ Inish/ Ballyteige Slob	Wexford	-	43	No
41	Richfield	Wexford	20.25	7	No
42	Grageelagh	Wexford	3.6	-	No

43	Ballinoulart	Wexford	36	24	No
44	Bolinrush	Wexford	14.45	17	No
45	Knocknalour	Wexford	-	3	No
46	Cappagh, Parkroe, Kilmore, Oldcastle	Tipperary	16	11	No
47	Moanvaun	Tipperary	0.66	1	No
48	Bunkimalta/Bauraglanna	Tipperary	42.5	17	No
49	Ballinveny/Borrisnafarney, Gortagarry	Tipperary	7	6	No
50	Skehanagh	Tipperary	5	5	No
Site ID	Site Location	County	Capacity (MW)	Turbines	Under Appeal?
51	Lacka	Tipperary	3	3	No
52	Ballybeagh	Kilkenny	-	5	No
53	Dromdeeveen	Limerick	10.5	7	No
54	Caherlevoy, Glengort South	Limerick	-	9	No
55	Tournafulla/Templeglentan	Limerick	25.5	17	No
56	Knocknasna	Limerick	2.55	3	No
57	Tooradoo	Limerick	5.95	7	No
58	Gortnagross	Limerick	8	-	No
59	Grouselodge	Limerick	12	8	No
60	Currachafoil	Limerick	4.25	5	No
61	Rosscurra, Aclare, Kilbranish North	Carlow	52.5	21	Yes
62	Moneypoint	Clare	22.5	9	No
63	Monmore South	Clare	12.6	7	No
64	Booltiagh	Clare	19.5	15	No
65	Cronelea Upper	Wicklow	2.55	3	No
66	Rin	Offaly	-	5	No
67	Pollduff	Galway	15	23	No
68	Derrybrien	Galway	60.35	71	No
69	Keelderry	Galway	48	48	No
70	Sonnagh Old, Kilchreest	Galway	7	10	No
71	Teevurcher	Meath	4.5	-	No
72	Teevurcher	Meath	7.5	5	No
73	Cuillalea	Mayo	3.4	4	Yes
74	Croughan West, Dooleeg More, Kilsallagh, Knockmoyle, Laghtanvack	Mayo	320	192	Yes
75	Alt, Bunnahowen	Mayo	3	3	No
76	Corrinshigo/Raragh (Clankee Barony)	Cavan	3	-	No
77	Gartnaneane	Cavan	15	10	No
78	Bindoo	Cavan	77.5	31	No
79	Ratrussan	Cavan	3	2	No
80	Edrans, Tullyco	Cavan	7	-	No
81	Mountain Lodge	Cavan	48	32	Yes
82	Artonagh, Tullyco	Cavan	26	26	Yes
83	Mountain Lodge	Cavan	37.5	-	No
84	Snugborough & Carrowmore	Cavan	10.5	7	No
85	Corrie Mountain, Tullymurray	Leitrim	3.96	-	No
86	Black Banks (ext)	Leitrim	6.8	8	No
87	Moneenatieve (Corrie Mountain ext)	Leitrim	5.1	6	No
88	Garvagh Glebe, Leckaun, Tullynamackduff, Bargowla, Seltan, Boleymaguire	Leitrim	32.5	13	No

89	Cunghill, Lavagh	Sligo	-	5	No
90	Carrownyclowan & Carrowmore	Sligo	6.4	6	No
91	Lackan Townland	Sligo	-	3	Yes
92	Cornacahan	Donegal	2.55	3	No
93	Corkermore Hill	Donegal	21	14	No
94	Meenacloghspar	Donegal	1.2	2	No
95	Meenanilta	Donegal	2.55	3	No
96	Meenahorna	Donegal	22.5	9	No
97	Meenalaban	Donegal	43.6	-	No
98	Meentycat	Donegal	22.5	15	No
99	Cark Expansion/Extension	Donegal	24.45	-	No
100	Cark, Newmills	Donegal	4.25	-	No
Site ID	Site Location	County	Capacity (MW)	Turbines	Under Appeal?
101	Drumkeen	Donegal	4.25	-	No
102	Ballystrang, Rareagh	Donegal	7.8	9.1	No
103	Glackmore Hill, Three Trees	Donegal	5	5	No
104	Sorne	Donegal	28	16	No
105	Bauville Keeloges	Donegal	-	3	No
106	Flughland	Donegal	8.9	5	No
107	Glasmullan & Shandrim	Donegal	8	8	No
108	Drumlough Hill	Donegal	-	13	No
109	Baile Thoir	Donegal	2	2	No
110	Arklow Bank	Offshore	520*	200	-

APPENDIX 2. VARIABLE USED IN FINANCIAL MODEL

Variable	**Description**	**Typical Range**
Cost of charging equipment	€ cost per kW for charging equipment (for example pumps or electrolyser)	€ 400 - € 1,500 / kW
Cost of storage equipment	€ cost per kWh for storage medium (for example water reservoir or tanks). Modelled at zero loss	€ 1 - € 20 / kWh
Cost of regeneration equipment	€ cost per kW for regeneration equipment (for example turbines, engines or fuel cells)	€ 400 - € 2,000 / kW
Operation and maintenance costs	€ cost (semi-scaled) for plant operations and maintenance	0. – 0.5 c / kWh
Input energy cost	c / kWh for input energy, typically the foregone attainable price by the wind energy producer	0 – 4 c / kWh
Output energy price	c / kWh for electricity supplied to the grid	3 – 7 c / kWh
Charging efficiency	Efficiency of charging equipment	40% - 90%
Discharge efficiency	Efficiency of discharge	20% - 90%
Hours of operation per day	Number of hours that the storage system discharges at rated power	5 – 20 hours
Green energy credit	Benefit accrued from either ROC or similar system	0 – 7 c / kWh
Cost of debt financing	Cost of primary debt for project	4 – 7 %
Cost of equity or mezzanine funding	Cost of subordinated capital	7 – 12%
Terminal value discount	Appropriate discount charge on future production after 20 years lifetime	5 – 16%
Capital structure	Debt / mezzanine / equity	80% primary debt
Tax rate	Tax rate for project	12% – 25%