A Review of Utility Scale Energy Storage Options and Integration with Offshore Wind in Massachusetts

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ABSTRACT

The purpose of this work is to review the state of the art in utility scale energy storage technologies which may have relevance to the Massachusetts electrical supply, and to investigate in detail two of the technologies which have already been considering as a plausible accompaniment to large scale development of offshore wind energy. These are compressed air storage and ammonia production.

1.0 INTRODUCTION/ BACKGROUND

Energy storage has been the subject of a number of recent technical books on various topics concerning energy storage. Some of these include the following topics:

1) New Approaches (Zito, 2010)

2) Thermal Energy Storage (Dincer and Rosen, 2011

3) Large Scale Storage (Barnes and Levine, 2011)

4) Compressed Air Storage (Al-Khoury and Bundschuh, 2014)

5) Energy Intermittency (Sorensen, 2015)

6) Renewable Energy Systems (Letcher, 2016)

There are basically four types of energy storage that could provide a useful role in the Massachusetts electrical system. A potential fifth option is end use storage that involves the creating some desired product at one point in time and storing it for use at a later time. End use storage is typically an accompaniment to load management.

As shown in the Figure 1.1, these four types include mechanical, electrical, thermal, and chemical storage. Examples of mechanical storage are pumped hydroelectric, compressed air and flywheels. In these cases, energy is stored by pumping water up hill, compressing air, or accelerating a flywheel; the energy is recovered by reversing the process. Examples of electrical storage include batteries and capacitors - these hold electric charge that can later be recovered as current. In thermal energy storage, a medium is either heated or cooled. In some cases, such as high temperature storage, the thermal energy may be converted back to mechanical and eventually electrical energy through a series of processes. In other cases, the energy is used to supply a thermal end use, such as space heating. Chemical energy storage involves the making or breaking of chemical bonds. The most common form of chemical storage is the production of some type of fuel, such as hydrogen, ammonia or hydrogenated biomass. Fuels produced in this way could either be used to generate electricity again or could be used other applications, such as for transportation.

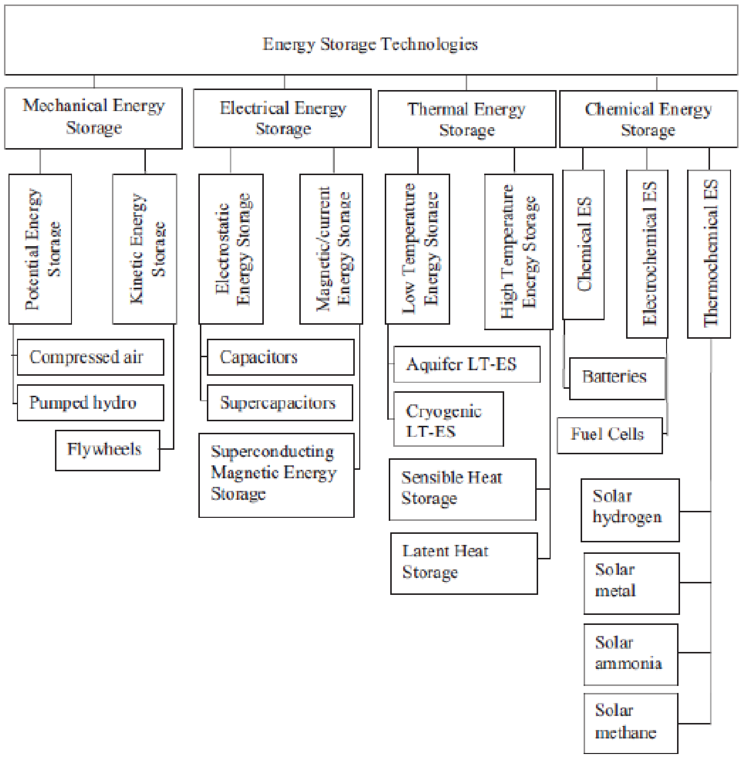

Figure 1.1 Examples of energy storage technologies (Evans, 2012)

In addition to a general review of utility scale energy storage, this report will review the state of the art in utility scale energy storage technologies which may have relevance to the Massachusetts electrical supply, and then to review two of the technologies which investigators have already been considering as plausible energy storage systems for the utility scale development of offshore wind energy. These are compressed air and ammonia production.

2.0 GENERAL OVERVIEW/REVIEW OF ENERGY STORAGE SYSTEMS

To supplement the previous list of energy storage texts, this section reviews seven overview technical references on utility scale energy storage (from 2009) that are most relevant.

1) <u>Akhil, et al, 2015) Sandia National Laboratories DOE/EPRI Storage Handbook</u>

This comprehensive report (over 300 pages) describes all the current (and some proposed) utility scale energy storage systems. It was written as a guide for utility engineers, planners, and decision makers for the planning and implementation of energy storage projects. It was also written as an information resource for investors and venture capitalists in order to provide the latest developments in technologies and tools for the evaluation of utility scale energy storage systems. It contains a comprehensive list of significant and recent utility scale energy storage projects. In addition, it includes a database of the cost of current energy storage systems.

In the overview section they note that the different types of energy storage technologies can be looked at via their power and energy relationships. Figure 2.1 gives a general view of their conceptual summary of the various energy storage technologies.

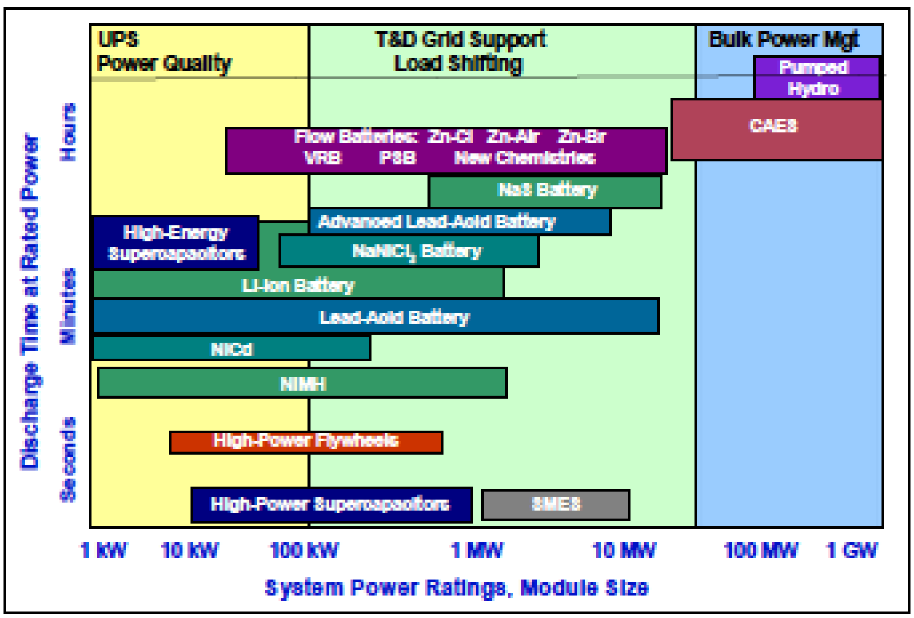

Figure 2.1 Positioning of Energy Storage Technologies (Akhil, et al, 2015)

In their overview chapter they considered the following utility-scale storage systems:

- Pumped Hydro
- Compressed Air Energy Storage
- Flywheel Energy Storage
- Electrical Storage via Batteries
- Emerging Technologies

Their overview of emerging technologies is shown in Figure 2.2.

Storage Type	Status/Innovation	Estimated Deployment Timing
Liquid Air Energy Storage Systems	System studies. Low-cost bulk storage. Small demos underway.	2013-2014 first +MW-scale demo.
Non/Low-Fuel CAES	System studies underway to optimize cycle and thermal storage system. Low-fuel and non-fuel CAES for bulk storage.	2015 pilot demonstration of 5-MW system
Underground Pumped Hydro	System studies. New concepts under development.	Under study.
Nano-Supercapacitors	Laboratory testing. High power and energy density; very low cost.	2013-2015
Advanced Flywheels	System studies. Higher energy density.	Under development. 2015.
H_2/Br Flow	Bench-scale testing. Low-cost storage.	2013-2014 pilot demo.
Advanced Lead-Acid Battery	Modules under test. Low cost; high-cycle life.	2013-2015 early field trials.
Novel Chemistries	Bench-scale testing. Very low cost; long-cycle life.	2013-2015 modules for test.
Isothermal CAES	2 MW and 1 MW System Development and Demonstration effort. Non-fuel CAES for distributed storage.	2013 pilot system tests.
Advanced Li-ion Li-air and others	Laboratory/basic science. Lower costs; high energy density.	2015-2020

Figure 2.2 Emerging Storage Options and Development Timelines (Akhil, et al, 2015

It should also be noted that they present a discussion of maturity and commercial availability for most of the utility scale systems that they describe. For example, Table 2.1 gives their summary via a “Technology Dashboard” approach for Compressed Air Energy Storage (Onland).

Technology Development Status	1st Generation Mature 2nd Generation - Demonstration	Commercial offer possible. System to be verified by demonstration unit.
Confidence of Cost Estimate	C	Based on preliminary designs Owners' costs and site-specific costs not included; these costs can be significant. First-time-engineering costs can be significant.
Accuracy Range	C	-20% to +25%
Operating Field Units	2nd Generation - None	Two of first-generation type
Process Contingency	15%	Key components and controls need to be verified for second-generation systems.
Project Contingency	10%	Plant costs will vary depending upon underground site geology.

Table 2.1. Technology Dashboard: Compressed Air Energy Storage (Akhil, et al, 2015)

In addition, for each energy storage technology, system costs are estimated for: 1) Present value levelized cost ($/kW), levelized cost of energy ($/MWh) and levelized cost of capacity ($/kW-yr). An example of their results for the present value costs of compressed air energy storage systems is given in Figure 2.3.

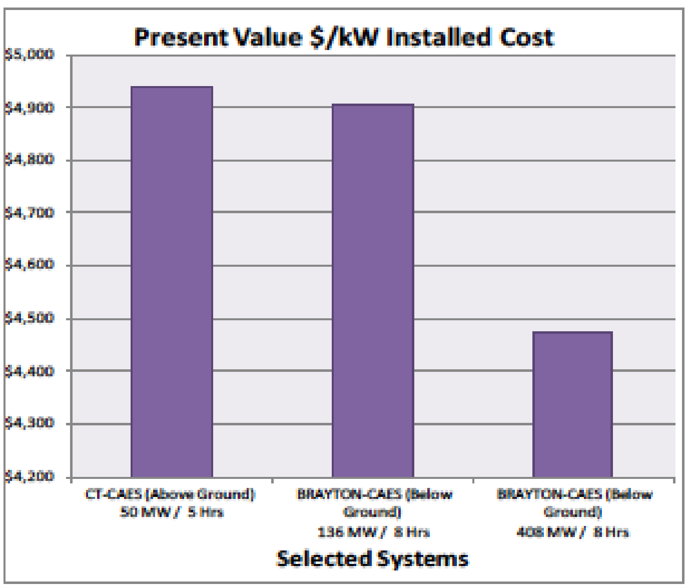

Figure 2.3. Present Value Installed Cost for CAES Systems (Akhil, et al, 2015)

The cost details of the various energy storage systems are presented in Appendix B of their report. Here it should be noted that the report really concentrates on the details of battery storage systems and thus is most valuable for the analysis of these systems.

2) Verma, et al. (2013) Energy Storage: A Review

Verma, et al (2013) present a general review of energy storage. This paper with 24 references presents a general description of utility scale energy storage methods. As shown in Figure 2.4, they cover the same basic systems as the 2015 Sandia report.

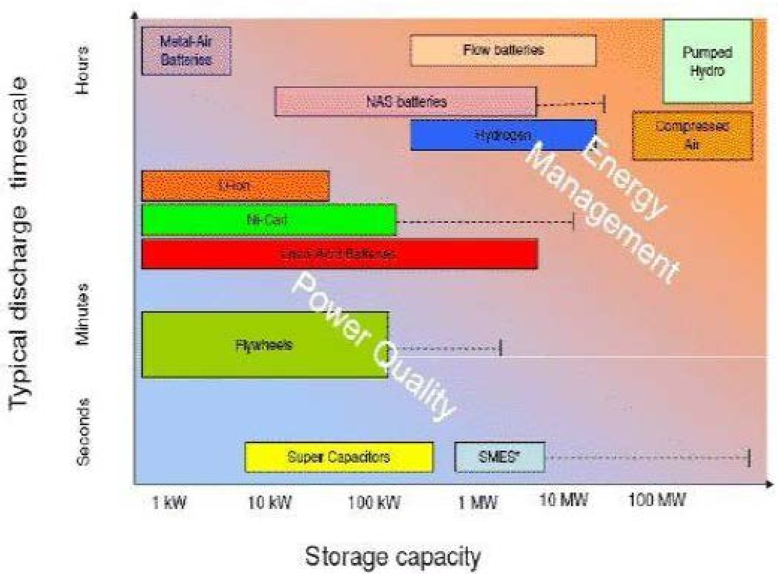

Figure 2.4. Different Techniques for Energy Storage (Verma, et al., 2013)

In their summary they conclude that long term energy storage systems like pumped hydro and compressed air systems are best suited for large-scale energy storage.

3) <u>Biswas, et al (2013) Towards Implementation of Smart Grid: An Updated Review on Electrical Energy Storage Systems</u>

This work gives a review of available energy storage systems applications for smart power grids. It has a good summary of the advantages of smart grids (see Figure 2.5) and their applicability to renewable energy generation systems. It also gives a short summary of hybrid energy storage systems (in a hybrid energy storage system two or more different energy storage systems are combined together electrically.

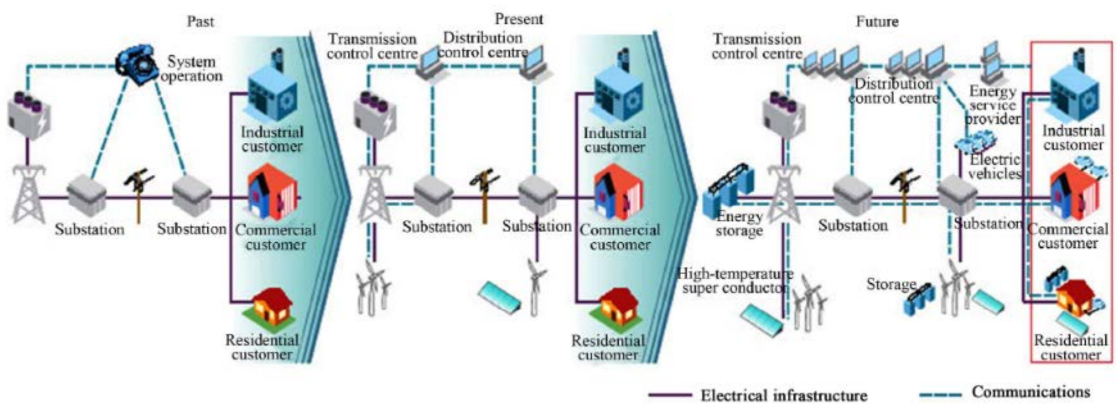

Figure 2.5. Smart Grid Electrical Systems (Biswas, et al., 2013)

The paper has 84 references and, as shown in Table 2.2, presents a summary comparison)(of different energy storage technologies.

Type	Energy Density (Wh/kg)	Energy Efficiency (%)	Power Density (W/Kg)	Life Time (Cycles)	Self Discharge (%/Month)	Environmental Effect
Battery	25 - 250	60 - 90	100 - 3000	150 - 3000	3 - 30	Toxic
Ultra Capacitor	<50	95	4000	10 k - 100 k	High	Benign
Flywheel	100 - 130	95	1000	>125,000	High	Benign
SMES	30 - 80	95	Very High	-	Negligible	Benign
CAES	10 - 30	50	Fair	40 Years	Negligible	Benign
PHS	0.3	65 - 80	-	75 Years	Negligible	Benign

Table 2.2. Comparison of Various Energy Storage Systems (Biswas, et al., 2013)

4) <u>Koohi-Kamal, et al (2013) Emergence of energy storage technologies as the solution for reliable operation of smart power systems: A review</u>

This highly detailed technical review paper (31 pages and 133 references) emphasizes the role of energy storage systems that can be used in future smart power systems. The paper presents the different energy storage technologies and emphasizes the combination of such systems with renewable energy systems. That is, particular attention is focused on flywheel, electrochemical, pumped hydroelectric, and compressed air storage systems.

The authors emphasize the role of energy storage in the growing level of renewable energy systems' penetration levels, controlling the frequency, upgrading transmission line capability, mitigating voltage fluctuations, and improving power quality and reliability. As shown in Figure 2.6, they estimate the magnitude of the power and the time needed for such applications.

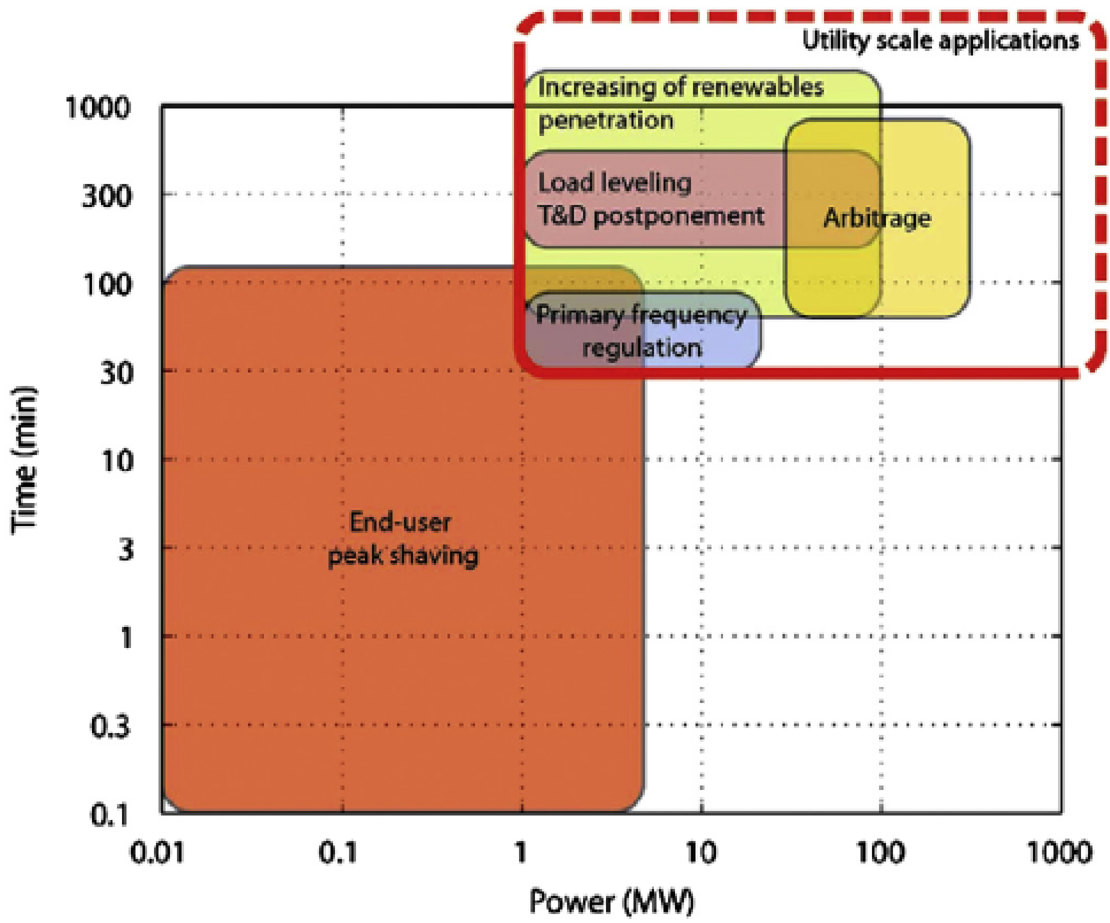

Figure 2.6. Utility Applications of Energy Storage Systems (Koohi-Kamal, et al , 2013)

5) <u>Pickard and Abbott, eds (2012) IEEE SPECIAL ISSUE ON ENERGY STORAGE</u>

This special issue of IEEE consists of 17 papers on a variety of subjects pertaining to large-scale energy storage. The papers tend to be of a review variety and are very well referenced in general. This issue also includes some information on small to medium sized storage systems and a discussion of the driving forces for energy storage.

The editors of this publication note that energy storage systems are conveniently divided into three parts:
1) An input energy conversion module that accepts energy from the grid and converts it to a storable form.
2) An energy storage module that warehouses the storable form.
3) An output conversion module that turns the stored energy back into electricity and returns it to the grid.

In addition to papers describing the general aspects of utility scale energy storage systems, this issue contains papers on the following subjects
1) Energy policy including technical topics on energy storage
2) Chemical storage
3) Mechanical storage
4) Thermal storage

There are no papers on storage systems involving wind energy input, however, and the main emphasis is on concentrating solar thermal systems.

6) Evans, Strezov, and Evans (2012) Assessment of utility energy storage options for increased renewable energy penetration

This technical paper presents a short but comprehensive (63 references) review of utility scale energy resource options that can be used to increase renewable energy penetration. The energy storage parameters that the authors compare include the following:

1) Efficiency
2) Energy capacity
3) Energy density
4) Run time
5) Capital investment costs
6) Response time
7) Lifetime (years and cycles)
8) Self discharge rate
9) Maturity

A summary of their results is shown in Table 2.3.

	Efficiency (%)	Capacity (MW)	Energy density (Wh/kg)	Run time (ms/s/m/h)	Capital ($/kW)	Capital ($/kWh)	Response time	Lifetime (Years)	Lifetime cycles	Self discharge (per day)	Maturity	Charge time	Environmental impact	Thermal needs
Mechanical storage														
CAES underground	70–89	5–400	30–60	1–24+h	800	50	Fast	20–40	>13,000	Small	Commercial	Hours	Large	Cooling
CAES aboveground	50	3–15		2–4 h	2000	100	Fast	20–40	>13,000	Small	Developed	Hours	Moderate	Cooling
Pumped hydro	75–85	100–5000	0.5–1.5	1–24+h	600	100	Fast	40–60	>13,000	Very small	Mature	Hours	Large	None
Flywheels	93–95	0.25	10–30	ms-15 m	350	5000	Very fast (<4 ms)	~15	>100,000	100%	Demonstration	Minutes	Benign	Liquid nitrogen
Electrical storage														
Capacitor	60–65	0.05	0.05–5	ms-60 m	400	1000	Very fast	~5	>50,000	40%	Developed	Seconds	Small	None
Supercapacitor	90–95	0.3	2.5–15	ms-60 m	300	2000	Very fast	20+	>100,000	20–40%	Developed	Seconds	Small	None
SMES	95–98	0.1–10	0.5–5	ms-8 s	300	10,000	Very fast (<3 ms)	20+	>100,000	10–15%	Developed	Minutes to hours	Moderate	Liquid helium
Thermal storage														
CES	40–50	0.1–300	150–250	1–8 h	300	30		20–40	>13,000	0.5–1%	Developing	Hours	Benign	Thermal store
HT-TES	30–60	0–60	80–200	1–24+h		60		5–15	>13,000	0.05–1%	Developed	Hours	Small	Thermal store
Chemical storage														
Pb-acid battery	70–90	0–40	30–50	s-h	300	400	Fast (ms)	5–15	2000	0.1–0.3%	Mature	Hours	Moderate	Air conditioning
Na–S battery	80–90	0.05–8	150–240	s-h	3000	500	Fast (ms)	10–15	4500	~20%	Commercial	Hours	Moderate	Heating
Ni–Cd battery	60–65	0–40	50–75	s-h	1500	1500	Fast (ms)	10–20	3000	0.2–0.6%	Commercial	Hours	Moderate	Air conditioning
Li-ion battery	85–90	0.1	75–200	m-h	4000	2500	Fast (ms)	5–15	4500	0.1–0.3%	Demonstration		Moderate	Air conditioning
Fuel cells	20–50	0–50	800–10,000	-24+h	10,000		Good (<1 s)	5–15	>1000	Almost zero	Developing	Hours	Small	Varies

TABLE 2.3 Summary of Energy Storage Technologies (Evans, et al., 2012)

7) <u>Hadjipaschalis, et al. (2009</u>) <u>Overview of current and future energy storage technologies for electric power applications</u>

This paper presents a state-of-the-art review of energy storage applications for electric power production. They give a comparison of the various technologies in terms of the most important technological characteristics of each technology. Their review places most emphasis on electrical energy storage systems (i.e., supercapacitors and batteries).

As shown in Figure 2.7, they give the deliverable power and energy capacity of the systems that they studied. Note that compressed air and pumped storage systems are not shown here since their scale exceeds the scale of the figure.

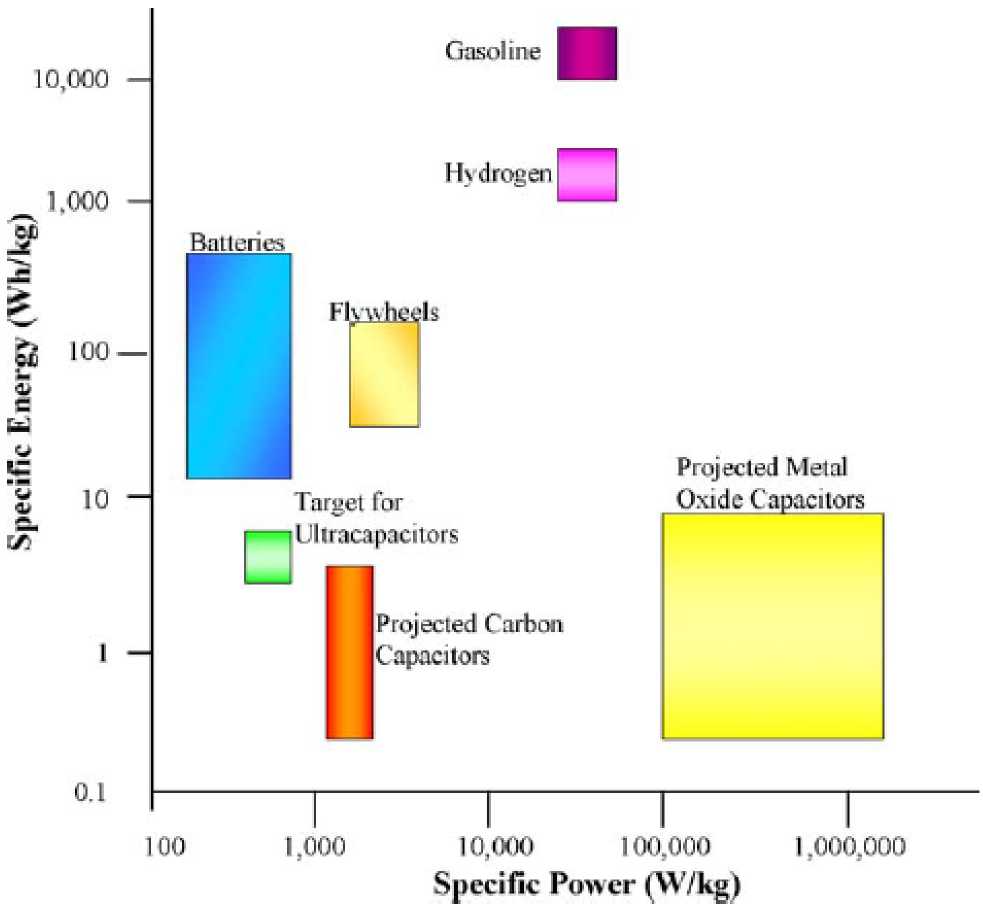

Figure 2.7. Comparison of specific power and energy storage for selected storage systems (<u>Hadjipaschalis, et al., 2009)</u>

3.0 ENERGY STORAGE BASED ON INPUT FROM RENEWABLE ENERGY SYSTEMS

3.1 General Overview

In addition to the previously mentioned book on the over subject of energy storage from renewable energy sources (Letcher, 2016), there are a number of technical papers on energy storage that include wind energy as the main renewable energy resource. A summary of selected references on this subject follows. Note that several of these papers are review oriented and contain a large number of references.

1) Lund, et al (2015) "Review of Energy System Flexibility Measures to Enable High Levels of Variable Renewable Energy"

This paper reviews the different approaches, technologies, and strategies that can be used to manage utility-scale renewable energy produced electricity from solar and wind sources. Both supply and demand side measures are considered. In addition to presenting energy system flexibility measures, their importance for renewable energy produced electricity is discussed. The flexibility measures discussed range from traditional ones, such as grid extension or pumped storage to more advanced strategies such as demand side management and demand side linked approaches (such as the use of electric vehicles to store excess energy). The authors conclude that the outlook for managing large amounts of renewable energy in terms of available options is promising.

Figure 3.1 illustrates their summary of power and discharge time of energy storage technologies

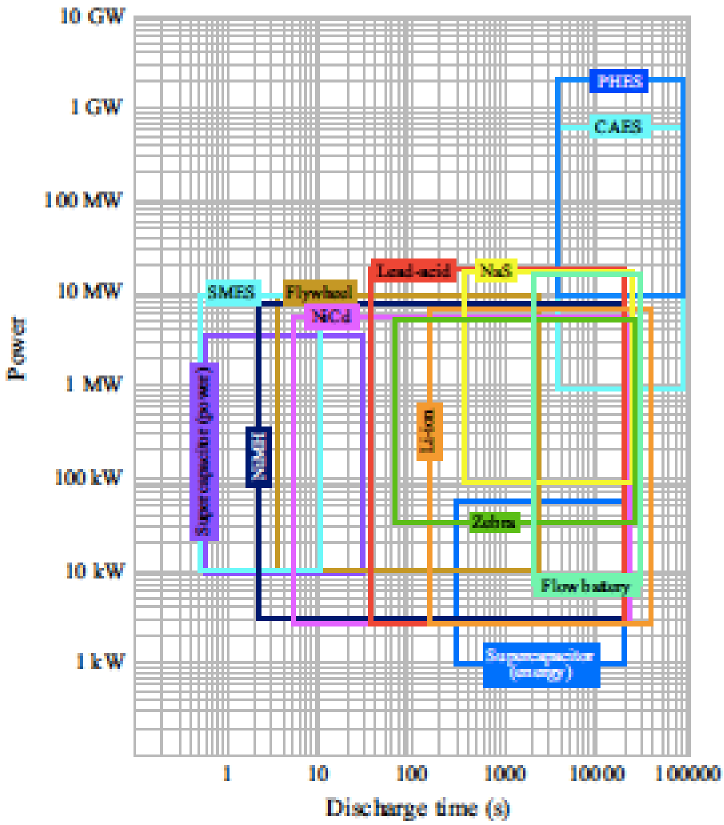

Figure 3.1 Power and discharge time of energy storage systems (Lund, et al., 2015)

2) Zhao, H., et al. (2015) Review of energy storage system for wind power integration support

This paper reviews various wind energy storage options (see Figure 3.2) for a number of various options. Initially modern energy storage systems and their potential applications for wind power systems are introduced and reviewed. Next, the planning problem in relation to the energy storage application for wind power integration is reviewed, including the selection type, and its optimal sizing and siting. A further section of this report considers and reviews the proposed operation and control strategies of a storage system for different applications purposes in relation to the wind power integration support.

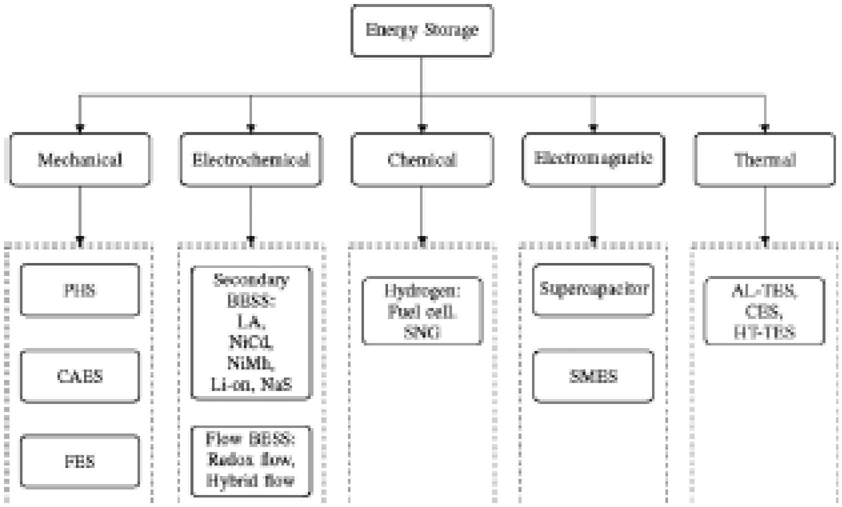

Figure 3.2 Energy Storage Options (Zhao, H., et al., 2015)

3) Hasan, et al. (2013) "Review of Storage Schemes for Wind Energy Systems."

The authors review four different types of energy storage systems for wind energy storage applications. These include: 1) compressed air energy storage, 2) superconducting magnet energy storage, 3) flywheel energy storage, and 4) hydrogen energy storage.

4) <u>Diaz-Gonzalez, et al. (2012), "A Review of Energy Storage Technologies for Wind Power Applications</u>

As shown in Table 3.1, this paper summarizes the operating principles and technical characteristics of 13 energy storage technologies that could be used in utility scale wind power systems. Note that it includes an extensive list (234) of applicable references.

Characteristics parameters of ESS.

Technology	Capital cost	Energy rating (MW h)	Power rating (MW)	Specific energy (W h/kg)	Specific power (W/kg)
PHS	10–20 €/kW h [7], 35–70 €/kW h [8]	500–8000 [9]	10–1000 [9]	–	–
HESS	2–15 €/kW h [7]	120 [5]	0.1–15 [5], 0.3–50 [10]	100-150 [11], 400–1000 [11]	–
CAES	3–5 €/kW h [7], 10–70 €/kW h [8]	2860 [12], 580 [12]	110 [12], 290 [12], 50–300 [13]	3.2–5.5 [13]	–
VRB	600 $/kW h [14]	2 [15], 6 [16], 1.2–60 [17], 120 [18]	0.25 [15], 6 [16], 0.2–10 [17], 12 [18]	20 [19], 25–35 [20]	166 [21]
ZBB	500 $/kW h [22]	0.1–3 [23], 0.15 [24], 0.4 [25], 2 [26], 2.8 [16], 4 [4]	0.1-1 [23], 0.1 [24], 0.2 [25], 2 [26], 0.5 [16], 1 [4]	60 [27], 70–90 [11], 75–85 [28]	45 [29]
PSB	125–150 €/kW h [7], 450$/kW [14], 360–1000 €/kW h [30]	0.005–120 [20]	0.1–15 [20]	–	–
NaS	210–250 €/kW h [7], 450$/kW h [22]	0.4 [31], 0.4–244.8 [32]	0.05 [31], 0.05–34 [32]	100 [27], 175 [33]	115 [29], 90–230 [34]
Lead-Acid	50–100$/kW h [13], 210–270 €/kW h [7], 185 €/kW h [15]	0.001–40 [15]	0.05–10 [15]	30 [13], 35–50 [35]	180 [13], 200 [29]
Ni–Cd	400–2400$/kW h [13]	6.75 [16]	45 [16]	30–40 [36], 50 [13,27], 45–80 [35]	100–150 [36], 160 [29]
Li-ion	900–1300$/kW h [13]	0.0016 [37], 0.5 [38], 0.0015–50 [39]	0.1 [37], 2 [38], 0.015–50 [39]	80–150 [13], 100–150 [27], 160 [35], 120–200 [40]	245–430 [36], 400-500 [33], 500–2000 [13]
SMES	–	0.001 [41], 0.00083 [4], 0.015 [42]	1 [41], 3 [4], 100 [42], 1–10 [28,43]	10–75 [43]	–
FESS	400–800$/kW h [13]	0.0052 [44], 0.025–5 [45]	1.65 [44], 0.1–20 [45]	20 [11], 5–80 [46], 5–100 [13]	11,900 [47]
SCESS	20,000 $/kW h [13], 6800 €/kW h [48]	0.01 [49]	0.05–0.1 [5], 0.25 [49]	2–5 [40], 5.69 [50], 1–10 [51], 10 [46], 5–15 [5], 30 [52]	800–2000 [5], 2000–5000 [40], 10,000 [13,51], 13800 [50], 23,600 [53]

Table 3.1 Potential Storage Systems for Utility Scale Wind Power Systems (Diaz-Gonzalez, et al., 2012)

5) Sundararagavan, S. and Baker, E. (2012) "Evaluating Energy Storage Technologies for Wind Power Integration."

This paper presents a cost analysis of 11 different types of storage systems for utility-scale wind power systems. A summary of their results is given in Table 3.2. The authors also identified the key characteristics that affect economic viability for these technologies and performed a sensitivity analysis based on key performance criteria and improvement that could make them more cost effective in the future.

Technologies	Energy cost ($/kWh)	Power cost ($/kW)	Balance of plant cost ($/kW or $/kWh)	Operation & maintenance cost ($/kW)	Efficiency (%)	Lifetime (years)
CAES	10[a]	450[g]	160 $/kW[a]	6[j]	70[b]	30[b]
PHS	12[d,e,f]	2,000[h]	2 $/kWh[e]	3[d]	80[h]	40[b]
Pb-acid	300[b]	450[b]	100 $/kW[a]	10[d]	75[d]	6[i]
ZnBr	400[a,d]	2,000[b]	100 $/kW[a]	26[a]	75[b]	10[b]
NaS	534[c]	3,000[b]	100 $/kW[a]	14[a]	85[b]	15[b]
VRB	630[c]	3,200[c]	100 $/kW[a]	28[a]	80[b]	10[b]
Ni-Cd	1,197[a]	600[b]	100 $/kW[a]	15[a]	65[b]	20[b]
Li-ion	1,500[b]	1,500[b]	100 $/kW[a]	10[d]	93[b]	15[b]
Flywheels	1,000[d]	350[b]	100 $/kW[a]	18[a]	90[d]	15[b]
SMES	10,000[b]	300[b]	1,500 $/kWh[e]	10[d]	95[d]	20[b]
EC	30,000[d]	300[b]	100 $/kW[a]	13[a]	95[d]	30[b]

Table 3.2 Summary of Cost Component Data for Energy Storage Systems (Sundararagavan, S. and Baker, E., 2012)

6) <u>Tuohy and O'Malley (2012), "Wind Power and Storage."</u>

This review is contained in Chapter 21 of Ackermann's book (2012). The authors review four potential wind powered storage systems: Pumped hydro, Compressed air, Battery storage, and Flywheel storage.

7) <u>Barnes, F. S. and Levine, J. G. (2011) Large Energy Storage Systems Handbook</u>

This reference involves a book long review of utility scale storage with some emphasis on wind powered systems.

8) <u>Ibrahim, H., Ilinca, A. and Perron, J.(2008), "Energy Storage Systems- Characteristics and Comparisons,"</u>

This reference reviews the characteristics of eleven potential utility-scale energy storage systems.

3.2 Storage Value in Utility Applications

Although not specifically related to renewable energy based storage systems, we thought that it was important to include a listing of some recent references that consider the storage value in utility based applications and modeling techniques that could be used to evaluate potential applications. Our review here yielded the following references:

1) Carbon Trust, Imperial College, London (2016), "Can Storage help reduce the cost of a future UK electricity systems?"

2) Mueller, J.M. (2015) "Increasing Renewable Energy System Value Through Storage," M.S. Thesis, Massachusetts Institute of Technology.

3) Zucker, A., et al. (2013) "Assessing Storage Value in Electricity Markets," JCR Scientific and Policy Reports, European Commission.

4) Eyer, J. and Corey, G. (2010) "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide: A Study for the DOE Energy Storage Systems Program," Sandia Laboratory Report: SAND2010-0815

5) Rastler, D. (2010) "Electricity Energy Storage Technology Options: A White Paper on Applications, Costs, and Benefits," Electric Power Research Institute Paper No. 1020676.

4.0 OFFSHORE WIND ENERGY STORAGE SYSTEMS: GENERAL REVIEW

4.1 INTRODUCTION

In terms of offshore energy storage where the typical installed capacity of offshore wind power plants are tens to hundreds of MWs, energy storage power plants capacity and energy requirements should exhibit a charging/discharging ability equal to the offshore wind park's nominal power and have a minimum total energy capacity between 1-3% of the total annual electricity production [Ng and Ran, 2016]. For example, an offshore wind park with a nominal power of 100 MW and a capacity factor of 30% would require a minimum storage capacity of about 2600 MWh. The actual storage capacity is dependent on the size of the wind park and its daily and seasonal variations in output, characteristics and generation resources of the electrical system it is connected to, as well as, the operational mode or algorithm of the wind-storage system. Theoretically, there may be several different storage technologies suitable to manage the variability and uncertainty inherent in wind. From a practical stand point, there are only two existing storage technologies that are suitable to meet these storage requirements in an offshore environment: Compressed Air Energy Storage (CAES) and Pumped Hydro Energy Storage (PHS) [Luo, et al., 2015]. The basics fundamentals and characteristics of these technologies are described in the following two sections.

<u>Compressed Air Energy Storage Systems</u>

A CAES power plant consists of a motor compressor, a turbine generator, and a space to store the compressed air. In a typical storage scenario, electricity drives a compressor during times of when the energy value is relatively low and air is stored to high pressures. During times when the value of energy is high, the high-pressure air is released and is expanded through a turbine generator producing electricity. CAES can be distinguished into three separate compressor/expansion systems: diabatic or conventional, adiabatic, and isothermal. These systems and methods of storing the air will be discussed in further detail in the next sections.

<u>Diabatic Compressed Air Energy Storage (D-CAES)</u>

In a D-CAES process, air is compressed and stored at near ambient temperature. The heat generated by the compressor is removed by intercoolers and is not recycled back into the system. During expansion, heat is supplied by the combustion of fuel mixing through the turbine. Air is preheated prior to the expansion process for two reasons. First, more work can be extracted by heating and expanding the air when compared to a lower temperature scenario. Second, low air temperatures produced during expansion have the potential to cause freezing issues with lubricants and ice build-up in the components. A simplified model of the charging and discharging modes of D-CAES system is shown in 4.1 (Budt, et al., 2016).

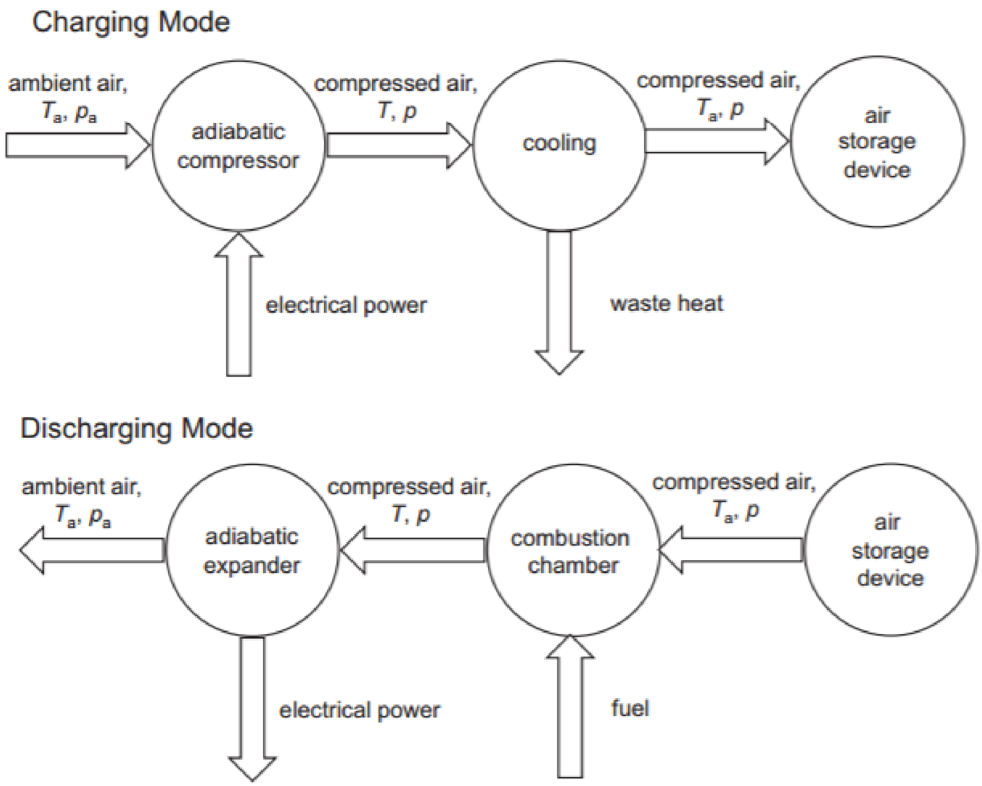

Figure 4.1: A simplified mode of the D-CAES system [Budt, et al, 2016].

Currently there are two conventional, D-CAES systems in operation, the first was constructed in 1978 in Neuen Huntorf, Germany, a 321 MW plant and later in 1991, McIntosh, Alabama, a 110 MW plant [Foley, et al., 2013]. The operation of the Huntorf CAES system is presented below in Figure 4.2 [Hoffeins, 1994]. Any electricity surplus provides power for a two-stage compressor with intercooling that compresses ambient air up to 70 bar. Either axial compressors achieving a pressure ratio of about 20 and mass flow rates of 1.4 Mm^3/h, or radial compressors, with flow rates of up to 0.1 Mm^3/h and a maximum pressure of 1000 bar can be used [Raju and Khaitan, 2012]. The compressed air is then led to an aftercooler to keep its temperature close to ambient, allowing a higher density of air to be stored, thus reducing the required size of the storage reservoir. Finally, the compressed air is stored in an underground storage reservoir. When storing compressed air, commonly considered reservoirs include underground caverns made of high-quality rocks, depleted natural gas storage caves, and salt domes with storage capacities ranging from 300,000 to 600,000 m^3. When power is needed, the compressed air is released, heated-up by a combustion chamber to obtain increased power during the expansion process.

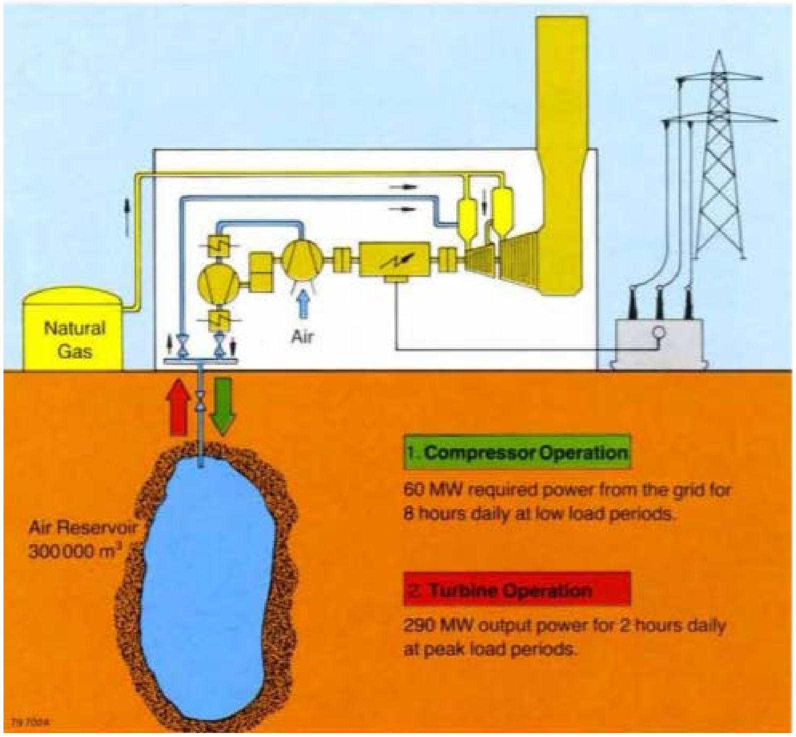

Figure 4.2: Structure of existing Huntorf CAES plant [Hoffeins, 1994].

To increase the overall efficiency, the stored compressed air can be preheated by the turbine exhaust through recuperators before it enters the combustion chamber. Implementation of this concept in the McIntosh plant results in increased efficiency by roughly 10%. A slight disadvantage to this design comes from the increased investment costs of the large recuperators. This structure has been applied to the second existing CAES plant in McIntosh. A list of the technical specifications of existing D-CAES plants are shown in Table 4.1 [Budt, et al., 2016].

Table 4.1 Technical specifications of the two existing D-CAES power plants [Budt, et al., 2016].

	Huntorf	McIntosh
Plant		
Operating utility	E.ON Kraftwerke	PowerSouth
Cycle efficiency[a]	0.42	0.54
Energy input for 1 kW h_{el} energy output	0.8 kW h_{el}/ 1.6 kW h_{gas}	0.69 kW h_{el}/ 1.17 kW h_{gas}
Energy content (related to power output)	642 MW h	2640 MW h
Planning – construction – commissioning	1969–1978	1988–1991
Compression		
Compressor manufacturer	Sulzer (today MAN Turbo)	Dresser-Rand
Max. el. input power	60 MW	50 MW
Max. air mass flow rate	108 kg/s	Approx. 90 kg/s
Compressor units	2	4
Charging time (at full load)	Approx. 8 h	Approx. 38 h
Storage		
Cavern construction company	KBB	PB-KBB
Cavern pressure range	46–72 bar	46–75 bar
Cavern volume	310,000 m^3	538,000 m^3
Expansion		
Turbine manufacturer	BBC (today Alstom)	Dresser-Rand
Max. el. output power	321 MW	110 MW
Control range (output)	100–321 MW	10–110 MW
Discharging time (at full load)	Approx. 2 h	Approx. 24 h
Start-up time (normal/ emergency)	14/8 min	12/7 min
Max. mass flow rate	455 kg/s	154 kg/s
HP turbine inlet	41.3 bar/490 °C	42 bar/538 °C
ND turbine inlet	12.8 bar/945 °C	15 bar/871 °C
Exhaust gas temperature	480 °C	370 °C (before recuperator)

[a] In the case of D-CAES plants cycle efficiency is not identical to AC/AC cycle efficiency as given for the other pure EES technologies, since additional firing is required for discharge (compare Section 3).

Adiabatic CAES

In the case of Adiabatic CAES (A-CAES) also termed, Advanced Adiabatic CAES (AA-CAES), heat generated during compression is captured without intercooling and stored in a separate Thermal Energy Storage (TES) System. When energy is needed, the system is reversed and heat is added back to the air during the expansion phase, thus eliminating the need for external heat sources (i.e. fossil fuels). TES requires heat to be transferred in and out of a pressurized steam of air. If there are more than one compressor/expander stage, there will be different pressures across each compressor/expander stage. To minimized the destruction of exergy, well designed systems will have the same number of compressors and expanders. A simplified model structure of an A-CAES system with multiple stages is shown in Figure 4.3.

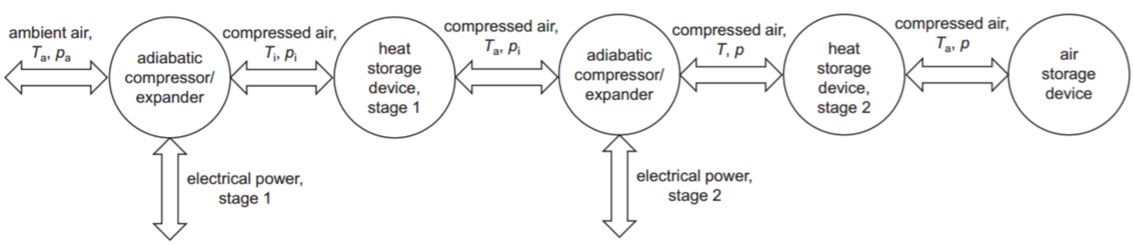

Figure 4.3: A simplified model of a two-stage A-CAES system [Budt, et al., 2016].

In a two-stage A-CAES system, heat is released in the low-pressure (LP) and high-pressure (HP) compressors and is stored in separate TES tanks. During discharge, heat from the LP and HP tanks is regained before the inlet to the HP and LP turbines. A two-stage system has the advantage to increase energy storage density, helping compensate for the increased complexity of the plant. There are several advantages of the A-CAES over conventional CAES. These include: the exclusion of fossil fuels and the associated emissions, the elimination of intercoolers allow for higher outlet temperatures from the compressor stage resulting in higher amounts of heat energy stored. In turn, overall efficiencies of adiabatic compressed air storage plants are expected to approach values of up to 70% [Odukomaiya, et al.' 2016]. This highlights the need of high heat capabilities for the heat tanks ranging from 120-1800 MWh_{th} and a need to design sufficient heat transfer rates to supply constant outlet temperatures [Ng and Rans, 2016]. This brings to attention a need for novel compressor designs in A-CAES systems that have high isentropic efficiencies since standard compressors cannot reach the high pressures and temperatures required for adiabatic compression. Recent work has developed three-part compressors consisting of 1) an axial or radial compressor, as a LP compressor in case of high or low air flow rates, 2) single-shaft radial compressors for the intermediate pressures and 3) high-pressure divisions [5]. The turbine needs to also be designed to achieve increased turbine inlet temperatures, higher air flow rates, and better efficiency. Additionally, there is a need for novel designs of the regulation stage with lower losses while improving pressure and flow rate fluctuations.

The low-temperature adiabatic CAES (LTA-CAES) is another proposed variant to A-CAES [Budt, et al., 2012], [Luo, eta., 2016], [Wolf and Budt, 2014]. This concept aims to avoid the technical challenges of dealing with high temperatures and pressures of the A-CAES system. Initial analysis of the LTA-CAES results in a reduction of the maximum process temperature by 90-200 C (down from the typical 600C value). Overall round trip efficiencies of LTA-CAES are lower 52-60%, however, advantages include faster start-up < 5 minutes, less expensive when compared to traditional CAES system, and good part-load behavior and control [Wolf and Budt, 2014].

Isothermal CAES

Effective management of thermal energy resource remains one of the primary challenges when dealing with compression-based energy storage schemes. Isothermal CAES (I-CAES) attempts to achieve near-isothermal compression and expansion thus avoiding any external heat exchangers to compress and expand the air. There have been several concepts that have been proposed that operate at isothermal or near-isothermal conditions [Rogers, et al., 2014], [Saadat, et al., 2015], [Sustain X, 2017]. Benefits include improved efficiency (~70-80%), operation at lower temperature (< 80 °C) and fuel-free operation. Three patented I-CAES technologies under development include: General Compression (2 MW, 500 MWh), SustainX (2 MW, 8 MWh), and LightSail Energy (2 MW, 8 MWh) [Rogers, et al., 2014]. These designs utilize an injection of liquid into a reciprocating piston cylinder during compression, or the bubbling of liquid in a liquid-piston. The heated liquid is separated and stored in a TES and is re-injected during expansion. Technical development challenges of I-CAES include: improving efficiencies of liquid/air heat transfer at high flow rates and efficient separation between the liquid and air. Table 4.2 provides a technical summary of the three primary CAES systems.

Table 4.1: Summary of technical and economic characteristics of CAES technologies [Budt, et al., 2016, Odukomaiya, et al., 2016].

Technology	Scale	RTE (%)	ED (kWh/m^3)	Capital Costs* ($/kWh)	Cycle Life (cycles)	Lifetime (years)	Maturity	Cycle Temp °C	Fuel Requirement	Advantages	Disadvantages
CAES (conventional)	MW-GW	42.54	3-6	2-120	8000-12,000	20+	Commercialized	Up to 750°C	Natural Gas	High Capacity,	Geographically Limited
		42	2-6	2-50	10,000+	25+				Heat input	Lower Efficiency
			5 @ 80 bar, 50% eff	3-80	10,000-30,000	30,40					
CAES (other)	KW-MW	$60-70^a$		$200-250^a$	30,000[a]	23 +[a]	R&D[a,b]	$500-600°C^b$	Minimal [b,d]	Geographic	Geographically limited[c]
		$69-70^b$	20 @ 200 bar, 70% eff[b]	30-40% higher than			Demonstration	< 80°C[e]	None [e]	flexibility[a,e]	Lower RTE[a,c,d,e]
		$30-60^c$	53 @ 400 bar, 80% eff[e]	Conventional			Concept[c,d,e]			Higher RTE[b,e]	
		$52-60^d$		CAES[b]							
		53^c									

* Capital costs is defined as costs associated with the capital or investment expenditures per unit of energy storage
[a] Above Ground CAES.
[b] AA – CAES (advanced – adiabatic).
[c] T – CAES (trigeneration system).
[d] LTA – CAES (low temperature – adiabatic).
[e] I – CAES (isothermal inclusing liquid – air).

Air Storage Systems

There are four typical approaches to storing compressed air: 1) hard rock caverns or aquifers, 2) above ground fiber wound pressure tanks, 3) near surface buried concrete, poly or composite pipework [Mahlia, et al., 2014]; and 4) under-water HDPE bag ballasted to seafloor [Pimm, et al., 2014]. Unlike fixed volume vessels, under-water storage vessels utilize variable volumes and allow for constant hydrostatic pressure. This gives an advantage of isobaric expansion conditions. More details on under-water CAES applications will be given in further sections. Table 4.3 provides the technical summary of air storage systems [Rogers, et al, 2014].

Table 4.2: Summary of technical and economic aspects of air storage for CAES systems [Rogers, et al., 2014].

	Under-Ground	Near Surface	Above-Ground	Under-water
Typical Pressure (bar)	40-80	100-200	200-400	1/10m depth
Energy Density (kWh/m^3)	7.5 @ 80 bar	30 @ 200 bar	65 @ 400 bar	4.75 @ 45 bar
Output Period (hours)	24+	3-5	3 – 5	1-24+
Capital Energy Storage Cost (2012 US $/kWh)	$3-$34 Geology dependent	$30-$40 Buried piping	$150-200	$5 @ 100m and 1$ @ 500m
Storage % plant costs	10%	15 – 20%	30 – 40%	15%
Replacement (years)	N/A	40 – 60	40 – 60	20-40

Pumped Hydroelectric Energy Storage (PHES) Systems

Pumped hydroelectric energy storage (PHES) is the most widely adopted utility-scale electricity storage technology and provides the most mature and commercially available solution to bulk energy storage. The Electric Power Research Institute (EPRI) has reported that PHES accounts for over 99% of the bulk energy storage capacity worldwide, representing 127GW [Rehman, et al., 2015]. PHES stores energy in the form of potential energy of water that is pumped from a lower reservoir to a higher elevation reservoir. PHES utilize low costs of energy during off-peak periods to run the pumps and raise the water resource from a lower to upper reservoir. Reversible turbine/generator units act as the pump or turbine. During periods of high power demand, the stored water is released through hydro turbines to produce electricity. There are two main types of PHES facilities, pure or off-stream PHES are known as closed-loop systems and rely on the water that has been pumped to an upper reservoir from a lower supply (reservoir, river, or sea). Pump-back PHES use a combination of both pumped water and natural inflow supplemented by hydro or glacial inflow to generate power [Deane, et al., 2010].

There are several benefits of the operating characteristics of the PHES facility to the electrical grid system. PHES can supply flexible generation with spinning and standing reserves proving both up and down regulation, while the quick start capability makes it suitable for black starts. A review of the operating characteristics of PHES when compared to other thermal power generation is provided in Table 4.4 [Deane, et al., 2010].

Table 3.4 Operating characteristics of PHES compared to other generating types [Deane, et al., 2010].

	Nuclear power plant	Coal fired plant	Oil fired plant	Gas turbine-peaker	PHES
Normal duty cycle	Baseload	Baseload	Baseload-midmerit	Peak load	Peak-midmerit
Unit start up-daily	No	No	Yes, hot	Yes	Yes
Load following	No	Yes	Yes	Yes	Yes
Quick start (10 min)	No	No	No	Yes	Yes
Frequency regulation	No	Yes	Yes	No	Yes
Black Start	No	No	No	Yes	Yes

PHES facilities provide large capacities of electricity, with low operation and maintenance costs, long asset life (50-100 years) and high reliability. In addition, the levelized storage cost of electricity using PHES are typically much lower than other electricity storage technologies. The efficiencies of PHES vary significantly from 60% with older designs, to nearly 90% using state-of-the-art technology [Rehman, et al., 2015; Deane, et al, 2010]. Table 4.5 summarizes the PHES cycle efficiency by operating components [Hayes, 2009].

Table 4.4 Composition of PHES cycle efficiency [Hayes, 2009]

	Component	Indicative Value, %
Pump cycle	Water Conductors	98.0 - 98.6
	Pump	90.0 – 92.0
	Motor	97.8 – 98.3
	Transformer	99.0 – 99.6
	Overall	*85.4 – 88.8*
Generating cycle	Water Conductors	98.6 – 98.0
	Turbine	75.0 – 91.0
	Generator	97.8 – 98.3
	Transformer	99.0 – 99.6
	Overall	*71.6 – 86.4*
Operational	Losses & Leakage	98.0 – 99.8

In the United States, there are a total of 40 PHES facilities in operation with a total capacity of approximately 22 GW [Akhil, et al., 2015]. The technical characteristics for selected PHES facilities in the United states are summarized in Table 3.6 [Hayes, 2009]. Most PHES projects in the United States and Europe were constructed in the 1960's – 1980's. These facilities were constructed to help utilize the excess energy produced by nuclear power plant and utilize single speed pump/turbine units. With the increased interest in integrating renewable energy, PHES has regained interest from developers. The United States Federal Energy Regulation Commission has reported that preliminary permits have been granted for proposed PHES projects in 12 states totaling 15 GW in capacity [FERC, 2017].

Table 4.6 Existing PHES facilities in the United States [Hayes, 2009]

Project	Initial Operation	Installed Capacity (MW)	Hours of Storage	Energy Storage (MWh)	Average Gross Head (feet)	Water Conduit Length (feet)	Length to Head Ratio L/H	No. of Existing Res./Lakes
Taum Sauk	1963	350	7.7	2,700	809	7,003	8.7	0
Yards Creek	1965	330	8.7	2,894	723	3,700	5.1	0
Muddy Run	1967	855	14.3	12,200	386	1,290	3.3	1
Cabin Creek	1967	280	5.8	1,635	1,159	4,340	3.7	0
Seneca	1969	380	11.2	3,920	736	2,520	3.4	1
Northfield	1972	1,000	10.1	10,100	772	6,790	8.8	1
Blenheim Giloboa	1973	1,030	11.6	12,000	1,099	4,355	4.0	0
Ludington	1973	1,888	9.0	15,000	337	1,252	3.7	1
Jocassee	1973	628	93.5	58,757	310	1,700	5.5	1
Bear Swamp	1974	540	5.6	3,019	725	2,000	2.8	0
Raccoon Mountain	1978	1,370	24.0	33,000	968	3,650	3.8	1
Fairfield	1978	512	8.1	4,096	163	2,120	13.0	0
Helms	1984	1,200	118.0	14,200	1,645	20,519	12.5	2
Bath County	1985	2,100	11.3	23,700	1,180	9,446	8.0	0

PHES is currently the most cost-effective means of storing large amounts of energy. There are several drawbacks to PHES technology, however. For example: high upfront capital costs and appropriate geography to provide suitable hydraulic head (200-300m). Additionally, construction may take several years to decades and the high upfront capital investment can lead to payback of the system occurring decades later [Akhil, 2015]. Environmental impacts have drawn attention to many recent proposed projects. Conventional PHES construction typically requires altering the terrain and damming water ways to create reservoirs which can negatively impact the natural aquatic ecosystem and terrestrial wildlife habitats [Yang and Jackson, 2011].

Seawater – Pumped Hydro Storage Systems

An alternative to traditional PHES is the direct use of seawater in the lower reservoir. Currently there is only one commercial Seawater PHES (S-PHES) constructed in 1999 in Okinawa, Japan with a 30 MW capacity at an elevation of 150 m above sea level [Fujihara, et al., 1998]. This system utilizes open sea water as the lower reservoir and provides a solution to the case of geographical constraints presented on traditional PHES systems and for areas where fresh water resources are scarce. Other S-PHES projects have been proposed in Greece, Belgium, Netherlands, Ireland, and Australia.

Other novel PHES include undersea PHES and energy island concepts. The undersea PHES utilizes hydrostatic water pressure at the bottom of the sea to store electricity from offshore wind turbines. The submerged pressure vessels are attached to the seabed and utilizes excess electricity to pump water out of the vessel (concrete sphere) through the generator. Figure 4.4 illustrates the Ocean Renewable Energy Storage (ORES) concept developed by MIT. Benefits of this system include predicted round trip efficiencies of 75-85%, the ability to complement floating offshore wind turbines by providing an anchoring point for the mooring lines, and the potential to be economically feasible at depths as shallow as 200 m [Slocum, et al.,2013]. Some of the drawbacks to this design include: relatively lower energy storage densities when compared to underwater compressed air storage designs at equivalent depths and the inability easily access the system in deep water.

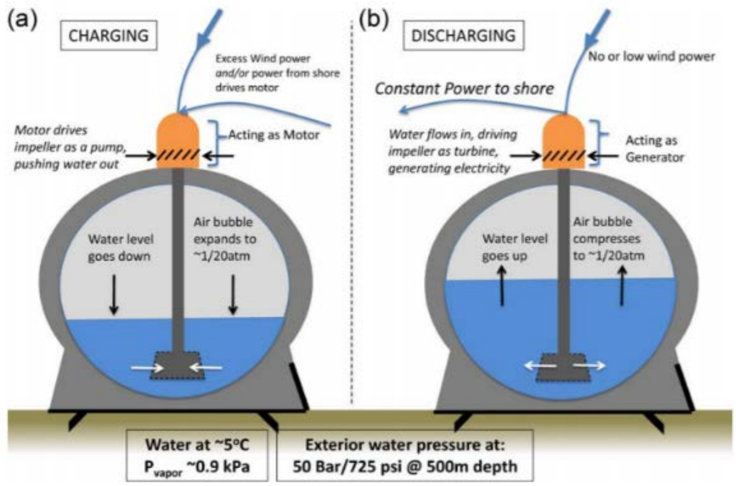

Figure 4.4 Diagram of undersea pumped hydroelectric storage system [Slocum, et al., 2013]

5.0 OFFSHORE COMPRESSED AIR STORAGE SYSTEM REVIEW

Introduction

As the United States promotes further RES development, offshore wind power will play a crucial role in meeting the demand for coastal load centers. Large-scale energy storage systems will be vital to store excess energy when the supply exceeds power demand, and regenerating energy when demand surpasses the supply. One caveat to the use of utility-scale storage systems are the geological constraints imposed by traditional systems. Among the different storage technologies, PHES and CAES have some inherent advantages over other forms of energy storage, but only CAES has the capacity of pumped hydro and the potentially lowest overall capital and capacity costs. Advances in system component design and utilization of TES has made CAES increasingly attractive. Furthermore, novel designs in air storage technologies have now allowed CAES to break away from site specific geological formations by allowing air to be stored underwater. Underwater-CAES (UW-CAES) has the advantage of isobaric characteristics, the ability to be hidden from the public view, and with many costal locations (both fresh water and seawater), provide suitable depths for this technology to be potentially economically feasible. The following sections describe UW-CAES technology and how it may play in important role in future storage development.

UW-CAES

With conventional CAES systems, air is typically stored in a fixed volume vessel or geological formation. With a UW-CAES system, compressed air is stored in vessels located on the seabed or bottom of the lake at approximately the same hydrostatic pressure as that of the surrounding water. Generally, compressed air can either be stored isochoric (at constant volume as is typical with conventional CAES system) or isobaric (at constant pressure). With an isochoric storage system, the storage volume remains constant and the storage pressure changes with the amount of air stored in the system. One drawback to isochoric systems is in order provide constant input pressure into the expansion unit, pressure needs to be throttled and thus pose exergy losses to the system. Isobaric storage remains at a relatively constant pressure by allowing the storage volume to change. Isobaric storage systems have two distinct advantages over isochoric storage systems: expander efficiency can be increased by 10-15% by avoiding the exergy losses associated with throttling losses, and the energy density remains higher [Pimm, et al., 2014].

The idea of storing air underwater was first proposed by Seymour utilizing rigid vessels vented to seawater [Seymour, 1997]. Seymour had proposed a 230 MW system for Carlsbad, CA with storage capacity of 2300 MWh over a 10 h discharge time to reduce the required variation in generation for the San Diego area by 40%. Figure 5.1 illustrates the ballasted, underwater storage vessels proposed by Seymour. Rigid vessels like this have several benefits. For example, rigid vessels provide some resistance to heat transfer from the air to the surrounding environment via the insulation characteristics of the structures walls. They can also be built to withstand the buoyancy forces that are proportional to the volume displaced.

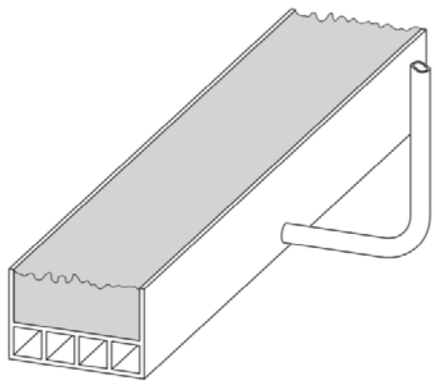

Figure 5.1: Ballasted underwater vessel for CAES [Pimm, et al., 2014].

A result is that the cost for storing air underwater is roughly independent of depth. Energy storage capacity increases with depth, however so deeper water provides a lower cost per unit of energy. Figure 5.2 illustrates the energy storage density based on ideal models of UW-CAES using different compression techniques and a PHES system that utilizes the underwater hydrostatic pressure as, opposed to elevation, to produce the required head pressure. To produce 1 kWh/m^3, the adiabatic model requires approximately 100 m of depth. Given the same parameters, the no Thermal energy storage (*No TES)* models requires 176 m of depth and the isothermal model requires 130 m. With underwater PHES, a depth of 367 m is required [Pete, et al., 2015]. It is also important to note that the *No TES* model refers to compressing and storing air that has not been reduced to ambient temperatures of the surroundings prior to underwater storage.

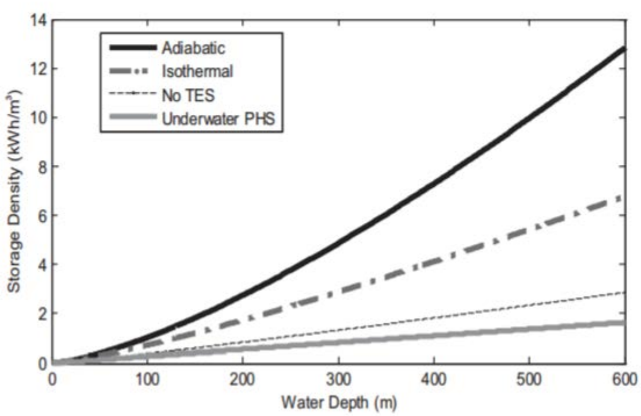

Figure 5.2 Energy storage densities of idealized UW-CAES and PHS models based on depth [Pete, et al., 2015]

One disadvantage of utilizing rigid structures for underwater pressure vessels is the induced varying loads that the structure must endure. An alternative solution (isobaric storage)is to utilize a fabric vessel. This enables the loads to be carried by tension rather than in bending.

The idea of storing air in flexible storage vessels was first proposed by Laing in 1986 [Laing and Laing, 1989] and has been intensively studied by researchers at the University of Nottingham and University of Windsor. Figure 5.3 illustrates energy storage bags being tested at the University of Nottingham. These bags are made of coated fabric serving with reinforced straps to carry the main buoyancy loads. The vessels have a single point of anchor and resemble designs like those used lift structures in underwater operations. Additionally, there are several advantages to using these flexible storage vessels: these can be manufactured to be watertight and remain functional over long periods (20+ years) [Pimm and Garvey, 2016], optimum vessels have the potential to have the lowest overall storage costs (when considering storing air only) [Rogers, et al, 2014], and offer a scalable design [Cheung, et al., 2014]. A disadvantage of flexible vessels is that they can become vulnerable to damage due to handling, but this can be mitigated with proper handling procedure and robust fabric materials.

Figure 5.3   Design and testing of underwater storage vessels for CAES [Pimm, et al., 2014]

In 2015, the University of Windsor, in partnership with Hydrostor, a Toronto-based company, developed the world's first UW-CAES demonstration plant. A 1.5 MW rated A-CAES facility, phased to expand from 750 kWh of storage capacity to multi-MWh utilizing both flexible and rigid storage vessels. This UW-CAES facility is located in the city of Toronto, Canada and is operated by the Toronto Hydro utility. The underwater air storage vessels are placed 2.5 km offshore in Lake Ontario in 80 m of depth [Hydrostor, 2015]. Figure 5.4 illustrates the Toronto Island UW-CAES demonstration plant. Additionally, Hydrostor has two other plants under contract. The Goderich UW-CAES, rated at 1.75 MW with 7 MWh, is under construction in Goderich, Canada. A second project is contracted for the island of Uruba; it is rated at 1 MW with 6 MWh's of storage capacity [Hydrostor, 2017].

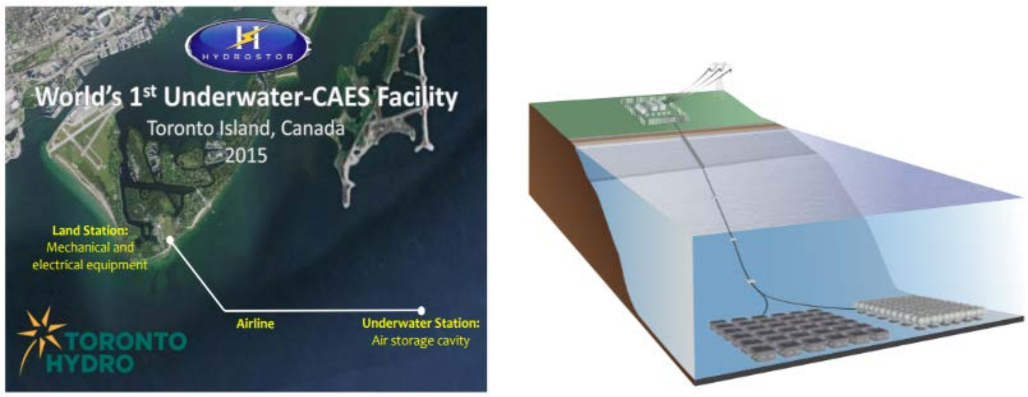

Figure 5.4 Illustration of Hydrostor's UW-CAES demonstration facility in Toronto, Canada [Hydrostor, 2013]

<u>System Configurations</u>

Up to this point, the discussion of CAES has focused on the configurations of compressing the air (single or multi-stage diabatic, adiabatic, and isothermal) and methods of storing (geological formations, pressure vessels, and underwater). This section will focus on the configuration and installation of UW-CAES. There are two basic configurations of UW-CAES: onshore and offshore. The onshore configuration places the CAES energy and thermal unit on land and a network of piping directs the air supply from land to the offshore, underwater storage vessels (like that used in the Hydrostor projects). In the offshore configuration, the entire CAES system is placed offshore and the only thing transmitted to land is electricity. Figure 5.5 illustrates these two different configurations [Cheung, et al., 2014]. There are many factors that determine the ideal location and configuration of the UW-CAES system. These include: the compression method, thermal management, and the relative costs of transmitting power by submarine cables vs. air to the storage vessels via a piping network [Pimm and Garvey, 2016; Cheung, et al., 2014]. If an adequate storage resource is close enough to shore, it makes financial sense to build the energy and thermal unit onshore for ease of construction and maintenance. There are several locations on earth where adequate resources can be found only a few kilometers from shore (see next section for details). In the case where the resource is farther offshore (greater than 5 km), the entire system could potentially be moved offshore via floating platforms for the energy and thermal conversion units. This could also be potentially advantageous if coupled with offshore wind farms providing storage on site and utilizing some of the same infrastructure, such as the electrical cable network that supplies power back to the grid. Additionally, the water could be used as a heat sink (i.e. for isothermal compression since water has a higher thermal conductivity than air).

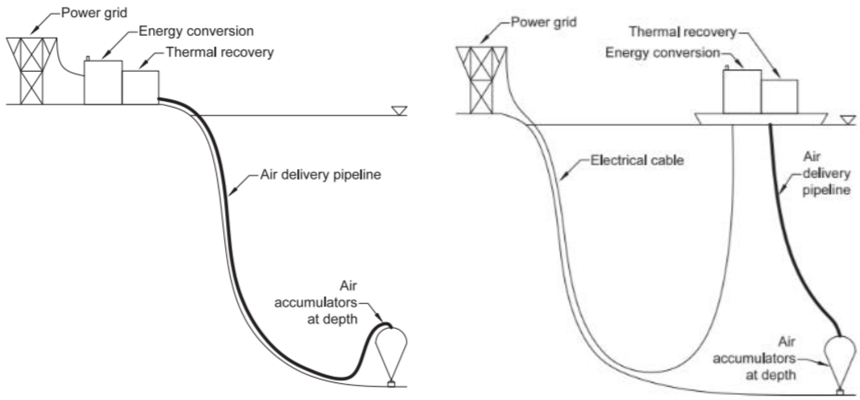

Figure 5.5 UW-CAES configurations of onshore (left) and offshore (right) applications [Cheung, et al. 2014].

In both configurations, the underwater storage vessels must be placed offshore. Underwater storage vessels have been deployed utilizing a technique by means of constructing on land and floating them directly to the site. Rigid underwater storage vessels have been design with buoyancy forces in mind and deployed by attaching temporary flotation devices to the vessel. This method enables a barge to tow several vessels at a time. Figure 5.6 and Figure 5.7 present this installation method used on Hydrostor's demonstration Project [Wanwalleghem, 2014].

Figure 5.6 Rigid underwater storage vessels used in Hydrostor's Toronto project being prepped with floatation's units [Wanwalleghem, 2014]

Figure 5.7 Barge transporting rigid storage vessels for Hydrostor's Toronto project [Wanwalleghem, 2014]

This method can also be used for installation of flexible storage vessels with the exception that a counterweight or anchor needs to be supplied to overcome buoyancy forces. There are several different anchors that can be utilized via piles driven, screwed, or suction anchored to the seabed. A gravity based anchor made of concrete, rocks or sand, however, is the simplest by design.

One proposed variation to the gravity base design is to allow the anchor material to be fully encased in a sealed enclosure. By adding enough air to the anchor, the storage vessel could be to towed to site, installed and later, recovered if needed. Figure 5.8 illustrates this floating mechanism for flexible storage vessels [Pimm and Garvey, 2016].

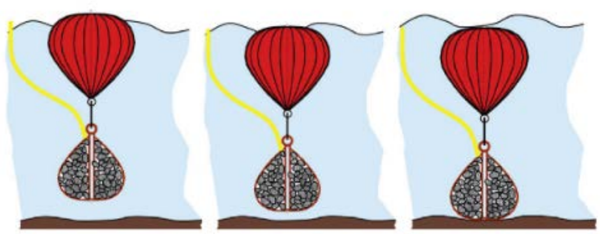

Figure 5.8 Underwater storage bags transportation mechanism by temporarily floating the gravity based anchor [Pimm and Garvey, 2016]

<u>Locations and Underwater Storage Resource</u>

As water depth and the corresponding hydrostatic pressure increase, the cost of storing air per unit of energy decreases. Potential sites that exhibit hydrostatic pressures above 40 bar (~ 400 m in depth) would exhibit similar inlet pressures of existing CAES facilities. In the United States and throughout Europe, there are many locations that present suitable depths near costal load centers. In the US, most of the locations are located along the western coastlines where deep water is present near shore. This could be advantageous for California. In 2013, the California Public Utilities Commission enacted the nation's first energy storage mandate ,AB 2415, directing investor-owned utilities to acquire 1.325 GW of additional storage by 2020 and be operational by 2024 [California Legislature, 2017]. Figure 5.9 illustrates selected areas highlighted in red along the California coastline where depths are greater than 400 m and are less than 5 km from shore [Pimm and Garvey, 2016].

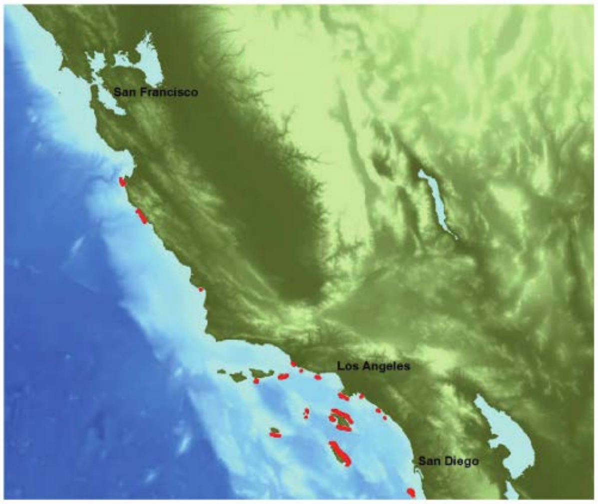

Figure 5.9 Potential areas of interest for UW-CAES along California's coastline depicting areas within 5 km from shore at depths greater than 400m [Pimm and Garvey, 2016]

In the northeast US, there is a lack of deep-water resources that reside relatively close to shore, but there is an enormous potential (nearly 5 TWh for depths over 250 m) of storage capacity for the New England region in areas located 50-100 km from shore. With offshore wind farms now being constructed over 100 km from shore [Smith, et al. 2015], the potential applications of offshore UW-CAES become increasing probable. Figure 5.10 and Table 5.1 illustrate the UW-CAES resource potential for the New England region. Areas highlighted in the lighter color of Figure 5.10 depict deeper waters (incremented by 50 m depths) and resulting higher UW-CAES density.

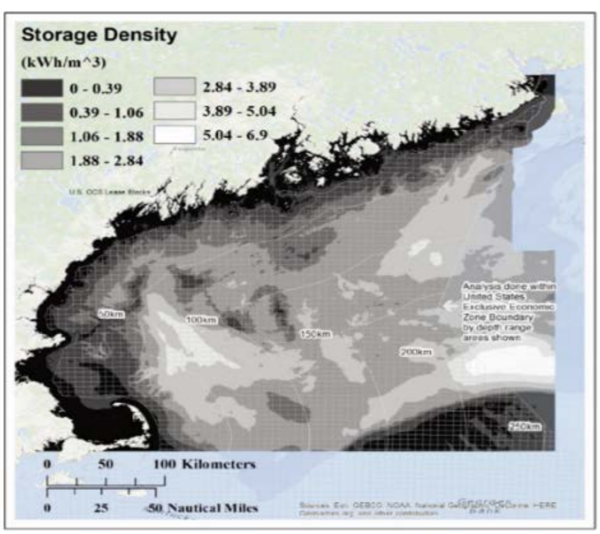

Figure 5.10 UW-CAES energy storage density map for New England [Pete, et al., 2015]

Table 5.1 Cumulative underwater resource potential for New England [Pete, et al., 2015]

Region	(1) 0–50 km		(2) 50–100 km		(3) 100–150 km		(4) 150–200 km		(5) 200–250 km		TOTAL	
Class	Area km^2	Capacity TWh	Area km^2	Capacity TWh	Area km^2	Capacity TWh	Area km^2	Capacity TWh	Area km^2	Capacity TWh	Area km^2	Capacity TWh
1	11190	**2.1**	89	**0.016**	238	**0.044**	1445	**0.26**	941	**0.17**	13904	**2.5**
2	9145	**6.2**	378	**0.27**	476	**0.32**	426	**0.29**	1495	**1.0**	11919	**8.1**
3	5793	**8.6**	3006	**4.5**	829	**1.2**	130	**0.19**	70	**0.11**	9828	**15**
4	3222	**7.7**	9617	**23**	8124	**19**	3775	**9.1**	214	**0.51**	24952	**60**
5	1595	**5.2**	5517	**18**	3665	**12**	1966	**6.4**	373	**1.2**	13116	**43**
6	83	**0.35**	1037	**4.4**	170	**0.72**	14	**0.061**	542	**2.3**	1847	**7.8**
7	0	**0**	0	**0**	0	**0**	0	**0**	211	**1.1**	211	**1.1**

Economics of UW-CAES

The estimates of implementing the underwater storage vessel and ballasts, assuming reasonable materials costs, improved manufacturing of the flexible storage vessel and a depth of 500 m, are less than 20 $/kWh [Pimm and Garvey, 2016]. Decreased water depths will increase costs as the energy storage density will decrease and require more volume to equate the same energy capacity at deeper depths. In [Rogers, et al., 2014], using various sources, UW-CAES was found to have comparable cost to that of underground storage costs, 5 $/kWh as compared to 3-34 $/kWh being geology dependent.

To date here has not been any specific study addressing the overall techno-economics of UW-CASES when coupled with wind. However, in a recent techno-economic assessment of a 200 MW offshore wind farm coupled with an offshore I-CAES (liquid piston design), assuming a offshore geological storage capacity ranging from 30 to 80 GWh, resulted in levelized costs ranging from 230 $/MWh with a capacity factor of 0.4 to 280-500 $/MWh at a capacity factor of 0.90. The list of key assumptions for this study are presented in Table 5.2 [Li and DeCarolis, 2015].

Table 5.2   Assumptions for offshore wind-CAES study] Li and DeCarolis, 2015]

Key technology cost and performance estimates used in the model.

Parameter	Symbol	Value	Units	References
Capacity, wind farm	X_W	200,000	kW	
Capital cost, wind farm	C_W	5794	\$/kW	[41]
Fixed O&M cost, wind farm	F_W	53.33	\$/kW yr	[41]
Variable O&M cost, wind farm	V_W	0	\$/kWh	[41]
Capital cost, converter	C_{con}	0.143	\$/VA	[44]
Capacity, all converters in total [a]	X_{con}	600	MW	
Capital cost, 20 MW transformer [b]	C_{TR}	\$426,000	\$/Unit	[51]
Capital cost, submarine cable, 33 kV, 20 MW	C_{cable}	\$233,000	\$/km	[50]
Cost constants of 132 kV submarine cable [c]	A_p	1.971×10^6	SEK/km	[29]
Cost constants of 132 kV submarine cable	B_p	0.209×10^6	SEK/km	[29]
Cost constants of 132 kV submarine cable	C_p	1.66	$(VA)^{-1}$	[29]
Installation cost, submarine cable	$C_{cable,I}$	2,400,000	SEK/km	[29]
Capital cost, liquid piston	C_L	1,200,000	\$/Unit	
Capacity, compressing/expanding	X_C, X_E	0.5	MW	[52]
Efficiency, compressing/expanding	η_C, η_E	0.837		[52]
Capital cost, undersea storage	C_S	10	\$/kWh	[38]
Capital cost, gas turbine	C_{GT}	974	\$/kWh	[41]
Fixed O&M cost, gas turbine	F_{GT}	6.98	\$/kW yr	[41]
Variable O&M cost, gas turbine	V_{GT}	14.7	\$/MWh	[41]
Efficiency, gas turbine thermal	η_{GT}	0.314		[41]
Natural gas price [d]	C_{NG}	4.32	\$/GJ	[53]
Hours in a year	T_y	8760	h/yr	
Lifetime of transmission cables, wind farms, gas turbines and liquid pistons	L	20	yrs	
Lifetime of undersea storage reservoir	L_S	50	yrs	
Discount rate for wind farms and OCAES	r	0.1		
Discount rate for gas turbines	r_{GT}	0.05		
Exchange rate	ex_1	0.15	USD/SEK	
Exchange rate	ex_2	1.35	USD/EUR	

[a] 40×5 MW AC/DC converters, 40×5 MW DC/DC converters and 10×20 MW DC/AC converters.
[b] Obtained by using formula by Lazaridis [51]. $C_{TR} = 0.03327 \times 10^6 \cdot P^{0.7513}$, where P is in MVA and C_{TR} in Euro.
[c] Undersea cable cost (SEK/km) from [29]: $A_p + B_p \exp(C_p S/10^8)$, S is the rated capacity of the cable (VA).
[d] From US Natural Gas Electric Power Price, 3-year average from August 2009 to

With the assumptions made, the results from the study suggest that utility-scale offshore CAES is currently not economical completive when compared to alternative low-carbon electric generation technologies, however, with a LCOE of approximately 300 \$/MWh and capacity factors exceeding 90% suggests that offshore CAES maybe a viable option if those conditions prevail. The authors suggests that near-term off-shore CAES applications may be best suited for niche applications such as islands with high electricity costs occur.

6.0 OFFSHORE CHEMICAL ENERGY STORAGE VIA NH_3

As noted in the introduction, another option to consider for storage systems is chemical energy storage, in the form of a liquid energy fluid. As shown in Figure 6.1, there are a number of options for liquid energy carriers, with ammonia (NH_3) as a popular choice. This section will present a summary review of the state-of-the-art of an emerging energy storage option based on the use of liquid ammonia.

Energy Carriers; their physico-chemical properties

	Pressurized Hydrogen (700MPa)	Liquid Hydrogen	Organic Hydride (Methyl Cyclohexane)	Ammonia
Molecular Weight	2.0	2.0	98.2	17.0
H_2 Content (wt%)	100	100	6.2	17.8
Volumetric H_2 Density (kg-H_2/m³)	39.6	70.8	47.3	121
Boiling Point (℃)	–	-253	101	-33.4
H_2 Release Enthalpy Change ※ (kJ/mol-H_2)	–	0.90	67.5	30.6
Other Properties	Widely used	High purity Low energy to pressurize	Existing oil infrastructures can be utilized	High H_2 density Direct use for combustion

※ H_2 release enthalpy change

Figure 6.1 Potential Energy Carrier Fluids

Ammonia (NH_3) is typically associated with nitrogen-based fertilizers because it contains fixed nitrogen atoms that are not bonded to other nitrogen atoms. The nitrogen atom in the ammonia molecule is bonded with three hydrogen atoms, making ammonia both a fertilizer and a hydrogen storage medium. Due to compact molecular packing, ammonia contains more hydrogen than liquid hydrogen per volume and therefore has a high volumetric energy content. In fact, ammonia has been used as a liquid fuel in internal combustion and diesel engines, with little modification; in the X-15 rocket jet; and in gas turbines [Morgan et al., 2014].

Ammonia has properties that are similar to propane - it is a liquid at standard temperature and 12 bar of pressure, or at ambient pressure and -33 °C. Ammonia has about 40% of the volumetric energy content of gasoline and emits only gaseous nitrogen (N_2) and water vapor when burned.

The use of wind energy to drive ammonia production systems has been recently investigated at the University of Massachusetts with systems such as shown in Figure 6.2 (Morgan, 2013; Morgan et al., 2014). This work demonstrated that ammonia production with offshore wind power has the potential to transform energy and fertilizer markets within the United States. Furthermore, a vast offshore wind resource can be converted directly into liquid ammonia using existing technologies. The liquid ammonia can then be transported around the country via rail, truck, barge or pipeline and used as either a fertilizer or a fuel. The work of Morgan (2013) reviewed the technologies required for all-electric, wind-powered ammonia production and offered a simple design of such a system. Cost models based on the physical equipment necessary to produce ammonia with wind power were developed; offshore wind farm cost models are also developed for near-shore, shallow, wind farms in the United States. The cost models were capable of calculating the capital costs of small industrial-sized ammonia plants coupled with an offshore wind farm. A case study for a utility-tied, all-electric ammonia plant in the Gulf of Maine was used to assess the lifetime economics of such a system. Actual utility grid prices and offshore wind were incorporated into a systems-level simulation of the ammonia plant. The results show that significant utility grid backup is required for an all-electric ammonia plant built with present-day technologies. This work demonstrated that the levelized cost of ammonia is high relative to ammonia produced with natural gas or coal, but is not as susceptible to spikes in ammonia feedstock prices. A sensitivity analysis showed that the total levelized cost of ammonia is driven in large part by the cost of producing electricity with offshore wind. The work also noted that major cost reductions were possible for systems that have long lifetimes, low operations and maintenance costs.

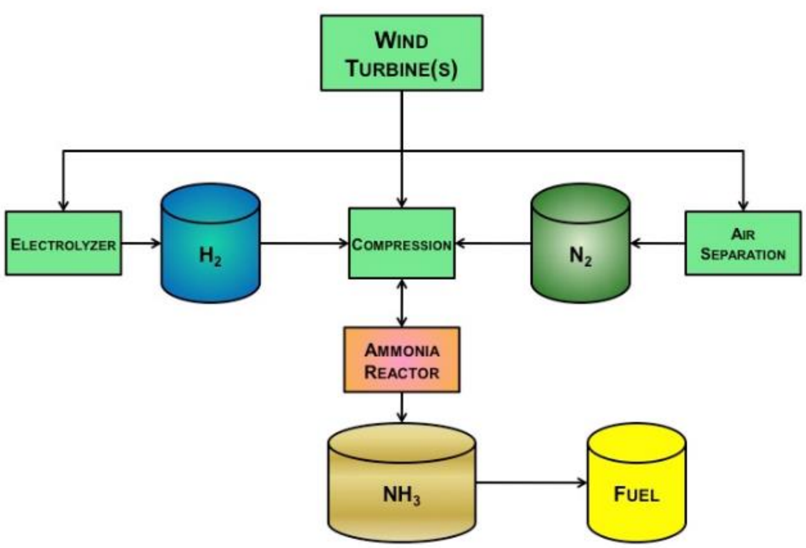

Figure 6.2 Wind Driven Ammonia Production System (Morgan, 2013)

In another UMass paper on wind driven ammonia systems (Morgan et al., 2014) investigated the potential of producing ammonia from a wind turbine in order to displace diesel fuel requirements on isolated islands. In this proposed system, wind power was used to produce fuel directly from water and air using traditional air separation units, alkaline electrolyzers, mechanical vapor compression desalination and a Haber-Bosch synthesis loop. The ability to produce synthetic fuel on site was potentially valuable both because it mitigated transportation costs and insulated the islanders from oil price fluctuations. A general overview of the process and required components was given. The analytical model used to calculate the technical and economic performance was summarized. A case study (Monhegan Island, Maine) for a wind-powered ammonia production facility was carried out to demonstrate the potential of the concept. Actual wind and electrical load data from the island were incorporated to determine the expected ammonia production for Monhegan Island. The results were compared to a system in which all fuels and electricity were ultimately derived from petroleum-based fuel. Total lifetime system costs were calculated with the results normalized so that the wind-ammonia system can be directly compared to a conventional diesel-only system. A “breakeven” diesel price was calculated at which wind-powered ammonia production became competitive.

In more recent times, there has been a significant amount of research and development in the U.S., Europe (e.g., Germany, Netherlands, and the U.K.), Israel, and Japan on the use of ammonia for energy storage and as a fuel source for numerous energy delivery systems. Some examples of this most recent work are given below.

1) Japan

As shown in Figure 6.3, this ongoing work includes a Strategic Initiatives Program (SIP) in Japan that includes ammonia production from renewable energy and use for electrical production and transportation systems (Japan Science and Technology Agency, 2015). Another part of this program involves the use of renewable energy produced ammonia for direct combustion applications (see Figure 6.4).

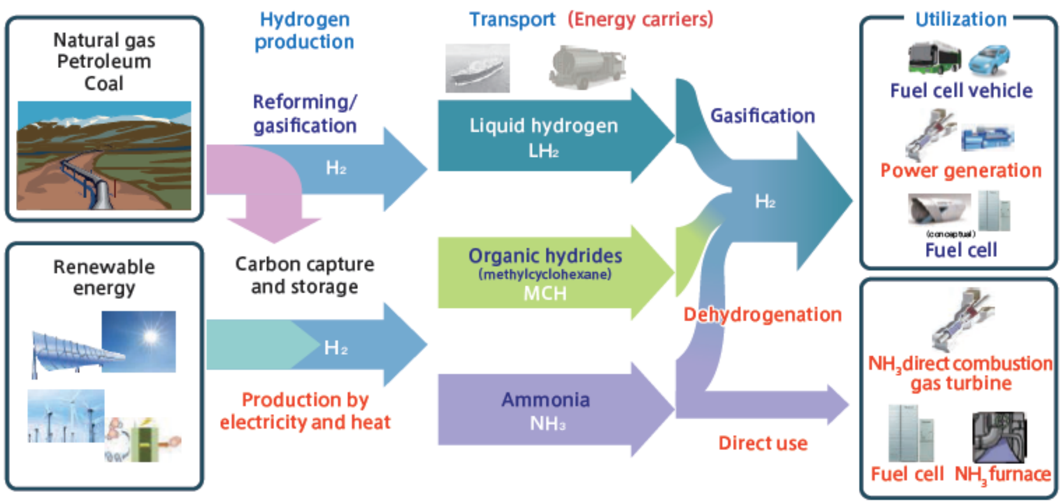

Figure 6.3 Strategy of Energy Carriers for Japanese Research Program (Japan Science and Technology Agency, 2015)

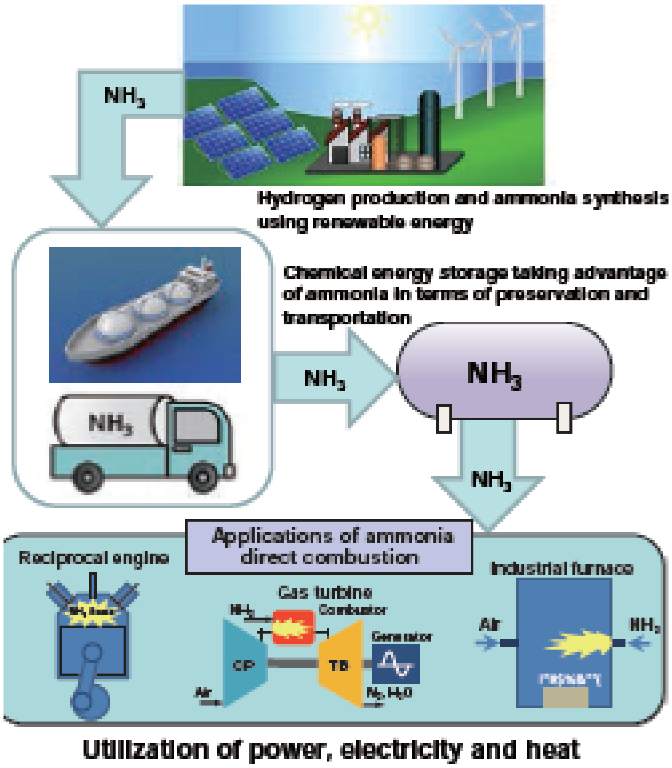

Figure 6.4 Application of Ammonia for Direct Combustion (Japan Science and Technology Agency, 2015)

2) U.K./ Germany

As shown in Figure 6.5, Siemens is carrying out a research program on an “all-electric ammonia synthesis and energy storage system.”

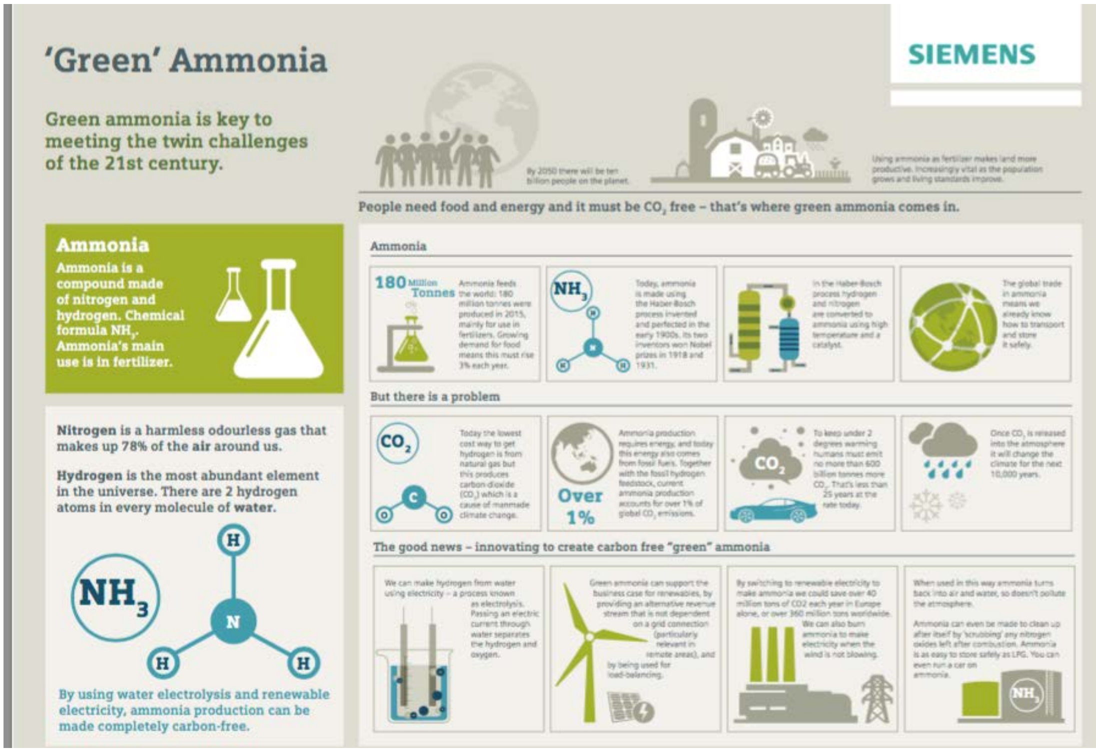

Figure 6.5 Siemens "Green" Ammonia Program Summary (Siemens, 2017)

3) Netherlands
In the Netherlands, Nuon is studying the feasibility of using Power-to-Ammonia "to convert high amounts of excess renewable power into ammonia, store it and burn it when renewable power supply is insufficient." Their system concept is shown in Figure 6.6.

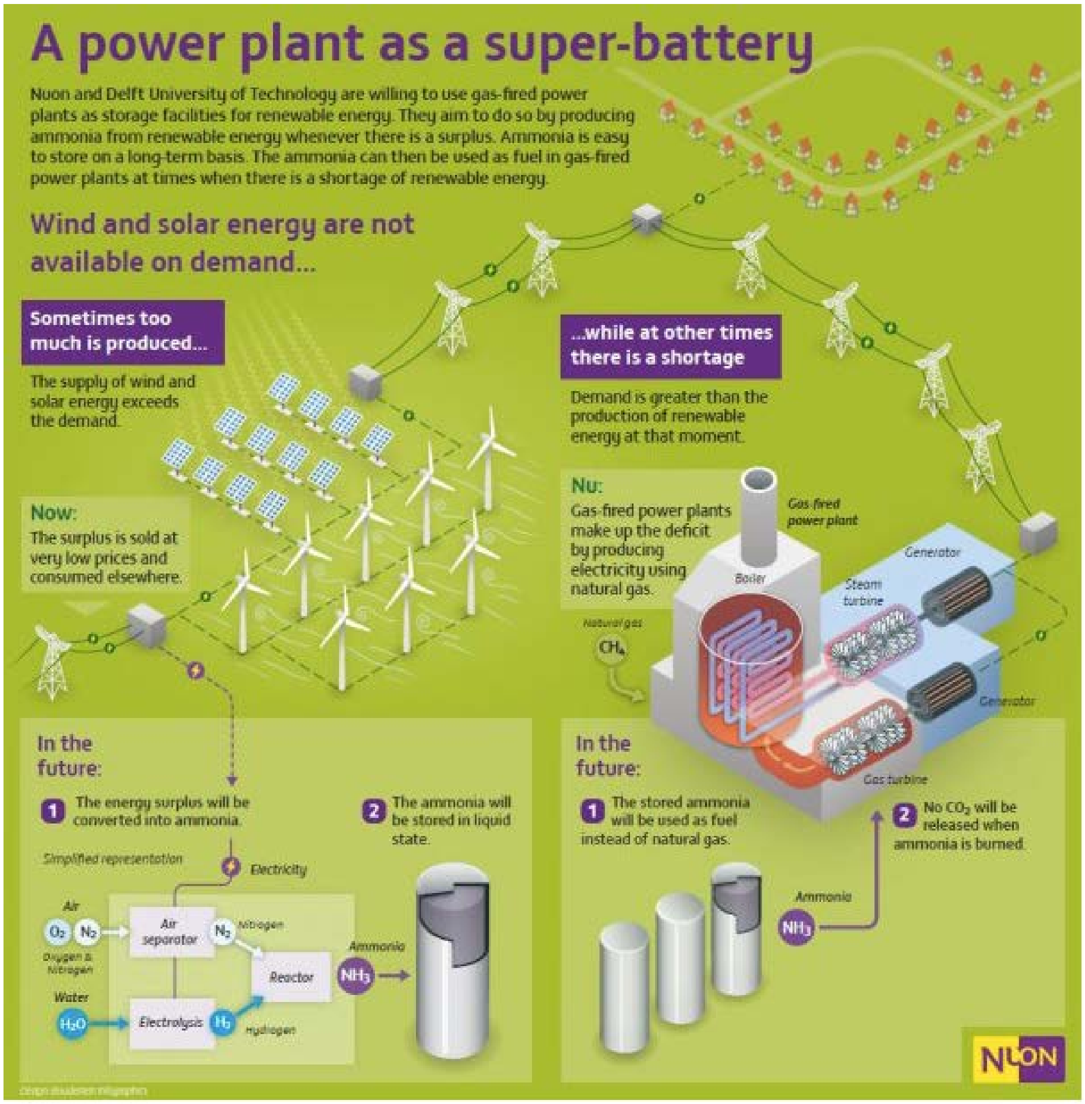

Figure 6.6 Nuon "Super Battery Concept" (Nuon, 2016)

4) United States

The US Department of Energy is funding (Ammonia Industry, 2016) a portfolio of renewable ammonia synthesis technologies through its Advanced Research Project Agency (ARPA-E). Results of this ongoing work have demonstrated that ammonia is already the lowest-cost, proven technology for long-term, large-scale energy storage, where "long-term" refers to any time period greater than one day (see Figure 6.7).

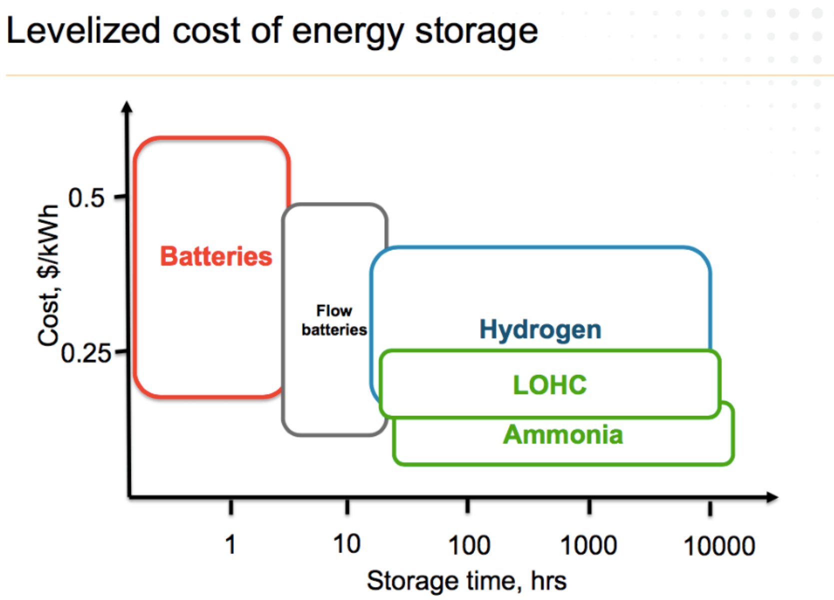

Figure 6.7 Levelized Costs of Energy Storage as a function of Storage Time (Ammonia Industry, 2016)

7.0 RECOMMENDED FUTURE RESEARCH

This work has summarized the current status of utility scale energy storage with an emphasis on what can be useful for offshore wind applications. It should be noted that there is much worldwide work on systems applicable for this type of application and that no one system appears to be the most cost-effective and technically feasible at this time. This is especially true for Massachusetts's applications as no offshore wind systems have been installed at the present time.

For future work on the subject we make the following conclusions and recommendations:
1) Offshore compressed air should be reviewed in more detail and its potential costs need to be estimated in more detail.
2) In the light of new worldwide developments, research on liquid ammonia energy storage systems and production from renewable offshore wind needs to be investigated in more detail, especially for the New England region

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