CHALMERS

Subsea Pumped Hydro Storage

A Technology Assessment

Master's Thesis within the Sustainable Energy Systems programme

JOHN ALMÉN

JOHAN FALK

Department of Energy and Environment
Division of Energy Technology
CHALMERS UNIVERSITY OF TECHNOLOGY
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Master's Thesis T2013-387

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JOHN ALMÉN

JOHAN FALK

SUPERVISOR

Emil Nyholm

EXAMINER

Filip Johnsson

Department of Energy and Environment
Division of Energy Technology
CHALMERS UNIVERSITY OF TECHNOLOGY

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Department of Energy and Environment
Division of Energy Technology
Chalmers University of Technology
SE-412 96 Göteborg
Sweden
Telephone: + 46 (0)31-772 1000

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ABSTRACT

A new technology for energy storage called Subsea Pumped Hydro Storage (SPHS) has been evaluated from a techno-economical point of view. Intermittent renewable energy sources are becoming more common in the electricity grid; hence the need of regulating power is increasing. One way of balancing the demand of electricity with the production is by implementing energy storage in the system. This thesis has assessed such a concept, which is a sea-based version of the already existing pumped hydro storage technology. A SPHS unit is composed of a hollow structure placed at the seabed which can be emptied of water by the use of a pump at times of low demand and high production of electricity in the system, the unit is at that point charged. When this excess energy is needed in the system water is allowed to flow back into the cavity through a turbine and thus generating electricity. This work has defined which components are needed for the concept to function and how these are implemented to create a complete technical system. In order to compare SPHS to alternative solutions for energy storage, so called Key Performance Parameters were determined and quantified. The two technologies pumped hydro storage (PHS) and compressed air energy storage (CAES) were used for comparison with the SPHS concept due to their similar operation characteristics. The last step of the analysis was performed with an energy systems model where energy storage was included in the Danish electricity system due to its high penetration of fluctuating wind power. A number of scenarios were examined and it was shown that at larger installation depths the capital cost was reduced due to a lower material requirement. It should however be clarified that the costs for installation at large depths are very uncertain. Compared to PHS (with a levelized cost of electricity, LCOE, of 187-278 €/MWh) it was concluded that the subsea pumped hydro storage concept (with a LCOE of 212-336 €/MWh) needs to be developed further in order to be competitive from a cost point of view. Furthermore, unless subsidies for the delivered electricity are implemented the storage technology will not yield a sufficient income when operating on the spot market as a buyer and seller of electricity. A better alternative could be to connect the technology to an offshore wind power plant where the wind energy can be stored directly as the wind turbine drives the pump in the storage unit mechanically. This would imply that electricity, which is more expensive than any other fuel, doesn't have to be bought at market price and that the wind power plant and storage unit become one integrated facility.

Keywords: energy storage, intermittency, balancing power, subsea construction, wind power integration

Undervattensbaserat pumpkraftverk
En teknikutvärdering
Examensarbete inom masterprogrammet Sustainable Energy Systems
JOHN ALMÉN
JOHAN FALK
Institutionen för energi och miljö
Avdelningen för energiteknik
Chalmers tekniska högskola

SAMMANFATTNING

En ny teknik för energilagring, ett undervattensbaserat pumpkraftverk, har utvärderats utifrån ett tekno-ekonomiskt perspektiv. Förnybara intermittenta energikällor blir allt vanligare i energisystemet, vilket gör att allt mer balanskraft krävs. Ett sätt att uppnå denna balansering är att implementera energilagring i systemet. Detta arbete har analyserat ett sådant koncept, vilket är ett undervattensbaserat alternativ till ett pumpkraftverk. Denna teknik består av en ihålig konstruktion som placeras på havsbottnen och som kan tömmas på vatten med hjälp av en pump då efterfrågan på elektricitet är låg och produktionen är hög, lagret är vid denna tidpunkt laddat. Då denna överskottsenergi efterfrågas i systemet låts vatten strömma in i håligheten genom en turbin som därmed alstrar elektricitet. Detta arbete har definierat vilka komponenter som krävs för att konceptet ska fungera och hur dessa samverkar för att skapa ett komplett tekniskt system. För att jämföra undervattensbaserade pumpkraftverk med alternativa lösningar för energilagring bestämdes ett antal nyckeltal. Det studerade konceptet jämfördes det med pumpkraftverk och energilagring med trycksatt luft på grund av de liknande driftegenskaperna. Slutligen skapades en energisystemmodell där energilager inkluderades i det danska elektricitetssystemet på grund av dess höga andel fluktuerande vindkraft. Ett antal scenarion studerades och det visades att vid större installationsdjup minskade kapitalkostnaden på grund av ett lägre materialbehov. Det bör dock tilläggas att kostnaderna för installation på stora djup är mycket osäkra. Jämfört med pumpkraftverk (med en produktionskostnad mellan 187-278 €/MWh) dras slutsatsen att konceptet för ett undervattensbaserat pumpkraftverk (med en produktionskostnad i spannet 212-336 €/MWh) måste utvecklas ytterligare för att kunna vara kostnadsmässigt konkurrenskraftigt. Vidare krävs även subventioner på den elektricitet som levereras från enheten för att en tillräcklig inkomst ska inbringas då denna arbetar på spotmarknaden som en köpare och säljare av elektricitet. Ett bättre alternativ kan vara att koppla tekniken till ett havsbaserat vindkraftverk då energin i vinden kan lagras direkt genom att vindturbinen driver pumpen i energilagret mekaniskt. Detta innebär att elektricitet, vilket är dyrare än något annat bränsle, inte måste köpas till marknadspriset och att vindkraftverket och energilagret kombineras till en integrerad anläggning.

Nyckelord: energilagring, intermittens, balanskraft, undervattenskonstruktion, vindkraftsintegration

Contents

Preface

This study has evaluated a new concept for energy storage called Subsea Pumped Hydro Storage. The work has been performed during the spring of 2013 at the Department of Energy and Environment, Chalmers University of Technology, Sweden.

The writers would like to thank Claes Nyqvist for providing the studied concept and for contributing with many useful insights to the project. Furthermore, the expertise of Lars Strömberg has also been very helpful in the process of analysing the technology. Finally, we would like to thank our supervisor Emil Nyholm for his continuous support during the spring, without which the completion of the thesis wouldn't have been possible.

Göteborg June 2013

John Almén and Johan Falk

Notations

d	=	diameter [m]
E	=	elasticity modulus [MPa]
E_T	=	electricity generation in the year T [MWh]
F_T	=	fuel price in the year T [€]
g	=	gravitational acceleration [m/s^2]
H	=	head [m]
I_T	=	investment cost in the year T [€]
$LCOE$	=	levelized cost of electricity [€/MWh]
M_T	=	operation and maintenance costs in the year T [€]
p	=	pressure [MPa]
P	=	power [W]
r	=	discount rate [-]
R	=	radius [m]
t	=	thickness [m]
T	=	time [years]
U	=	energy density [MWh/m^3]
$\dot{V}$	=	volume flow [m^3/s]
η_d	=	efficiency [-]
v	=	Poisson's ratio [-]
ρ	=	density [kg/m^3]

1 Introduction

In the following sections the thesis work will be introduced through descriptions of the underlying aspects of the problem at hand, the problem itself and the aim of the thesis.

1.1 Background

The amount of anthropogenic greenhouse gases in the earth's atmosphere is constantly increasing, leading to an increase of the average temperature (Intergovernmental Panel on Climate Change, 2007). The sector which contributes primarily to these emissions is the power generation industry (Intergovernmental Panel on Climate Change, 2008). In order to reduce the emissions of carbon dioxide, which is the largest contributor to the increase of greenhouse gases (Intergovernmental Panel on Climate Change, 2008), renewable energy sources are being built in an increasingly rapid pace. These intermittent energy sources, such as wind and wave power, are becoming increasingly influential in the present energy system and efficient technologies to balance the fluctuating supply and demand of electricity are needed. Currently, thermal power plants are used to balance intermittent production by operating at part load or by standing by as reserve units. Such balancing power is possible up to a certain level of intermittent generation, but eventually other means of balancing are required such as; demand side management, increased transmission capacity and energy storage systems, the latter which will be the focus of this master thesis work. At present, there are a number of such storage technologies; both emerging and more developed ones. As renewable energy power plants are being constructed at an increasing rate, with a large portion of those at or close to the sea, new means of accumulative capacity at those locations is needed. Space close to populated and industrial areas where electricity is needed is also becoming scarcer, which demands the development of storage technologies at locations without competition with housing or industry etc.

The largest utility scale storage technology as of today is by far pumped hydro storage which provides approximately 99% of all storage (Electric Power Research Institute, 2010). The large drawbacks with these types of storage facilities are the unique siting issues arising for each unit as they all need to be completely custom-made depending on location as well as the severe impacts they have on the surrounding environment and population.

Combined, these issues create the need for a sea-based energy storage technology which will not compete for space with other sectors of the society.

1.2 Purpose and aim

This thesis will evaluate a new technology concept for energy storage called Subsea Pumped Hydro Storage, SPHS in short. The aim is to describe the technology, determine its performance based on a number of criterions and compare it to other means of energy storage.

1.3 Scope

Due to the early development phase in which the SPHS technology is no detailed mechanical analyses of the constituent parts will be performed. The ecological impacts from the technology will also be neglected in this study. The technologies used for comparison with the subsea pumped hydro storage concept will be limited to pumped hydro storage and compressed air energy storage since these two are at the moment the only options for large-scale energy storage.

1.4 Thesis outline

To create a knowledge base the report will begin with a theory chapter in which current alternatives for energy storage will be presented. The concept of the Nordic power system will also be introduced to the reader, creating a context on which following reasoning will build. The subsequent method part will describe in what way the work was conducted, stating important assumptions and simplifications. The results gained from the methods used will thereafter be presented and a thorough discussion of these results will be conducted in order to connect them to theories stated earlier and to state the certainty of them. Finally, the conclusion will summarize the findings and describe possible future studies regarding the technology.

2 Theory

The concepts and theories used in this master thesis will be introduced in the following sections.

2.1 Energy system

The electricity system's main task is to supply the end-users with a sufficient amount of power at all times. This is achieved with a combination of several different electricity generating technologies forming a system. The demand curve varies over time (yearly, monthly, daily, hourly, instantly) and to supply the required load there is a need for an efficient and balanced system. With the increased amount of sustainable energy sources (which often correspond to intermittency) in the future, development of the system is needed to keep utilization factors high, i.e. avoiding high over-capacity for long times.

2.2 The Nordic power system

The Nordic power system is unregulated and primarily governed by Nord Pool Spot, a company which manages the trade of electricity in the region. Prices are set on a day-ahead basis on the Elspot market – with the possibility to trade continuously, up until 30 minutes before the delivery of electricity, on the Elbas market. Prices are determined by supply and demand, using the power transmission capacity as a limit, and contracts for buying electricity can be created in advance for long periods of time. Balancing of the power grid, which means ensuring security of supply and the correct grid frequency, is carried out by the Transmission System Operator (TSO) in each country. In order to achieve this balance the TSO has the possibility to change the operation of power plants taking part in a certain agreement (Nord Pool Spot, 2013).

2.3 The Danish power system

The Danish power systems consists mainly of coal fired power plants, natural gas power plants and wind turbines. Almost 30% of the electricity share is currently generated from wind power, (Energistyrelsen, 2012) making Denmark the world's leading wind power producer in terms of share of production. The power exchange is included in the Nord Pool Spot market and the transmission system operator is Energinet.dk. Future plans are to expand the wind power to be able to achieve the EU environmental targets (European Commission, 2010). In 2035 Denmark expects the power sector to be 100% carbon dioxide emission free with only renewable sources contributing to power output. The final target is set to be reached in 2050. This includes a full electrification of the transport sector and a system completely free from fossil fuels (Danish Ministry of Climate, Energy and Building, 2012).

2.4 Energy storage

Energy storage technologies can be categorized into several development areas:

- Electrochemical storage - batteries and hydrogen storage (in combination with fuel-cells)
- Mechanical storage - pumped hydro, compressed air and flywheels
- Electrical storage - super capacitors
- Heat storage - accumulators

This thesis will focus on one of the balancing measures mentioned above, mechanical energy storage. These units traditionally accumulate the energy generated by larger thermal plants with low flexibility in order to even out loads at peak and off-peak hours. Financing of these constructions is accomplished by using the price difference of energy at different times to make economically beneficial trades (Barnes & Levine, 2011). The efficiency of the electricity system is increased through the use of energy storage as power generating plants can run for longer at optimum levels despite lower demand, as long as the storage capacity is high enough and the system can handle the loads. Without energy storage no more than 15 (Cavallo, 2001) to 20% (Denholm & Kulcinski, 2003) of the electricity demand in a region can be fulfilled by intermittent energy sources.

When the power generation fluctuates by up to about 10% balancing can most often be achieved by using spinning reserves, i.e. modifying the operation of running plants in the system (Barnes & Levine, 2011). However, when fluctuations increase a need for non-spinning reserves arises. These reserves consist of plants not usually connected to the system but with short start-up times, such as gas turbine power plants, and plants with the possibility to be shut off (Huggins, 2010). To remove these fossil fuelled plants from the system energy storage units could be implemented instead. The storage facilities may be placed near the location of generation to balance loads during peak or off-peak hours, close to the load to reduce transmission losses on lower voltage levels or to supply an area with sufficient power in times of increasing demand (Barnes & Levine, 2011).

The components of energy storage units can be grouped into three different categories; the storage medium, the power conversion system and the balance of plant equipment. The cost of the storage medium becomes more influential with the size of the storage unit. This is why the largest types of units utilize water and air, which are cheap and plentiful and have low losses, as a medium. From an economical point of view the cost of the medium is usually half of that of the entire storage facility. This cost can be divided into the cost for acquiring the medium and the cost for keeping it in a state of energy storing. The power conversion system handles the conversion between alternating and direct current and vice versa, and is the interface between the storage facility and the electricity grid. For mechanical energy storage units the PCS consists of the motor and generator train, which convert kinetic energy to electrical. Apart from power conversion, the subsystem also acts as a security buffer to prevent damage to the storage facility and the electricity grid by controlling the power conditions. This system is often very expensive, with costs reaching almost half of the cost for the entire storage unit. The balance of plant comprises all surrounding equipment required to keep the facility running, including housing, control systems and connections between power conversion system and the grid. This part requires the least amount of funds and the cost is largely dependent on whether the subsystem is highly modular or customized to a certain storage unit (Baxter, 2007).

2.4.1 Key performance parameters

To characterize energy storage technologies certain key performance parameters are used:

- Round trip efficiency (RTE)
- Energy storage capacity
- Rated power
- Energy density
- Cost
    - Investment cost
    - Operation and maintenance costs
    - Discount rate
    - Levelized cost of electricity
- Lifetime

The round trip efficiency is, when considering the electricity system, a parameter unique for energy storage technologies. Regular electricity generation plants use some kind of resource (wind, solar flux, fuels etc.) which generate electricity through an energy conversion process. The energy content in the resource and the electricity generation is known and thus the efficiency can be calculated. For the energy storage technologies the same procedure is used when releasing energy to the system. The difference is that the resource (water elevation, chemical energy, rotational speed, pressure difference etc.) is charged by a non-perfect energy converting technology. This charge implements energy conversion from electricity to potential energy of some sort (depending on which technology is used). The round trip efficiency includes the losses from both charging and generating mode of the storage unit and is simply a combination of the two efficiencies. In some cases it can also include losses occurring during storage.

Depending on which application is considered, the capacity and rated power is of interest. The energy storage capacity is simply the amount of energy (in MWh) one storage unit can contain. The rated power relates to the size of the power generating unit (turbine, generator etc., in MW). The combination of rated power and energy storage capacity determines the discharge time, i.e. the time during which a continuous level of power can be delivered.

Energy density relates to the energy content per volume, usually in kilowatt hours per cubic meter. The energy density is calculated differently depending on energy storage technology, but the result can be used for comparison between technologies. The purpose of this is to be able to see the difference in volumes required for different technologies, and it can be a useful tool when determining the best storage technology for a given location.

Considering cost, a comparison could be made regarding different aspects. Firstly, the investment cost comprises the costs of all components and sub-systems and it is often expressed as a cost per installed power. The annual capital costs relates to the investment cost, discount rate and the expected economic lifetime of the unit. This is a tool for profitability calculations of the investment since the annual cost and income generates the yearly results, however, it also provides the payback time etc. Operation and maintenance costs include all the costs of keeping the unit running and functional. It includes reparation, employees' salaries, working capital and generation bills, generally these vary with production. To compare the different technologies an economic assessment widely used is the levelized cost of electricity (LCOE). This includes all the cost features, including investment, interest rate, operation and maintenance costs and efficiency (IRENA, 2013). The LCOE (in €/kWh or €/MWh) is calculated using the total investment, operation and maintenance costs, and total power generation during the lifetime of the technology, and it is a measure of how much each unit of generated electricity needs to be sold for in order for the technology to break even. The levelized cost of electricity is expressed as:

$$LCOE = \frac{\sum_{T=1}^{n} \frac{I_T + M_T + F_T}{(1+r)^T}}{\sum_{T=1}^{n} \frac{E_T}{(1+r)^T}} \tag{1}$$

I_T = investment cost in the year T
M_T = operations and maintenance costs in the year T
F_T = fuel cost in the year T (electricity cost)
E_T = electricity generation in the year T
r = discount rate
n = economic lifetime

2.5 Energy storage technologies

Today there are a number of technologies which can be used to store electric energy in a variety of ways. Two technologies with similar operational properties as subsea pumped hydro storage will be introduced and described in the following sections.

2.5.1 Pumped hydro storage

Pumped hydro storage, or PHS, has by far the largest capacity of the energy storage technologies being used today. Roughly 127 GW is currently installed worldwide (Rastler, 2010), and facilities generating over 1 GW of power for a total time of 24 hours are installed on several locations (Ginley & Cahen, 2012). Because of the beneficial operational aspects (fast response times), this is an appropriate technology for balancing the fluctuating power generation and load in the system.

The technology needs two fundamental resources to work:

- Water
- Elevation (referred to as head)

These two properties determine how large capacity the plant will have. The location at which the technology is placed determines available resources, meaning that if the head is larger the water requirements can be small, and vice versa. At places where there are limited amounts of water it is desirable to maximize the head, and where there are limited heads it is desirable to maximize the flow in order to maximize the power output.

The technology works similarly to regular hydropower by using the difference in potential energy between locations at different altitudes. This potential energy is converted to kinetic energy with a high efficiency when releasing the water through paths from a higher to a lower elevation. The difference from regular hydropower is the possibility to pump water in the opposite direction to store energy. For this to be possible the facility must include several different main parts such as: upper and lower reservoirs (the elevation difference between these yields the head and the reservoirs can be natural or man-made), waterways (including penstocks, head works, tailraces and one or several surge tanks), turbines and pumps. Pumping back the water can either be done by using the turbines in reverse mode, the component is then called a pump-turbine, or by using separate components.

With the high efficiency of turbines, pumps, motors, generators and electrical equipment the overall storage round trip efficiencies (RTEs) of modern PHS plants reach around 0.7-0.8 (Barnes & Levine, 2011). Losses depend mainly, as mentioned, on component efficiencies but also on pressure losses (due to turbulence and friction) in the waterways.

Depending on the location, different configurations of plants are used. The two most important design criteria are, as mentioned, water resources and head. Considering these, three common turbine types are used:

- The Kaplan turbine
- The Francis turbine
- The Pelton turbine

More detailed information about the different turbine technologies can be found in Chapter 2.6.1.

Current research within PHS technology is mainly focusing on upgrading existing plants, implementing variable speed turbines and underground PHS (UPHS). With today's technology a lot of existing old plants can be upgraded and show remarkable change in power output. There are examples where the power output has increased by as much as 12% after an upgrade (Ginley & Cahen, 2012).

With an increased amount of renewables in the energy system, it is important to have turbines running with variable speeds in order to have the ability to follow the fluctuations from these sources. Research is on-going to improve the offset efficiency of the system when storage units are operated outside their design point.

The configuration of the turbines and pumps (number of stages, number of units etc.) will determine capital costs but also other parameters, e.g. time for switching from pumping to generating mode and efficiency. The issue becomes an optimization problem with certain trade-offs, and depending on the properties sought a lot of different configurations are possible (Ter-Gazarian, 2011).

2.5.2 Compressed air energy storage

In a compressed air energy storage (CAES) system air is pressurized by a compressor powered by an electrical motor, the air is then stored in geological formations (cf.

CCS) or man-made pressure vessels at the same temperature as the surroundings (since the reservoirs are uninsulated). When the compressed air has been stored in the reservoirs electric energy can be extracted at any given moment by expanding the pressurized air through a turbine which powers a generator. Often a single motor/generator unit is used to reduce costs and complexity of the CAES facility and a transmission system is used to shift between the different modes of operation (compression or expansion). To increase flexibility and to decrease the switch time a separate motor and generator could be used, meaning that theoretically both can be used simultaneously. Before entering the turbine the air is heated by letting it flow through a heat exchanger together with the turbine exit gases. During expansion fuel is combusted in the stream of pressurized air in order to increase the temperature and thus increasing the work output and reducing the risk for ice formation at the blades due to gases cooling down during expansion. Using porous rock formations as reservoirs often result in the lowest costs, but hard rock mines and aquifers can also be used. Underground CAES systems have the best cost-efficiency as the storage already exists, however the airtightness needs to be examined before construction and lead times are long. Water compensated systems can be used, where an underground water reservoir provides a constant head to the storage volume; however this requires a deep storage volume to get an adequate pressure. Constructing a CAES system above ground is more flexible but capacity is reduced. CAES has a high part-load efficiency compared to regular gas turbines since temperatures are kept constant while the mass flow of air is controlled instead of the other way around. The ramp rates are very high with rates reaching up to 19 MW per minute (Barnes & Levine, 2011). A CAES system produces roughly three times more power in the expansion part of the system than a conventional gas turbine, in which two thirds of the power generated by the turbines is needed for compression of the air, since compression has been achieved prior to production (Ter-Gazarian, 2011). In the future, adiabatic systems not using any external fuel are proposed, these systems would store the heat generated at compression and use it to reheat the air before expansion. The compressor inlet temperature has a large impact on the work needed to drive the compressor, a temperature of -10°C (winter) instead of 30°C (summer) requires 10-15% less work (Dinçer & Zamfirescu, 2011).

2.5.2.1 Underwater CAES

Air can be stored in large underwater balloons where the weight of the surrounding water provides the pressure needed for compression. The flexible structures used will not be able to withstand an as high pressure as solid geological formations and thus the energy density will suffer. A depth of 80 m has been proposed as reasonable for the application. Research has been conducted at the University of Windsor in Ontario, Canada (Cheung, Carriveau, & Ting, 2012).

Nottingham University is also involved in the development of the technology and they propose an operation depth of 500 m.

2.6 Subsea Pumped Hydro Storage

Subsea Pumped Hydro Storage, or SPHS, is a new version of the existing Pumped Hydro Storage (PHS) technology. The main difference is that the head of water is obtained from the natural pressure at the bottom of the sea instead of building dams to create large, controllable water volumes. The concept is a construction of hollow structures which are submerged to the bottom of the sea, with a connection to the surface to facilitate a flow of air. These can be emptied by the use of a pump which runs on excess electricity. The electric energy is thus transformed to potential energy which is stored until there is a deficit of electricity in the power system. Water can at that point flow through a turbine back into the storage chamber thus generating electricity again. A conceptual sketch of the idea is shown below in Figure 1.

The main advantage of this technology compared to PHS and CAES is that it can be placed at more locations around the world, and that it does not infringe on space which could be claimed by other systems, technological or ecological. It is also important to find a technology that can provide balancing power close to offshore power plants, which are usually placed far from the main grid, in order to reduce transmission losses.

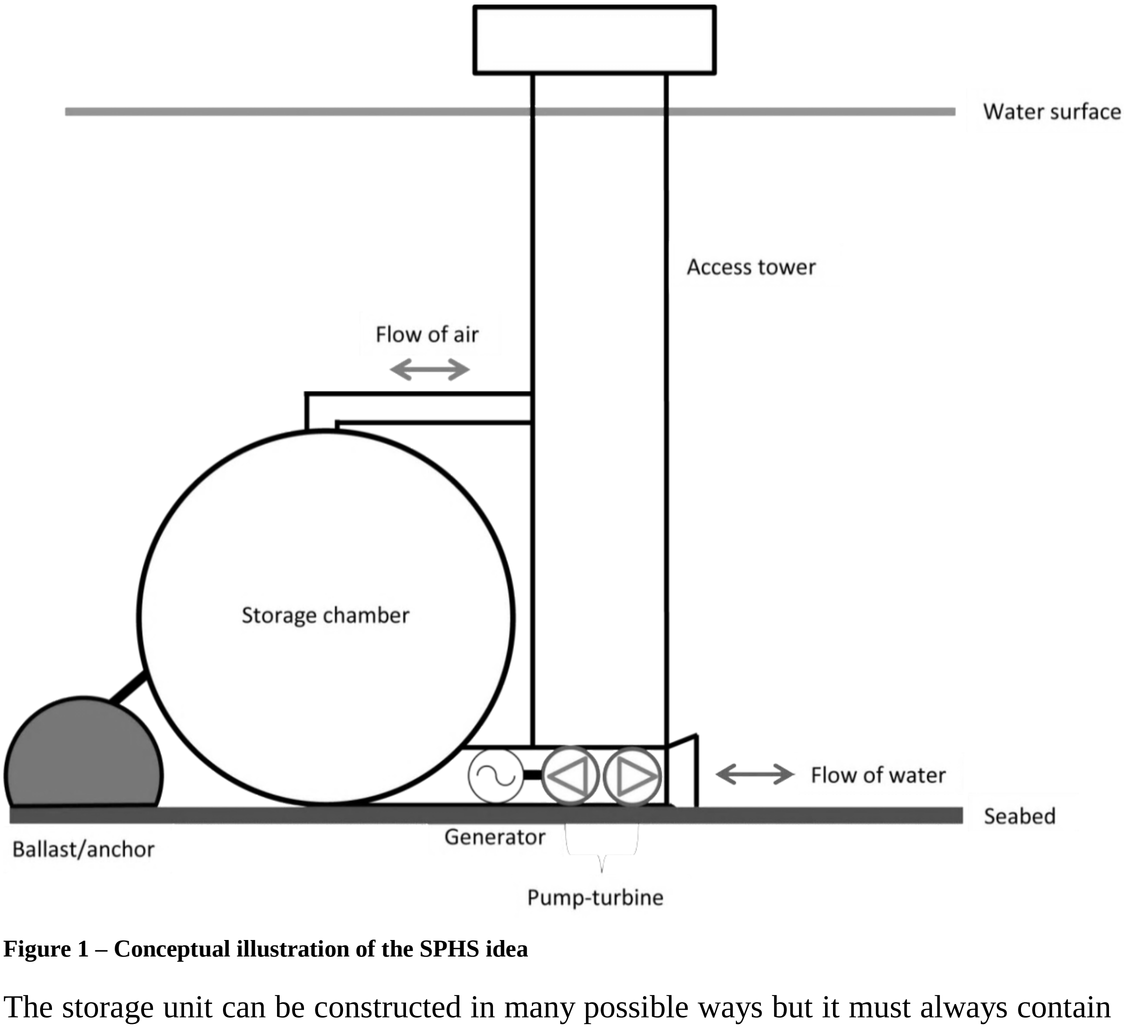

Figure 1 – Conceptual illustration of the SPHS idea

The storage unit can be constructed in many possible ways but it must always contain the following critical components:

- Water reservoir (sealed container)
- Power converting technology (turbine/pump)
- Electricity converting technology (generator)
- Power transmission (cables)
- Controller technology
- Transformer (substation)

2.6.1 Turbine and pump

The turbine's main purpose is to convert the kinetic energy in flowing water to rotational energy in a shaft. The conversion can be done with different types of turbines working under different types of principles, and for regular hydropower and PHS there are two main categories depending on how the power is extracted; impulse and reaction turbines. The choice of turbine usually depends on the location (head and water supply), but also on cost, variation in flow and part load behaviour. While not extracting energy from a flow of water, certain turbines can also be used as pumps (when operating in reverse direction); the unit is then called a pump-turbine.

The reaction turbine is driven by a hydrostatic pressure of water (the change in velocity and reduction in pressure while passing the turbine makes the runner rotate) and the housing enclosing the runner maintains this pressure profile. The fundamental theory regarding this technology is described by Newton's third law. The impulse turbine is driven by the flow of water which uses its kinetic energy to make the shaft rotate; a larger water velocity gives higher energy transfer and more torque (Wagner & Mathur, 2011). In this type the rotor blades are bucket-shaped to catch as much water as possible. Before the turbine, nozzles create high velocity water jets that impinge on the turbine blades. Unlike the reaction turbine, the energy transfer process operates under atmospheric conditions (Guerrero-Lemus & Martinez-Duart, 2012).

The Kaplan turbine is a reaction turbine suitable for small heads (see Figure 3), usually not more than a few meters (Sorensen, 2011). It has a rotor shaped like a propeller, and when operating according to the design point an as high efficiency as 0.9 (Sorensen, 2011) can be reached. When working during offset conditions the efficiency remains high for a large variation of water mass flows (see Figure 2). For PHS systems the Kaplan turbine is rather inefficient in pumping the water upwards (though it is possible), and for instalments that are using this turbine separate pumps and pathways are usually constructed.

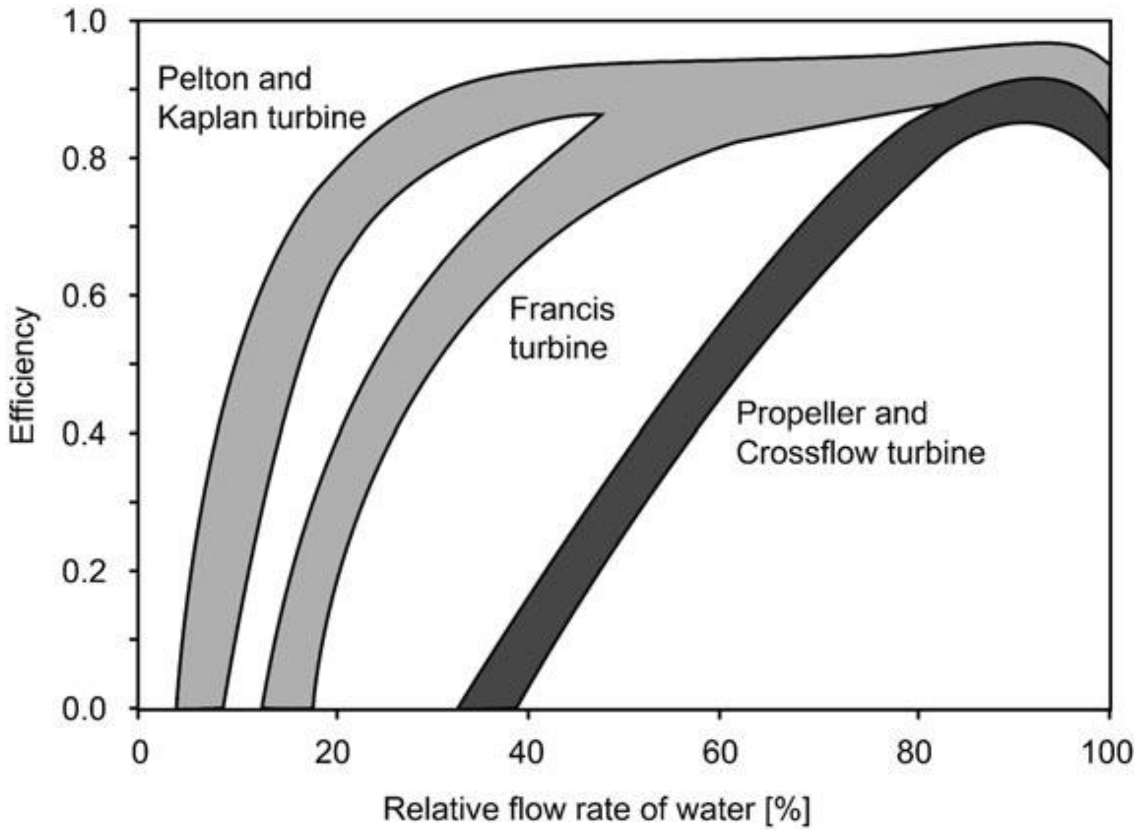

Figure 2 – Influence of relative water flow on the efficiency for different types of turbines

Similarly as the Kaplan type, the Francis turbine is a reaction turbine. It can be used in a large spread of configurations and heads up to around 1500 m (Sorensen, 2011) are possible. In this type there are fixed guiding blades (stator) that lead the water to rotating blades (runner or more commonly known as rotor). The stator gives the water an optimum impact angle when reaching the rotor and high efficiencies (as high as 0.95 (Sorensen, 2011) in both generating and pumping mode) are possible. Considering energy storage there are instalments with round trip efficiencies of up to 0.8. The Francis turbine can, similarly to the regular gas turbine, be designed with multiple turbine stages and these are mainly used when very large heads are present. Considering cost, Francis turbines have the advantage of having high efficiencies for the turbine in both generating and pumping mode. A separate pump installation is thus not needed and a lower investment cost can then be achieved compared to the Kaplan type.

The Pelton turbine extracts energy through impulse and is mainly used for large heads with high water velocities. It consists of a bucket wheel that is being driven by the kinetic energy of the flowing water, which is transformed to a rotational energy through the movement of the buckets. The water jets are created with nozzles before impinging on the runner. This kind of turbine is suitable for a large number of power arrangements and efficiencies of 0.9 are common. The losses are mainly caused by leakage, i.e. when water is passing through the turbine without contributing to an energy exchange.

The operating range of the three different turbines mentioned is illustrated in Figure 3 below.

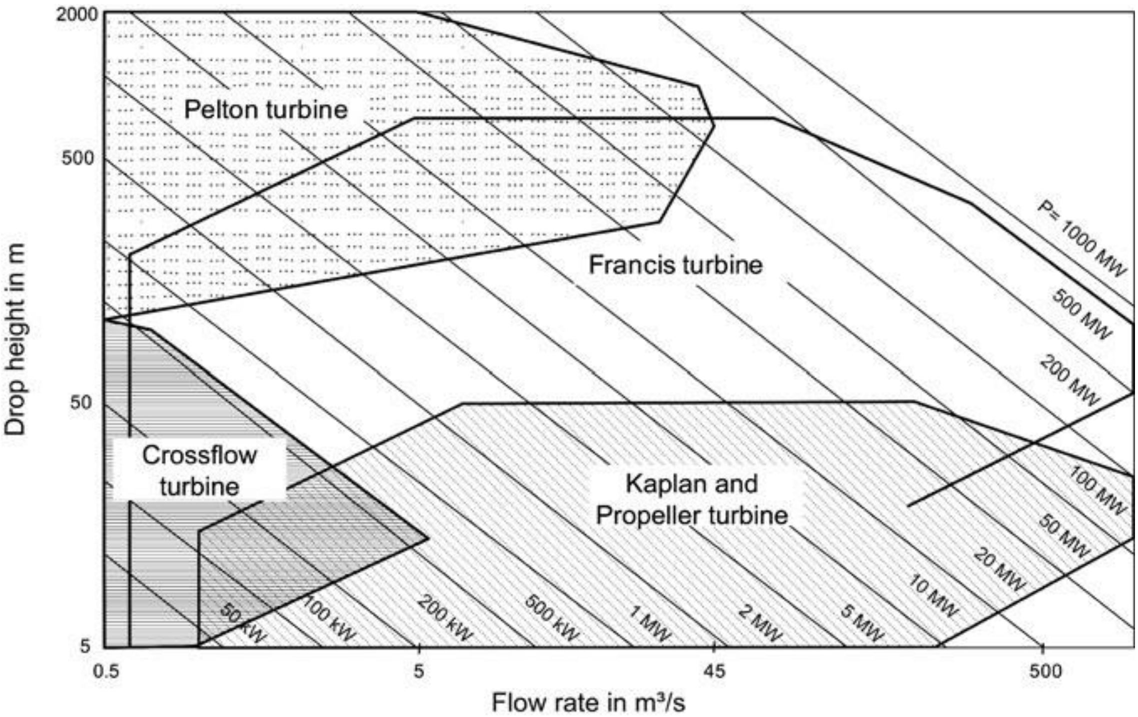

Figure 3 – Operation characteristics for the three most common turbine types

Power output for a turbine can be described with the formula:

$$P = \eta_d \rho \dot{V} g H \qquad (2)$$

Where:

η_d = net efficiency
ρ = density of water
$\dot{V}$ = volumetric flow rate
g = gravitational acceleration
H = head

2.6.2 Generator

A generator is a device designed to take advantage of the electromagnetic induction in order to convert torque into electricity. Interaction between a primary (rotor) and a secondary side (stator) allows energy conversion from mechanical to electrical energy. An external rotation force spins a bar magnet (on the primary side) resulting in a magnetic field which changes over time. The changing magnetic field induces an alternating current (AC) and voltage (AV) in a loop of wire (armature) on the secondary side. The AC in turn produces its own magnetic field, which acts to retard the motion of the spinning magnet. The interaction of magnetic fields mediates the energy conversion between mechanical and electrical energy. Typically the rotor contains the magnet and the stator the armature. The standard generator in the power system has three conductors corresponding to three phases in the transmission lines. Each of these phases constitutes an own power circuit and are separated from each other.

A generator running in the opposite direction (converting electrical to mechanical energy) is called a motor. For pumped hydro storage the generator works as a generator in discharging mode and as a motor in charging mode.

For the hydroelectric turbine technology the rotational speed of the turbine is low compared to other turbine technologies (usually around 500 rpm). The standard operation frequency for the electrical grid and generators in Europe is 50 Hz (von Meier, 2006). To achieve the needed condition generators have more pole pairs and these induce electricity more than once in each revolution. A generator connected to a 500 rpm turbine and working with 50 Hz frequency should have 6 pair poles to achieve the wanted condition.

There are two types of generators. The synchronous generators are the most common in the electricity system and they deliver power with a rotor and a stator field operating at the same frequency. These are, together with shunt capacitors, the backbone for stability in the electric power system. For offshore wind farms induction generators are usually used. These are asynchronous generators and operate without a dependent source for its rotor field current. The rotation is not fixed and varies with power, having the ability to absorb fluctuations of mechanical power (delivered by the fluctuating wind resource). Certain equipment (controlling platforms) is then used to deliver the right frequency to the grid. Another advantage compared to the synchronous generator is the lower cost.

2.6.3 Storage chamber

The size of the submersed chamber will be determined by the demands on energy storage capacity from the power system.

2.6.3.1 Subsea construction

The thickness required to withstand the outer forces from the water is found as a function of the external pressure and the properties of the chamber material. The main mode of failure which needs to be avoided when constructing shells that will be experiencing an external pressure is buckling. Buckling is a mode of failure caused by the formation of dimples in a hollow shell when it is exposed to a high enough external pressure. When the energy storage reservoir has been lowered into place at the seabed it will experience a varying external pressure along its height due to the increasing water pressure with depth. It will also be subjected to a cyclic load when the chamber is emptied and filled, which could lead to fatigue failure. To get a first approximation of the thickness the situation is simplified as a case with constant pressure across the chamber, corresponding to an occasion when the chamber is empty, and where there are no cyclic loads.

It is assumed that the storage unit is spherical as this shape gives the least amount of surface area per unit of volume and also withstanding pressure better than any other shape; due to its lack of corners it experiences an equal force in every direction. The thickness can then be obtained from classical buckling theory, where the buckling pressure of a spherical shell with radius r is described as (Samuelson, 1990):

$$p = \frac{2E}{\sqrt{3(1-\nu^2)}}\left(\frac{t}{r}\right)^2 \tag{3}$$

Concrete is chosen as the construction material for the reservoir due to its low price and the vast competence connected to it. The material has a Poisson ratio (ν) of 0.2 and an elasticity modulus (E) of 36 GPa, which gives a simplified formula as

$$p = \frac{2E}{\sqrt{2.88}}\left(\frac{t}{r}\right)^2 \tag{4}$$

According to (Mekjavić, 2011) buckling occurs at approximately 10% of the theoretical buckling pressure, a typical value of the safety factor is 6 (Sinnott, 2005) giving an expression for the thickness t as:

$$t = r\sqrt{\frac{6 \cdot p\sqrt{2.88}}{2E \cdot 0.10}} \tag{5}$$

2.6.3.2 Energy density

The energy density U for the SHPS technology is dependent on the depth d at which the unit is placed. Energy is extracted from the head of water above the turbine, corresponding to a value per cubic meter of water of:

$$U = \rho g d \tag{6}$$

When the reservoir is filled with water during discharging the energy density continuously decreases as the pressure potential is decreased. Because of this the height of the storage unit becomes restricted if there is a limit on the accepted loss of head. The restriction becomes more influential at lower depths where the height of the structure is proportionally larger than at larger depths. If the necessary energy storage capacity is known, the depth at which the storage unit will be placed determines the required inner volume of the reservoir. Regardless of the shape of the reservoir the volume and height restrictions together produce restrictions on all other dimensions.

2.6.4 Conceptual design

There are two possible concepts for the energy storage unit. Either a centralized capacity is used, where several storage units are connected and the power is generated from a single turbine and generator. Or a decentralized capacity is considered, with each unit containing a separate turbine and generator. In the centralized case additional pipes are needed to connect the units to the turbine, this will lead to some pressure losses in the system. There will be lower investment costs for the power generating components (fewer components), but higher investment costs for the additional piping and a cost related to the increased pressure losses. Maintenance and operation costs will be lower for the centralized option. The decentralized option has a higher investment cost for the mechanical components, however, the pipe network connecting several tanks is not needed. The turbines will be located either inside the container or outside in a sealed water filled container (to maintain the high conversion efficiency). Depending on the design reparation costs will differ, though in both cases it will be substantially higher than for the centralized option. Feasible constructions will give the limitations for the energy capacity. Depending on if a centralized or decentralized configuration is chosen what is feasible will differ. A centralized facility has the potential for capacities in the order of gigawatt hours and is entirely dependent on the geographical location. The separate units have a limited amount of energy (most likely in the order of megawatt hours) since it is not feasible to construct too big reservoirs, but this is entirely dependent on the depth.

In both cases a connection between the storage unit and the surface is needed for facilitating the needed flow of gas (air), transmitting energy and controlling the system. A connection tower could serve this purpose. Due to cost related issues this would probably only be implemented for shallow locations. For deep ocean sites a different design would most likely be implemented. The facilitating of needed gas would then be solved with a membrane construction compressing the gas when water fills the container. When water is pumped out the membrane expands (pressure difference) and the void created is filled with the expanding gas. For controlling and transmitting energy to the surface cables which connect the units to substations are used.

Considering energy density, the height of the water pillar gives the amount of energy stored in a given volume. The depth in SPHS (head in PHS) thus determines the energy density. Considering a fixed energy storage capacity, a shallow location will need a larger container compared to if the depth is increased. Furthermore, since a large reservoir is needed the cost for construction will be high. On the other hand the cost for installation, operation and maintenance increases with increased depth yielding a trade-off between the different costs.

There are several aspects and design considerations when choosing the turbine. The water depths give limitations on which turbine types that are possible to implement. Design properties like using a separate pump or a reversible turbine, constant rpm (mass flow) or constant power output, part load efficiencies and starting characteristics of the turbine are important to consider. Choosing a constant power output the rpm of the turbine will change during operation. When charging and discharging the efficiency of SPHS changes since the turbine is not working under designed conditions. Another concept that affects the efficiency is turbulence and frictional losses from water movement. Since the penstock is virtually inexistent, these losses are considered to be very low.

Because of the large amount of possible configurations the cost for the turbine setup can differ widely. Mainly two types of turbines, Francis and Kaplan, were considered for implementation. Both types shows good properties for low heads (Francis works at a wider range and large heads are possible). The advantage with the Kaplan turbine is the ability to work under changing conditions without dropping much in efficiency (Figure 2). The main disadvantage with this technology is the bad efficiency in pumping mode, (reversed direction) which leads to the fact that if choosing a Kaplan turbine a separate pump is essential for remaining a high round trip efficiency. More components do not only increase the investment cost but also the operation and maintenance costs (operation and maintenance cost are already substantial considering the fact that the technology will operate on the seabed). The Francis turbine on the other hand has the advantage of having high efficiency in both pumping and generating mode (if working under designed conditions) and fewer components are thus needed.

For other electronic components, such as generators and transformers, several solutions are possible. The wanted voltage and current levels determine the size of the transformers. Generally an as high voltage level as possible (and hence low current level) is wanted to minimize the losses in transmission (von Meier, 2006). An induction generator is most likely to be used since the properties of having a relatively low cost and the ability to absorb mechanical fluctuations are considered to be favourable. Discussions (Nilsson, 2013) led to the decision of using a regular asynchronous generator (induction) and then converting the electricity to the right frequency. The generator will not be designed to yield a given frequency since the turbine rotational speed will change and with it the frequency. The frequency would, with frequency changers, be correlated in the substation to match the grid's design.

Cables used are dimensioned based on the operating current and voltage of the turbine and generator (Åkerlind, 2013). Two cables for each unit are needed for connection to the surface and the substation. Further, connecting the substation to the grid onshore, HVDC cables (Bresesti, Kling, Hendriks, & Vailati, 2007) are generally used for offshore wind power today. Since the energy storage sites would be near offshore wind power units, the same substation and connection to the grid could be used to keep the investment costs down (Odenberger, 2013).

The material decision is of great importance since the SPHS units will mostly be located in the ocean. The operating medium is salt water which requires a material that is highly resistant to corrosion. The cost for offshore implementation will thus be higher compared to units exposed to freshwater.

2.6.5 Geographic aspects

Different locations are possible for subsea pumped hydro storage, and criteria for the locations depend on several design parameters (discussed in the previous chapter) of the technology and also on implementation in the electricity system. The water depth determines, as mentioned, the possible pressure drop and energy density. A higher density corresponds to smaller units for the same energy content. It is important to note that the related costs for operation increases with increased depth due to the need of more sophisticated technologies.

As offshore wind farm developments increase, a combination of the two technologies can contribute to a more steady electricity output profile. For this implementation in the energy system it can be preferable to place the storage units close to a wind farm, mainly because of the substantial cost of high voltage cables. The combination of these technologies limits possible sites since there are restrictions from both to account for.

Other aspects that affect the choice of location could be availability and surroundings that affect installation.

3 Method

Considering the large amount of wind power in the Danish electricity system, this was considered suitable for a case study as it would represent a region with a highly fluctuating power production. The future energy targets in this region are also well defined and give a solid base for modelling future scenarios. The Nord Pool spot market provided an extensive database for the Danish power system including data for demand and electricity prices, and the Danish TSO, energinet.dk, provided data for wind power output, imports and exports and centralized power production.

3.1 Design requirements

Large variations of setups are possible and the challenge is to find the most suitable configuration for implementation. Literature study and guidance by involved individuals determined a suitable design. Deeper technological evaluation was disregarded in this study and reliance on insights from competent people was considered to be enough.

3.2 Comparison with other technologies

Studying the possible energy storage technologies, not all serve the same purpose as SPHS. Regular PHS and CAES are technologies considered for the same widespread implementation (bulk storage). As mentioned in Chapter 2.4.1, the key performance parameters are indicators used to characterize and compare different energy storage technologies. With a literature study and interviews with the industry these inputs could be determined and a comparison between the technologies was made.

When estimating the LCOE a modified version of equation (1) was used. Since the comparison is made between energy storage technologies and not power generation, the fuel costs should be interpreted differently. Here, the electricity price was implemented instead since, similar to fuel costs, this is a variable costs that increases with increased utilisation. For calculations, the energy amount and electricity cost were determined with the actor's perspectives energy model (see Chapter 3.3). The RTE was included in the electricity cost since the utilisation of power differs between technologies. Considering the discount rate, a large variation of numbers is used and depending on which one the result will differ widely. For wind projects the rate varies between 5.5% and 12.5% (IRENA, 2012). The discount rate was determined by choosing a mean value of this interval, resulting in 9%. The capital costs vary depending on references, but the most recurring values from different sources were used for calculation, see Appendix A for capital cost intervals. Estimating the cost for operation and maintenance a literature study provided values, and the mean value method was used to determine the inputs used. Depending on what technology was studied different economic lifetimes were implemented in the calculation.

With all these parameters determined, a levelized cost of electricity could be calculated and the result provided a value for comparison between the technologies.

3.3 Energy system modelling

In order to illustrate the characteristics of the chosen reference energy system and to evaluate the potential of energy storage, an energy systems model was created. The model uses production data for wind and thermal power as well as the load curve and the corresponding price for the Danish power system to model the charge and discharge characteristics of a generic energy storage technology. The thermal power is assumed to be generated at constant levels during winter and summer to simulate a case where these electricity generating technologies are not part of the balancing power in the grid; this function is covered by the energy storage instead. The amount of electricity generated by the thermal plants remains the same, but this generation becomes more efficient as the plants can run at their design point for a longer time without major changes in operation. The system characteristics, with and without the assumption of constant thermal power generation, are shown below in Figure 4.

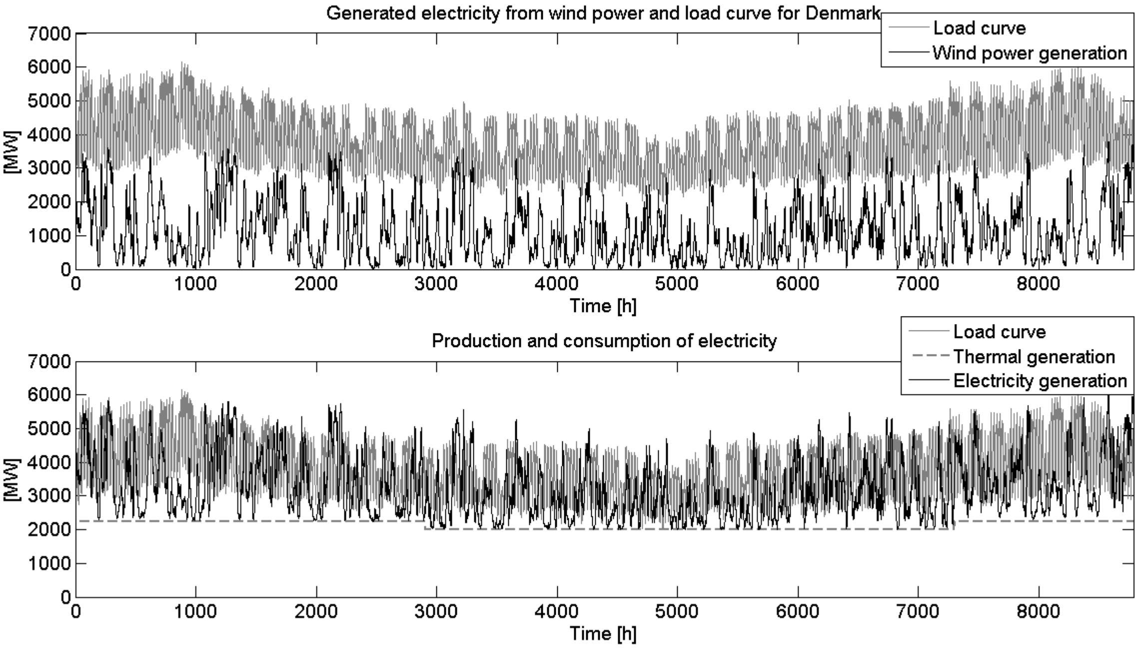

Figure 4 - System characteristics with and without the assumption of constant thermal generation

To find how the energy storage behaves in terms of charging and discharging during a year a number of properties were analysed continuously at each time step. The data for electricity generation, from both wind and thermal power, was measured every five minutes so this time step was used in the model. The price and load curve for the chosen year (2012) only contained data entries at every hour so these curves were interpolated to match the more detailed production curves. The criteria for charging is that there is a surplus of electricity in the grid after the thermal production curve has been evened out and that the price level of electricity is low enough. The amount of energy which can be stored is also limited by the capacity of the power conversion system. The criteria for discharging are the opposites of the charging criteria, but the limitations of the power conversion system still apply. The principle of charging and discharging is illustrated in Figure 5 below.

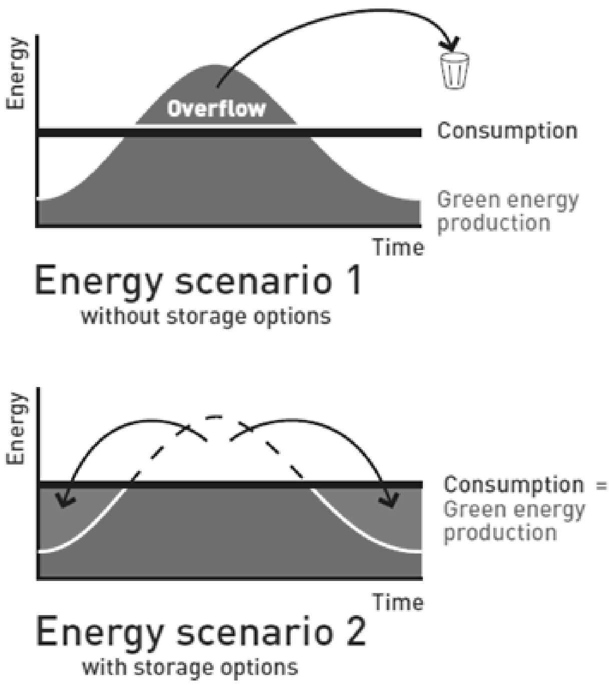

Figure 5 – Concept of evening out the power fluctuations with energy storage

The first part of the model determines the total balancing need that arises due to the assumption of constant thermal power. The model runs through every time step, comparing the load to the production (wind and thermal power), and if the production surpasses the demand at that point the excess energy is stored to a vector. As long as this behaviour is observed the value at each vector position represents the accumulated energy stored. When the opposite occurs, that the production is lower than the demand, the required energy to cover this gap is released as long as the stored energy doesn't drop below zero. The value of the specific vector position (the amount of energy currently stored) is decreased slightly more than what is released to the system due to an assumed efficiency which represents the losses throughout the storage process; all losses are allocated to the discharge for simplification. The total storage curve can be used to determine the maximum capacity needed for balancing all fluctuations and to estimate how often a certain capacity is needed.

In order to balance all of the arising fluctuations the storage needs to be dimensioned for one maximum capacity case, but since it is unlikely that this will be accomplished due to the resulting low utilization factor two other cases with lower storage capacities will be examined as well. The storage capacity in the first case is based on the mean value of storage requirements throughout the year, and the second case evaluates a case where the storage limit is half of the maximum storage limit.

The three chosen storage limits were implemented in the next step of the storage model. Compared to the first step, the methodology remains the same, but with an added upper limit of energy storage as a complement to the physical limit that describes an empty unit. The possible power in- and outputs from pumps and turbines were also considered by limiting the conversion of energy at each time step to the rated power. To determine the total power, the number of units was calculated. This is achieved by comparing the storage capacity of a single unit, which is set to a fixed value, to the system capacity for each limit. In addition to fixing the single unit storage capacity, the power is set as well. The two parameters result in a limit of energy conversion for each scenario. Furthermore, an economic aspect was implemented to evaluate the possibilities of profit from using the technology. The financial flow can be determined by applying the current electricity price to the amount of energy being stored or released at each time step and at the end of the year the result is obtained.

In an effort to improve income and illustrate a more likely operation of an energy storage unit, the electricity price was implemented as another criterion for charging. In the Nordic power system the electricity prices for the following 24 hours are revealed daily through Nord Pool, this means that a scheme for charging and discharging based on this information can be created in order to maximize income. Since the power-to-storage capacity ratio is fixed, the charge and discharge times are known. The model uses this to choose the hours with the cheapest and most expensive electricity prices for the following 24 hours in order to schedule charging and discharging, within the predefined limits of the technical system.

3.3.1 Actor’s perspective

The energy model created uses input data based on the current power system of Denmark and in order to keep these characteristics the energy storage technology is implemented in the model from an actor’s perspective. This implies that only one unit is studied as a part of the system, and due to its small impact the system as a whole is not affected. For the single unit it is assumed that there is always a sufficient amount of electricity in the system, due to a well-developed power grid, and that the charging and discharging occurs when prices are low or high enough.

3.3.2 Future developments

The Danish government has set ambitious energy targets for the future. In the year 2020, 50% of the electricity generation (Danish Ministry of Climate, Energy and Building, 2012) has to come from wind power. With the increased amount of power fluctuations due to the large share of intermittent wind power, more problems with regulating power will become apparent. Trends show that the demand will not increase significantly (Rasch, 2009) because of energy efficiency measures on the demand side (more efficient energy services and end-use). In order to reach the 50% target the yearly energy output from wind power needs to be increased by 83%, which was implemented in the energy systems model.

3.3.3 Sizing of subsystems

As a first estimate it was assumed that the storage chamber should be able to store energy from a large offshore wind turbine (5 MW) for four hours. This 20 MWh storage unit was used as a definition of a single decentralized unit throughout the analysis. The effects of varying storage capacity and pump-turbine power were also evaluated.

3.3.4 Input data

Data for price and consumption levels for the year 2012 in the chosen system was obtained from the Nord Pool website (Nord Pool Spot). The data entries are given for each hour of the year, resulting in a total of 8784 entries (due to that 2012 was a leap year). The analysis considers all of Denmark as the chosen system and data for this region is obtained by using the mean value of the two price areas in the country. In Figure 6 below the price behaviour of 2012 is shown and it can be seen that prices drop below zero at some occasions. This occurs when electricity generation is high, which many times can be contributed to a high wind power output in combination with a low demand from the consumers. The phenomena can both be the result of subsidies, which can make it profitable for a utility to sell electricity even though the market price is negative since they are compensated by other means, and the fact that in some instances it is more cost-effective for a utility to keep running its large power plants and paying to release electricity to the grid rather than shutting down and subsequently starting the plant again.

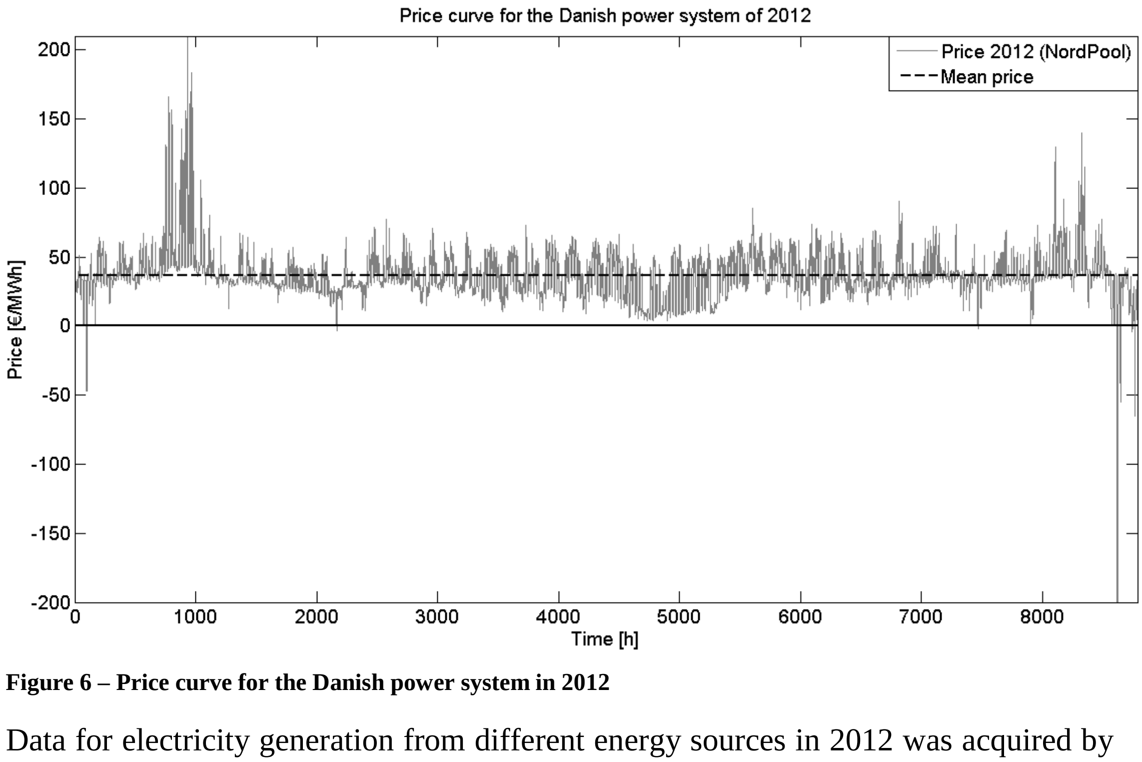

Figure 6 – Price curve for the Danish power system in 2012

Data for electricity generation from different energy sources in 2012 was acquired by access to the five minutes' metering provided by the Danish TSO (Energinet.dk). Since the entries per hour are 12 times more for this detailed data compared to the Nord Pool data an interpolation of the price and consumption data was needed in order to achieve an equal number of entries for both sets, allowing for a step-by-step analysis to be carried out.

To study future developments and how these influence the use of an energy storage unit, price curves for the year 2020 was needed. This information was obtained from a model created at the Division of Energy Technology, which simulate a possible outcome given certain parameters.

Price information for the different components of the Subsea Pumped Hydro Storage unit was attained through contact with representatives from the industry and through literature studies of relevant technologies with similar properties.

3.4 Scenarios

Different scenarios were implemented in both the calculation of the LCOE and the evaluation in the energy systems model in order to capture the characteristics of the energy storage technology.

3.4.1 Centralized or decentralized configuration

The additional cost for centralisation was assumed to be an increase in construction costs of 10% (see Chapter 4.1) to account for additional piping and connecting several storage units. This additional cost was used throughout the entire investigation.

3.4.2 Charge and discharge time

Considering different discharge times the LCOE changes. Lower charge and discharge times improve the ability to take advantage of peaks in the electricity price throughout the day. A potential higher income for the energy storage unit can be reached since shorter time intervals for buying and selling electricity yields lower and higher mean values of the price (and a larger difference between buy and sell price). To analyse the behaviour of changed charge and discharge times, both a 5 MW and a 10 MW pump-turbine were implemented in the LCOE calculations.

3.4.3 Depths

Considering the possibility of installing the technology at different depths, the investment differs and apart from the power converting components, all the costs change. Unlike the installation cost, which increases, the concrete structure cost decreases with increased depth. The first depth analysed was 100 m, which was chosen since it is likely that an installation at this depth can be achieved within a foreseeable future. Lower depths have the advantage of higher energy densities which lead to smaller constructions, so the depths at which the concrete cost was reduced to half and a third of that of the first case was chosen for analysis as well. These depths where determined to be 458 m and 1212 m, respectively. The increased cost of installation is difficult to estimate since there are no facilities in operation, but a symbolic rate was used. For a depth of 458 m an increase of 20% was estimated and used for installation and operations and maintenance costs. At 1212 m an increase of 62% (to keep the same cost increase per meter) in installation and operations and maintenance costs was used.

3.4.4 Future scenarios

As explained in Chapter 3.3.4, a price curve for a possible future Danish power system (in the year 2020) was obtained from an external electricity price forecast model. Fluctuations in this curve were lower than in 2012 so further scenarios were implemented. The third scenario implemented a price increase of 20% compared to the situation of 2012. The highest fluctuating region regarding price from the 2020 forecast model, the UK2 price area, was also analysed as it was believed that this would be a good representation of a future highly intermittent region.

3.4.5 Best and worst case scenario

Because of the uncertainties in the design inputs, an analysis is necessary to show the range of possible outcomes. The critical parameters are: installations costs, operation and maintenance costs, the round trip efficiency, electricity prices and the water depth. When implementing the analysis into the model the impact will be a changing cost for the energy storage unit. A best and worst case scenario is included containing a change in all the parameters at the same time. With these scenarios a LCOE interval can then be estimated describing a possible cost range for the technology. With this, a more accurate LCOE analysis resulted in a range of costs rather than exact values. For the low boundary (best case scenario) the installation cost was approximated to be the same as the estimations of (Garg, Lay, & Füllmann, 2012), namely 300 €/kW. The operation and maintenance cost was set to be the same as the lower value of offshore wind power (IRENA, 2012). The pump-turbine cost remained the same for all the calculations because this was considered to be the most certain value (Sander, 2013). Due to the uncertainty of the performance of the technology, the RTE for the best case scenario was set to 80%, as high as the best pumped hydro storage facility today (IRENA, 2012). Considering the depth, 1212 m was chosen since with the lower values of operating cost the 62% increase affected the unit less than for the original case.

The worst case scenario includes an efficiency of 70% and a water depth of 100 m which yielded a concrete structure cost of 1973 €/kW. The installation cost was set to 500 €/kW and the operation and maintenance cost was set to 5 €cents/kWh, higher than the highest value for offshore wind power (IRENA, 2012).

3.4.6 Subsidies

To see how economic support influences the possible income for an energy storage technology, a subsidy is incorporated into the energy systems model. The value of the subsidy was chosen as that for offshore wind power in Germany, 150 €/MWh (dejure.org), since that technology share many issues with Subsea Pumped Hydro Storage.

4 Results

In the following sections the results from the techno-economic analysis and the energy systems model will be presented.

4.1 Techno-economic analysis

4.1.1 Turbine

A consultation (Nilsson, 2013) led to the decision of using a Francis turbine. The turbine is set to operate under a fixed power output. This yields a varying rotational speed since the pressure head changes while the storage unit is filled with water. Depending on the location, the technical properties for the turbine varies. For shallower depths a larger mass flow of water is needed to yield a given power output compared to a deeper location. Different water depths (depths of 100, 458 and 1212 meters were evaluated) will thus give different volume flows for the same power output and are calculated with equation (1).

Table 1 - Water volume flows as functions of depth

	100 m	458 m	1212 m
Centralized, 100 MW	104.6 m^3/s	22.8 m^3/s	8.64 m^3/s
Decentralized, 5 MW	5.23 m^3/s	1.14 m^3/s	0.43 m^3/s

The efficiency will change while operating the turbine at different rotational speeds. To estimate the correct efficiency behaviour, more detailed fluid dynamic calculations are needed. The efficiency used in the model was thus a simplification of the real value. It was assumed that a mean value for the efficiency across the operating range provided sufficiently accurate information.

When considering the decentralized case, the costs for a 5 megawatt pump-turbine of Francis type with a suitable generator is around 600 €/kW (Sander, 2013). Including a contingency of 50% the cost reaches 900 €/kW, yielding a total investment cost of around 4.5 million euros. For the centralized option the costs per kilowatt installed power is lower. A 100 megawatt pump-turbine with generator costs approximately 30 million euros (the kilowatt cost is around 300 €), but there will be a need of additional equipment, such as a pipe network, for connecting the storage units to each other and to the turbine. Another aspect is that the piping network will contribute to pressure losses in the system. The cost for the additional equipment and the pressure losses is hard to estimate, a 10% cost increase of the construction was used as an approximation.

The technology is expected to work at a similar round trip efficiency as regular pumped hydro storage. This approximation is valid since the power generating components work with similar efficiencies in both technologies.

4.1.2 Lower reservoir

The size of the storage unit and the thickness of its walls are dependent on the depth at which it is placed. The cost is decreased by placing the shell at larger depths as the required volume decreases (due to a higher energy density, see Figure 7), however a larger wall thickness is needed (see Figure 8) which increases the amount of material required.

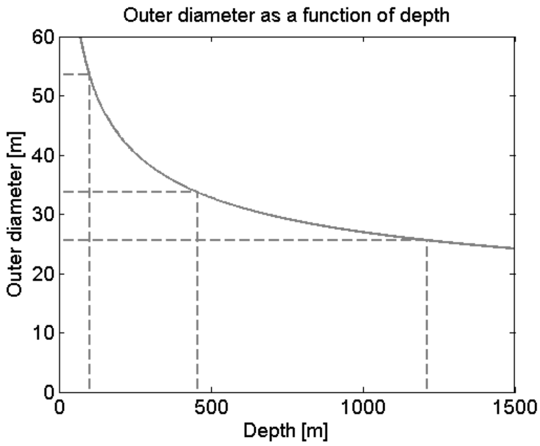

Figure 7 – Outer diameter as a function of depth

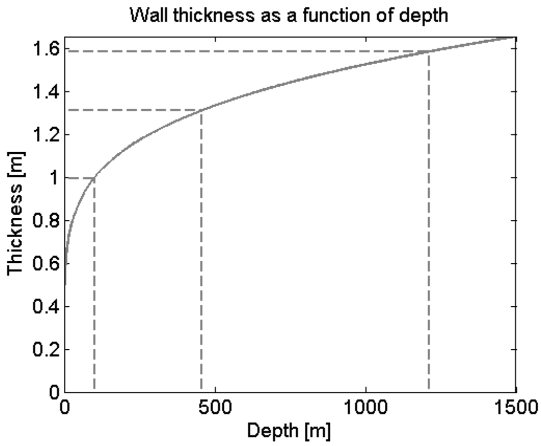

Figure 8 – Wall thickness as a function of depth

Table 2 below shows the correlation between depth and reservoir size. As can be seen the needed concrete volume decreases with increasing depth and hence also the concrete cost (here expressed in €/kW).

Table 2 – Properties of concrete sphere as a function of depth

	Sphere diameter	**Wall thickness**	**Concrete volume**	**Concrete cost**
100 m	53.51 m	0.99 m	8,619 m^3	1,973 €/kW
458 m	33.64 m	1.31 m	4,307 m^3	986 €/kW
1212 m	25.60 m	1.58 m	2,872 m^3	657 €/kW

4.1.3 Total cost

Using contacts in the industry, cost estimations for concrete (1,164 €/m^3) (Daleke, 2013) and pump-turbines (900 €/kW for a 5 MW unit to 300 €/kW for a 100 MW unit, including a contingency of 50% to take the subsea installation into account) (Sander, 2013) were obtained. The installation cost was set equal to that of offshore wind, 445 €/kW (IRENA, 2012), in order to capture the issues of sea-based constructions.

The total cost for each subsystem is presented below in Figure 9 for each of the three depths chosen and for a decentralized and a centralized configuration. It is shown that at a depth of 100 m the concrete structure is the largest contributor to the cost though this share decreases when the amount of concrete needed decreases with depth.

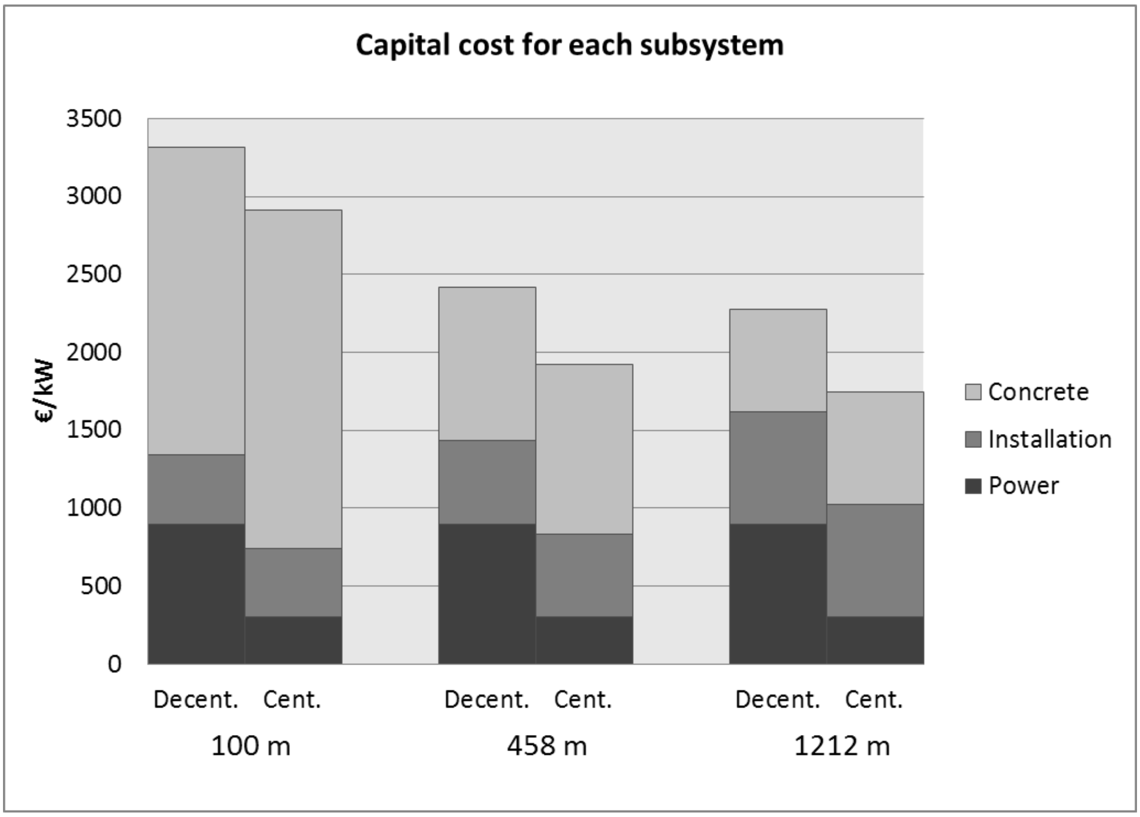

Figure 9 – Capital cost for each subsystem as a function of depth, for both a decentralized and a centralized configuration

As can be seen the depths affect the concrete and the installation cost differently. Oppositely from the concrete cost, the installation cost increases for deeper locations.

4.2 Comparison of energy storage technologies

Following chapters contains the results of comparing the key performance parameters for the different energy storage technologies.

4.2.1 Round trip efficiency

The round trip efficiency for SPHS was estimated to approximately 75%. Comparing to regular PHS, which has RTEs in the range of 0.7-0.8, the efficiency is approximated to be similar. CAES is still in the developing phase, only two facilities have been built, and the RTE potential for the technology is estimated to be around 50% (Pickard, Hansing, & Shen, 2009) which is considerably lower than for SPHS and PHS.

4.2.2 Energy capacity

The energy capacity of SPHS is in the order of MWh (20-30 MWh for a decentralized option). Compared to regular PHS, with bulk storage units in the magnitude of GWh (and a discharge time of days when running at 100% power), a lot of storage units will be needed to get the same capacity. A centralized facility could have comparable capacity to a regular PHS unit. The CAES energy capacity is, similar to PHS, entirely dependent on the geographical location, and facilities in the order of GWh are possible. Summarizing, the centralized option could be comparable to both CAES and PHS.

4.2.3 Rated power

The rated power for PHS varies almost as much as the number of facilities. Different plants have different design configurations and the range is in the magnitude of kilowatts to gigawatts. As mentioned the wanted discharge time and the available energy storage capacity determines what rated power is used. With a large container and short discharge time, the rated power can be high per storage unit and vice versa. The centralized SPHS could have a rated power in the order of hundreds of megawatts maybe even gigawatts (if a fast discharge time is wanted). For the CAES the rated power has the potential of being as high as the energy storage capacity allows. The wanted configuration of the plant and the geographical location determines the limit.

4.2.4 Energy density

The energy density for PHS and SPHS are approximately the same (same equation and principle). In Figure 10 the energy density for different depths are visualized.

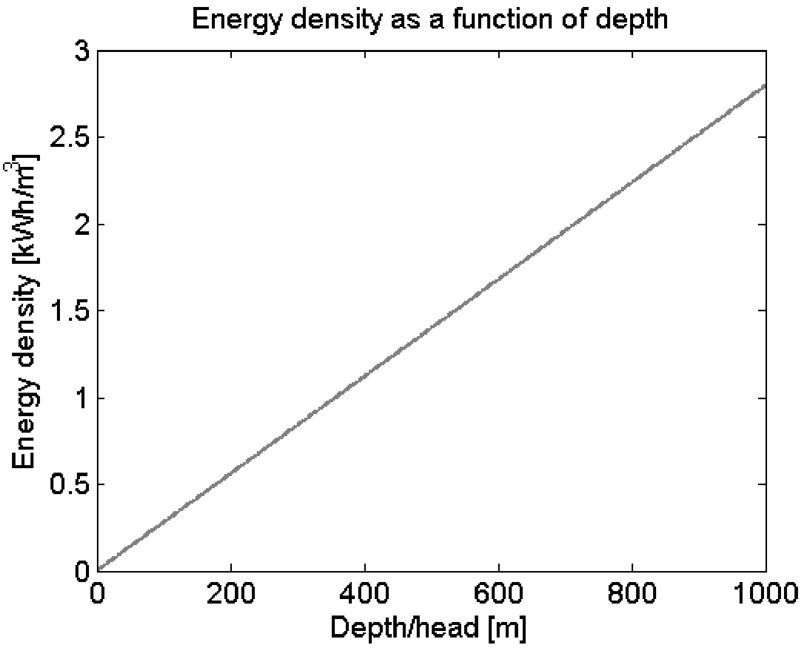

Figure 10 – Energy density as a function of depth for SPHS and head for PHS

For the CAES the operating pressure determines the energy density. Regular CAES has a potential of as high as 12 kWh/m^3 (Ibrahim, Ilinca, & Perron, 2008).

4.2.5 Levelized cost of electricity

When calculating the LCOE for different charge and discharge times the RTE was estimated to be 75% and the capital cost for a depth of 100 meters was used (see Chapter 4.1.3). Operation and maintenance costs for SPHS are considered to be similar to that of offshore wind turbines and thus the estimated cost of 2.86 €cents/kWh (IRENA, 2012) was used. When evaluating different pump-turbine sizes, it is found that using a larger pump-turbine will result in a higher cost for the same amount of energy released (the cost is higher for a 10 MW turbine compared to a 5 MW alternative). Figure 11 shows the LCOE for the two options located at a 100 m water depth.

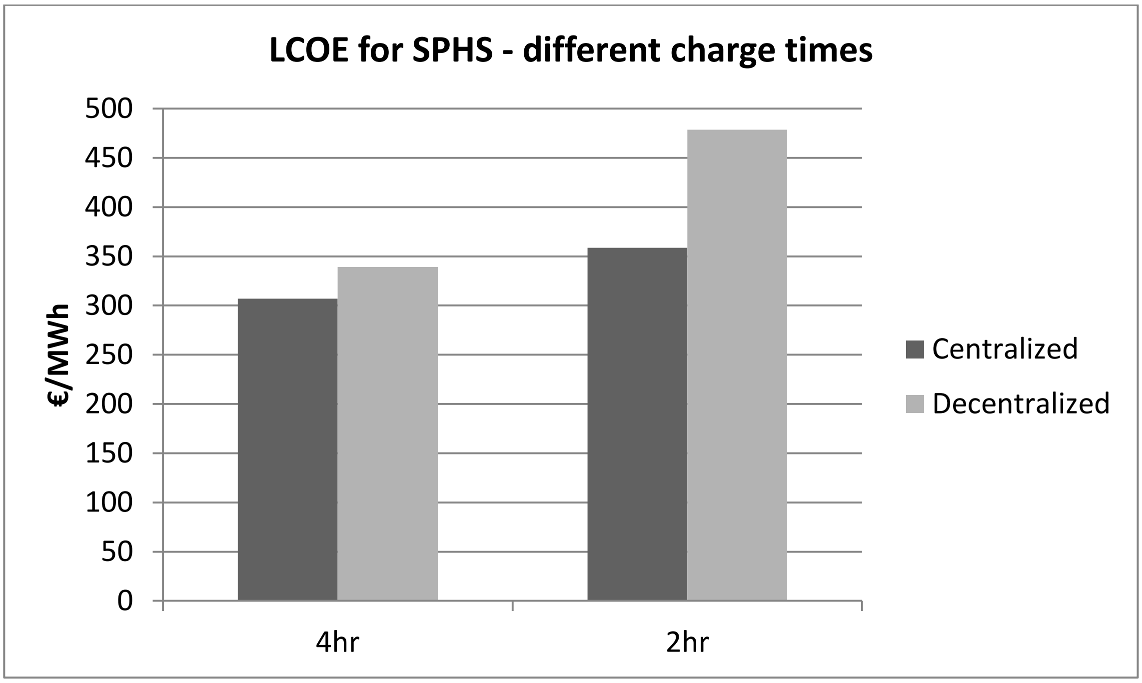

Figure 11 – Levelized cost of electricity for the centralized and decentralized SPHS units, with different charge times

Since the shorter charge and discharge times due to a larger pump-turbine leads to a higher cost, the case with the two hour charge time is omitted in further studies.

The results of calculating the LCOE for different depths are presented in Figure 12 below. Similarly to the previous evaluation, the calculation used a discharge time of four hours and a RTE of 75%.

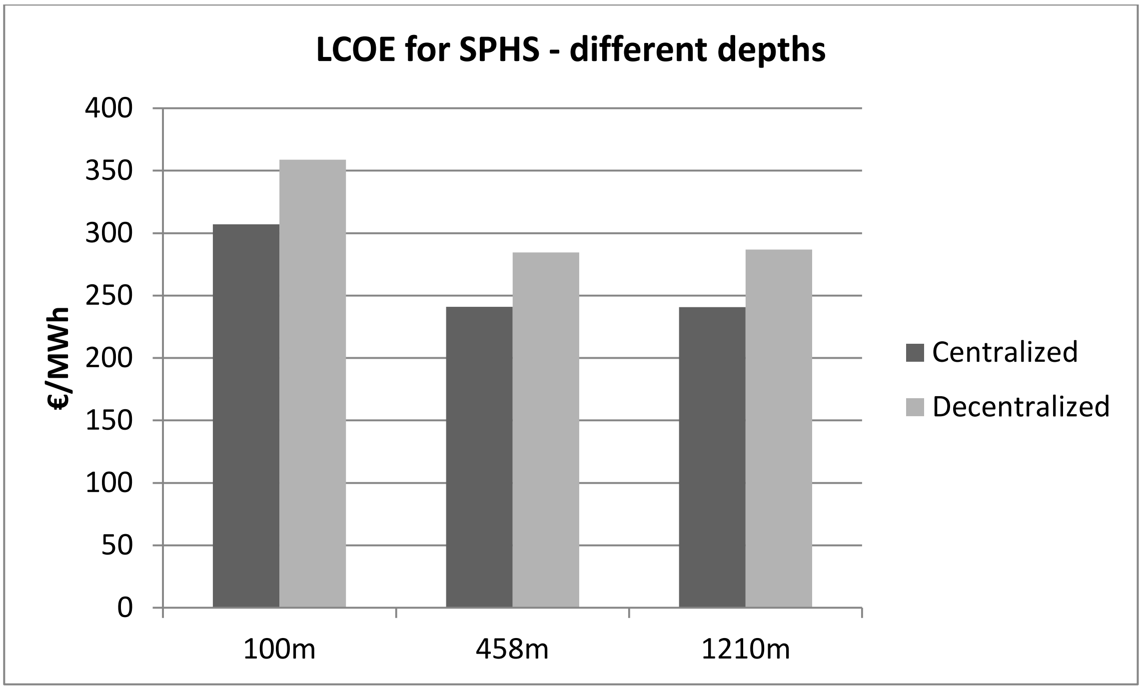

Figure 12 – Levelized cost of electricity for SPHS based on different installation depths

The total investment cost decreases when increasing the depth. This is explained by an increased energy density. At a deeper location the energy density is higher and even though the thickness of the container shell needs to be increased, the material needed for the construction is less. When going even deeper the concrete structure cost decreases further but because of increasing cost for installation, operation and maintenance the LCOE will not continue to decrease indefinitely. There will be an optimum in this trade-off where the LCOE is minimized. Due to the uncertainty in the assumptions this optimum was not estimated.

Figure 13 shows the intervals for the centralized and decentralized options in which the LCOE could end up.

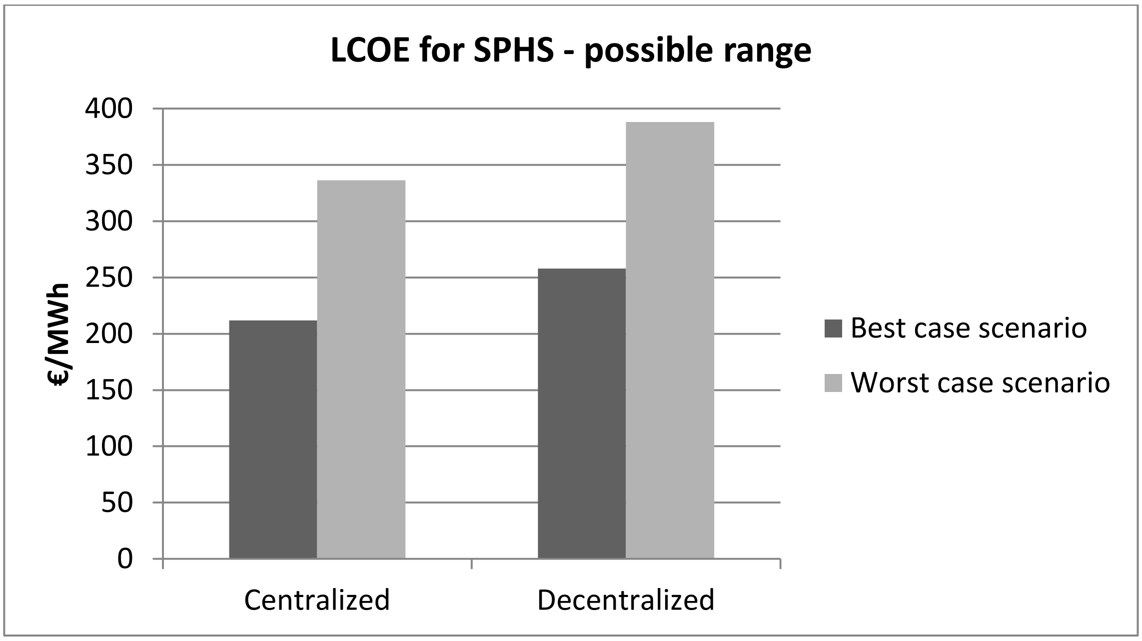

Figure 13 – Cost range for centralized and decentralized versions of SPHS

The comparison of LCOE between the technologies is presented below in Figure 14. Similarly to the analysis of SPHS, a range of values for the cost components were used for PHS and CAES, the most occurring values in literature were in this case used (see Appendix A).

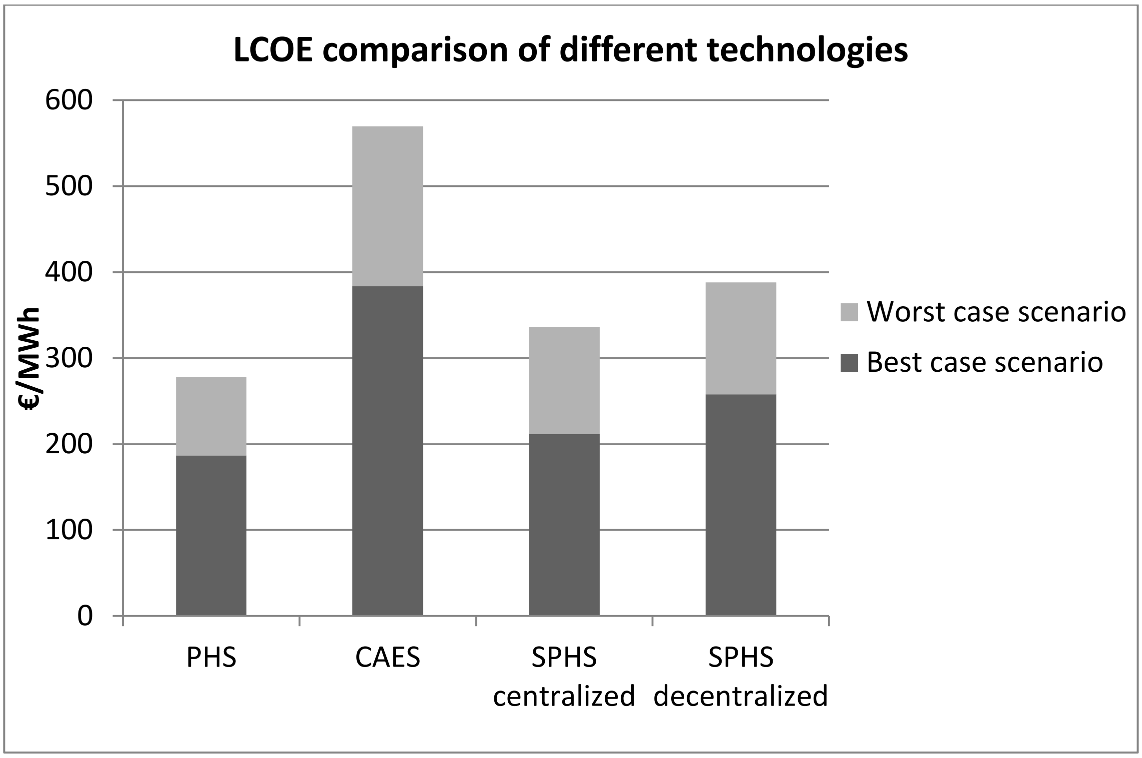

Figure 14 – Comparison of LCOE for different energy storage technologies

The large difference in cost between CAES and the two other technologies is due to the usage of natural gas, which is very expensive.

4.3 Energy systems modelling results

The results from the energy systems model will be presented in following sections. When evaluating the financial results, storage capacity and the power conversion system the actor's perspective defined in Chapter 3.3.1 is used to describe the technology on a single unit level.

4.3.1 Financial results

4.3.1.1 Income

When running the energy systems model it became apparent that the income, i.e. the income from selling electricity at peak hours minus the cost of buying it at off-peak hours, was not enough to overcome costs for operations and maintenance. As seen in Figure 15 the result for a single decentralized unit, during all scenarios, becomes negative unless a subsidy is implemented.

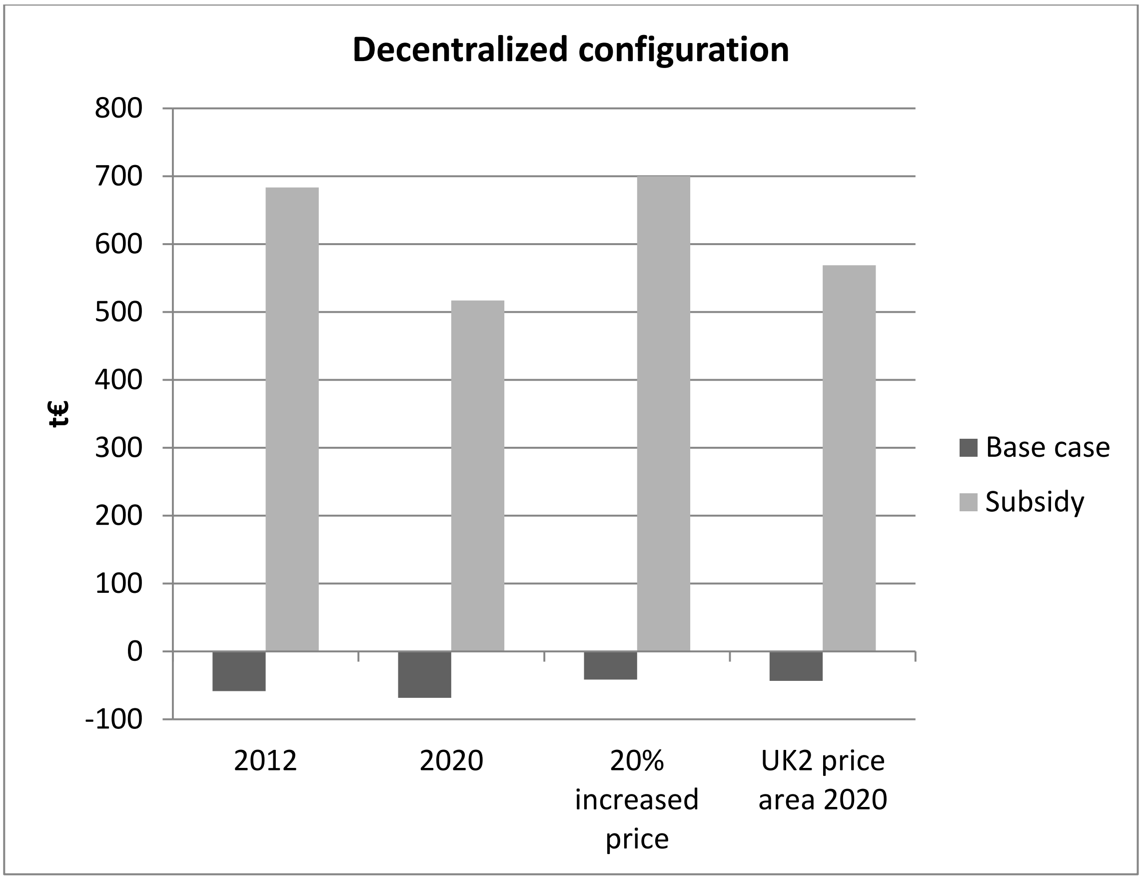

Figure 15 – Yearly income for a decentralized configuration during different scenarios

Similarly, the centralized configuration also needs a subsidy to be profitable, as seen in Figure 16. It can be observed that the increase in storage capacity by a factor of 20 leads to roughly an equal increase in income.

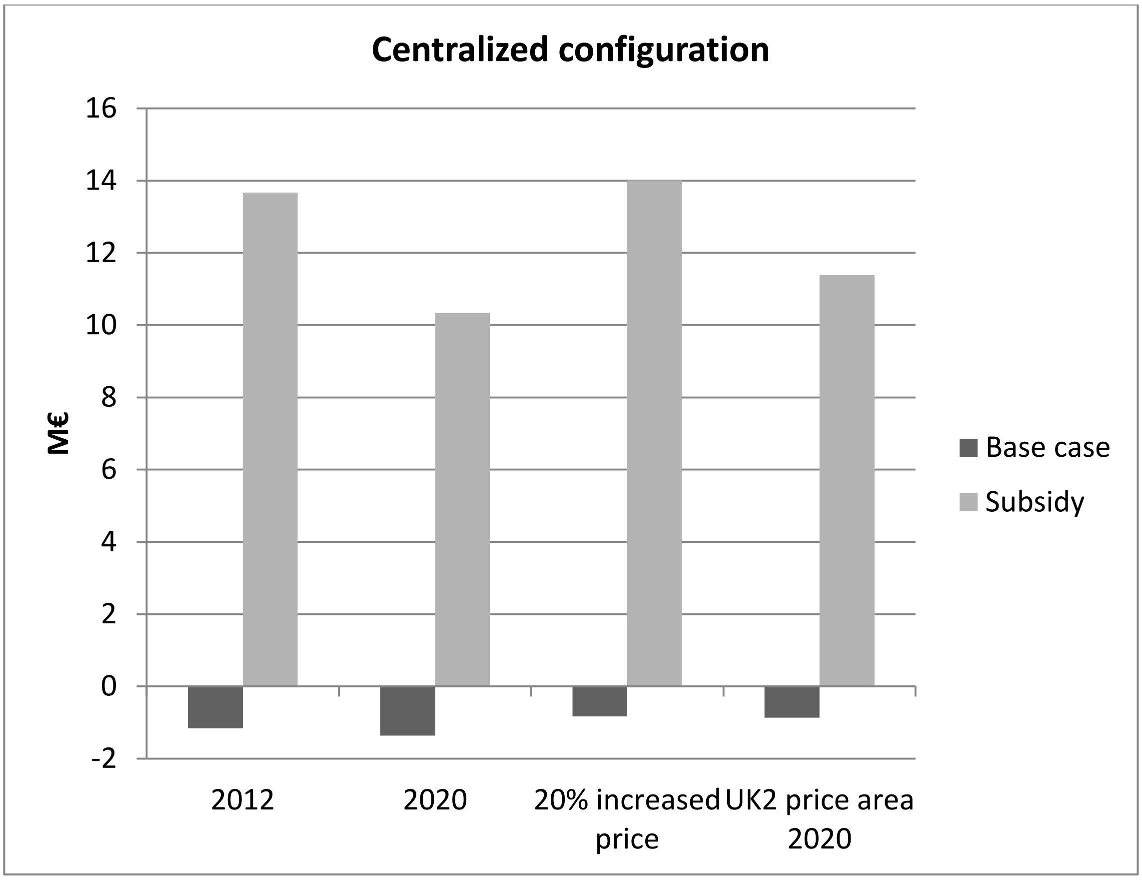

Figure 16 – Yearly income for a centralized configuration during different scenarios

4.3.1.2 Payback period

The payback period provides a solid base for an investor's decision to invest in a unit or not. Since the profit for storing energy with the SPHS technology is non-existing without subsidies, these cases are not considered when presenting the payback periods. In Table 3 below the payback period is shown for the best and worst case (as determined by depth).

Table 3 - Payback period for the best and worst case for the different scenarios, in years

		Best case (1212 m)	Worst case (100 m)
2012	Decentralized	15	24
	Centralized	10	20
2020	Decentralized	19	32
	Centralized	14	26
20 % increased price	Decentralized	14	24
	Centralized	10	19
UK2 price areas	Decentralized	18	29
	Centralized	12	24

The best payback period including the subsidy was calculated to 10 years, which can be compared to the estimated economic lifetime of 40 years. For detailed information about payback periods for the different scenarios, see Appendix B .

4.3.2 Subsystem analysis

4.3.2.1 Storage reservoir

As described in Chapter 3.4.2 the charge and discharge times can be changed by varying the storage capacity. During the analysis of this capacity a constant pump-turbine size of 5 MW was assumed and the electricity price curve for Denmark in 2012 was used. A larger capacity means that more energy can be stored at times of cheap electricity, but unless this amount can be sold within a reasonable timeframe, at a profitable price, the benefit of the large capacity is lost. Larger capacities also means larger investment costs as the physical size of the reservoir increases, as well as a decreasing specific income due to a lower utilisation factor. These trade-off characteristics are shown below in Figure 17.

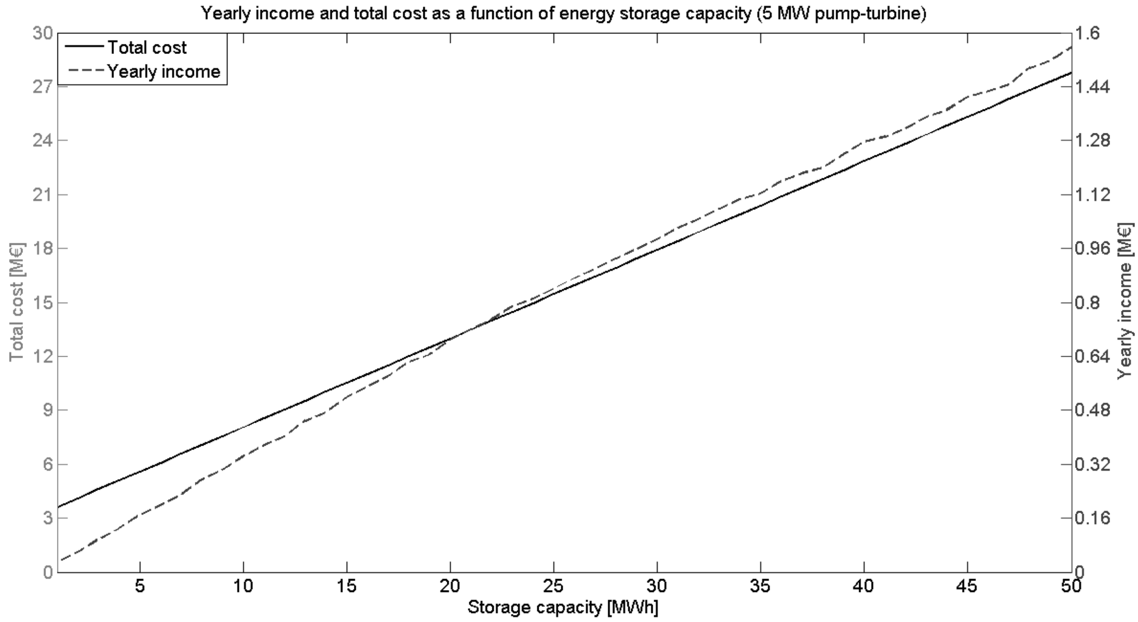

Figure 17 - Behaviour of total cost and yearly income with varying storage capacity (5 MW pump-turbine)

From Figure 17 it can be concluded that the yearly income is increasing more with storage capacity than the total cost, which is also illustrated as the payback period in Figure 18 below. After about 20 MWh the reduction in payback period as the storage capacity increases is negligible and it evens out slightly below 20 years.

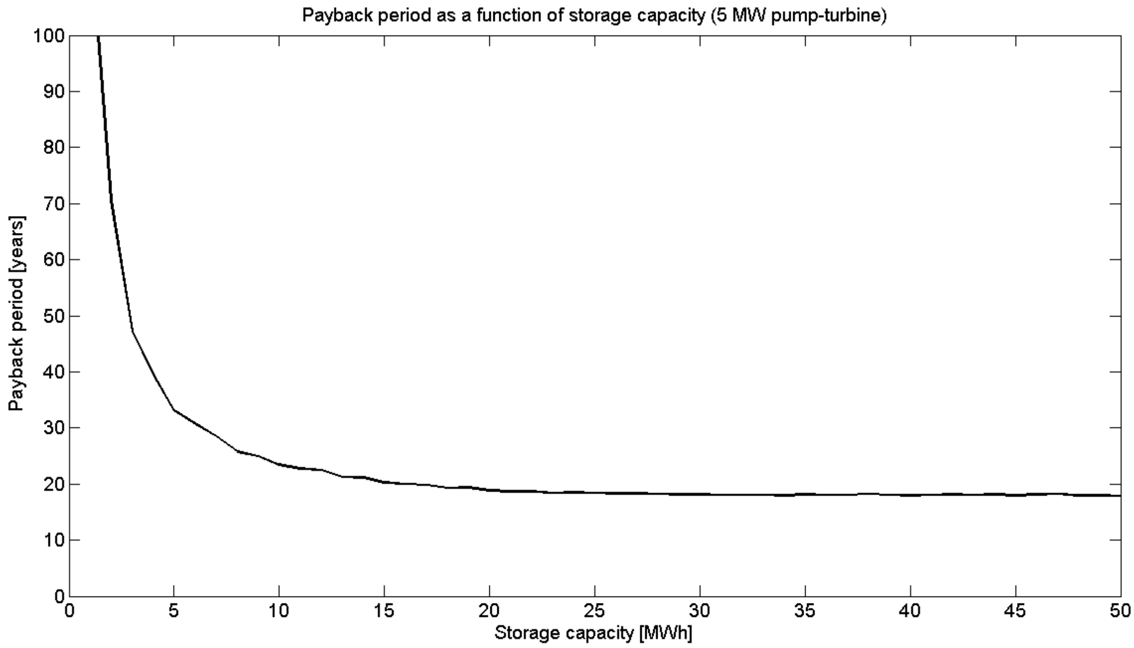

Figure 18 – Payback period for a storage unit as function of storage capacity

The specific income decreases with energy storage capacity as longer charge and discharge times leads to a less efficient way of taking advantage of electricity price arbitrages. Figure 19 below shows this behaviour.

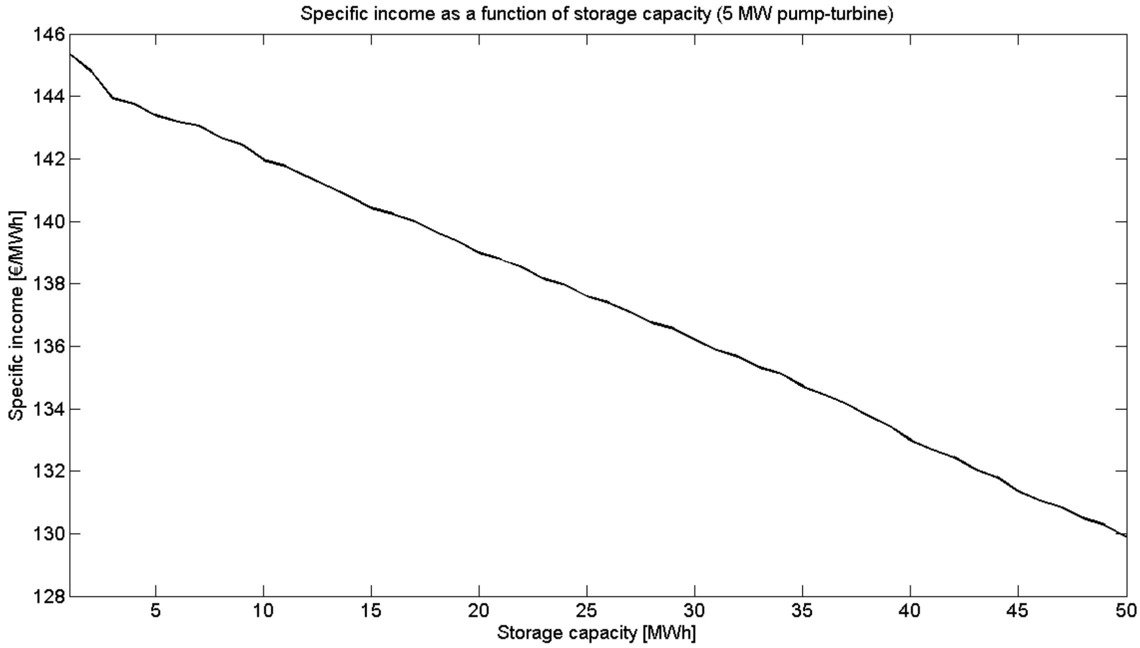

Figure 19 - Specific income as a function of storage capacity (5 MW pump-turbine)

4.3.2.2 Power conversion system

The storage unit will require both a pump and a turbine to accommodate for charging and discharging. It is believed that the use of a combined pump-turbine will decrease costs as only one component is needed, which would also simplify maintenance and thus reduce costs even further. The downside of choosing a pump-turbine is that the pump and turbine operations cannot be optimized individually, possibly resulting in a lower efficiency compared to a case where both a pump and a turbine were to be used. In a situation where the pump component is mechanically driven by a wind power plant it would be beneficial to use a separate pump and turbine, since at times of high demand and wind output it is desirable to run the unit in both pump and turbine mode simultaneously so that the fully charged storage does not limit the operation of the wind power plant.

The size of the pump-turbine component will be decided by the charge and discharge time requirements. A larger component means shorter charge and discharge times since the flow of water through it increases, this will in turn result in the ability to better take advantage of shorter peak and off-peak periods. If prices drop to a low level, or increase to a high level, during a very short time a high capacity PCS will be able to take advantage of this to a higher extent than if a lower capacity PCS was installed. On the other hand, a larger pump-turbine will be more expensive. The relation between cost and income for different pump-turbine sizes is illustrated in Figure 20 below.

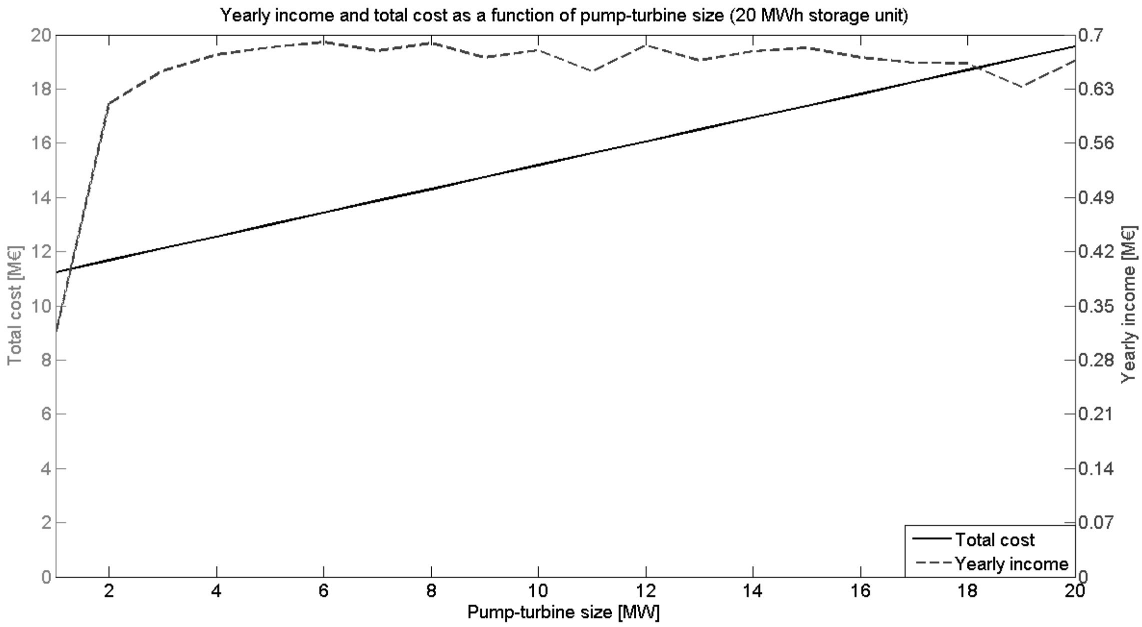

Figure 20 – Behaviour of total cost and yearly income with varying pump-turbine power (20 MWh storage capacity)

In contrast to the storage capacity, the pump-turbine power does not have the same influence on the income; due to that the same amount of electricity is traded regardless of power conversion size. How this behaviour affects the payback period is shown below in Figure 21.

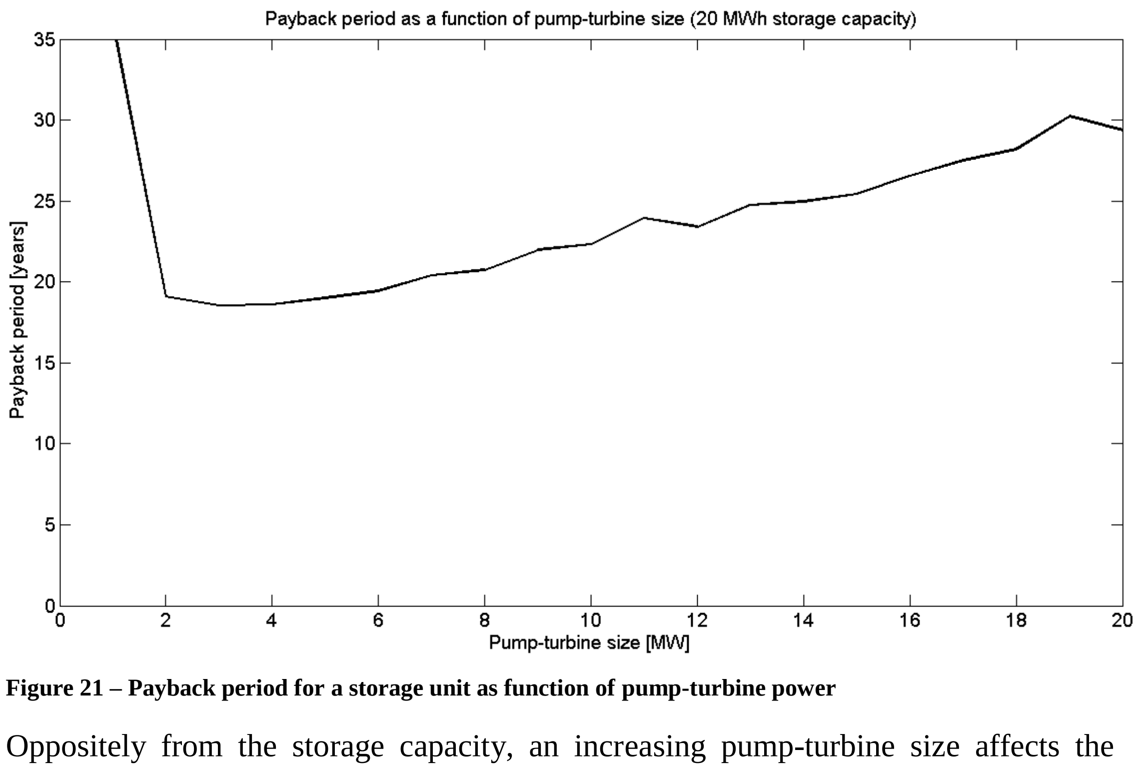

Figure 21 – Payback period for a storage unit as function of pump-turbine power

Oppositely from the storage capacity, an increasing pump-turbine size affects the specific income in a beneficial way (see Figure 22 below) since the resulting shorter charge and discharge times means that the arbitrage between buy and sell prices is increased. This phenomenon is explained further in the following chapter.

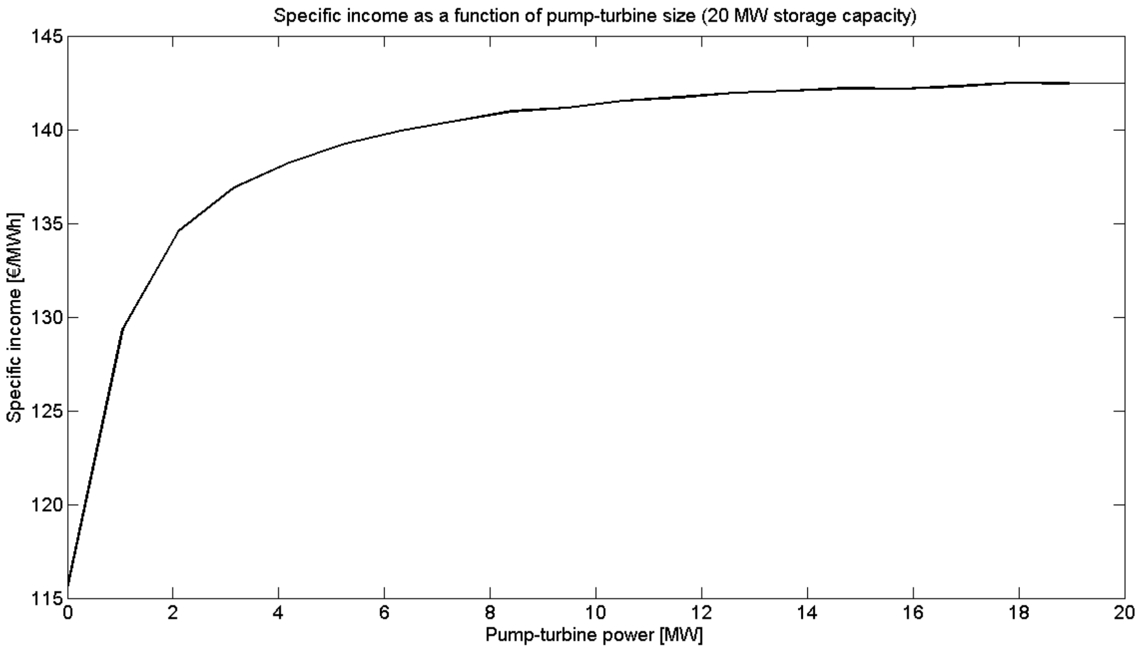

Figure 22 – Specific income as a function of pump-turbine power (20 MWh storage capacity)

4.3.2.3 Interaction between storage capacity and pump-turbine power

Figure 23 below shows the mean daily electricity price for the Danish power system of 2012, and when charging and discharging occurs, for two different charge and discharge times. It can be seen that the two hour charge time case (in grey) yields a higher arbitrage between buying and selling electricity than the four hour case (in black).

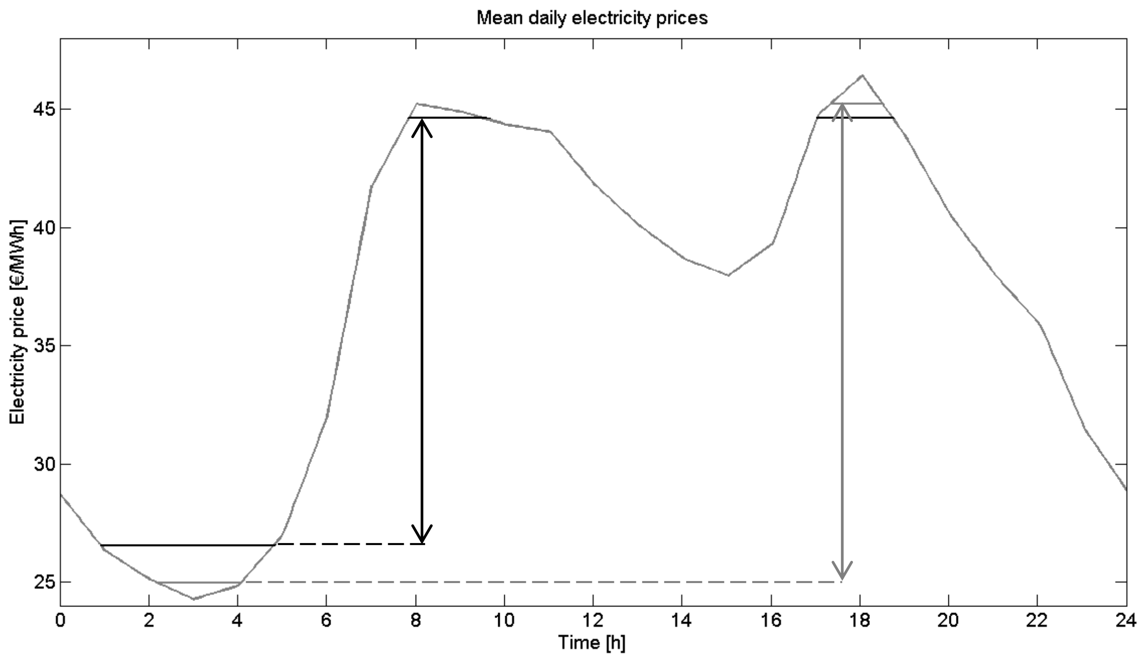

Figure 23 - Price curve and arbitrage levels for different charge and discharge times

As discussed earlier, in order to achieve the lower charge time and higher arbitrage, a larger investment for the pump-turbine is needed for a given storage capacity.

4.3.3 Storage requirement

In 2012, the model determined that 4945 MWh of electricity is delivered to the grid from a single decentralized storage unit. The maximum possible amount of delivered electricity from the storage unit, with an efficiency of 75%, is:

$$5\ MW \cdot \eta \cdot \frac{8784\ h}{2} = 16\ 470\ MWh$$

The factor ½ means that discharge can occur at most half of the time during a year given that the pump and turbine are the same size. The utilisation factor for this simulation case becomes 30%.

For the centralized case the amount of delivered electricity is 98 650 MWh, an equally large increase as the increase in storage capacity (20 times). Similarly to the decentralized case, the utilisation factor is 30%. The other scenarios resulted in similar energy amounts, corresponding to the relation between incomes for these.

The storage capacity required to balance the entire Danish power system when all thermal plants are used for base load only was also determined. Figure 24 shows how storage occurs during 2012 given that the thermal power plants are assumed to be run at a constant level as explained in Chapter 3.3.

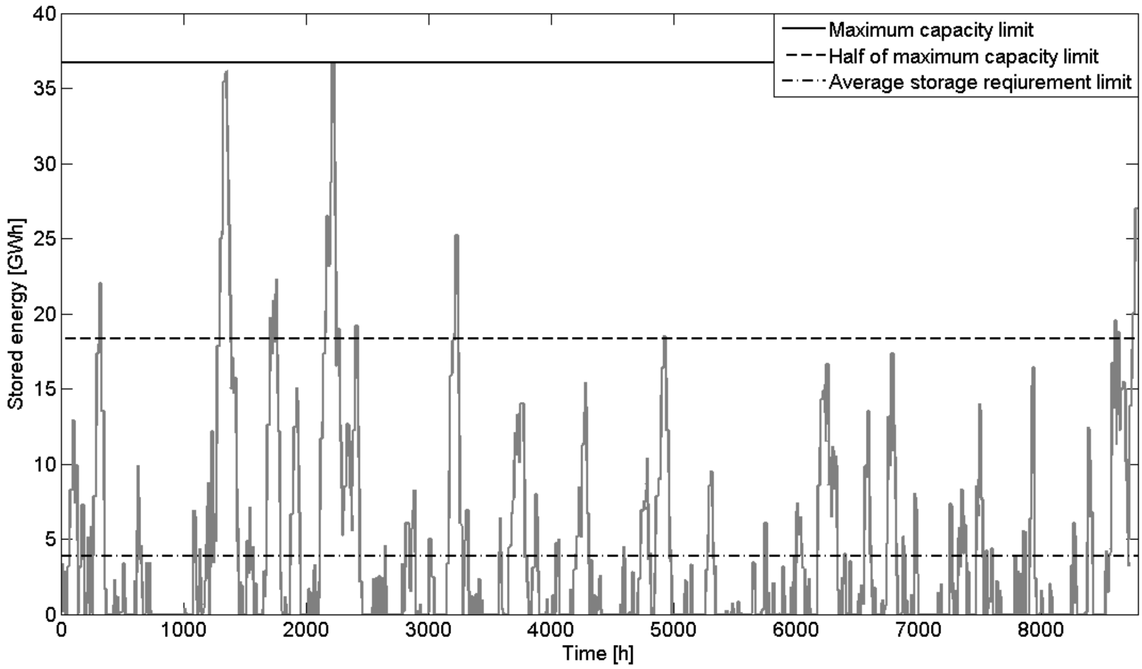

Figure 24 – Amount of stored energy throughout the year in the Danish electricity system of 2012 when thermal power generation is assumed to be constant

On such a large scale the only reasonable configuration to use is the centralized version which results in a maximum of 317 units. Adding a restriction on when charging and discharging can occur based on the electricity price, the model is constricted and only 92 units are needed. Studying the cases with lower capacities (one half of that of the maximum requirement and one corresponding to the average storage need), it is seen that the income per unit increases with a decreasing number of units, which is due to the higher utilisation. It would be unrealistic to build a storage farm which could cover a maximum balancing need which only occurs once, since the utilization factors would become very low.

5 Discussion

In the following chapter the results will be discussed from a number of perspectives, regarding construction options, future scenarios, etc.

5.1 Construction aspects

When analysing the operation of the turbine many simplifications where made. No consideration was taken regarding the off-design characteristics under which the power conversion unit will work due to the changing head during charging and discharging. To evaluate how this aspect affects the flow and efficiency more detailed simulations are required on a component scale. The unique application of pump and turbine will most likely impose new problems on this type of storage technology but by using available information from the hydro power industry in combination with new approaches to simulation of turbomachinery these can be overcome.

The basic estimation of the thickness of the storage reservoir and thereby the material use should in the future be refined with a FEM model in order to capture all load characteristics during operation. This would ensure a sufficient security factor for the unit to withstand all forces exerted on it during its lifetime. The lifetime estimated in this report is based on that of pumped hydro storage, but using more advanced modelling tools for the power conversion system and storage reservoir a more qualified determination can be made.

In this report focus has been put on constructing a spherical, concrete storage chamber in order to minimize the need of material. It should, however, be noted that there are a number of alternative solutions which can be considered. With respect to the external pressure, the second best shape to withstand this is a cylinder. There is extensive knowledge about submerged cylindrical containers through the developments of pipelines for the off-shore oil and gas industry. The learning gained from these developments could provide an alternative solution to the storage chamber challenge, possibly to a lower cost. A larger seabed area might in such a case be required, but as stated in the introduction there are no major limitations regarding space at the bottom of the sea.

In general, by grouping a number of volumes, no matter what shape, the material requirements can be reduced due to a larger amount of shared surfaces. A good example found in many applications is the honeycomb. As can be seen in Figure 25, this configuration offers great possibilities for material minimisation when creating an aggregate of separate units. This is difficult to achieve when using spheres, which is why it is believed that the material use can be reduced when for example constructing a centralized facility.

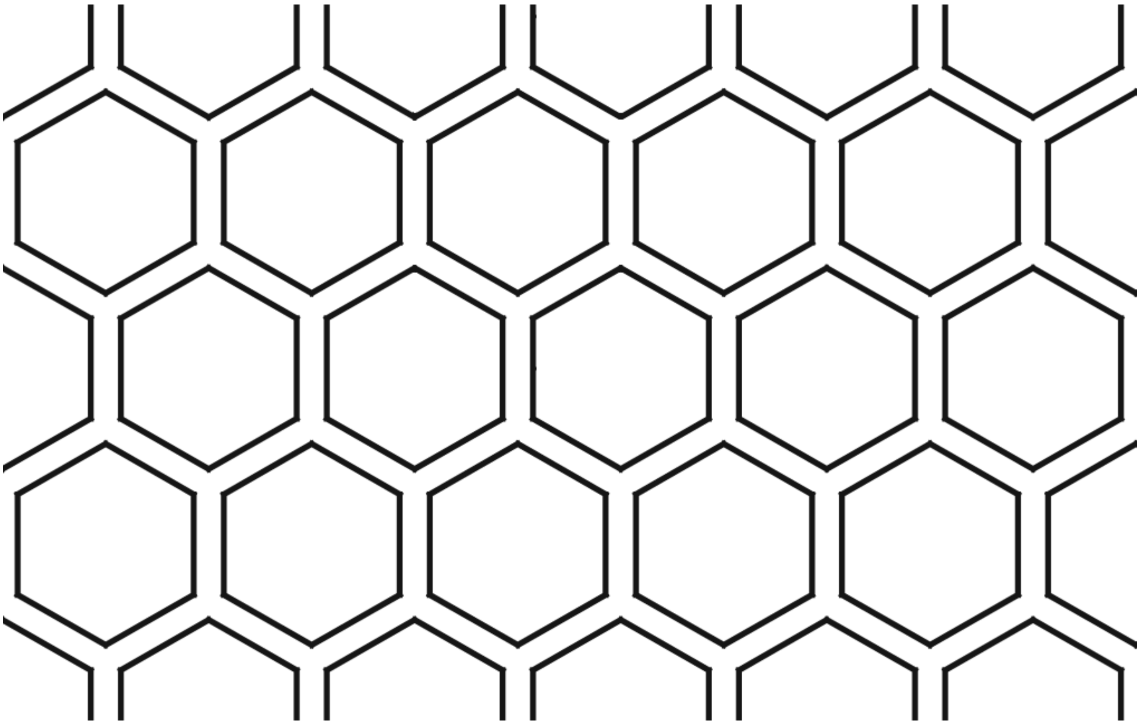

Figure 25 – Honeycomb structure, an example of a shape suitable for aggregation

Material needs may be reduced even further if some sort of truss system is incorporated into the chosen structure which means that the wall thickness does not have to carry the entire load from the surrounding water. Since only water and air will occupy the volume the struts in the truss will not interfere with flow in any significant way.

This report has only considered concrete as the material to use for construction of the storage reservoir due to its low cost, low scarcity and the large amount of knowledge connected to it. There are, however, a number of other options which should be investigated in further studies. The development of new metal alloys and composite materials, together with means of increasing their strength such as constructing sandwiched compositions, creates a broad spectrum of options when trying to reduce construction costs. Apart from the obvious strength requirements of the material, corrosion resistance and environmental impacts could also be investigated further.

5.2 Future developments of the power system

The data given from models created at the Division of Energy Technology provides electricity prices with time steps of three hours, for a three-week period, during each of the four seasons of the year. This means that the data needs to be stretched over each season, which in turn gives a somewhat simplified and evened out representation of the price behaviour. Since the extreme peak and off-peak values seen in the data of 2012 only occurs during very short time intervals due to specific events, they are absent in the modelled 2020 case. This means that the extreme arbitrage levels, which can lead to higher incomes, are lacking in this scenario. It should also be pointed out that the price data for 2020 comes from a model which simulates a possible future energy system; however this may not be realized. In some parts of the world price fluctuations are bound to increase when the power system is not expanded in a high enough pace to account for increasing amounts of intermittent energy sources. These increased fluctuations could provide a system where subsea pumped hydro storage is profitable, even when working as a buyer and seller of electricity on the market.

Future economic means of reducing CO_2-emissions could lead to a higher potential income as the running costs for power plants run on fossil fuels will increase. Taxes and emission trading schemes would affect these facilities but not renewable sources, which already have low running costs, and as the renewable power system is expanded the off-peak prices will be reduced as CO_2 neutral power providers are able to deliver all needed electricity at those times. These two mechanisms will result in larger price fluctuations and a better possibility for high incomes for energy storage technologies.

5.3 Alternative storage solutions

Other technology concepts similar to the studied version of SPHS are:

- Combination of storage and generation
- The Energy Island concept

5.3.1 Combination of storage and generation

One possible implementation of the energy storage unit could be that of a mechanical energy transfer directly from the wind turbine. The lower reservoir could then serve as the foundation for the wind tower and thus lowering the total investment costs. Figure 26 below illustrates the concept. Less power generation components are needed since the generator is not needed in the nacelle of the wind turbine. On the other hand there will be a need for a mechanical energy transfer system from the top of the wind tower to the drive the pump at the energy storage unit. This could restrict the depth at which the storage can be located, since there is a limitation in length of a mechanical axis or hydraulic system.

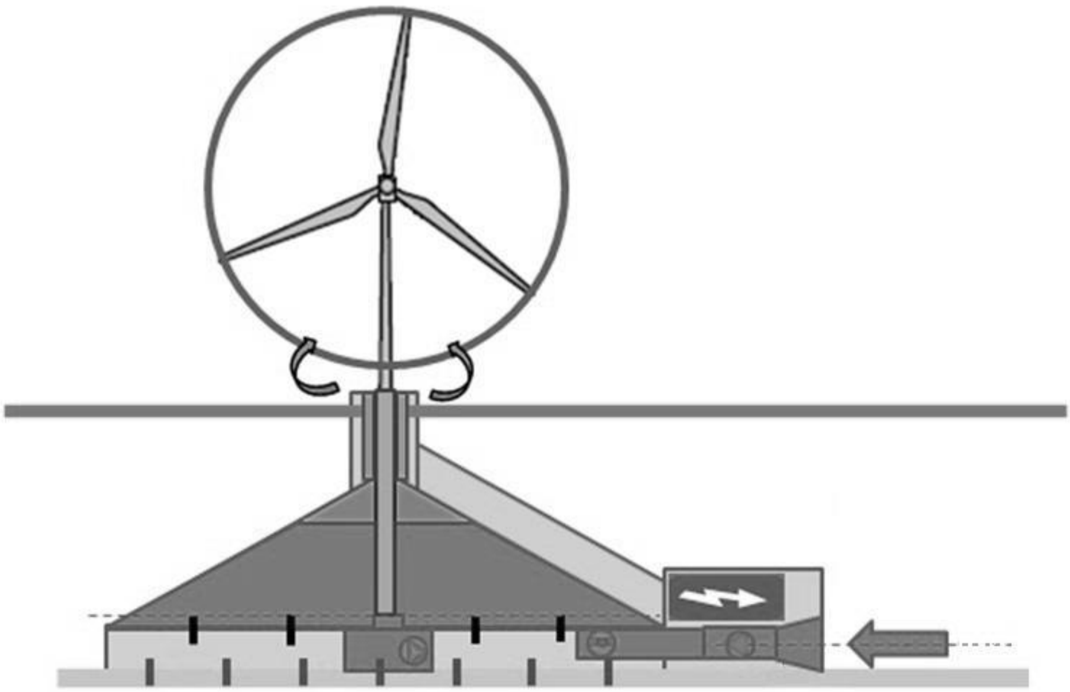

Figure 26 – Direct mechanical drive of the pump in an alternative SPHS concept

Since there is a conversion step less in the process a higher efficiency is expected, though it is important to take into account the added mechanical energy system losses in these sorts of calculations. A shaft or some kind of hydraulic system will be needed and this will lead to some additional losses.

The whole unit will work in an electricity generating mode without the ability to generate electricity when the energy storage is full. The disadvantage is that if there is an excess of wind and the storage unit is not releasing electricity due to low prices, the unit will not take advantage of the unused energy. To mitigate this problem one solution is to implement the use of a separate pump and turbine; in such a case they could be run simultaneously in order to extract as much energy as possible from the wind output.

A large share of the costs for both storage and generating technology will be shared if this concept is implemented. The storage volume and the foundation for one or more wind turbines could be combined into one structure, and transmission cables would in such a scenario be used by both units. From a cost perspective this means that both technologies can experience a reduction in capital cost.

5.3.2 Energy Island

A possible future alternative for sea-based energy storage could be to build so called "Energy Islands" (modified version of PHS, see Figure 27) which would be a version of the centralized SPHS concept. Instead of constructing an underwater facility of storage units a wall is built surrounding an inner lake where the water level would be lower than sea level, possibly around 30-40 meters (DNV KEMA). The Island would also contain and be surrounded by offshore wind turbines that are directly connected to pumps which (similarly to regular pumped hydro storage), when there is a surplus of wind energy, would pump out water from the inner lake to the surrounding sea. In generation mode (shortage of wind), the water is allowed to flow back through turbines and generate electricity.

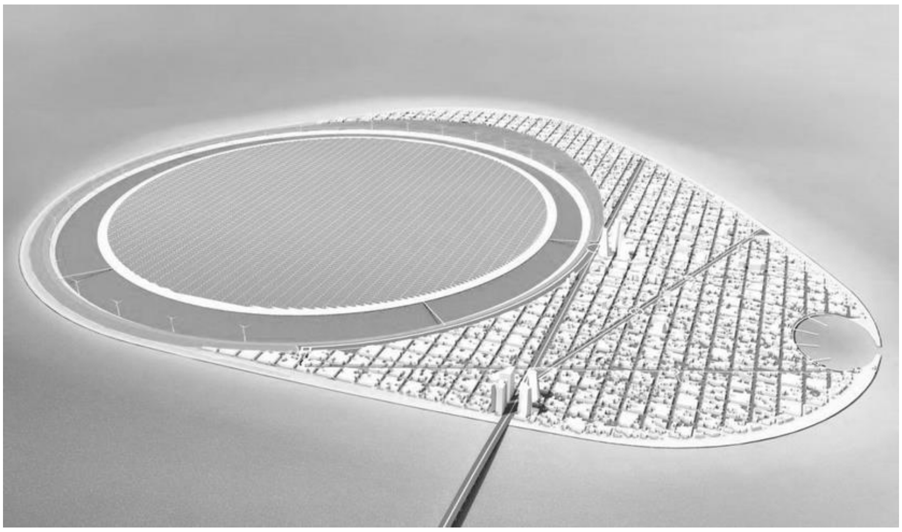

Figure 27 – Possible design of an Energy Island

This concept has the potential of reaching high energy storage capacities while reducing the specific material use per unit of stored energy, since the entire storage volume does not have to be enclosed by an artificial structure on all sides.

The Energy Island could also comprise other resources like algae cultivation and solar power. The reservoir would be serving as a production basin for the algae, which later could be converted into high energy biofuels (Gottlieb Paludan).

5.4 Required electricity price arbitrage

Since the income of the SPHS technology is insufficient to reach break-even within the unit's lifetime without subsidies, it is interesting to find out at what price arbitrage the technology will become profitable on its own. A larger difference between the prices of purchase and sale of electricity during charging and discharging will result in a higher income. This arbitrage is a result of the electricity system in such a way that a system with a large amount of fluctuating power output will experience fluctuating prices to a similar extent. With this information it is possible to identify at which locations it would be profitable to place an energy storage unit.

5.5 Uncertainty in estimated parameters

Even though an interval for the levelized cost of electricity was used there are large uncertainties in the input parameters and it is important to note that the actual cost can be outside this range. The installation and operations and maintenance costs experience the greatest variations because of the currently untested methods and technology to which these costs are attached. One important variable which will influence the cost is the depth, how this affects installation and maintenance is very uncertain and further studies regarding this is needed. The values used in this work are very arbitrary and it is believed that they underestimate the costs of subsea constructions.

In the comparison between SPHS and regular PHS there is an important aspect missing from the discussion. A dam used for pumped hydro storage can be charged naturally, without the need of artificial water flows, by rain or inflows from other water sources upstream of the dam. This means that the PHS technology is a combination of a storage and generation unit, resulting in lower costs for storage compared to other storage technologies and higher costs for generation compared to a hydro power plant.

6 Conclusion

The SPHS concept is one possible solution for balancing an increasingly intermittent power system. The subsystems which make up the technical system are well developed and fairly simple on a component level, which should lead to an easy construction process. The main remaining issues to be dealt with are those of installation and maintenance at the seabed. Underwater operations are always very costly and if the technology is to be placed below about 50 m due to the higher energy densities there, divers cannot be used and cost increases even further. From such a point of view it is advisable to construct an as maintenance-free unit as possible, with the option of sending crucial parts to the surface if needed.

To minimize capital costs it is advisable to build the facility in a centralized fashion, using one or a few large power conversion units connected to an aggregate of subsea reservoirs. This would require a lower investment per installed kW of power due to cheaper pumps and turbines and the possibility to use the same supporting walls for several of the reservoir sections. Furthermore, the total operation and maintenance cost will be lower due to the fact that fewer components are needed.

Compared to similar technologies it was shown that subsea pumped hydro storage has a lower cost than compressed air energy storage due to that the operation does not require any fuel. However, regular pumped hydro storage is still a cheaper option for energy storage due to its maturity and utilization of existing geological formations.

It was shown that operating the energy storage unit as an actor on the electricity market, buying and selling electricity at spot prices, will not be profitable unless subsidies are implemented. Due to this finding it is recommended to investigate an alternative concept, in which an offshore wind turbine is directly connected to the storage unit. In such a case the wind turbine foundation would also work as the energy storage’s reservoir, or vice versa, thus reducing costs if the two units are considered as one instead. Apart from the foundation/storage reservoir, substations for power quality control and cables for transmission can be shared between the two technologies and thus reducing capital costs further. Regarding the possibilities for income; if the pump is directly powered by a wind turbine, expensive electricity does not have to be bought for this purpose. The potential for high revenue is thereby increased since the specific cost per unit of electricity only has to be overcome by the electricity price and not the arbitrage between the price of buying and selling electricity.

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Appendix A Costs for comparable technologies

Investment costs

PHS: 760 €/kW (Schoenung & Hassenzahl, 2003) - 3070 €/kW (IRENA, 2012)
CAES: 460 €/kW (Rastler D. , 2008) - 760 €/kW (IRENA, 2012)
SPHS centralized: 3200 €/kW
SPHS decentralized: 2600 €/kW

Operational costs

PHS: 1.9 €/kW-yr (Schoenung & Hassenzahl, 2003)
CAES: 1.9 €/kW-yr (Schoenung & Hassenzahl, 2003)
Cost of natural gas for CAES: 84.27 €/MWh (Europe's Energy Portal)

SPHS: 0.0286 €/kWh (IRENA, 2012)

Lifetime

PHS: 40 years, > 13000 cycles (Evans, Strezov, & Evans, 2012)
CAES: > 13000 cycles (Evans, Strezov, & Evans, 2012)
SPHS: 40 years

Appendix B Payback periods for all scenarios

2012, decentralized

Depth	Total cost	Annual income	Payback period
100 m	16.6 M€	683,656 €/yr	24 years
458 m	11.7 M€	683,656 €/yr	17 years
1212 m	10.0 M€	683,656 €/yr	15 years

2012, centralized

Depth	Total cost	Annual income	Payback period
100 m	292 M€	13,672,156 €/yr	21 years
458 m	192 M€	13,672,156 €/yr	14 years
1212 m	174 M€	13,672,156 €/yr	13 years

2020, decentralized

Depth	Total cost	Annual income	Payback period
100 m	16.6 M€	516,882 €/yr	32 years
458 m	11.7 M€	516,882 €/yr	23 years
1212 m	10.0 M€	516,882 €/yr	19 years

2020, centralized

Depth	Total cost	Annual income	Payback period
100 m	292 M€	10,336,749 €/yr	28 years
458 m	192 M€	10,336,749 €/yr	19 years
1212 m	174 M€	10,336,749 €/yr	17 years

20 % price increase, decentralized

Depth	Total cost	Annual income	Payback period
100 m	16.6 M€	700,322 €/yr	24 years
458 m	11.7 M€	700,322 €/yr	17 years
1212 m	10.0 M€	700,322 €/yr	14 years

20 % price increase, centralized

Depth	Total cost	Annual income	Payback period
100 m	292 M€	14,005,447 €/yr	21 years
458 m	192 M€	14,005,447 €/yr	14 years
1212 m	174 M€	14,005,447 €/yr	12 years

UK2 price area 2020, decentralized

Depth	Total cost	Annual income	Payback period
100 m	16.6 M€	569,069 €/yr	29 years
458 m	11.7 M€	569,069 €/yr	21 years
1212 m	10.0 M€	569,069 €/yr	18 years

UK2 price area 2020, centralized

Depth	Total cost	Annual income	Payback period
100 m	292 M€	11,381,379 €/yr	26 years
458 m	192 M€	11,381,379 €/yr	17 years
1212 m	174 M€	11,381,379 €/yr	15 years