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The present profitability of grid-scale lithium-ion batteries in Finland and future prospects

Thesis submitted in partial fulfilment of the requirements for the degree of Master of Science in Technology.

Espoo, 29.6.2018
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Abstract

This thesis studies the present profitability of grid-scale lithium-ion batteries in Finland combined with their future prospects in the market. The future outlook is limited to 2030.

The thesis is based on a lithium-ion electrical energy storage technology literature review which estimates the installed system costs, cycle life, calendar life, round-trip efficiency as well as operation, maintenance and administrative costs. The details of the review are combined with the data on the Finnish electricity market, provided by Fingrid and Nord Pool AS.

The profitability is estimated in the day-ahead market, the intraday market and the reserve markets. The frequency containment reserve for normal operation is found to be the most attractive marketplace due to the highest revenue potential and the technical suitability. Hence, the levelized cost of storage method is used to estimate the profitability in the day-ahead and intraday market and the net present value to estimate the profitability in the frequency containment reserve.

The profitability is calculated after reviewing information about the distribution costs, taxation and cost of capital. The investment is found to be highly unprofitable. Sensitivity analyses reveal, however, that the investment is significantly sensitive to the installed system cost and to the cycle life.

The prices of the lithium-ion batteries are expected to decrease in the near future. Also, the technical performance characteristics, for example cycle life, are expected to improve. In addition to these, the electricity market conditions are going through favorable changes, including the increasing amount of inflexible and intermittent power sources, such as wind power, and the decreasing grid inertia. The rules will also become more demanding in the frequency containment reserve for normal operation. On the contrary, the demand response is expected to worsen the already-poor energy arbitrage capability of the lithium-ion batteries. However, the demand response was found not to be a competitor of the lithium-ion batteries in the frequency containment. Thus, it is predicted that the lithium electricity storage will not be widely used in the energy arbitrage applications but might become an important part of the frequency containment in Finland by 2030.

Keywords lithium-ion, battery, electrical energy storage, profitability

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Diplomityön tiivistelmä

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Tiivistelmä

Tässä diplomityössä selvitetään verkkoon kytkettävien, suuren kokoluokan litiumionivarastojen kannattavuutta Suomessa tällä hetkellä. Lisäksi tarkastellaan teknologian tulevaisuudennäkymiä Suomessa 2030 saakka.

Työ pohjautuu litiumionitekniikan kirjallisuuskatsaukseen, jossa selvitetään yleisimpien litiumionitekniikoiden investointikustannus, syklinen elinikä, kalenterielinikä, hyötysuhde, purkaussyvyys sekä käyttö- ja kunnossapitokustannukset. Katsauksen tiedot yhdistetään Fingridin ja Nordpoolin dataan Suomen ja Pohjoismaiden sähkömarkkinoista

Kannattavuus arvioidaan vuorokausimarkkinoilla, päivänsisäisillä markkinoilla ja reservimarkkinoilla. Markkinapaikoista taajuusohjattu käyttöreservi todetaan houkuttelevimmaksi korkeimman liikevaihtopotentiaalin ja teknisten vaatimusten takia. Siksi kannattavuutta ja sen herkkyyttä arvioidaan painotetun varastointikustannuksen avulla vuorokausimarkkinoilla ja päivänsisäisillä markkinoilla sekä nettonykyarvon menetelmällä taajuusohjatussa käyttöreservissä. Yhdistämällä tiedot sähkön siirtohinnoista, verotuksesta ja pääoman kustannuksesta havaitaan, että varastoinvestointi ei ole kannattava. Herkkyystarkastelun perusteella todetaan kuitenkin, että esimerkiksi investointikustannus ja syklinen elinikä vaikuttavat huomattavasti varaston kannattavuuteen.

Litiumioniakkujen hintojen ennustetaan putoavan lähitulevaisuudessa. Toisaalta joidenkin teknisten ominaisuuksien – esimerkiksi syklisen eliniän – odotetaan parantuvan. Myös todennäköiset markkinamuutokset hyödyttävät litiumioniakkuja. Lisäksi joustamattoman ja vaihtelevan tuotannon ennustetaan lisääntyvän, mihin vaikuttaa esimerkiksi tuulivoiman lisääntyminen, ja järjestelmän inertian odotetaan pienentyvän. Samalla taajuusohjatun käyttöreservin sääntöjä tullaan tiukentamaan. Toisaalta kysynnän jouston havaitaan huonontavan litiumioniakkujen mahdollisuutta energia-arbitraasiin, mutta kysynnän joustoa ei havaita litiumvarastojen merkittäväksi kilpailijaksi taajuudensäädössä. Siten litiumionivarastoiden ei odoteta yleistyvän energia-arbitraasisovelluksissa, mutta taajuudensäädössä niistä saattaa tulla oleellinen osa seuraavan vuosikymmenen loppuun mennessä.

Avainsanat litiumioni, akku, sähkövarasto, kannattavuus

Foreword

This thesis was the final part of the ÅF Future Talent program 2017. The topic was selected after discussions with Karoliina Joensuu and Timo Laakso to find a topic which was interesting for the company and also for me personally. Lithium-ion technologies have been highly discussed in the media when it comes to storing electricity. Moreover, the storage of electricity allows a wider penetration of clean and sustainable energy production and makes the balance of supply and demand easier.

I want to thank ÅF, my colleagues there and especially Karoliina Joensuu for allowing me to find an interesting subject for the master's thesis and getting guidance along the work. My writing process was well supported by being able to work on projects which matched with the subject of the thesis. Then again, I was let to completely focus on the thesis on those periods when the topics of the ongoing projects did not have similar contents.

A special thanks goes to professor Sanna Syri for guiding me during the process and giving guidelines for a proficient thesis. She also successfully recommended me to be elected to the Stanford Summer Session International Honors Program.

The Guild of Civil Engineers introduced the student life for me, and Teekkarien LVI-kerho was my first experience in student organizations. The people and events of the guild and the club have been a core part in my study life.

During the latter part of my studies, Varsinaissuomalainen osakunta has been the way of taking a break from technology and energy-related stuff and giving something totally different to my studies. With no particular order, I want to thank all the great people and the friends I met there.

Finally, I want the thank my family and friends for supporting me in my free time and for the memorable moments during my studies.

Espoo 29.6.2018

Juhani Riikonen

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Nomenclature

c	Euro cent
$	Dollar
€	Euro
GW	Gigawatt
GWh	Gigawatt hour
Hz	Hertz
kW	Kilowatt
kWh	Kilowatt hour
kWh-year	Kilowatt hour per year
kW-year	Kilowatt per year
l	Liter
MW	Megawatt
MWh	Megawatt hour
MW-year	Megawatt per year
TWh	Terawatt hour
W	Watt
Wh	Watt hour

Acronyms

aFRR	Automatic frequency restoration reserve
AMR	Automated meter reading
BEV	Battery electric vehicle
CAES	Compressed air energy storage
CAPEX	Capital expenditure
DoD	Depth of discharge
DOE	The US Department of Energy
DR	Demand response
DSO	Distribution system operator
EES	Electrical energy storage
EMS	Energy management system
EPC	Engineering, procurement and construction
EV	Electric vehicle
FCR	Frequency containment reserve
FCR-D	Frequency containment reserve for disturbances
FCR-N	Frequency containment reserve for normal operation
FRR	Frequency restoration reserve
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ISP	Imbalance settlement period
LCOS	Levelized cost of storage
LFP	Lithium-iron-phosphate
LiB	Lithium-ion battery
Li-ion	Lithium-ion
Li-ion EES	Lithium-ion electrical energy storage
LMO	Lithium-manganese-oxide
LTO	Lithium-titanate-oxide
MEAE	The Ministry of Economic Affairs and Employment
mFRR	Manual frequency restoration reserve
NCA	Nickel-cobalt-aluminium-oxide
NMC	Nickel-manganese-cobalt-oxide
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operation, maintenance and administration
P2G	Power-to-gas
PCS	Power conversion system
PHEV	Plug-in hybrid electric vehicle
PHES	Pumped hydroelectric energy storage
RES	Renewable energy source
RTE	Round-trip efficiency
SoC	State of charge
TMS	Thermal management system
TSO	Transmission system operator
VPP	Virtual power plant
VRB	Vanadium redox flow battery
WACC	Weighted average cost of capital
ZNBR	Zinc bromine flow battery

1 Introduction

The penetration of intermittent renewables (RES) has created a vast global interest in storing electricity, as the varying generation makes it harder to balance the electricity supply and demand. The problems in the balance settlement create a market niche for companies who can help the balance responsible parties. Hence, this thesis studies the profitability of the grid-scale lithium ion electrical energy storage (Li-ion EES) in the Finnish electricity market. The profitability is studied in 2018, and the results are differentiated between the most common Li-ion EES technologies. Future aspects of the installed system costs, technical performance and essential changes in the electricity markets are also given. The outlook of the possible trends is limited to 2030.

First, this thesis gathers scientific literature to establish an approximation of the techno-economic performance of Li-ion EES systems, combined with data from appreciated consultants and international organizations. Li-ion EES has numerous competing storage technologies but those are only briefly listed in the beginning. When it comes to the number of planned projects, Li-ion dominates not only the portable devices and electric vehicles (EVs), but also the global grid storage projects (1) (2). Li-ion EES is already the leading technology in the deployed grid-scale projects in the US (3).

The technical performance data studied include the key attributes that affect the Li-ion EES profitability. These are power-to-energy ratio, cycle life, calendar life and round-trip efficiency. Some other concepts, such as depth of discharge and self-discharge rate are explained as they are central definitions considering EES systems. Detailed temperature performance and density characteristics are not given, as they are inessential in the profitability of grid-scale, stationary EES.

Installed system cost review is the core part of the techno-economic outlook. The installed cost for a system in Finland is approximated with global price data on cell, pack and uninstalled system as well as global installed system cost estimations. Multiple sources are combined to establish a future cost estimation. The outlook is finished with an overview of the operation, maintenance and administration costs as well as cost breakdown estimation.

The techno-economic outlook is linked to the current Finnish electricity market to assess the methods for generating revenue and profits in different marketplaces (Figure 1). All the main physical marketplaces in Finland are discussed, including day-ahead market and intraday market, but also reserve markets because in the future, there might be more value on providing power than bulk energy as the share of the intermittent RES increases (4) (5) (6). EU's goal to improve the time resolution of the electricity markets also favors the idea of valuing power instead of energy (7). The profitability is estimated using the concepts of levelized cost of storage and net present value. Their sensitivities are also measured.

The profitability is estimated for a storage operated by an energy company which is not a balance responsible party. The base scope is to analyze the profitability of an independent storage, without own production or consumption of electricity on the site. However, the sensitivity analyses enlighten various cases, including the effect of taxation, transmission and distribution expenses, allowing to assess cases where a Li-ion EES is installed for example next to a power plant or a large electricity consumer.

Finally, this thesis gathers the most important market trends for an EES. The changes are qualitatively assessed by whether its effect is positive or negative to the Li-ion EES profitability.

The perspective of the thesis is entirely about making profits. In other words, the feasibility is assessed from an economical viewpoint. The adequacy of electricity on the Finnish system level is not a key concept in the thesis, nor is the environmental life-cycle impact analyzed. Furthermore, distributed, small-scale storages are not discussed in this thesis. The system level costs are not directly comparable per kWh between a small and a large system because of the more advanced power electronics and auxiliaries required in a large-scale system. A comprehensive review of both small and large-scale systems cannot be fitted in this thesis. One must observe that the cell and pack level costs and technical performance, however, are comparable so the thesis can be partly used as a basis for small-scale storage feasibility analyses.

Numerous reports, studies and reviews have been released on the subject of energy storage economics but most of them consider international markets (3) (8) (9) (10). This thesis focuses on Finland. Recent papers have also been released on EES in the Finnish markets but those mainly assess the operation of the EES rather than estimating the precise techno-economic performance, such as installed system costs or cycle life (11) (12) (13) (14). Most of all, many of the papers and studies do not differentiate between the different Li-ion chemistries (3) (10) (11) (12) (13). This thesis enlightens the differences between the chemistries.

The goal of the thesis is to be a precise tool for assessing Li-ion EES projects in Finland during the near future. The data used in the calculations is as transparent as possible so the details can be revised as the Li-ion technologies and market conditions develop. The used pre-assumptions are also clearly marked.

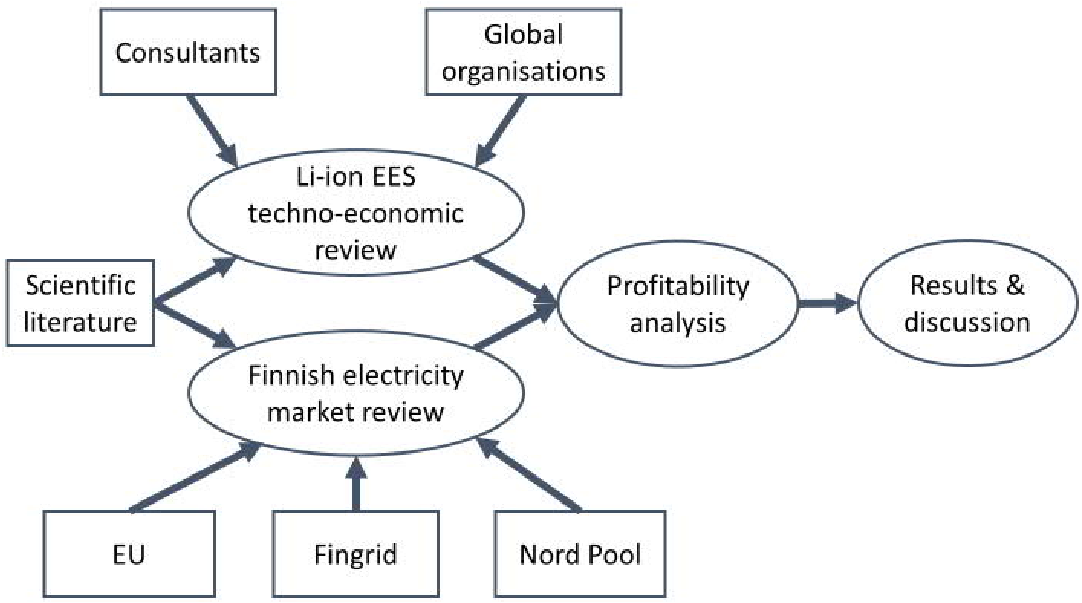


Figure 1 The core process followed in this thesis. Information from scientific literature, EU, consultants and various other sources are combined in a Li-ion EES techno-economic review and Finnish electricity market review. The data from the analyses are combined to assess the profitability, and finally the results are discussed with future aspects.

2 Storage Technologies

This chapter reviews the current technologies used for electricity storage. The other technologies are competitors to the Li-ion EES, therefore it is crucial to give an overview of the other EES technologies before penetrating further into the Li-ion techno-economics. Numerous ways to classify storage technologies exist, but in this thesis, they are classified as:

- Bulk energy storage
  - Pumped hydroelectric energy storage
  - Compressed air energy storage
  - Power-to-gas
- Batteries
  - Flow batteries
  - Lead-acid batteries
  - sodium-sulphur batteries
- Other storage technologies
  - Supercapacitors
  - Flywheels.

The most recent publications in the literature are used to give a basic understanding of the current storage technologies. Large international associations, such as IEA and IRENA, as well as international consultants, have released reports suitable for this purpose as they are mainly reviews of the latest research combining that with other expertise. One must note that profit making organizations, but also non-profit organizations, can be prone to conflicts of interest. Conventional organizations, such as IEA, might have more conservative scenarios when it comes to EES. Then again, IRENA might predict excellent future for the EES as EES can support a wider penetration of the intermittent RES.

2.1 Overview of the competing technologies

2.1.1 Bulk energy storages

Bulk energy storages are used to store large amounts of electrical energy. Precisely this means that the ratio of power to energy is rather low, i.e. < 1 MW/MWh. In this thesis, the discussed bulk energy storages include pumped hydroelectric energy storage (PHES), compressed air energy storage and power-to-gas.

PHES stores electricity by pumping water up to a reservoir when the price of electricity is low. By pumping the water up, the potential energy of the water is increased. The stored water is run back to the lower reservoir, through a turbine, when the price of electricity has reached a certain value. Modifying the size of the reservoir, the storage capacity [MWh] can be altered without changing the power output [MW].

PHES is by far the most common technology used in terms of the installed capacity [MW]. There are about 165 GW of operational PHES globally compared to the total 177 GW of the operational EES technologies based on the Global Energy Storage Database by the US Department of Energy (DOE) (January 2018). (2)

Feasibility of PHES is highly dependent on the specific site of the storage, which limits further investments. Even with a suitable site for hydropower, PHES might have doubled capital costs compared to a conventional hydropower plant. (15) A one cycle of PHES performs with an efficiency of about 70 – 85% with a lifetime of over 40 years. (3) (16)

As stated, PHES is used to store large amounts of energy. However, in Finland, hydropower is also used in the electricity reserve markets, providing frequency containment services (13). In other words, hydropower provides power quickly for short periods of time. Thus, a PHES could certainly be used for this application as well. On the other hand, operation as a frequency containment reserve might wear down the moving parts (13). This gives an advantage to chemical storages without moving parts, such as Li-ion batteries.

In addition to PHES, compressed air energy storage (CAES) stores electricity to mechanical energy. In CAES, air is compressed to an underground cave or an aboveground vessel on off-peak hours, and then heated and directed through a turbine generator. CAES is a rather matured technology. For example, A 290 MW/1100 MWh CAES plant has been operational in Germany since 1978. (3) Like PHES, CAES storage duration can be designed rather independently from the power output by different cave volumes. The number of operational and planned CAES stations is low, probably due to the large initial investment as well as poor round-trip efficiency (2). In 2015, Luo et al. estimated a round-trip efficiency of about 50% (16).

Another bulk energy storage method is called power-to-gas (P2G). It is a technology which transforms electricity into chemical energy during periods of low electricity prices. The chemical energy is released at times of high electricity prices or deficit of electricity. One of the most common ways is to make hydrogen from water via electrolysis and later use the hydrogen as a fuel in a fuel cell, which can also be called power-to-hydrogen. Alternatively, the hydrogen can be processed to methane to ease the storage and transportation of the gas. Currently, P2G is not widely used due to high installed costs of the system as well as problems in transportation and storing, especially in the case of hydrogen (16) (17). However, a high interest towards P2G among the electricity storage market actors is noticeable (18).

2.1.2 Batteries

Batteries store electricity to chemical energy. They consist of a cathode (+) and an anode (-), separated by an electrolyte and a porous separator. The ions move in the electrolyte while the electrons flow through a conductor. (16) Even though the operation principle is the same between different batteries, the chemistries and the technical solutions vary across battery technologies. In addition to Li-ion batteries, Lead-acid, Sodium-Sulphur and flow batteries have achieved global interest (2).

Lead-acid batteries are widely used in combustion engine vehicles. Their benefits include fast response time, small self-discharge rates (< 0.3%/day) and rather low installed system cost. (16) The barrier for a large-scale adoption in grid EES is the poor cycle life, meaning that they can endure less than a thousand full cycles during its lifetime (19). Lead-acid batteries also exhibit weak performance in low temperatures. (16)

Sodium-sulphur (NaS) batteries are considered promising for high power EES applications. The materials used are non-toxic and inexpensive but the NaS EES requires a temperature of around 600 K as a normal operational condition. Thus, an extra system to maintain the temperature is necessary, leading to high operation costs. (16) When it comes to the global number of grid-scale projects, the Li-ion EES dominates the NaS batteries (2).

Flow Batteries are based on the reduction-oxidation reaction of two electrolytes. The electrolytes are stored in separate tanks, and the redox-reactions take place in a cell stack. The cell stack determines the power output of the system, while the volume and concentration of the electrolyte determines the energy capacity [MWh] of the system. Thus, the MW and MWh characteristics of flow batteries can be designed independently. (16)

Common types of flow batteries include vanadium redox (VRB) and zinc bromine (ZNBR) of which VRB seems to be the most popular (2) (16) (20). VRB round-trip efficiency is up to 85%, whereas the one of ZNBR is slightly lower, 65 – 75%. Drawbacks of the system are related to the complexity of the system and thus to the high system costs. (16)

2.1.3 Other storage technologies

The other storage technologies remain marginal regarding the global installed energy capacity and power. (2) Flywheels and capacitors are mentioned because of their characteristic of providing quick and high power outputs.

Flywheels store electricity to kinetic energy in the form of angular momentum. In other words, electricity accelerates the spinning rotor, and the momentum is used when excess electricity is needed. Flywheels are small in terms of the stored capacity [kWh] because kinetic energy is a rather ineffective way to store energy per unit of mass. Furthermore, flywheels might have up to 20% self-discharge rate of the stored capacity during an hour. (16) However, due to the response times of only 4 ms or less, they are used for controlling frequency and voltage quality of the grid, but also to provide back-up power to secure the availability of power in critical applications. (3)

Capacitors and supercapacitors store electricity in an electrostatic field, but supercapacitors also store energy chemically by using an electrolyte and a membrane between the conductor electrodes, yielding higher energy densities and cycle efficiencies. Still, with both types, the poor characteristics in storing energy [MWh] is the reason why these are only suited for short term, power quality related storage. (16)

2.2 Applicability comparison

Table 1 gives an overview of the discussed technologies and their technical suitability to the Finnish electricity system. It should be noted that *seasonal*, *weekly* and *daily* do not have clear limits, i.e. there is no certain value between seasonal and weekly storage. The aim is to show a coarse comparison of the different time scales. However, the reserve markets are the ones maintained by Fingrid. The reserve markets are further discussed in chapter 4.4.

Table 1 The technical suitability of the discussed EES in the main Finnish grid-scale applications. XX = technical suitability, X = limited technical suitability (9) (13) (21) (22) (23)

Technology	Seasonal storage	Weekly variations	Daily variations	Frequency restoration reserve	Frequency containment reserve
Power-to-gas	XX	XX	X		
PHES	XX	XX	XX	XX	X
CAES	XX	XX	XX	XX	
VRF		X	XX	XX	X
ZNBR			X	X	X
Li-ion			X	X	XX
NaS			X	X	XX
Lead-acid			X	X	XX
Flywheel					XX
Capacitors					X

The table shows the differences between the applicability of different technologies. It is an approximation, and the storage system might be used in an application even if it would not have a mark on that column. The idea is to differentiate between the technologies. For example, all batteries are generally suitable to storages with short timescales but VRF is suitable for slightly longer time periods. Moreover, PHES and CAES are suitable for bulk storages but also provide frequency restoration services. Finally, power-to-gas is regarded as the technology with the longest cycling periods. One must also note that the technical suitability does not guarantee economical profitability.

3 Lithium-ion electrical energy storage

This chapter studies the Li-ion EES technology and its techno-economic characteristics. First, brief technical operating principles are given. Then, a comprehensive review on the techno-economic attributes is presented.

3.1 Technical overview

The core of a Li-ion system is a cell containing electrodes, electrolytes and a separator (24). Fuchs et al. made a clear sketch of the operating principle (Figure 2).

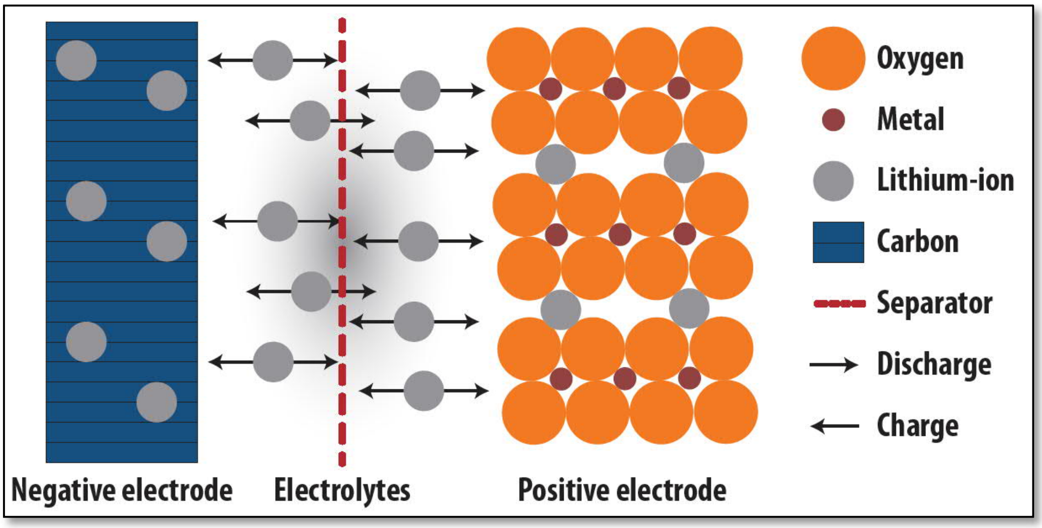


Figure 2 The operating principle of a Li-ion cell with a metal oxide cathode (the positive electrode) and a carbon-based anode. (24)

Figure 2 is an example of a lithium metal oxide cathode (the positive electrode), and a carbon-based (graphite) anode. The current EES markets are dominated by this kind of Li-ion cells (2) (4).

Lithium ion batteries are generally regarded as a single type of technology. However, Li-ion batteries are a family of different chemistries which usually contain Li-ion as a part of the cathode, as in Figure 2, and have a graphite anode. (4) Different Li-ion cells vary widely in performance, cost and safety characteristics, and a chemistry is chosen to meet the techno-economic objectives of an application (3) (9). The different cathode chemistries are presented in Table 2.

Table 2 The most common Li-ion cathode technologies with one's formula, abbreviation, market share and applications. (4) (25)

Formula	Abbreviation	Market Share	Applications
$LiCoO_2$	LCO	21%	Laptops and portable electronics
$LiNi_{0,8}Co_{0,15}Al_{0,05}O_2$	NCA	9%	Electronics, increasingly EVs
$LiNi_{1/3}Mn_{1/3}Co_{1/3}O_2$	NMC	26%	Electronics, high power applications, increasingly EVs
$LiMnO_2$	LMO	8%	High power applications, e.g. power tools and EVs
$LiFePO_4$	LFP	36%	EVs, other high power applications

In addition to the graphite anodes, a lithium-titanate based anode is also an alternative, yielding higher cycle life than the chemistries with a graphite anode (26) (27). These are called LTO batteries or LTO cells. For example, Helen Suvilahti storage uses LTO anodes (11). Unfortunately, Toshiba, who supplied the LTO cells, does not reveal the cathode used in the application. Typically, however, an LTO anode is combined with an LFP cathode (26).

Based on Table 2, the studied chemistries included in this thesis include NCA, NMC, LMO and LFP as a cathode and graphite as the anode. In addition to this, LTO cells are also included. LCO is not further discussed due to its usage and suitability in small, portable applications rather than grid-scale storages (4) (28).

The cells are connected in parallel and in series to increase the current and the voltage after a favorable cell chemistry has been found for the application. Combining with a thermal management system (TMS) and an energy management system (EMS), the cells form a battery pack. (1) (9) Some authors also use a concept of module which is a step between a cell and a pack. A module is formed by connected cells and modules are used for a favorable pack configuration. (29) (30) An operational, grid-scale Li-ion EES is formed by further connecting packs together with a power conversion system (PCS), including inverters, and additional auxiliaries (9) (17) (30).

3.2 Technical performance

The performance of batteries can be described with multiple key figures. This chapter reviews some of the recent literature to find reliable values for the operational characteristics of the Li-ion EES. However, the figures should be interpreted carefully. The field lacks defined standards and common approaches to measure and provide cost and performance data. Thus, the sources from literature are combined with references to reports made by large non-profit organizations as well as international consultants to establish a reliable review. The citations are listed carefully allowing a full transparency of data.

3.2.1 Power-to-energy ratio

Power-to-energy ratio is a typical way to compare battery technologies. P/E ratio, not to be interpreted as the financial price-to-earnings ratio, is given as the ratio of the nameplate power output and the energy capacity. Some authors mention E/P ratio (energy-to-power ratio) (26) (27). This is another example of the lack of standards, mentioned in the introduction of this chapter 3.2. For this thesis, P/E ratio or power-to-energy ratio is used.

Plotting the visible projects in the DOE Energy Storage Database reveals the performance of the current Li-ion projects. The database proves that Li-ion batteries have been demonstrated in various projects with highly different P/E performances (Figure 3). (2)

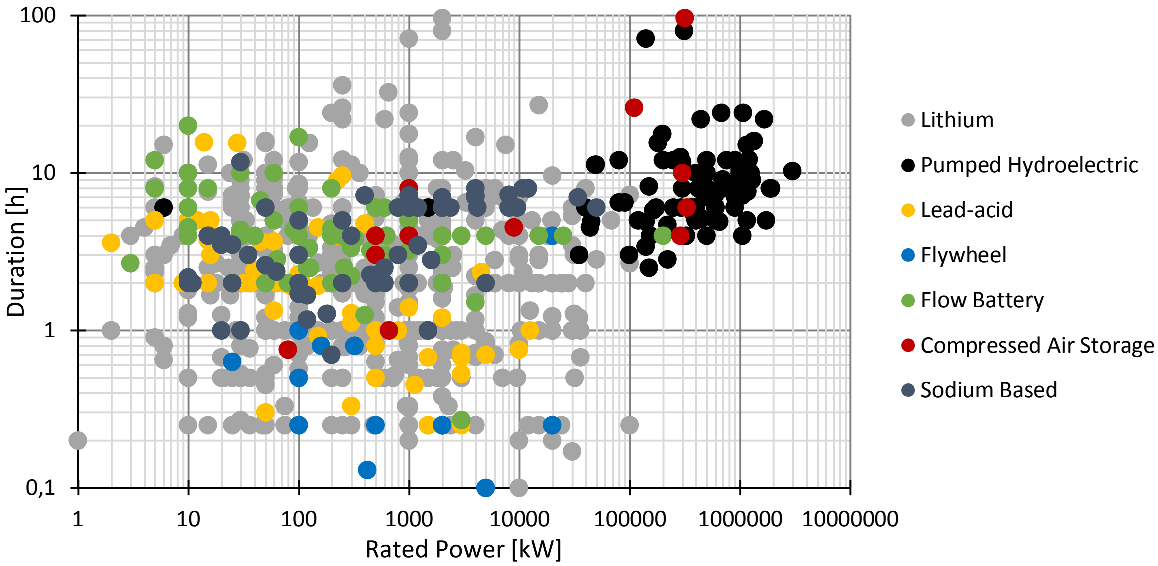


Figure 3 All projects listed in the DOE Energy Storage Database which are announced, contracted, under construction or operational. The duration refers to the amount of time which the EES can operate with the rated power. (2)

For example, a 1 MW storage with a duration of four hours yields a P/E ratio of 1 MW/4 MWh = 0.25. For bulk energy applications, the P/E ratio is low to decrease costs per kWh, and correspondingly, for power quality and reserve applications the P/E ratio are over 1 to decrease costs per kW. For comparison, electric vehicle batteries typically have P/E ratios > 4, and the plug-in hybrid electric vehicle batteries even higher (31).

Table 3 presents the quantities of the projects in Figure 3. The Li-ion EES seems to dominate all the other EES types.

Table 3 Quantity of different EES projects listed in the DOE Energy Storage Database which are announced, contracted, under construction or operational. (2)

Technology	n
Lithium-ion	542
Pumped hydroelectric	84
Lead-acid	71
Flywheel	19
Flow battery	90
Compressed air storage	13
Sodium Based	69

Figure 3 also includes projects that have not been verified by DOE. However, for example Fortum Järvenpää and Helen Suvilahti have been listed in the database but have not been verified by DOE (2). Thus, the listing of unverified projects also is worthwhile, and it is quite reliable to state that Li-ion EES is the most dominant grid-scale EES technology globally.

3.2.2 Cycle life and depth of discharge

Measures to estimate the lifetime of an EES are crucial when evaluating the profitability of a Li-ion EES investment. The lifetime of an EES is usually expressed in cycles and years, referring to *cycle life* or *calendar life*. Chapter 3.2.3 further explains the concept of calendar life but it is already important to understand the fundamental difference between the attributes. For example, with a cycle life of 2000, a battery can serve five years with 400 cycles/year but about ten years with 200 cycles/year. However, if the calendar life of the components is less than ten years, the EES would require replacement investments.

Depth of discharge (DoD), or cycling window or cycling, is a key parameter used to describe the operation of an EES. DoD describes the amount of energy stored in the EES in the present compared to the nameplate energy capacity of the system. (19) For a 1 MWh system, a DoD of 100% means a fully discharged system while a DoD of 80% would mean that 0.2 MWh is stored. Hence, the DoD is independent of the power of the storage. DoD drastically affects the cycle life of the Li-ion EES, where high DoD decreases and low DoD increases the cycle life (1) (19) (20) (29).

The literature has large variations in the cycle life estimations so pooling of the estimations is required. The variance is understandable because there are no common standards for measuring the EES performance as stated in the beginning of chapter 3.2. For example, there is no common DoD level for the measurement. Ambient temperature also affects cycle life. Moreover, cycle life is not a clear limit between an operational and a malfunctioning battery. It is a limit where the deliverable energy capacity of a battery has fallen below a certain limit due to a gradual performance degradation during the operation. Typically, the limit is 80% of the installed capacity but the industry might tabulate the cycle life with lower values to make the cycle life more attractive (32) (33).

Table 4 lists the literature used for the cycle life determination. DoD is also listed in the tabulation. A couple of future estimations are presented to give a rough estimation of the stage of development. For the estimations in the past, the release year of the paper is given, and for the future estimations, the year for the projection. The results of the review are shown in Figure 4.

Table 4 The list of sources cited for the cycle life review. The year of the release date is presented to give an overview of the cycle life performance in the past. If the estimation is to the future, the year for the estimation is given to approximate the cycle performance in the future.

Author	Paper released or year for projection	Cycle life	DoD	Reference #
Fuchs et al.	2012	1000 – 5000	100	(24)
Battke et al.	2013	1000 – 30 000	80	(34)
IRENA	2015	200 – 20 000	100	(8)
Zakeri & Syri	2015	1500 – 4500	80	(17)
Pearre & Swan	2015	750 – 6000	100	(19)
Jülch	2016	7000	80	(20)
IRENA	2017	0 – 20 000	84 – 100	(9)
Baumann et al.	2017	1000 – 9750	80	(26)
Jaiswal	2017	1200 – 27 000	not given	(35)
Few et al.	2020	1500 – 11 500	80	(1)
Jülch	2030	10 000	100	(20)
IRENA	2030	1000 – 40 000	84 - 100	(9)
Fuchs et al.	2030	3000 – 10 000	100	(24)
Few et al.	2030	1500 – 25 000	80	(1)

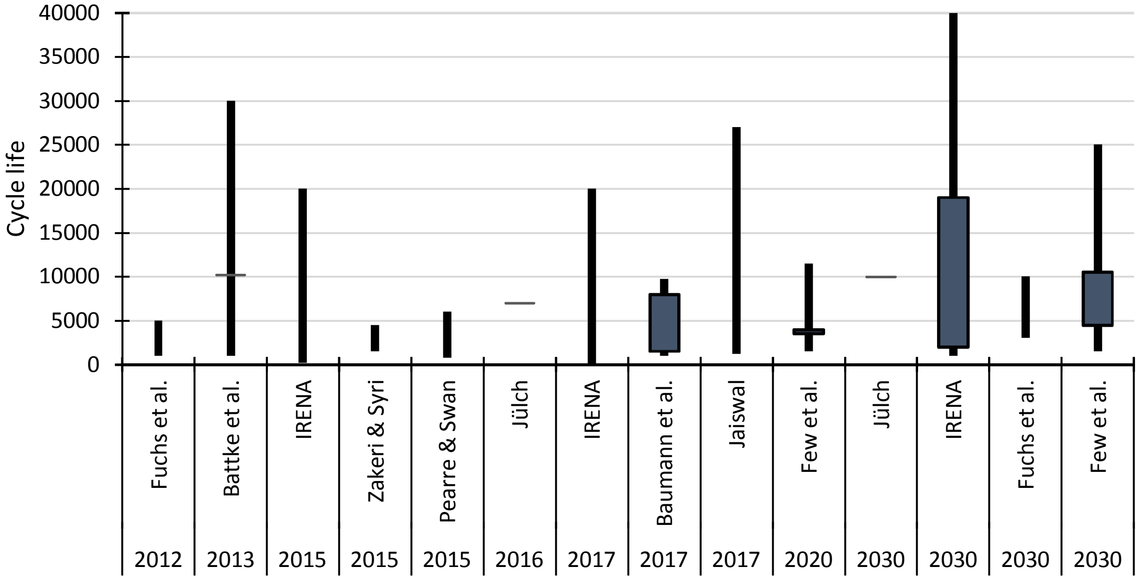
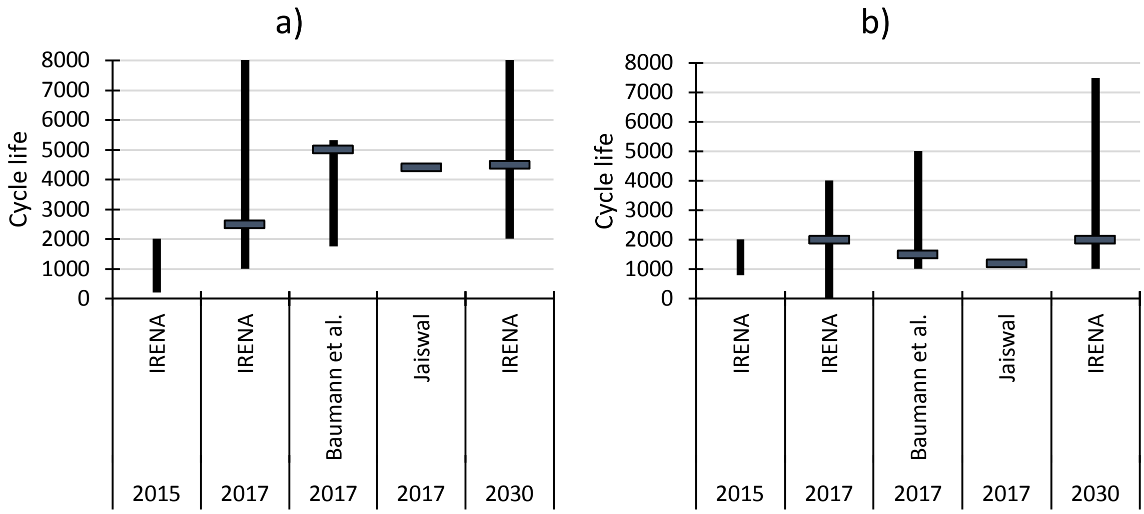


Figure 4 The result of the cycle life review. The thick bar indicate where the author has given a range of the most probable cycle life performance. The corresponding year is also presented, listed also in Table 4.

Figure 4 shows the vast deviations and the reason is clear. Traditionally, the literature seems to tabulate the Li-ion EES values as a family. However, the difference between a graphite and an LTO anode is tremendous. Differentiating between the chemistries slightly reduces the ranges for cycle life. Figure 5 reveals the cycle life variation between the chemistries, which have been tabulated by a couple of authors. The authors have been listed in Table 5.

Table 5 The list of sources cited to estimate the cycle life differences between the Li-ion chemistries.

Author	Paper released or the year for the estimation	DoD	Reference #
IRENA	2015	100	(8)
IRENA	2017	84 – 100	(9)
Baumann et al.	2017	80	(26)
Jaiswal	2017	not given	(35)
IRENA	2030	84 – 100	(9)



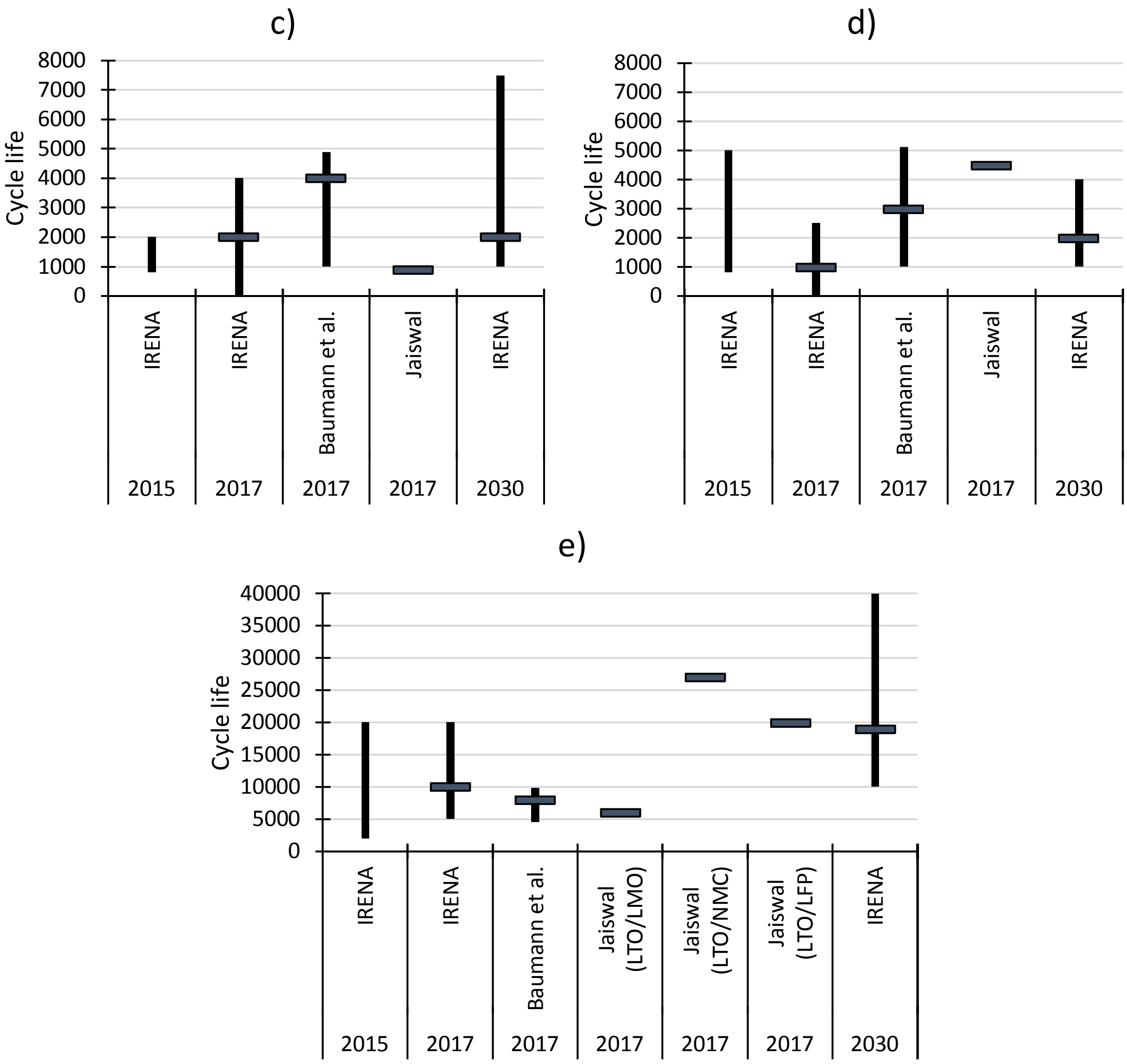


Figure 5 a) - e) The cycle life estimations for LFP, LMO, NMC, NCA and LTO storages (in the order). One should note the different scale for LTO. Jaiswal has differentiated the LTOs with different cathodes.

This reveals that LMO, NCA and NMC perform far less than 10 000 cycles, as does LFP. LTO might endure significantly more cycles, even up to 30 000. Based on the figures, however, for this thesis, the LTO is approximated to endure 9000 cycles, while the rest of the technologies are estimated to be able to provide 3000 cycles.

As stated earlier, the DoD affects the cycle life of the system. Thus, it would seem worthwhile to invest in a system which is larger than necessary. This way, the DoD would never reach 100%, increasing the cycle life of the system. However, Pearre & Swan found out that despite the lowered cycle life, operating between DoDs of 0 – 100% would maximize the amount of energy stored and discharged during the lifetime of the EES and thus maximize the revenue. (19) In other words, operating at low DoD increases the cycle life, but the amount of energy throughput is low compared to using the entire energy capacity. What is more, increasing cycle life with decreased DoD might expand the lifetime of the EES and spread some of the revenue further to the future reducing the present value of the cash flow.

3.2.3 Calendar life

As stated earlier in chapter 3.2, the DoD affects drastically the extent of the operational life of a Li-ion ESS. Thus, the absolute lifetime of the EES decreases with a more frequent cycling. Additionally, the aging of the material also consumes the performance. Pearre & Swan even stated that calendar life is independent of cycling. According to them, the materials would degrade to a limit where the risks of failure have increased sufficiently high, so that the EES must be removed from the service after a certain period of time, independently of the cycling (19). In other words, even if the EES was not used often, its components' performance would worsen.

Some authors have approximated a constant deterioration, e.g. Müller et al, who estimated that the performance degrades 1% per year of operation (23). By any means, it is necessary to estimate the calendar life of a Li-ion ESS. The cited authors are listed in Table 6 and the results presented in Figure 6.

Table 6 The list of sources cited for the calendar life review.

Author	Paper released or the year for the estimation	Reference #
Fuchs et al.	2012	(24)
NREL	2015	(36)
Zakeri & Syri	2015	(17)
Jülch	2016	(20)
IRENA	2016	(9)
Lazard	2017	(37)
Lin & Wu (Tesla)	2017	(38)
Baumann et al.	2017	(26)
Fuchs et al.	2030	(24)
Jülch	2030	(20)
IRENA	2030	(9)

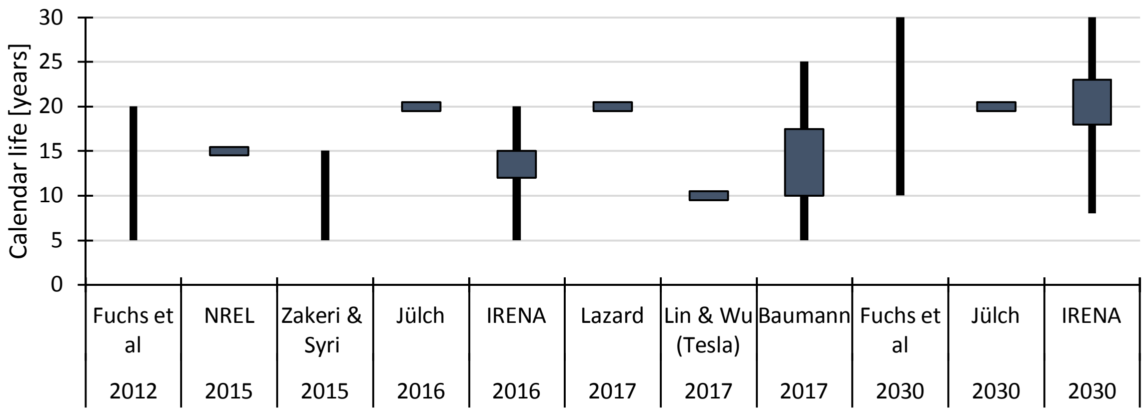


Figure 6 The results of the calendar life review. The thick bar refers to the range which is the most probable calendar life of an EES according to the corresponding author.

While the upper figure combines data from generally Li-ion storages, Figure 7 differentiates between the chemistries. The authors cited are listed in Table 7.

Table 7 The list of sources cited to estimate the cycle life differences between the Li-ion chemistries.

Author	Paper released or the year for the estimation	Reference #
IRENA	2016	(9)
Baumann et al.	2017	(26)
IRENA	2030	(9)

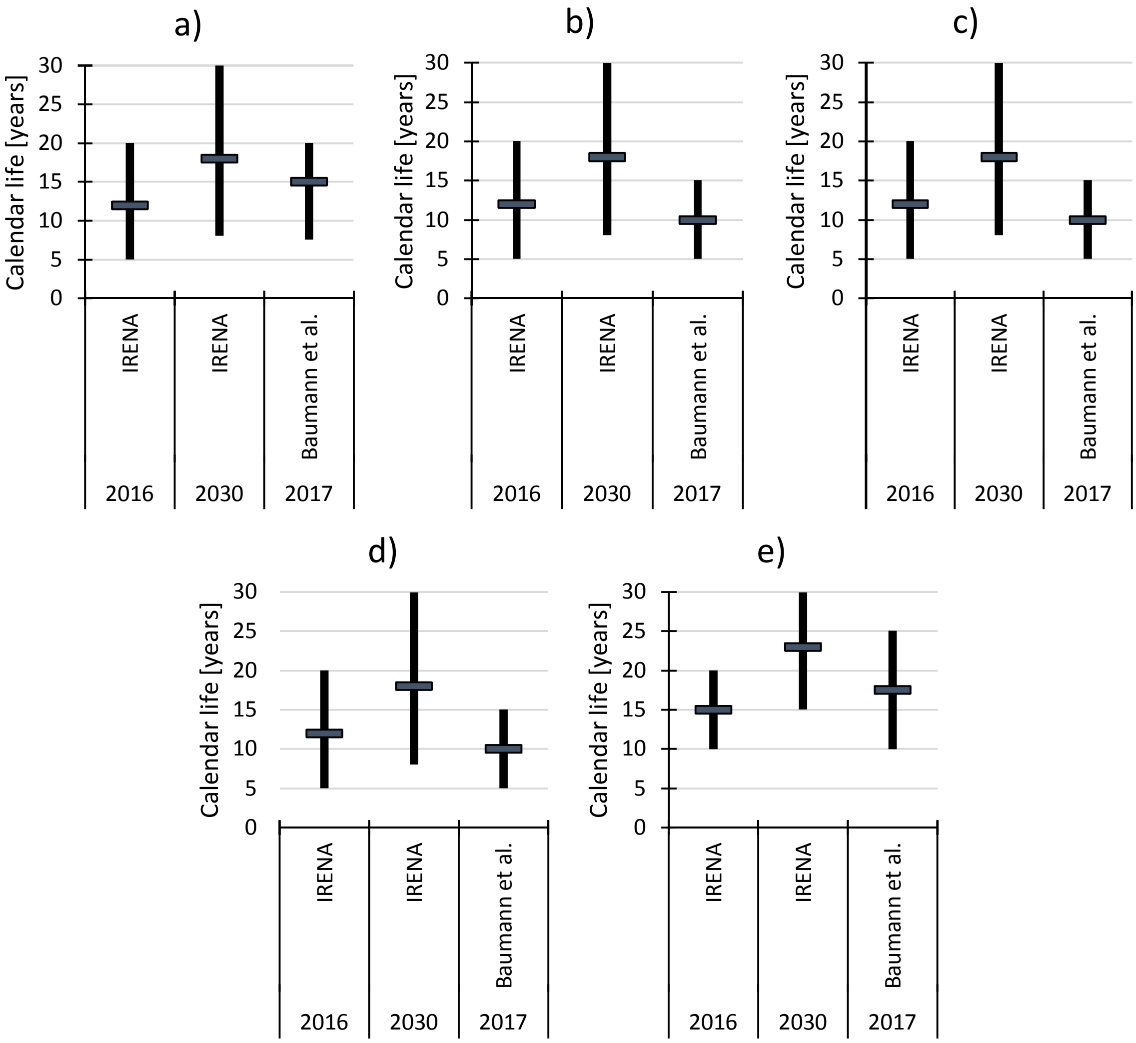


Figure 7 a) - e) The calendar life estimations for LFP, LMO, NMC, NCA and LTO storages (in the order).

In contrast to the cycle life, the calendar life seems to be rather independent of the Li-ion chemistry based on the cited authors. LTO might be able to function slightly longer time periods. Hence, it is estimated that LFP, LMO, NMC and NCA have a calendar life of 10 years and LTO 15 years.

3.2.4 Efficiency

The efficiency describes the amount of electrical energy conserved during the process of charging and discharging. Round-trip efficiency (RTE) or cycle efficiency are commonly used for Li-ion EES instead of determining separate efficiencies for charging and discharging, Efficiencies can be determined for the entire system or only for the storage part. DC – DC-efficiency refers to the direct current storage and thus describes the efficiency of a battery pack or cell. AC – AC-efficiency refers to the efficiency of the system where the efficiency of the power conversion system has also been taken into account. For this thesis, the AC – AC-efficiency is the most interesting as it describes the performance of the entire system.

Table 8 lists the references used for determining the RTE. Some DC – DC-efficiencies have also been tabulated for a comparison. The DC efficiency gives an overview of how the different components of the Li-ion EES (the storage part and the PCS) perform. Finally, Figure 8 presents the results of the review.

Table 8 The list of sources cited for the round-trip efficiency review.

Author	Paper released or the year for the estimation	RTE Type	Reference #
EPRI	2010	AC-AC	(39)
Fuchs et al.	2012	AC-AC	(24)
Battke et al.	2013	DC-DC	(34)
NREL	2015	AC-AC	(36)
IRENA	2015	AC-AC	(8)
NREL	2015	AC-AC	(40)
Zakeri & Syri	2015	AC-AC	(17)
Jülch	2016	AC-AC	(20)
IRENA	2016	AC-AC	(9)
Lazard	2017	AC-AC	(37)
Yu & Foggo	2017	AC-AC	(41)
Baumann et al.	2017	DC-DC	(26)
Fuchs et al.	2030	AC-AC	(24)
Jülch	2030	AC-AC	(20)
IRENA	2030	AC-AC	(9)

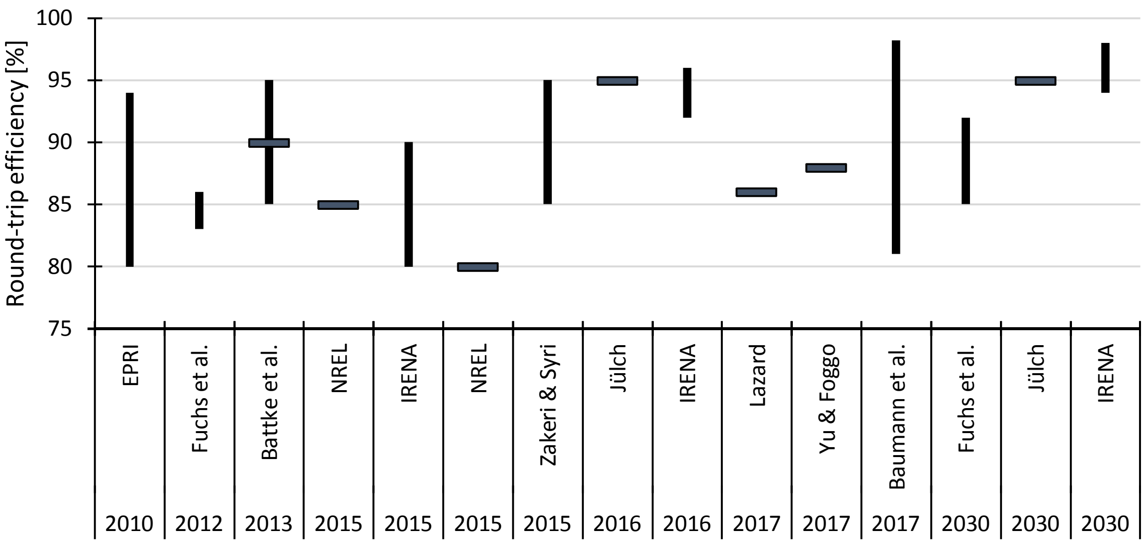


Figure 8 The results of the RTE review. The horizontal bar refers to the value which is the most probable RTE of a Li-ion EES according to the corresponding author. One should pay attention to the range of the Y-axis.

Estimations for the future reveal great performances in the 2030, with system efficiencies of at least 85 %. However, the difference between 2016 – 2017 values and the future values are not that significant. Today, an efficiency of 85 – 95% seems a somewhat reliable estimation, while estimations predicting RTE < 85% seem to date to 2015 or earlier, except Baumann et al.

Again, IRENA and Baumann et al. have differentiated between the different Li-ion chemistries. (9) (26) The results are shown in Figure 9.

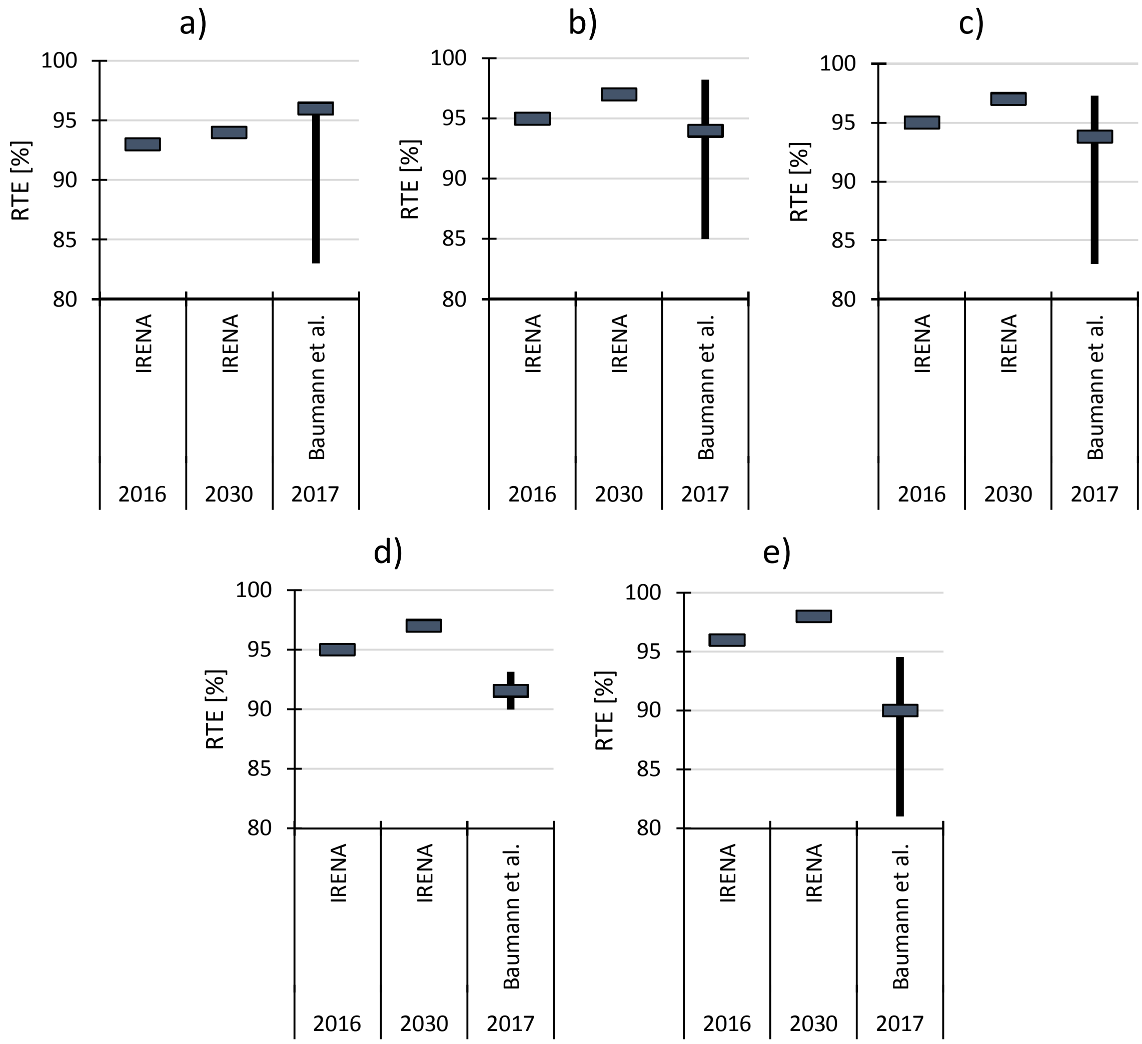


Figure 9 a) - e) The RTE estimations for LFP, LMO, NMC, NCA and LTO storages (in the order). One should pay attention to the range of the Y-axis.

Figure 9 implies no significant difference between the different Li-ion chemistries. Thus, for this thesis, an RTE of 90% is used for all the Li-ion EES chemistries.

3.2.5 Other performance figures

In addition to the previous attributes, there are additional concepts which describe the performance and the operation of an EES. An opposite expression to the DoD is the state of charge (SoC). The SoC tells how fully the EES is charged. For example, a 1 MWh EES containing 0.7 MWh of energy has a SoC of 70%. The sum of SoC and DoD equals 100%

at all times. This thesis uses the concept of DoD instead of SoC when discussing the state of operation of an EES.

When it comes to electricity storage, density is also an interesting attribute. In this case, it usually compares the volume or weight to the performance of the technology, rather than weight to volume ratio. Some authors also use the concept of specific power or specific energy relating performance to the weight of the system. (16) Li-ion batteries are superior in terms on volumetric energy density (200 – 500 Wh/l). Their power density is also remarkable (2 – 10 kW/l). (9) Thus, their popularity among mobile applications is reasonable. In utility scale applications, however, the density is not that crucial, at least not in Finland. On the other hand, the small size is highly valued for urban applications. Still, for example 1 MW/1 MWh Li-ion EESs are sized in intermodal containers which can be fitted to urban conditions. Thus, density of the Li-ion EES is not further discussed in this thesis.

While storing energy, whether thermal or electrical, some of the stored energy is lost during the storage, even if the storage would not be operated. Self-discharge rate describes how fast the system discharges itself without active charging. Table 9 lists some of the Li-ion values mentioned in the literature.

Table 9 The list of sources cited for the self-discharge rate review.

Author	Year	Self-discharge rate [%/month]	Reference #
Fuchs et al.	2012	5	(24)
Fuchs et al.	2030	1	(24)
Chen et al.	2009	3.0 – 8.6	(42)
Jülch	2016	1	(20)
Yu & Foggo	2017	1.65	(41)
IRENA	2017	2.7 – 10	(9)

Table 9 shows that with daily cycles, the self-discharge rate is negligible. Even on a few-month long-term storage, the losses would probably be less than 10%. Hence, the self-discharge rate is not taken into account in the profitability calculations in chapter 5.

3.3 Financial performance

This chapter reviews the economic details of the Li-ion systems. As with the technical details, the literature sources are combined with figures from international consultants and non-profit organizations. However, the review is more comprehensive than the review of the technical details due to the vast spread in the information. For example, the industry and consultancy data can be biased and misleading. Some costs might be estimated slightly below the actual costs in order to induce public interest and to gain market share, as Few et al. remind. (1) Then again, if the consultant is towards conventional industries, they might predict the prices over the actual costs. Still, the different types of sources generate variance to the results so that a reliable range for the costs can be found.

3.3.1 Review background

As stated in Chapter 3.2, the difficulty in predicting the EES performance is that there are no standards in assessing the techno-economic attributes of EESs. Moreover, when it comes to the estimations from different years, the age of the estimation must be taken into account. In the approximation of the technical details, however, it is not that problematic because technical performance has not improved drastically during the last few years, as seen in chapter 3.2. Thus, the information from the reports is still somewhat valid. Differently with the economic details, old reports must be revised carefully due to the immense decreases in the Li-ion EES costs in the recent years (30) (43).

There are some public reports about the Li-ion EES costs which are somewhat new. The problem is that the reports refer to old studies consuming the credibility in 2018. For example, European Commission released a working paper called *Energy storage – the role of electricity* on 2017 (44). Unfortunately, the cost data presented in the working paper was adopted from a paper by FCH JU which was released in 2015 (45). Correspondingly, FCH JU report utilizes data from 2012 (24). Thus, the data presented in 2017 was five years old. Similarly, an AECOM Report from 2015 utilizes data from 2013 which uses data from EPRI report from 2010 (39) (46) (47).

Reviewing the scientific literature is also complicated. An example can be seen by Amirante et al. who overviewed the recent developments in the field of energy storage (48). The paper was released in 2017, but its Li-ion power cost data relies on two studies, one from 2015 by Luo et al, which was cited in chapter 2, and another form 2014 by Kousksou et al. (16) (49). The price data by Luo et al. relies on five studies, unfortunately from 2009 – 2010, including a review by Chen et al. (42). Similarly, Kousksou et al. have adopted Li-ion costs from Chen et al. like Luo, but also from a report from 2001.

Another article, by Pearre and Swan, whose technical details were valuable in chapter 3.2, mapped the economic possibilities for different storage systems in 2015 (19). The prices of lithium batteries were adopted from sources between 2009 – 2012. Similarly, Jaiswal analyzed the different Li-ion chemistries and their suitability for off-grid solutions (35). The Li-ion EES price data was entirely adopted from a conference presentation from 2010 by Choi et al. (50). Equivalently, Battke et al. proposed a model for lifecycle cost of stationary batteries in 2013 (34). The price data for the Li-ion EES, however, was adopted from literature from 2008 to 2011. Kim et al. studied numerous cases in the USA in 2017 but the cases were started around 2010, over seven years ago (51). They also cited the review by Chen et al. from 2009 (42).

The lack of standards mentioned in chapter 3.2 causes obstacles for a reliable and comparable review, in addition to the usage of old data. When estimating the installed system costs, authors might tabulate cell costs, battery pack costs or the costs of the entire system. In addition to this, authors might tabulate the storage part and the power conversion systems separately. To solve the problem, the attribute of the tabulated value is also presented in the pool of chapter 3.3.2.

The most complexity is caused by the units [€/kWh] and [€/kW] as their meaning is strictly linked to the context of the paper requiring a careful analysis. Some authors differentiate between kWh and kW costs referring to the storage part and the power conversion part of the system, for example Battke et al. and Fuchs et al., meaning that the total installed cost for the system is a sum of these two factors (34) (24). This is rather logical, as the storage part provides capacity as kWh and the power conversion system costs depend on the rated power output in watts. Differently, some authors list the total cost as €/kWh or €/kW yielding the total installed costs of the system including the storage, power conversion system and other auxiliaries (37).

More differences exist. DOE/EPRI lists various details about the installed system costs, including the total plant costs as $/kW and $/kWh but also as a sum of the power and energy parts. (3) On the contrary, IRENA states that the power part of the cost is set to zero for the electrochemical batteries as their energy capacity and power cannot be separated. (9) That is correct according to Fuchs et al. as the energy and power content depend on each other due to the design of the cell (24). Moreover, Fuchs et al. claim that high energy capacity means high power. However, this can cause confusion when comparing bulk storages to the storages used in reserve markets providing power. What is more, high energy capacity does not imply high power outputs, at least when it comes to grid storages. Figure 3 in the beginning of chapter 3 already showed that Li-ion EES projects are designed and operational with various P/E ratios. Hence, varying the P/E ratio is another factor which toughens the installed system cost review because most of the studies do not differentiate between high power and high energy applications.

The P/E ratio is directly related to the way in which cells and packs are assembled, affecting the price as individual cell design affects the manufacturing costs significantly (52). Higher P/E ratios require more advanced and expensive materials per kWh, for example thinner electrode cells, as they must be able to provide more power with a similar storage capacity. (31) Furthermore, as stated earlier, grid-scale storages are stacked battery cells/packs. Thus, the P/E ratio of the system directly relates to the P/E ratios of the battery packs of the systems. Hence, the determination of the installed system costs per kWh is reasoned but interpreting the data is important. With this method, bulk storages gain lower costs/kWh than power reserve storages.

Few et al. argue that pooling numerous Li-ion battery (LiB) studies would be impractical as they have different scopes (e.g. EV vs. off-grid). (1) Certainly, the EV LiBs' P/E ratios have been optimized to suit cars. The battery electric vehicle (BEV) and plug-in hybrid electric vehicle (PHEV) batteries have larger P/E ratios compared to grid storage as stated earlier in chapter 3 making them not directly comparable. However, Sakti et al. plotted NMC-battery cost as a function of P/E ratio. The BEV Li-ion battery had a P/E ratio of about 2, while the PHEV batteries had P/E ratios of over 3. The PHEV batteries had large specific manufacturing costs [$/kWh] but the BEV battery was quite close to the Tesla Powerwall while Tesla Powerwall had a P/E ratio of about 0.5, only 25% of the one of BEV-battery. The manufacturing costs of Tesla Powerwall were 210 $/kWh while the BEV battery was about 240 $/kWh. (31) (52) In other words, the relative difference between P/E ratios was large (3 to 2) but the difference between the specific costs [$/kWh] was quite small (8 to 7) meaning that the P/E ratio did not have that significant effect on the system costs. Hence, it is reasonable to pool some of BEV-reviews as a part of this thesis as they give a glimpse of the cost performance and development in the Li-ion battery industry, especially on the pack level costs.

3.3.2 Installed system cost

This part gathers the cost data from the literature to ultimately find an estimation for the installed system cost in Finland. The data is plotted as a function of the year of the data or the year of the estimation. The year given is the year of announcement, if possible, not the commissioning year, because the cost of the EES is contracted before the commissioning date.

The X-axis is linear unlike in the figures of the technical details in chapter 3.2. As the information is scattered around sources, plotting the cost as a function of the year of the estimation makes the different sources more comparable. The type of the figure is also given, whether it refers to a cell, pack, storage part or the entire installed system.

As stated in chapter 1, power might be more valuable than bulk energy in the future. Still, the installed system cost is estimated as €/kWh, as this is the unit that is used by most authors in the cited documents. Moreover, the cost in €/kWh can be transferred to €/kW with the power-to-energy ratio.

Table 10 lists the used sources for the plot (Figure 10) of installed system costs [€/kWh] where [kWh] refers to the energy capacity of the system. Most of the original costs approximations are given in USD so those values are transferred to EUR to make the information more valuable. Table 11 presents the USD/EUR exchange rates, using the average of high and low prices on the 1st of July of each year.

Table 10 The list of sources cited for the installed system cost review.

Author	Report released	Type of cost	Reference #
Avicenne Energy	2017	cell and pack	(53)
Battke et al.	2013	storage + power part	(34)
Baumann et al.	2017	cell	(26) (54)
BNEF	2017	pack	(55)
Catenacci et al.	2013	pack	(56)
Chen et al.	2009	installed system	(42)
DOE/EPRI	2015	installed system	(3)
Eneco, Energy Live News, Cobouw	2017	installed system	(57) (58)
EPRI	2010	installed system	(39)
Few et al.	2018	pack	(1)
Fortum	2017	installed system	(59)
Fuchs et al.	2012	storage + power part	(24)
Helen	2015	installed system	(60)
IRENA	2015	cell	(8)
IRENA	2017	installed system	(9)
Jülch	2016	storage + power part	(20)
Kim et al.	2017	installed system	(51)
Kittner et al.	2017	pack	(61)
Lazard	2017	installed system	(37)
Müller et al.	2016	system, ex. works	(23)
NREL	2017	storage + power part	(40)
NREL	2016	pack	(36)
Nykvist & Nilsson	2015	pack	(43)
Schimdt et al.	2017	installed system	(30)
Siemens	2018	installed system	(62) (63)
A Storage Seller	2018	system, ex. works	(64)
Tesla, BBC, Business Insider	2017	installed system	(65) (66) (67)
Yu & Foggo	2017	storage + power part	(41)
Zakeri & Syri	2015	installed system	(17)

Table 11 The exchange rates used for transferring $/kWh costs to €/kWh. The value is the average of the high and low prices on the 1st of July of the corresponding year. (68)

Year	USD/EUR
2010	1.26
2011	1.42
2012	1.23
2013	1.30
2014	1.35
2015	1.10
2016	1.10
2017	1.15
2018 – 2030	1.22

For the years 2018 – 2030, the same rate of 1.22 is used which is the average of high and low rates on 1 January 2018. A speculation of the future exchange rates is not included in the scope of this thesis and not changing the exchange rate allows to compare the situation to the present. The rates in the past are useful, as they slightly change the slope of the curve.

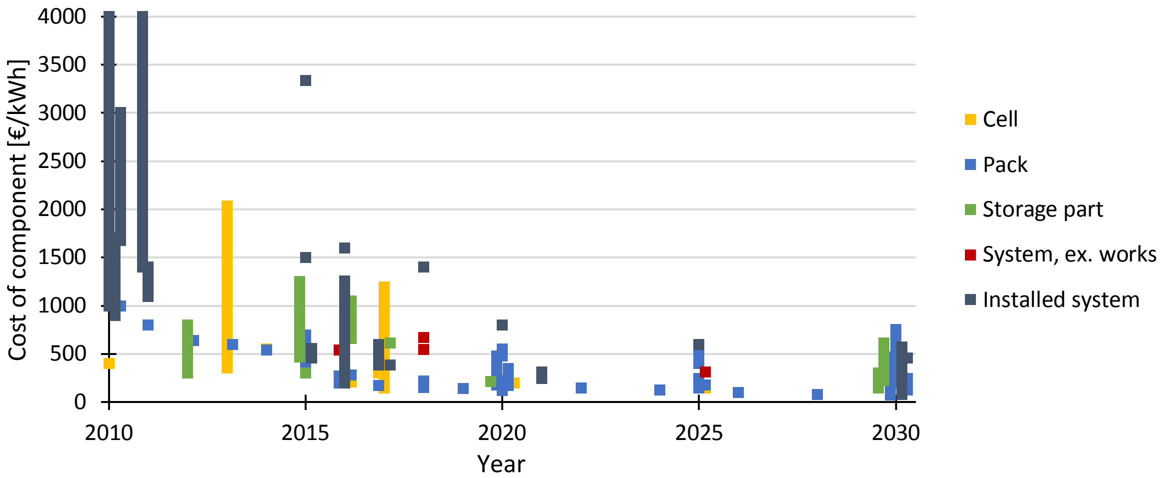


Figure 10 Results of the installed system cost review. The unit €/kWh refers to the nameplate energy capacity of the system. A dot refers to a single estimation by an author, a bar to an estimation range.

The data in Figure 10 reveals a neat trend of decreasing costs. However, the data is still rather scattered. Cell prices should be clearly cheaper than the pack prices but the graph does not reveal that. An explanation could be the fact that Li-ion batteries are generally treated as a single technology instead of differentiating between the different chemistries. To reveal the vast differences between the chemistries, IRENA and Baumann et al. have compared the costs of different Li-ion chemistries, like they have done for the technical characteristics, presented in chapter 3.2 (9) (26). The results are given in Figure 11.

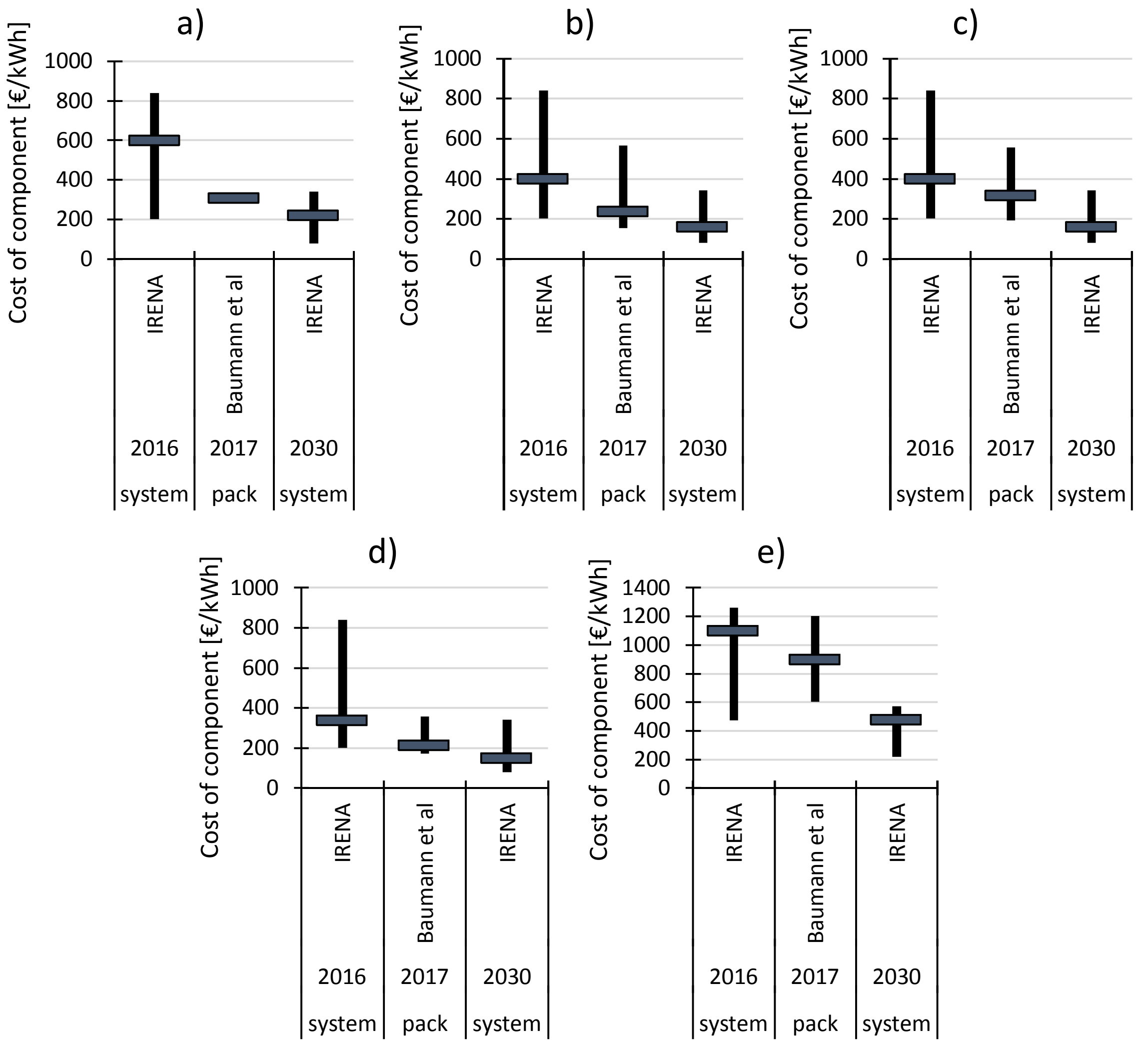


Figure 11 a) - e) The cost estimations for LFP, LMO, NMC, NCA and LTO storages (in the order). LTO has a different scale. System refers to an installed system cost.

The graphs reveal the differences between the costs. Especially LTO has significantly higher costs than the other technologies. The rest of the technologies seem to have slightly similar costs, with LFP being the more expensive and NCA the cheaper alternative. Still, a reliable differentiation between the four chemistries is hard to establish, especially when taking the low number of sources into account. Thus, in this thesis, LFP, LMO, NMC and NCA systems are approximated to have the same system level installed costs, while the one of LTO is higher. Today, the four chemistries have an installed system cost of 1000 €/kWh and LTO 1500 €/kWh for a system with a P/E ratio of 1.

3.3.3 Installed system cost breakdown and future cost estimation

Figure 10 pooled price data from the different applications, from authors listed in Table 10. The Li-ion EES cost breakdown is estimated (Figure 12) to allow a better understanding for the future system costs. In this way, a cost estimation for a pack can be compared to an estimation for an installed system cost, for example. Multiple sources, listed in Table 12, are combined and discussed as there are no common standards in determining the installed system costs.

Table 12 The list of sources cited for the installed system cost breakdown approximation

Author	Type	Reference #
Avicenne	pack	(53)
Kittner et al.	pack	(61)
Müller & Viernstein et al.	system, ex. works	(23)
Schmidt et al.	system	(30)
DOE/EPRI	system, bulk energy	(3)
DOE/EPRI	system, freq. reg.	(3)
Siemens	system	(62)
Lazard	system	(37)

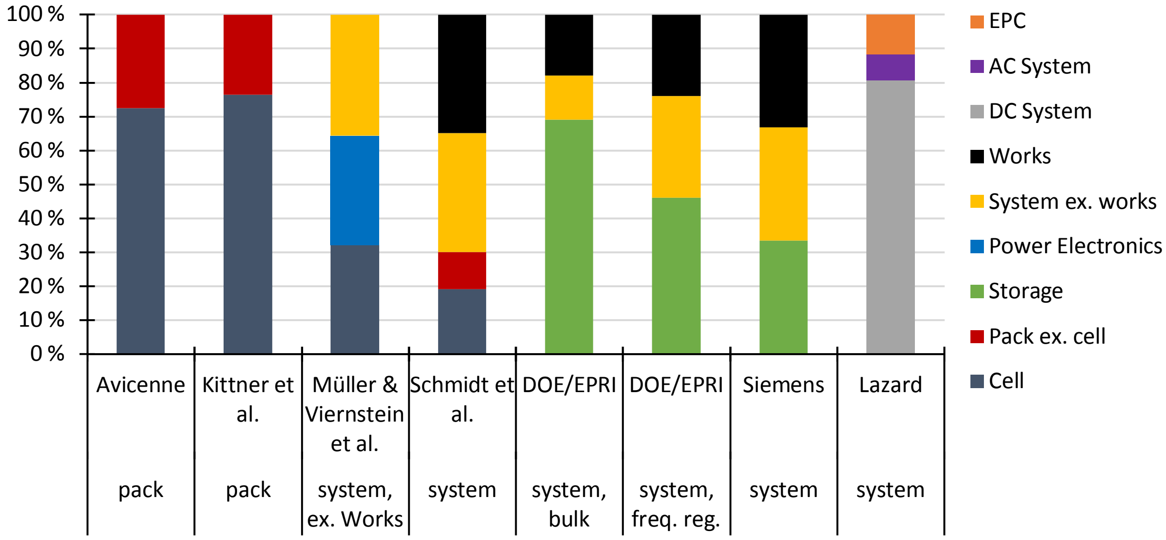


Figure 12 Installed system cost breakdown approximation from different sources

Figure 12 reveals another problem of reviewing different Li-ion installed system costs. Many of the authors did not clearly state the breakdown of the installed system costs: they might have included the system costs but did not comment on whether the system price included the labor costs, such as engineering, procurement and construction (EPC) as well as transportation and commissioning of the system.

Relating the cell or pack costs to the installed system cost is also complicated. According to Schmidt et al, the cells and packs account for 20% and 30% of the installed system costs, respectively. Unfortunately, DOE/EPRI did not differentiate cell or pack expenses but the storage costs instead, probably including TMS and EMS. The PCS was not included in the storage costs by DOE/EPRI, as the portion of storage costs in a frequency regulation storage was lower than the portion in bulk energy storages. Considering the difference between Schmidt et al. and DOE/EPRI *Works*-costs, about 40% would be an approximate portion of the pack cost of the installed system cost for storages with a P/E of 1. The rest of the material costs of the system would account for 30% and the works for 30%. Transportation is also included in the works cost. When P/E > 1, the share of pack decreases, yielding probably 20 – 30% of the installed system cost. In both cases, cells account for 70% of the pack cost.

The authors did not differentiate between the different Li-ion chemistries in the cost distribution estimation. Thus, it is assumed that the authors had listed the values for a storage using the most common chemistries: LFP, NMC, LMO or NCA.

Figure 10

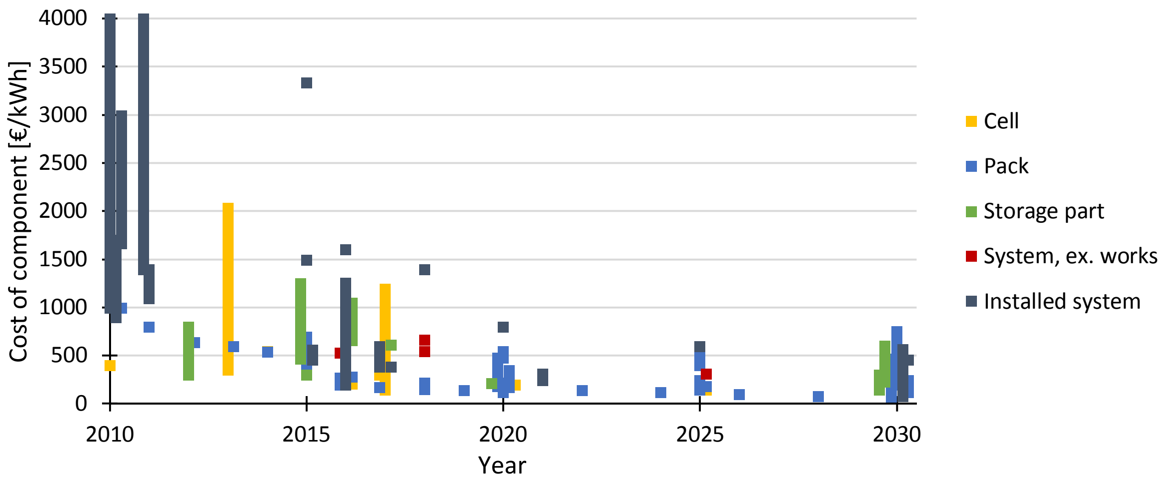


Figure 10 is modified with the approximations above to reflect the installed system cost of an operational system. If the source had listed data as a battery pack price, the data is modified to reflect the installed system costs including the power conversion systems, additional TMS and EMS as well as transportation and installation costs. Similarly, if the cell price was given, it is first converted to a battery pack cost and then the approximations of a PCS and other cost components are added. Then again, some authors listed the price of the storage, excluding the PCS and other auxiliaries. In this case, the costs of the PCS and other auxiliaries given in the data are added to the corresponding cost of storage [€/kWh] using a P/E ratio of 1.

Using conversion factors, i.e. percentages, to compare system and pack costs would be difficult. An author might have estimated a price range of 200 – 750 €/kWh for a battery pack in 2030 (56). The share of 40% for a pack would yield an installed system cost of 500 – 1875 €/kWh which seems high compared to the current installed system cost levels. Hence, the share of 40% cannot be expected to remain also in the future because the highest uncertainties are related to the pack itself and to the auxiliaries particularly meant for electricity storage, the TMS and the EMS. The rest of the cost components of the installed system cost, in this case 60%, are rather independent on the cost of the battery pack chemistry itself. These cost components include inverters, the other parts of the PCS, housing and containers as well as the EPC. Hence, if the cost of the pack does not decrease, the costs of other components might still decrease. Thus, the approximation of the cost shares as percentages can be inaccurate, so the shares are given as absolute values, as €/kWh.

The approximated installed system cost for an LTO system in 2018 was found to be 1500 €/kWh and 1000 €/kWh for the rest of the chemistries, with a power-to-energy ratio of 1. The data presented in Figure 12 was probably estimated for the rest of the chemistries, as stated earlier, so the percentage distribution of 30% cell, 10% pack, 30% other components and 30% works is used for the four common chemistries. In other words, materials account for 70 % of the installed system costs and the rest, 30 %, includes labor costs related to, for example, planning, transportation to Finland and to the commissioning of the system.

The previous percentages are used to calculate the absolute costs for different components (Figure 13). The cost distribution of an LTO system can be made based on the cost components calculated for the most common technologies, only varying the cell level cost. This is reasonable because the cost of PCS, for example, is mainly a function of the kW rating of the system, not of the chemistry.

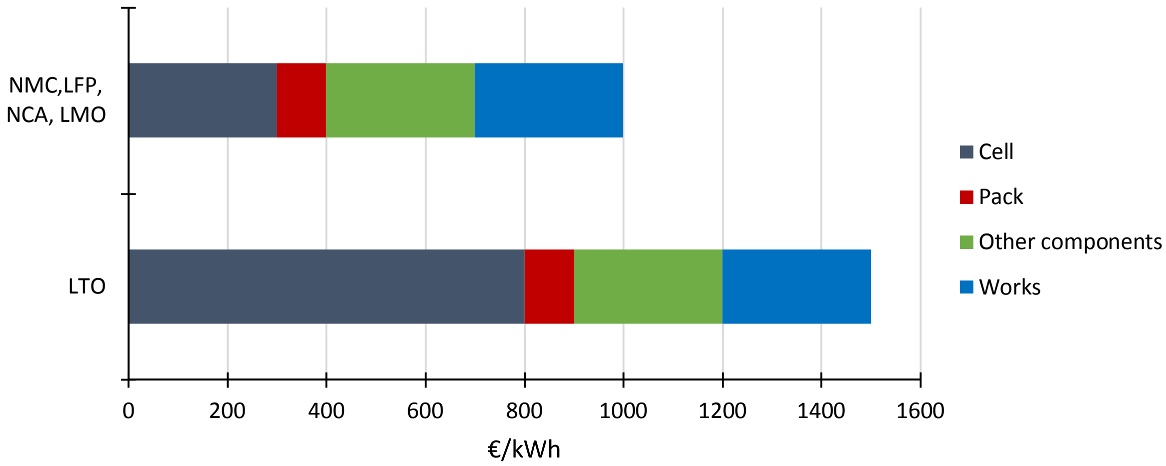


Figure 13 The approximated installed system cost breakdown for a ready-installed system in Finland. The unit €/kWh refers to the nameplate energy capacity of the system.

In other words, the packing with EMS and TMS of the cells costs additional 100 €/kWh and other materials cost 300 €/kWh. These figures are used to transform the *cell*, *pack* and *system, ex. works* costs to installed system costs today. The approximation by Müller et al. is used to approximate the cost components of a future system. They predicted a 7% yearly drop in the power conversion systems, packings and auxiliaries and 8% on cell prices. (23) The *works* costs are estimated to decrease 5 % yearly, based on a similar learning rate than with the physical components which is partly reversed by the increasing salaries. Hence, the following costs are used (Table 13):

Table 13 Cost breakdown of the Li-ion EES installed system in Finland in the future.

Year	Cell [€/kWh]	Pack [€/kWh]	Other components [€/kWh]	Works [€/kWh]
2018	300	100	300	300
2019	276	92	279	285
2020	254	85	259	271
2021	234	78	241	257
2022	215	72	224	244
2023	198	66	209	232
2024	182	61	194	221
2025	167	56	181	210
2026	154	51	168	199
2027	142	47	156	189
2028	130	43	145	180
2029	120	40	135	171
2030	110	37	126	162

One must note that these figures are used only to transform different types of costs to total installed system costs. If an author has forecasted a pack cost for 2030, 126 €/kWh + 162

€/kWh are added to the forecast. Similarly, if the author has forecasted a cost for an uninstalled system, i.e. *system, ex. works*, 162 €/kWh is added on top of the materials costs.

Figure 14 presents the results. A dot refers to an estimation based on a single value from an author, a bar to a range of values from an author.

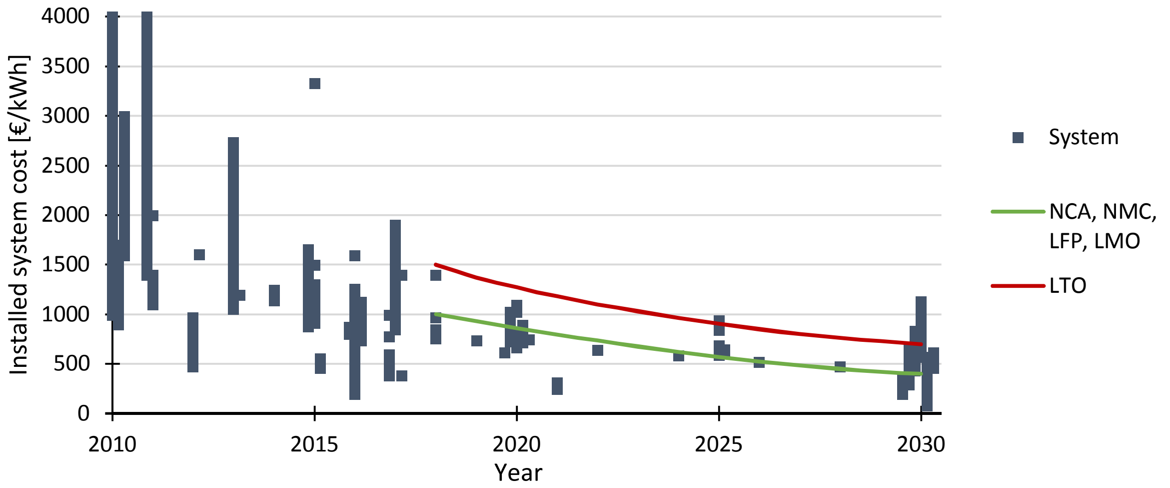


Figure 14 The installed system cost based on the approximations from different authors. The lines present the projected cost of an installed system in Finland with a power-to-energy ratio of 1. The unit €/kWh refers to the nameplate energy capacity of the system.

The lines present an estimation for the development of the installed system cost for a system with a power-to-energy ratio of 1. The green line present an average estimation for LFP, NMC, NCA and LMO-based EES. One should note that the technologies have slight differences. NMC and LMO lie in the middle of the range, LFP lies on the expensive side and NCA on the low-priced side. LTO is predicted to remain significantly more expensive than the other four (9).

3.3.4 Installed system cost's relation to the power-to-energy ratio

The DOE Energy Storage Database is used to estimate the effect of P/E ratio on the installed system cost per kWh. Plotting the installed system cost as a function of P/E ratio does not reveal any correlation with the Li-ion EES projects. However, selecting the projects which are *frequency regulation*, *resiliency* or *electric energy time shift* reveals that there might be a correlation between P/E ratios and $/kWh and €/kWh costs (Figure 15). The hybrid power plants are left out if the installed system costs are not clearly differentiated between the storage and the power production component.

Fortum Järvenpää, Helen Suvilahti and Eneco storages as well as the newest Siemens project in Finland have been added manually to Figure 15, as their installed system cost data is not listed in the database. The differences between the costs are explained by the chemistries and sizes. Fortum and Eneco are using NMC storages with energy capacities of 1 MWh and 50 MWh, and Helen uses an LTO storage (58) (60) (69) (70). Siemens does not reveal the used chemistry (62).

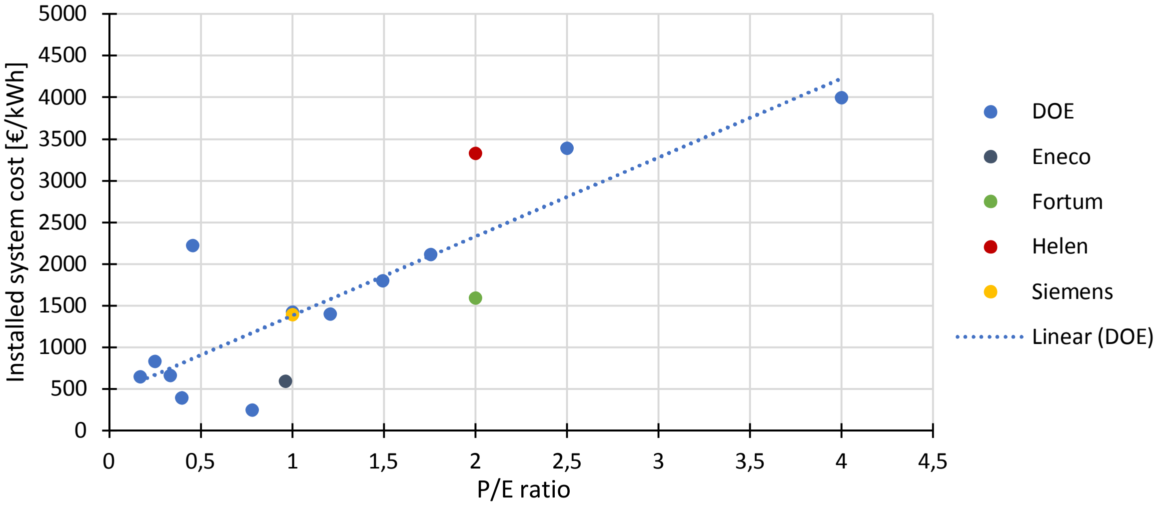


Figure 15 Installed system cost as a function of P/E ratio based on the DOE Energy Storage Database. Fortum Järvenpää, Helen Suvilahti, Siemens and Eneco have been added manually. (2) (57) (58) (59) (60) (62) (63)

The linear fit reveals a relation. However, the sample is small. Moreover, the figure does not take the year of announcement into account, and most of the projects have been commissioned before 2016. Furthermore, the figure does not take different Li-ion chemistries into account. Thus, the correlation between the P/E ratio and $/kWh costs is not entirely reliable, and thus for this thesis, a more gradual correlation is used. The P/E ratio of 1 would lead to an installed system cost of 1000 €/kWh for NMC, LMO, LFP and NCA today. A P/E ratio of 0.2 would correspond to a cost of 500 €/kWh and the ratio of 4 a cost of 3000 €/kWh. The line lies lower, taking account the age of the projects in Figure 15 and the decreasing costs presented in Figure 14. For an LTO Li-ion EES, the P/E ratios of 0.2, 1 and 4 would lead to costs of 700, 1500 and 4000 €/kWh.

The correlation cannot be entirely explained with the different cell properties, as stated earlier in chapter 3.3.1. Sakti et al. found that decreasing the P/E ratio with 33%, the battery cost per kWh dropped by about 13% (31). Similarly, Pistoia found that a certain 50 kW/8 kWh NCA PHEV battery cost $348/kWh, while a 50 kW/16 kWh NCA PHEV battery was $251/kWh (27). Thus, reducing the P/E ratio by 50% reduced the $/kWh cost by about 28%. The differences are small compared to the approximation made based on Figure 15. In the approximation, the reduction of the P/E ratio from 4 to 2 (50%) decreased the installed system cost from 3000 €/kWh to 1667 €/kWh (44%). The difference can be explained by the power conversion systems because the examples by Sakti et al. and Pistoia considered battery packs and Figure 15 grid-scale systems. A PCS for a 4 MW/1 MWh storage is more expensive than one for a 2 MW/1 MWh storage, increasing the cost without increasing the energy capacity.

In reality, the relation is not perfectly linear, however. All cost components are affected by the economies of scale: the PCS suited for 4 MW costs less per MW than the PCS for 2 MW. Still, the linear approximation can be utilized in the scope of this thesis. It allows to estimate the magnitude of the relation of the P/E ratio to installed system cost per kWh.

3.3.5 Operation, maintenance and administrative costs

A couple of sources have estimated the operation, maintenance and administrative (O&M) costs of Li-ion EES. The most popular method seems to be relating the O&M costs to the power output of the storage, i.e. €/kW per year. Other authors tabulate the costs as a cost per installed energy capacity [€/kWh per year] or as a percentage of the capital expenditure (CAPEX) per year. In addition to the fixed part, some authors have also included a variable part [€/kWh] where [kWh] indicates the electrical energy output. Table 14 and Table 15 list the cited sources.

Table 14 The list of sources cited for the O&M cost approximation

Author	Year	Value	Unit	Type	Reference #
NREL	2015	9	\$/kW-year	system	(36)
NREL	2030	7.6	\$/kW-year	system	(36)
Lazard	2017	2.44 – 3.06	\$/kWh-year	system	(37)
Yu & Foggo	2017	8.18	\$/kW-year	system	(41)
Baumann et al.	2017	11 – 30	€/kW-year	pack	(26)
Battke et al.	2013	19	€/kW-year	cell	(34)
Zakeri & Syri	2015	2 – 13.7	€/kW-year	system	(17)
Jülch	2016	2	% of CAPEX per year	system	(20)
DOE/EPRI	2015	5.7 – 9.2	\$/kW-year	system	(3)

Figure 16 visualizes the values. By using a P/E ratio of 1, the O&M cost of Lazard is also 2.44 – 3.06 \$/kW-year. An exchange ratio of 1.2 is used for the USD/EUR conversion.

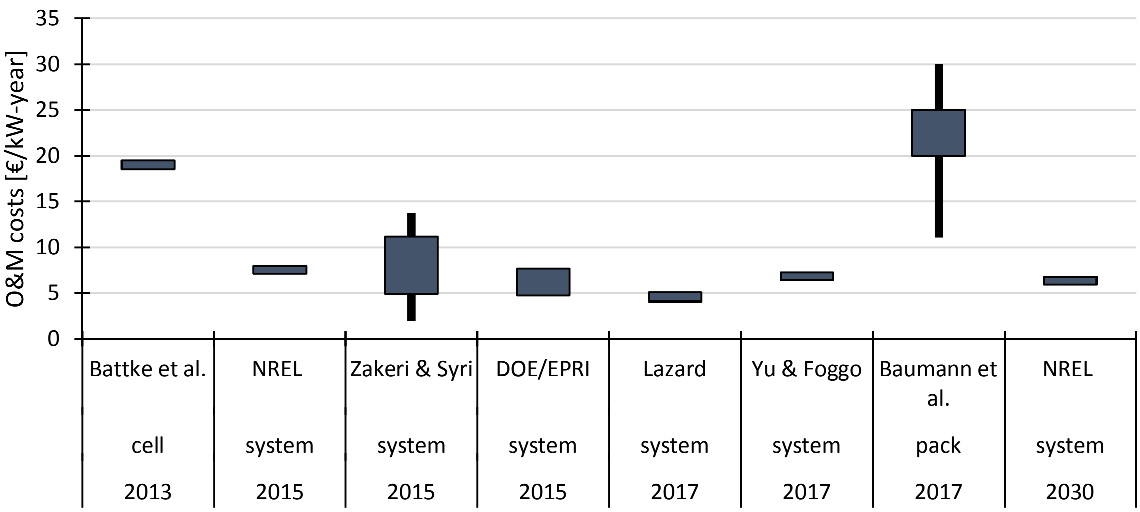


Figure 16 O&M cost approximations from different sources.

Figure 16 reveals that the O&M costs of system are most likely between 5 – 10 €/kW per year. For this thesis, the value of 8 €/kW-year is used based on the figure. Battke et al. and Baumann et al. gave rather conservative approximations, which is reasonable, as those estimations are for a cell and a pack. Connecting dozens of packs to a single system increases the total O&M costs but reduces the specific costs because the system and its pack can be operated and maintained together.

Table 15 Estimations for the variable O&M costs.

Author	Year	Value	Unit	Type	Reference #
Yu & Foggo	2017	5.48	$/MWh	system	(41)
Zakeri & Syri	2015	0.4 – 5.6	€/MWh	system	(17)
DOE/EPRI	2015	0.5 – 5.5	$/MWh	system	(3)

The relative variations in the variable costs are large. Due to the lack of data, the variable O&M cost is not included in this thesis, as a reliable value cannot be concluded.

3.3.6 Replacement costs and residual value

Replacement costs have not been approximated by most authors listed in Table 10 which lists the citations for the installed system cost review. This is probably due to the scarcity of the information about ongoing projects. Replacement costs are thus ignored, as establishing a reliable estimation would be difficult. In other words, the thesis assumes that the project is used until the end of the cycle life and all the cells in the EES stop working after the cycle life have been reached.

In this thesis, the residual value is also ignored. The scope of the thesis does not allow a reliable estimation for the value, even though the other components in the system might have some value left after the lifetime of the batteries. Transformers can operate for 30 – 40 years compared to the lifetime of the storage of likely less than 15 years (23). Also, as the Li-ion EES projects are relatively new, the literature discussing the topic might not be trustworthy. Thus, the uncertainties can be reduced by not taking residual value into account.

The end-of-life and recycling costs are also ignored as there are few reliable sources in the literature (26). One should also note that at least a portion of the recycling costs could be reverted with the possible residual value of the EES.

3.4 Summary

This chapter reviewed the techno-economic attributes of Li-ion EESs. The results are gathered to Table 16 and finally used for the profitability calculations in chapter 5. The values are for a system with power-to-energy ratio of 1 in 2018.

Table 16 The summary of the techno-economic characteristics of the Li-ion EESs.

Attribute	Value	Unit
RTE	90	%
O&M costs	5 – 10	€/kW-year
Calendar life (LMO, NMC, LFP, NCA)	10	years
Calendar life (LTO)	15	years
Cycle life (LMO, NMC, LFP, NCA)*	3000	cycles
Cycle life (LTO)	9000	cycles
Installed system cost (LMO, NMC, LFP, NCA)*	1000	€/kWh
Installed system cost (LTO)	1500	€/kWh

*considerable dependence on the chemistry

4 Finnish Electricity Market

This chapter discusses the most relevant attributes of the Finnish electricity market. The assessment of the market allows to evaluate the different methods for the revenue generation with the Li-ion EES.

The Finnish electricity market is a part of the Nordic electricity market. The Nordic market consists of day-ahead market, intraday market and reserve markets. The financial markets of the Nordic electricity market are not discussed in this thesis.

Currently, the Nordic market is balanced on hourly periods. In the Q2 of 2020, however, the imbalance settlement period is suggested to be changed to 15 minutes in the intraday and reserve markets. (71)

The viewpoint of the analysis is to maximize the revenue per installed MW of EES power. This does not speculate where the prices might end up to as it cannot be fitted to the scope of this thesis. The scope is not to forecast electricity prices, so only some possible trends of the prices are given in chapter 6.

The market analysis is based on the years 2015 – 2017 because the electricity market has been changing. The international transmission capacities in the Nordics have increased (72), condensing power has retired and the share of wind power has increased. Moreover, Fingrid has changed the rules in the reserve markets (73). Thus, analyzing years 2014 or before would give little reliable data usable in the thesis.

4.1 Technical overview

The generation mix of Finland is characterized by high portions of nuclear power, hydropower and imports mainly from Sweden (74). Figure 17 presents the estimated available capacity during the winter peak 2017 – 2018, and the actual electricity produced during the winter peak 2017 – 2018. In addition to these figures, 707 MW of peak load capacity is ready for operation (75).

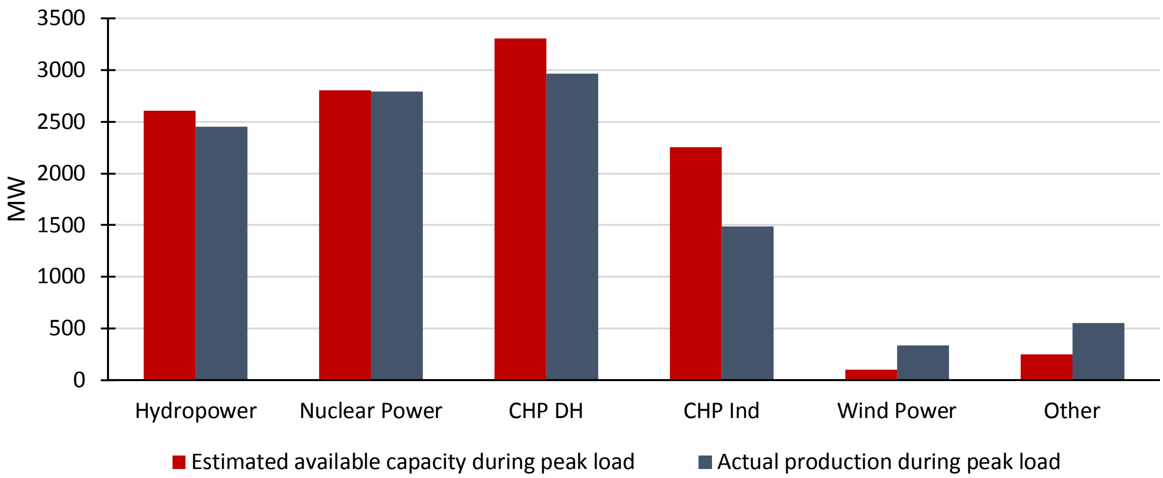


Figure 17 The estimated available capacity and the actual electricity production during the peak load in winter 2017 – 2018. (75) (76)

The installed capacity determines the competitors for the Li-ion EES, and the generation mix is the basis for the feasibility. The EESs benefit from intermittent and inflexible generation that cannot easily follow the demand. These technologies include and wind power, and on global level also solar power. Also, nuclear power is typically not following the demand providing constant power output instead.

Finland is linked with transmission lines to Sweden, Norway, Estonia and Russia, which are used to balance the supply and demand with exports and imports. For Finland, the case is usually net import, and the level of imports are heavily used for fast intraday changes in the electricity demand instead of base energy. (74) (77) Table 17 lists the current transmission connection capacities available for markets. The Norwegian transmission connection is not available for markets (72).

Table 17 Maximum net transfer capacities between Finland and neighboring countries. Import denotes import to Finland from the corresponding country. (78) (79)

Country	Maximum import capacity available for markets [MW]	Maximum export capacity available for markets [MW]	Type
Sweden (SE1)	1500	1100	AC
Sweden (SE3)	1200	1200	DC
Estonia (EE)	1016	1016	DC
Russia	1300	320	DC
Total	5016	3636	N/A

A high amount of transmission capacity can have both positive and negative effects for an EES. The capacity allows Swedish and Norwegian hydropower to balance the Finnish market. On the other hand, Sweden has a high share of wind power which needs increasingly more regulating power. Sweden and Norway will also have an economic incentive to export more electricity to the Central Europe and the UK in the future to balance the high share of intermittent generation there. If the electricity flows to the Central Europe, Finland will need more ways to balance the supply and demand, benefitting the Li-ion EES. The future outlooks are further discussed in chapter 6.2.

4.2 Day-ahead market

Day-ahead market is the marketplace with the highest volumes of electricity. The settlement period of the market is one hour, and the prices of the following day are determined by bids which are submitted before 13:00 (GMT+2) on the previous day. The Finnish day-ahead market is a part of the Northern European power market operated by Nord Pool AS. (5) (80)

In the day-ahead market, an EES can make profits via price arbitrage where the EES is charged during the hours of low electricity prices and discharged during hours with high prices. In other words, an EES holder is interested in the absolute price differences, not in the magnitude of the prices.

To estimate the maximum arbitrage potential, the highest and lowest prices of the day must be compared. The difference is calculated by deducting the lowest hourly price of the day from the highest hourly price of the same day. Figure 18 plots the daily differences, and Figure 19 arranges the differences as duration curves in Finland from years 2015 – 2017, including each day of the years. Year 2016 was a leap year.

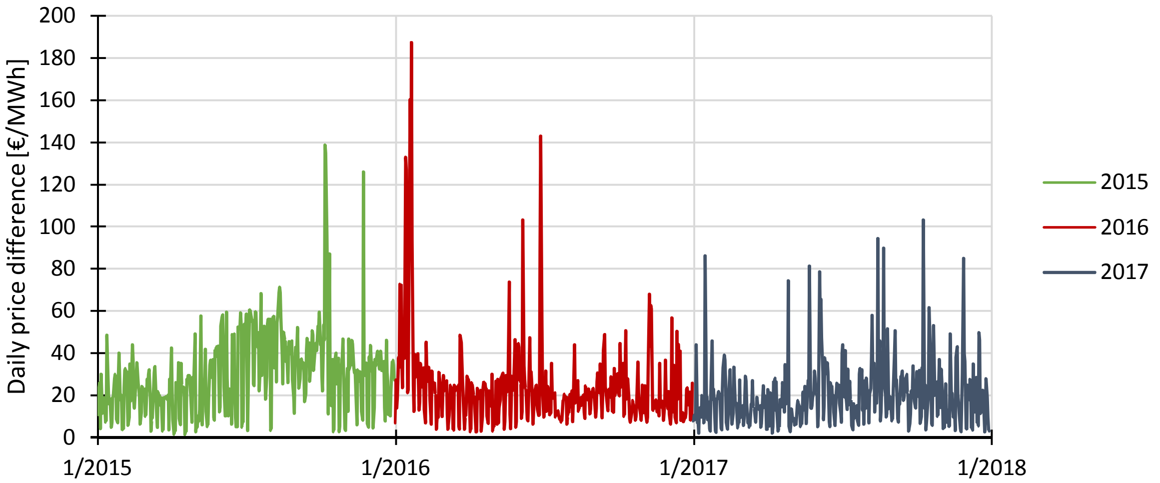


Figure 18 The difference between the highest and lowest hourly price of a day in Finland in 2015 – 2017. The difference is calculated for each day. (81)

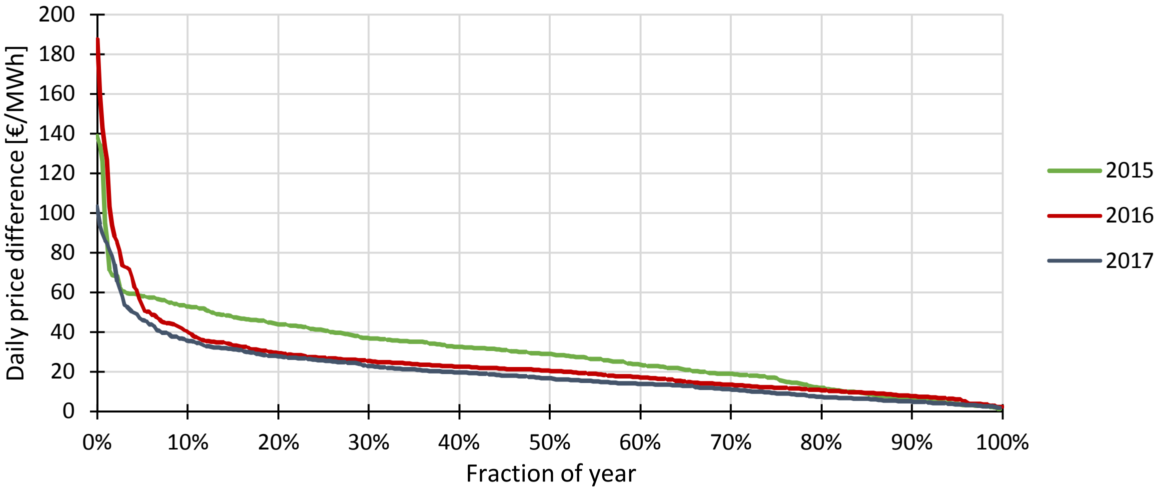


Figure 19 The difference between highest and lowest hourly day-ahead price in Finland in 2015 – 2017. The difference is calculated for each day, and the differences are arranged as a duration curve to estimate the occurrence of different price differences. (81)

Based on the figures, the average maximum price difference is currently about 20 – 25 €/MWh, when giving more weight to the most recent prices (2016 and 2017). One must note that the daily low and high prices might be peaks that only last for one hour. For the owner of the EES, this makes it difficult to time the bids correctly, meaning that the operator might not be able to fully discharge the EES during the highest prices. Furthermore, if the power-to-energy ratio of the EES is smaller than one, the EES cannot be fully discharged, nor fully charged, during one hour, preventing the utilization of a full cycle with maximum price arbitrage.

4.3 Intraday market

Intraday market supplements the day-ahead market by balancing the supply and demand closer to the delivery. Intraday trading is continuous like stock markets, closing one hour before the delivery. Like the Finnish day-ahead market, the intraday market is operated by Nord Pool AS. (5) (82)

Unfortunately, an automated download of intraday market data is not allowed due to the Nord Pool AS rules so the information must be downloaded manually (83). Manual downloading of intraday data for three years cannot be fitted to the scope of this thesis so the characteristics of the intraday market are analyzed with data from January, February, July and August from 2015, 2016 and 2017. Figure 20 plots the average prices during hours in Finland.

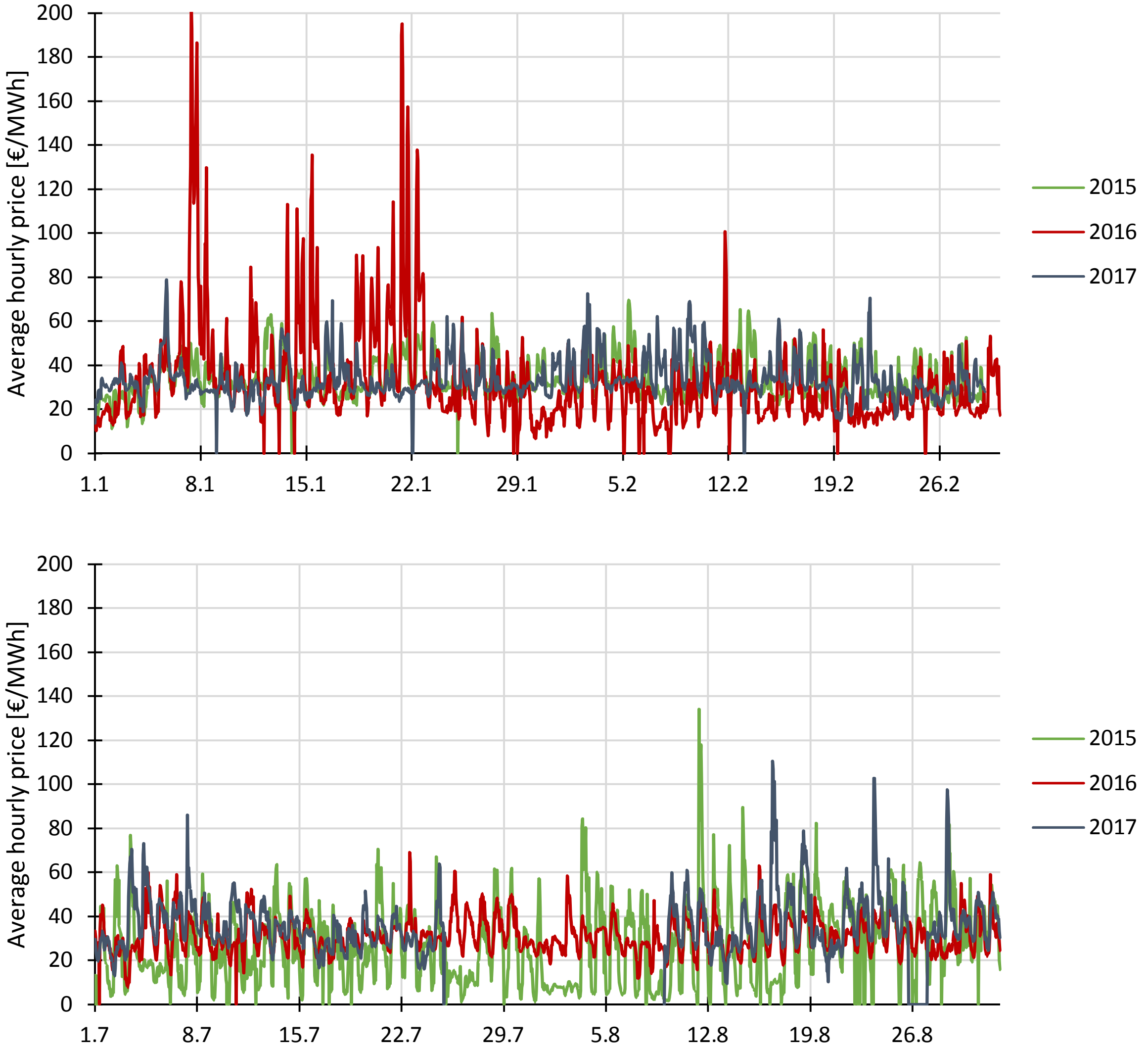


Figure 20 a), b) The average hourly intraday prices in January, February, July and August in 2015, 2016 and 2017. Year 2016 was a leap year, and 2017 data has a gap between July 25, 0:00 – August 9, 1:00. (83)

The energy arbitrage potential can be evaluated by comparing the *high* and *low* prices, like in the analyses of the day-ahead market. Figure 21 shows the price difference between the highest and lowest price of the day.

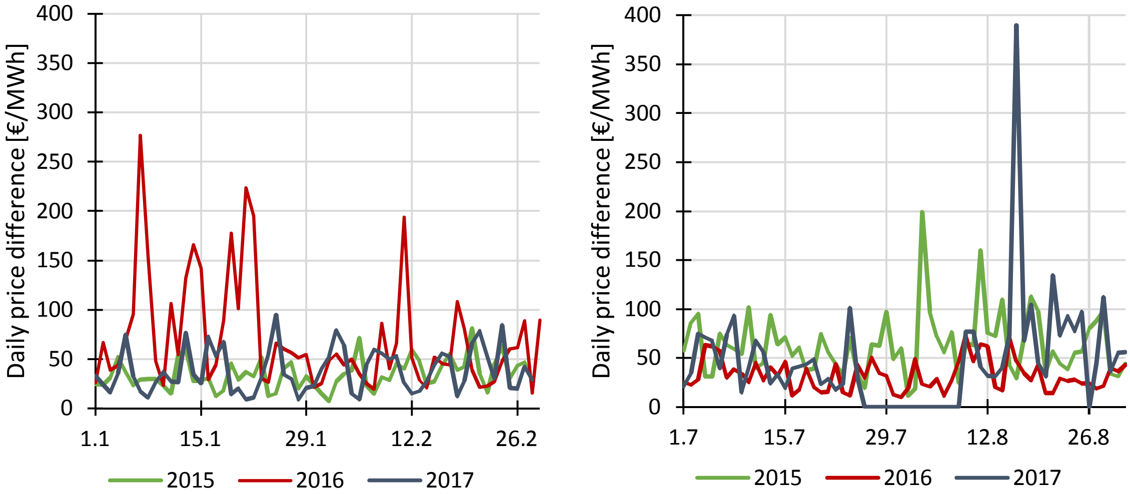


Figure 21 a), b) The difference of the highest and lowest intraday price of a day in January, February, July and August 2015, 2016 and 2017. (83)

Based on Figure 21, the maximum theoretical arbitrage potential seems to vary around 50 €/MWh. The unweighted average price differences are (Table 18):

Table 18 Unweighted average difference between the highest and lowest intraday price of the day. (83)

Year	Average daily price difference, Jan – Feb [€/MWh]	Average daily price difference, Jul – Aug [€/MWh]
2015	34.43	63.43
2016	70.90	32.65
2017	38.25	58.28

The prices differences are taken from the absolute highest and lowest occurred prices, and in practice, the absolute value of the price cannot be predicted. In other words, the market actor would need to offer exactly the highest intraday price and ask for the lowest price in order to obtain the price differences in Table 18. The problem is that these prices cannot be forecasted in advance. Still, even the limited overview of the intraday prices reveals the highest magnitude of the differences and the highest potential for price arbitrage. Thus, it is safe to claim that an EES cannot gain more than 80 €/MWh on average via intraday price arbitrage, based on the data. The actual potential is most likely even less, based on the table.

4.4 Reserve and balance market

The day-ahead market and the intraday market need support to match the supply with the demand. The reserve and balance markets are smaller than day-ahead markets and intraday markets in terms of volume, allowing a more precise balance than with bulk energy. In Finland, there are four marketplaces for reserve and balancing power

- Frequency Containment Reserve for Normal Operation (FCR-N)
- Frequency Containment Reserve for Disturbances (FCR-D)
- Automatic Frequency Restoration Reserve (aFRR)
- Manual Frequency Restoration Reserve (mFRR). (84)

4.4.1 Frequency Containment Reserves

The frequency containment reserve for normal operation (FCR-N) and the frequency containment reserve for disturbances (FCR-D) are used to contain the frequency at 50 Hz. They are controlled automatically as a function of the frequency. The FCR-N operates to maintain the frequency between 49.9 – 50.1 Hz. (85) If the frequency decreases below 49.9 Hz, the FCR-D is activated. The FCR-D is not used to decrease frequency. (86)

The FCR-N and the FCR-D are separate marketplaces, and a single reserve can participate to either or both as long as the requirements of the both markets are met (87). The reserve unit must be capable of at least 30 min of continuous activation in both markets (85) (88). For a Li-ion EES, this means that the EES must be able to provide continuous power via discharging or load via charging for 30 min.

The FCR-N reserve holder operates almost linearly between 49.9 – 50.1 Hz utilizing relays. If the frequency changes 0.1 Hz, the reserve shall be fully activated within three minutes. (85) Li-ion EESs are capable of achieving this, as the EESs can switch from full charge to full discharge in less than second (89). Between 50 ± 0.05 Hz the reserve is allowed not to regulate. An FCR-D reserve unit can function linearly with relays similarly to the FCR-N. At 49.5 Hz, the unit must be fully activated within 1 second. Usually these reserves are large loads which can be quickly shut down. (85) Figure 22 shows the basic operation principle of the FRC reserves.

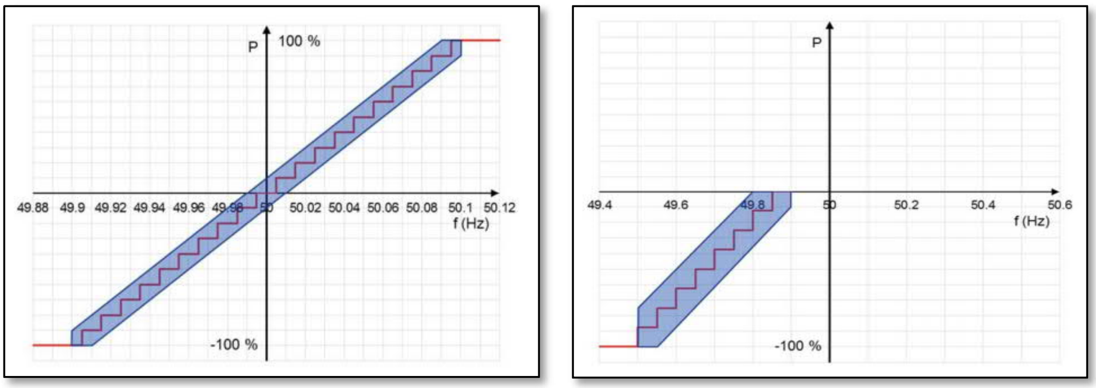


Figure 22 a), b) The basic principle of the operation of the FCR reserves, adopted from Fingrid. (85)

The FCR-N and the FCR-D markets function on a yearly and hourly basis (87). For the yearly market, the price [€/MW/h] is constant and depends on the auction which is arranged once a year, in the autumn of the previous year (90). The price is determined by the most expensive accepted bid (91).

The hourly markets supplement the yearly market, and Fingrid purchases the reserves once a day, if necessary, based on the bids placed by the reserve holders. The bids include the capacity of the reserve [MW] and price of the availability [€/MW/h]. The bids for the hours of the following day can be submitted until 18:30 (GMT+2) and Fingrid confirms the transactions by 22:00. The reserve holder, whose bid has been accepted in the yearly market, can participate in the hourly markets only if the holder has fully supplied the volume specified in the yearly agreement for the particular hour of the following day. The required accuracy for a bid is 0.1 MW (87)

The reserve holder, whose bid has been accepted, receives a fee based on the available reserve capacity and the energy used. The capacity fee is determined by the most expensive bid ordered by Fingrid and paid to every reserve holder whose bid was accepted. The energy fee is paid to the reserve holder's balance provider for the electricity purchased by Fingrid, and the energy fee is charged from the balance provider for the reserve electricity sold by Fingrid. (87) As the energy fee is paid to the balance provider, it does not necessarily generate revenue for the reserve holder. Thus, the energy fee of the FCR reserves is not further discussed in the thesis.

If the reserve holder has participated in both yearly and hourly markets, the holder receives the capacity fee from the hourly markets only if the yearly volume is fully delivered on that hour (87). As described earlier, the viewpoint of the thesis is to maximize revenue per installed MW, meaning that one MW cannot attend both hourly and yearly FCR markets at the same time. Thus, the hourly and yearly FCR markets must be treated separately.

Table 19 summarizes the key attributes of the FCR-N and the FCR-D yearly markets. The maximum revenue is obtained by multiplying the yearly price [€/MW/h] by 8760 hours. The values of 2018 have also been included in the summary as the yearly FCRs already has the full year data for 2018 unlike other marketplaces.

Table 19 Comparison of the yearly markets of the FCR reserves. (90)

Attribute	FCR-N	FCR-D	Unit
Minimum bid	0.1	1	MW
Maximum bid	5	10	MW
Price 2015	16.21	4.13	€/MW/h
Price 2016	17.42	4.5	€/MW/h
Price 2017	13	4.7	€/MW/h
Price 2018	14	2.8	€/MW/h
Maximum revenue 2015	142 000	36 179	€/MW
Maximum revenue 2016	152 600	39 420	€/MW
Maximum revenue 2017	113 880	41 172	€/MW
Maximum revenue 2018	122 640	24 528	€/MW
Volume 2015	73.6	298	MW
Volume 2016	89	367	MW
Volume 2017	55	456	MW
Volume 2018	72.6	435	MW

To estimate the potential of the hourly markets, the FCR-N hourly capacity fees are arranged to duration curves (Figure 23).

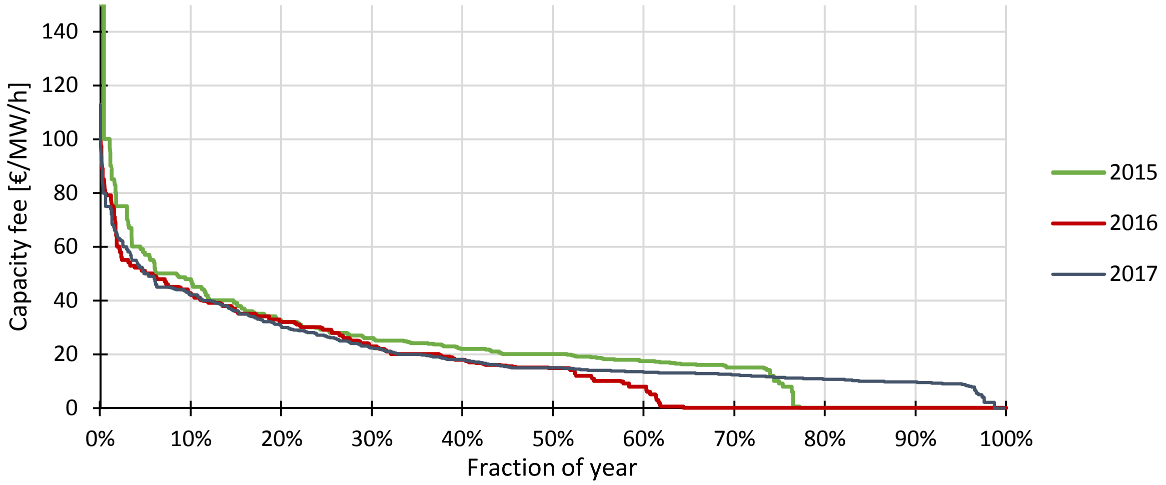


Figure 23 Duration curves of the hourly FCR-N capacity fees from 2015 – 2017. The highest peak of 2015 reaches 500 €/MW/h. (92)

The theoretical maximum revenue gained from the FCR-N hourly markets would have been 195 532 €/MW in 2015, 147 530 €/MW in 2016 and 182 202 €/MW in 2017. The revenue is obtained by adding the hourly prices of a year together. The potential for the revenue gain per MW seems to be drastically lower with the FCR-D hourly market (Figure 24):

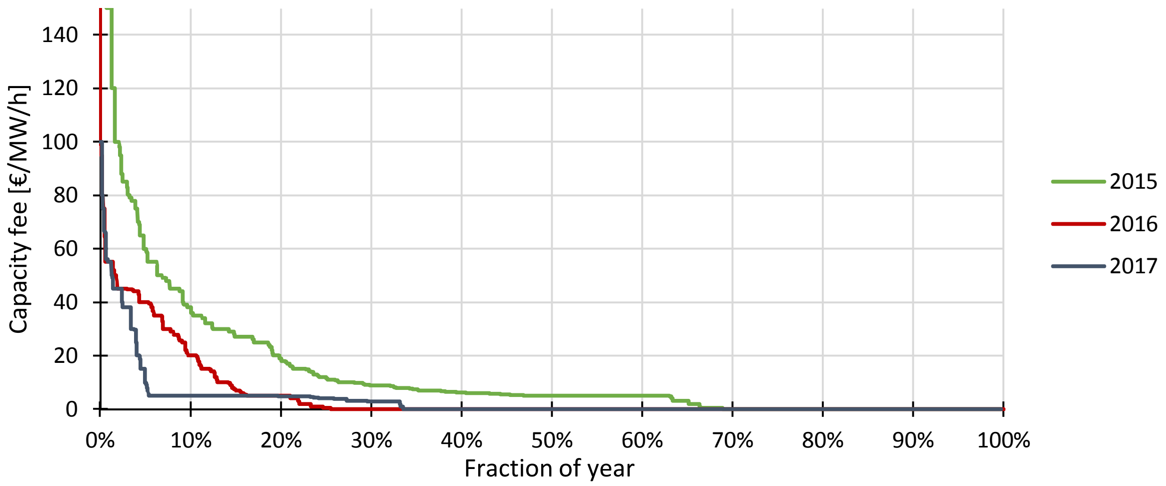


Figure 24 Duration curves of the hourly FCR-D capacity fees from 2015 – 2017. The highest peak in 2015 reaches 500 €/MW/h. (93)

The theoretical maximum revenue would have been 126 426 €/MW in 2015, 45 200 €/MW in 2016 and 29 676 €/MW in 2017. Again, the revenue is achieved by adding every hourly price of a year together.

4.4.2 Automatic Frequency Restoration Reserve

The automatic frequency restoration reserve functions based on the activation signals sent by Fingrid. The aFRR is used to return the frequency back to the nominal value of 50 Hz but also to release the activated frequency containment reserves for later frequency regulation. The full activation is required in two minutes after the signal. Fingrid procures aFRR reserves from the hourly markets and from other Nordic countries. (94) (95)

The reserve holder bids to hourly market before 18:00 (GMT+2) on the previous day. The minimum size of a bid is 5 MW, and the bid includes either or both lower and upper balancing power capacities and the corresponding prices [€/MW/h]. Any accepted aFRR offer receives a fee which is equal to the price of the bid of the holder, in contrast to the FCR reserves where every accepted offer receives the fee equal to the highest accepted bid price, as stated in chapter 4.4.1. (96) Figure 25 plots the average upper balancing power price and Figure 26 plots the lower.

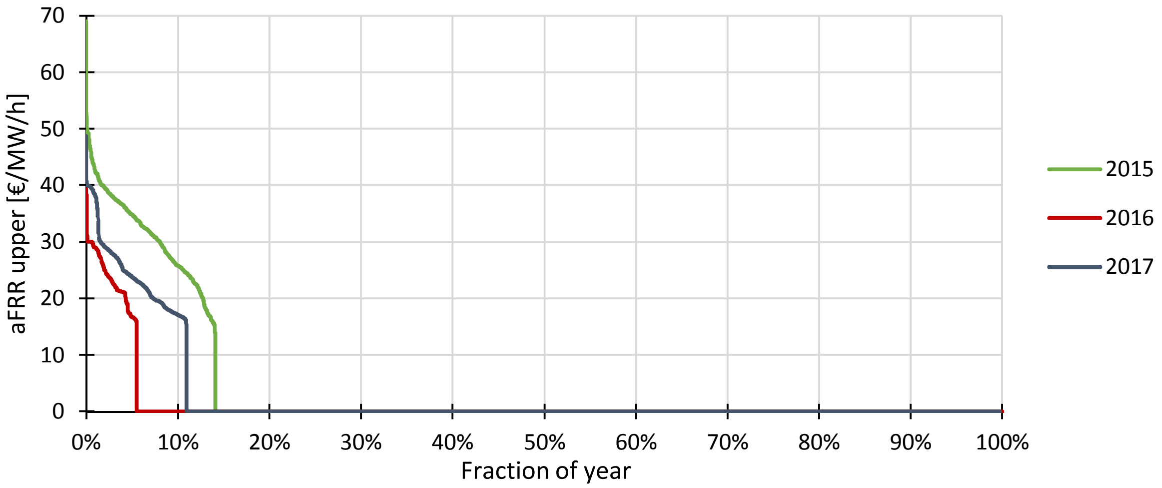


Figure 25 Duration curve of the average upper balancing power prices in the aFRR market. (97)

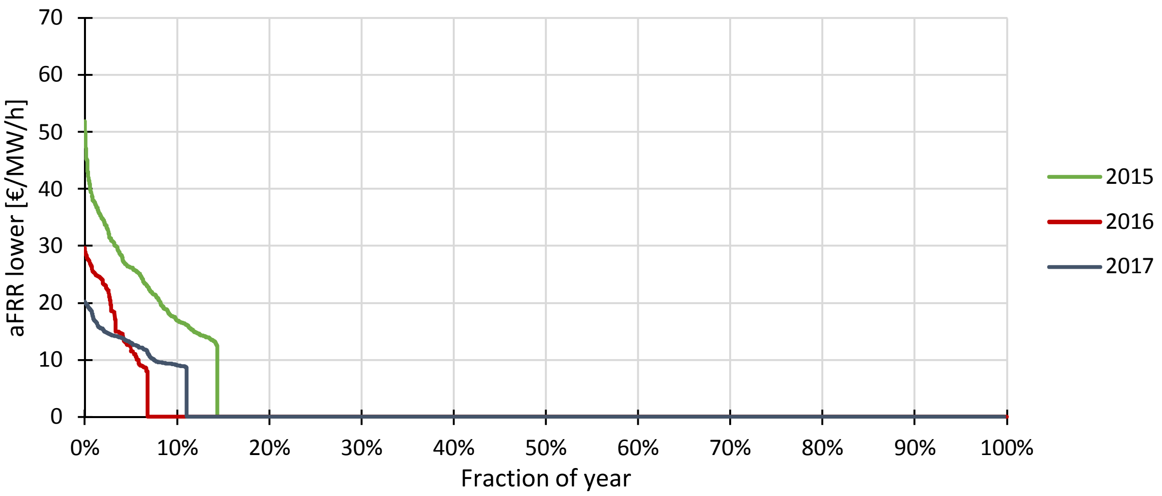


Figure 26 Duration curve of the average lower balancing power prices in the aFRR market. (98)

The total theoretical revenue gained from the aFRR upper prices would have been 38 452 €/MW in 2015, 11 401 €/MW in 2016 and 23 477 €/MW in 2017. The maximum revenue from the lower prices would have been 29 833 €/MW, 10 524 €/MW and 12 269 €/MW, respectively. The revenue potential is significantly lower in the aFRR than FCR, which is probably because aFRR is only procured during certain morning and evening hours which are informed in advance. Moreover, the price data used were average prices, not the highest accepted bid like in the FCR markets. The average prices describe the potential better in this case, however, as this market operates by the pay-as-bid principle instead of the marginal price.

4.4.3 Manual Frequency Restoration Reserve

mFRR is the abbreviation of the manual frequency restoration reserve. The concept contains the balancing energy and balancing capacity markets as well as Fingrid's own and leasing reserve power plants. Like the name states, Fingrid activates the offers manually. (73)

The balancing energy market is a marketplace for the regulating power. The market in Finland is part of the Nordic balancing market, and the bids given in other Nordic countries can be utilized in Finland if enough transmission capacity is available. (73) (99)

The bids must be given 45 min prior to the hour of operation, with a minimum capacity of 5 MW. The reserve holder can give bids to either or both of the upper and lower balancing power with the price [€/MWh] and capacity [MW]. The Nordic bids are sorted starting from lowest to highest price with the upper balancing power, and the lower starting from highest to lowest price, taking the transmission capacity into account. The price of the upper balancing power is equal to the highest bid which was used. Similarly, the price of the lower balancing power is equivalent to the lowest used bid. If the import capacity has been reached, only Finnish bids are accepted and the price is determined by the method above. For the energy procured by Fingrid, the reserve holder is paid according to the product of the amount of energy [MWh] and the upper balancing power price [€/MWh]. Correspondingly, Fingrid charges the reserve holder for the electricity sold based to the lower balancing power price. (99)

The balancing capacity markets ensure that Fingrid has necessary amount of reserves to cover the dimensioning fault, also during a maintenance of the reserve power plants. The reserve holder, whose capacity bid is accepted in the balancing capacity markets, is required to bid upper balancing energy to the balancing energy markets. In exchange, the holder receives a fee based on the capacity [MW] which the reserve holder has bid. (73)

The trading period is one calendar week (CET), and the capacity bids shall be given six days before the beginning of the week in the balancing capacity markets. A bid includes a capacity [MW/week] and a price [€/MW/week] and both are constant along the week. The minimum bid is 5 MW. Fingrid selects the capacity bids optimizing Fingrid's costs, the volume of bids and alternative sources of FRR. An accepted bid receives a fee based on the price of the bid, i.e. pay-as-bid. However, the price is multiplied by a factor which reflects the actual availability, i.e. fixity, of the reserve. The accepted bid obliges the reserve holder to give a bid to the balancing energy markets, in terms of MW and €/MWh, before 13:00 (CET) on the previous day. (100) The possible acquired energy fee from the balancing energy markets is taken into account, where the energy fee reduces the total capacity fee paid to the reserve holder. (100)

When Fingrid buys regulating power from the balancing energy markets, the bids given straight to the balancing energy market are used first as long as the physical constraints of the electricity system are met. The bids given via the balancing capacity markets are activated only if not enough bids are available in balancing energy markets. (99) (100) (101)

Figure 27 summarizes the two revenue gaining methods from the mFRR markets. The path on the left describes the procedure when utilizing only balancing energy markets, and the right one with both balancing energy and balancing capacity markets. The numbers given are examples, except the times mentioned.

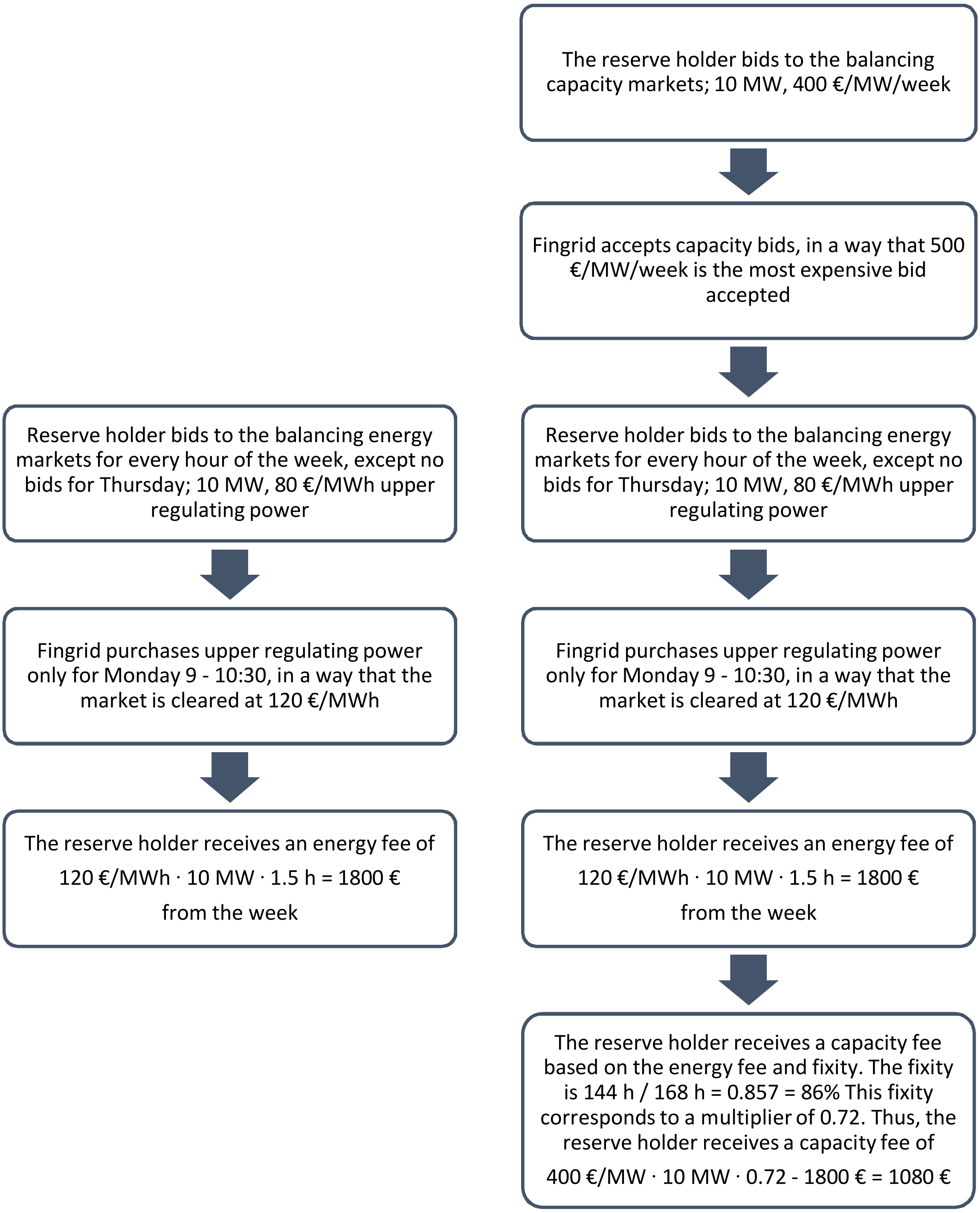


Figure 27 The methods of gaining revenue in the mFRR market. The left path describes a situation where the EES utilizes only balancing energy markets. The right pathway combines both balancing energy and balancing capacity markets. The numbers given are examples, except the times mentioned. (100)

To approximate the suitability of the balancing markets, the energy and capacity markets must be combined. Figure 28 plots the available balancing capacity market data from 2016 and 2017. Year 2015 is not included because the balancing capacity market started in 2016. The prices are averaged [€/MW/week].

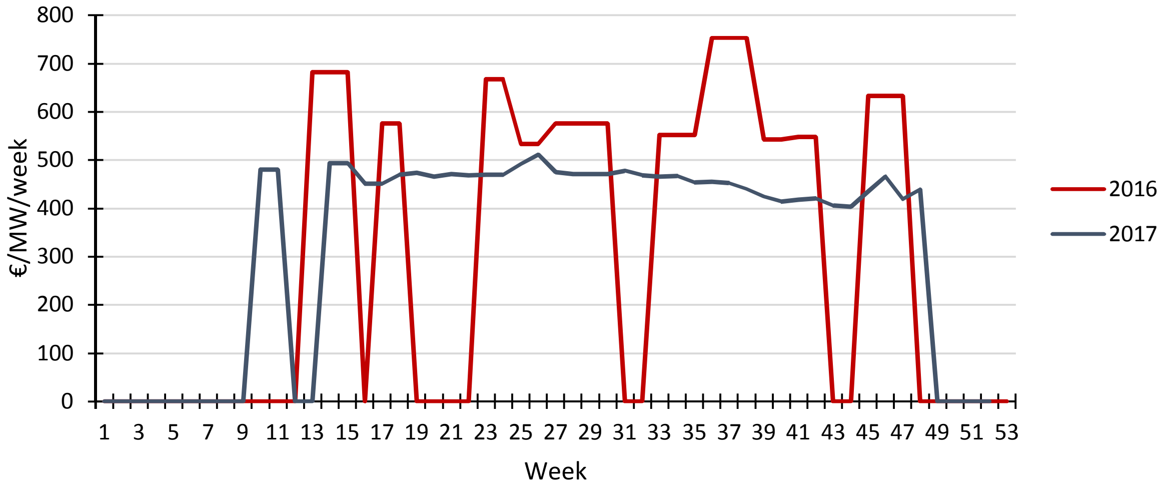


Figure 28 The average balancing capacity market prices in 2016 and 2017 as €/MW per week. (102)

The theoretical maximum capacity fee would have been 15 907 €/MW in 2016 and 16 965 €/MW in 2017. The fee is obtained by adding every weekly price of a year together.

When it comes to the balancing energy markets, the determination is more complex. In the review period, Fingrid procured upper regulating energy [MWh/h] as (Figure 29):

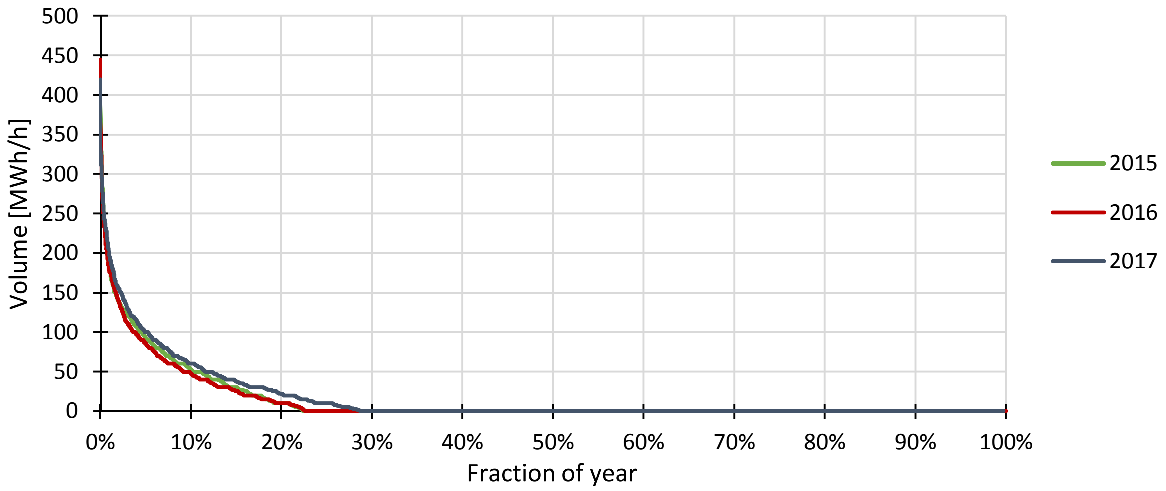


Figure 29 The volume of balancing energy procured by Fingrid. The curve of 2015 is almost identical to the one of 2016. (103)

Based on the data, Fingrid did not procure electricity from the balancing markets for over 6000 hours in each year. This can be compared to the price data in Figure 30. The highest peak in the 2016 data reaches 3000 €/MWh.

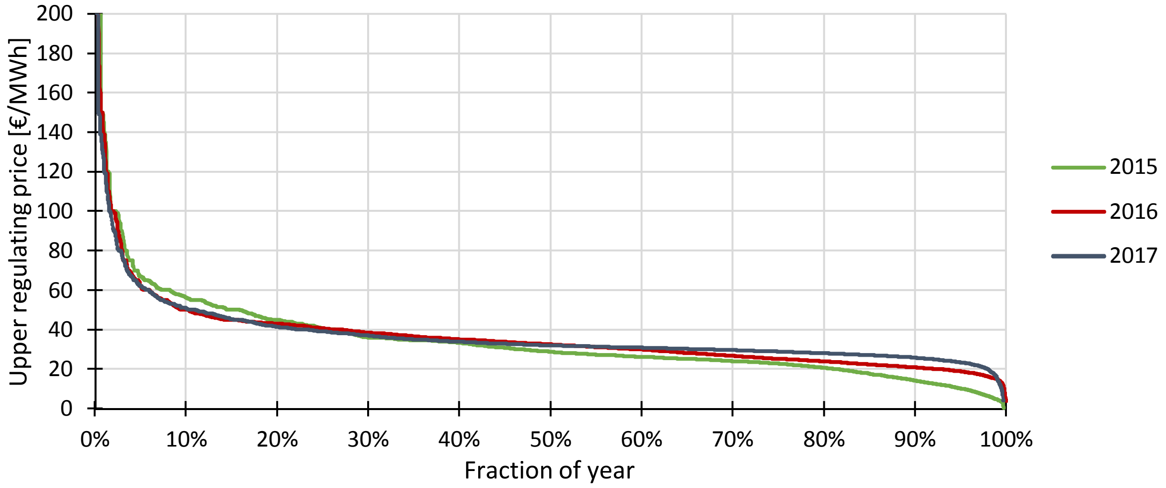


Figure 30 Upper regulating price in the balancing energy markets. The highest peak in 2015 reaches 2000 €/MWh, 3000 €/MWh in 2016 and 699 €/MWh in 2017. (104)

The figure suggests that the prices seem to be below 40 €/MWh most of the year. Filtering out the hours when Fingrid did not procure electricity reveals the true potential for the revenue gain (Figure 31).

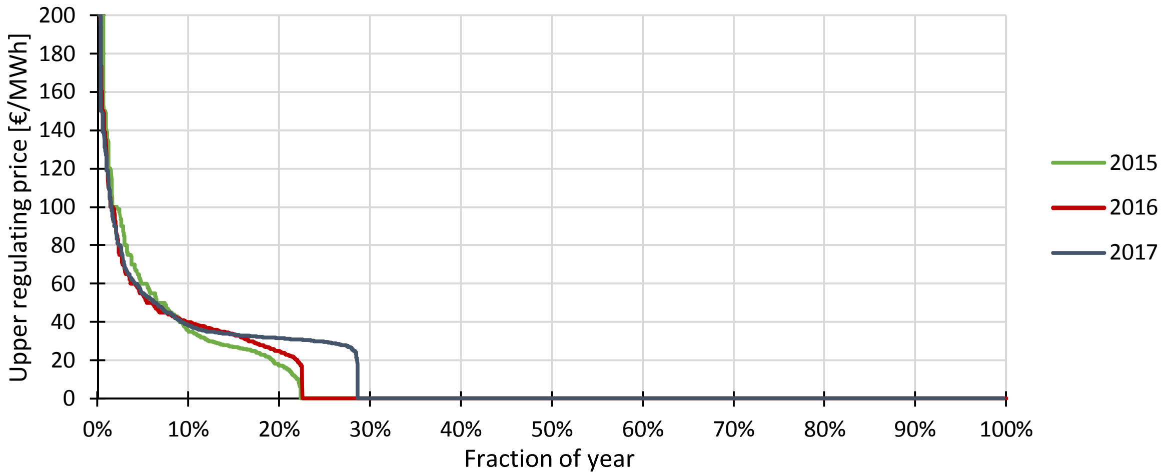


Figure 31 Upper regulating price in the balancing energy markets during the hours when Fingrid procured upper regulating power (103) (104)

The maximum theoretical revenue would have been 103 992 €/MW in 2015, 101 356 €/MW in 2016 and 116 090 €/MW in 2017. The revenue is achieved by adding every €/MWh price of the year together and multiplying with one hour. In case of an EES, the value seems unrealistic. This value would require full operation during each hour of the procured balancing power. If the high prices occur in consecutive hours, the EES would not be able to charge between the hours of discharge, failing to discharge during the next hours. The data reveals that the problem is real: Fingrid procured upper balancing power in 3.5-hour periods on average in 2015 – 2017 (103). In other words, upper balancing power was procured for 3.5 consecutive hours on average on times when upper balancing power was procured.

Another issue is that currently, the gains from the balancing energy market reduce the balancing capacity earnings. If the holder earns energy fee equal or more to the capacity fee, the capacity fee is reduced to zero. (100) In addition to that, all the electricity charged would need to be purchased, comparing to the FCR-N where a portion of the charged electricity comes from the operation itself at times when the frequency is above 50.05 Hz. This further limits the current potential of the Li-ion ESS in the mFRR markets.

4.5 Summary of marketplaces

Table 20 summarizes the key data from different electricity marketplaces in Finland, using the 2015 – 2017 review. The volume units differ between marketplaces in the table.

Table 20 Summary of different electricity marketplaces in Finland in 2015 – 2017.

Marketplace	Maximum theoretical revenue per year [€/MW]	Volume	Volume Unit
FCR-N hourly	148 000 – 196 000	10 – 34	MW/h on average
FCR-N yearly	114 000 – 153 000	55 – 89	MW/year
FCR-D hourly	30 000 – 126 000	5 – 12	MW/h on average
FCR-D yearly	25 000 – 41 000	298 – 456	MW/year
aFRR, up	11 000 – 38 000 on average	5000 – 16 000 1.2 – 5	MWh/year MW/h on average
aFRR, down	11 000 – 30 000 on average	–3200 to –13 000 1.8 – 5	MWh/year MW/h on average
mFRR, up	101 000 – 116 000	116 – 147	GWh/year
mFRR, down	–	–174 to –201	GWh/year
Intraday market	< 80 €/MWh, cycle	710 – 1040 780 – 920	GWh/year (buy) GWh/year (sell)
Day-ahead market	20 – 25 €/MWh, cycle	55 – 60 42 – 46	TWh/year (buy) TWh/year (sell)

Based on the maximum revenue analysis, the FCR-N is the most attractive marketplace for the Li-ion EES operation. The mFRR might also provide rather high revenues, but as stated in chapter 4.4.3, the energy volumes in the mFRR might probably be too high for the EES.

The technical operation mechanisms of the FCR-N hourly and yearly markets are similar. However, currently the hourly market seems to yield higher revenues. Thus, the FCR-N hourly market is used as a basis for the profitability calculations.

4.6 Taxation, transmission and distribution costs

The current legislation does not acknowledge electricity storage. Thus, when charging a battery from the grid, the storage is regarded as a consumer of electricity and is required to pay for the transmission, distribution (T&D) and the taxes in addition to the energy price. When the storage feeds the stored electricity back to the grid, the final consumer of the electricity has to pay the taxes and T&D cost again. Thus, the electricity is taxed twice.

Currently, the taxation of electricity is as follows: 7.03 €/MWh for industry, data centers and greenhouses and 22.53 €/MWh for the rest, including the stockpile fee of 0.13 €/MWh. A value-added tax (VAT) of 24% is also added to the energy tax as well as to the energy and the T&D-costs. (105) The VAT can be deducted in the taxation only if the electricity is bought for the purpose of a taxable business and if the buyer, in this case the EES holder, and the seller, in this case the party from which the electricity is bought, are VAT taxpayers. (106) Selling reserves to Fingrid is VAT liable so the reserve holder is a VAT taxpayer (87). Hence, the reserve holder can deduct the VAT from the electricity bought and charged, and thus it does not affect the profitability of the EES. As a result, the EES is obliged to pay 22.53 €/MWh for the tax and the stockpile fee from the electricity charged.

The distribution costs vary across the country depending on the distribution system operator (DSO) and the contract. For this thesis, the weighted average prices are used to establish an overview of the costs around Finland as the prices per kWh generally decrease with higher consumption. Figure 32 plots total electricity prices, T&D-costs and taxes for different enterprise customers. Table 21 explains the classification used in the figure.

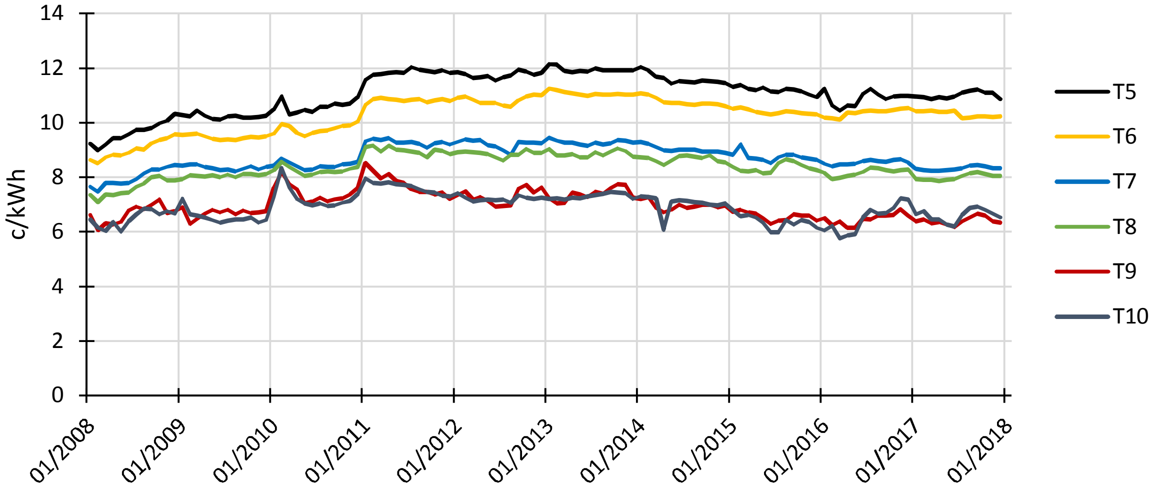


Figure 32 The weighted average total electricity cost for enterprises with different sizes. (107)

Table 21 Classification of the different enterprise consumers of electricity. (107)

Class	T5	T6	T7	T8	T9	T10
Yearly electricity consumption [MWh]	< 20	20 – 499	500 – 1999	2000 – 19 999	20 000 – 69 999	70 000 – 150 000

When operating as an FCR reserve, all the electricity charged has to carry distribution costs and taxes, whether it is charging due to the normal operation as the reserve or buying additional electricity from the other marketplaces, e.g. intraday markets (108). Chapter 5.2.1 estimates the amount of the electricity charged to estimate the total costs of electricity.

4.7 Weighted average cost of capital

The weighted average cost of capital (WACC) must also be estimated to evaluate the profitability of the investment. The WACC is a parameter taking account the financing of the project (debt to equity ratio), cost of equity and debt, risk premiums and risk-free interest rates.

The scope of this thesis does not allow a comprehensive determination of the WACC. Hence, a few sources are cited to estimate the WACC for the Li-ion EES. They give an overview of the WACCs in the energy industry providing a fine value for the profitability estimation.

Both Jülch and Zakeri & Syri used a WACC of 8% when levelizing the cash flows of the battery investments (17) (20). Deloitte and Bloomberg estimated 5.8% and 5.2% WACCs for the European electricity sector in 2016, and 6.1% and 5.6% in 2015. The renewable sector was estimated having WACCs of 6.5% and 4.5% in 2016. (109) The small values of WACC reflect the problems in the sector: the price of electricity is low and thus the profitability margins are low. Moreover, many European countries have implemented subsidies for the RES guaranteeing rather safe investments for the RES investors. However, the Li-ion EES technologies are relatively new compared to wind or solar power justifying a higher WACC in terms of the higher technology risk. Thus, a WACC of 7% is used for the profitability calculations.

4.8 Energy Aid

The Ministry of Economic Affairs and Employment (MEAE) can grant an energy aid which aims to promote *the introduction and market entry of a new energy technology* (110). The problem for the EES technologies is that currently the aid is not granted for EES projects unless the EES is a part of a larger whole (111). What is more, the projects which qualify for the aid have installed system costs of usually below 100 000 € which is a rather small amount for a grid-scale EES (112).

Fortum battery in Järvenpää received a 30% subsidy for the investment cost as the project qualified to a key energy project (59). However, the MEAE considers carefully which projects receive the aid, and thus the execution of a grid-scale EES should not rely on the key energy project aid (112). Hence, the energy aid in not directly considered in the profitability calculations in the next chapter, but the sensitivity analysis of the installed system cost allows to estimate the effect of the aid.

5 Profitability of the Li-ion EES

An economic analysis is made on the profitability of Li-ion storage in Finland based on the data presented in the previous chapters 3 and 4. The profitability is estimated with levelized cost of storage (LCOS) and net present value (NPV) on the 2018 markets. Their sensitivities to various parameters are evaluated. The selection of a Li-ion EES with a suitable P/E ratio is also discussed. The NPV sensitivity analysis is more thorough due to the complexity compared to the calculation of the LCOS. The NPV is calculated for the FCR-N market and LCOS is compared to the day-ahead and intraday markets.

5.1 Levelized cost of storage

The LCOS is a figure which describes the cost of storage excluding the charging cost. Thus, the LCOS gives the needed difference between the cost of charged electricity and the price of sold electricity per kWh for a profitable EES investment, making it a helpful tool to estimate the energy arbitrage potential. It is given as

$$LCOS = \frac{CAPEX + \sum_{t=1}^{n} \frac{A_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{1}$$

where A_t refers to the annual costs of the system and E_t to the annual energy output of the system. n is the lifetime and r the discount rate. (20)

5.1.1 Base Values

Due to the trend of daily cycles of low and high prices of electricity, 300 cycles per year is used. With a cycle life of 3000 (chapter 3.2.2), this yields a life time of 10 years which fits to the approximated calendar life (chapter 3.2.3). The LTO's life time is limited by the calendar life because it could supply 30 years with 300 cycles based on the cycle life. Table 22 summarizes the input data from chapter 3.

Table 22 The values used for the LCOS estimation.

Attribute	Value	Unit
Installed system cost (LMO, NMC, LFP, NCA)	1 000 000	€/MWh
Installed system cost (LTO)	1 500 000	€/MWh
Cycle life (LMO, NMC, LFP, NCA)	3000	cycles
Cycle life (LTO)	9000	cycles
Cycles per year	300	cycles
Calendar life (LMO, NMC, LFP, NCA)	10	years
Calendar life (LTO)	15	years
RTE	90	%
O&M costs	8000	€/MW-year
P/E ratio	1	
Discount rate	7	%

The values yield an LCOS for LMO, NMC, LFP and NCA of

$$LCOS = \frac{1\,000\,000\,\frac{€}{MWh} + \sum_{t=1}^{10} \frac{8000\,\frac{€}{MW} * 1\,\frac{MW}{MWh}}{1.07^t}}{\sum_{t=1}^{10} \frac{1\,MWh * 300 * 0.9}{1.07^t}} = 556.95\,\frac{€}{MWh} \quad (2)$$

and for the LTO

$$LCOS = \frac{1\,500\,000\,\frac{€}{MWh} + \sum_{t=1}^{15} \frac{8000\,\frac{€}{MW} * 1\,\frac{MW}{MWh}}{1.07^t}}{\sum_{t=1}^{15} \frac{1\,MWh * 300 * 0.9}{1.07^t}} = 639.60\,\frac{€}{MWh} \quad (3)$$

making the Li-ion EES unsuitable for energy arbitrage in Finland. Moreover, with the requirement of paying distribution costs and taxes, the value is far too high for energy arbitrage.

5.1.2 Levelized cost of storage sensitivity analysis

The sensitivity is estimated with varying the installed system cost, cycle life and power-to-energy ratio. The installed system cost is changed based on the projection in chapter 3.3. This way, the future LCOS can also be estimated (Figure 33):

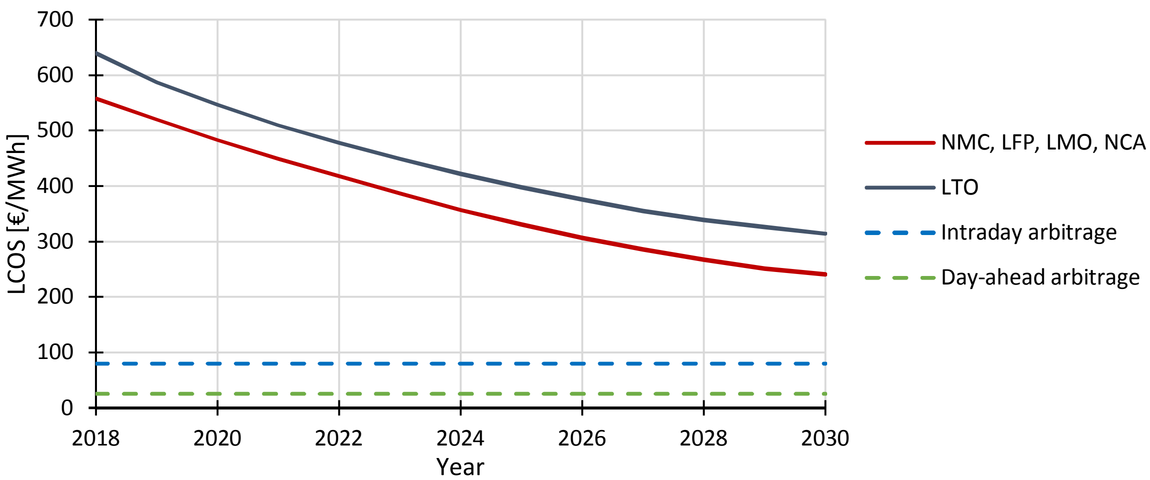


Figure 33 The projected LCOS development of the Li-ion EES in the near future compared to the estimated energy arbitrage potential of energy markets.

The figure shows that the Li-ion EES will probably not be widely used for energy arbitrage solutions during the next decade. The LCOS is exceedingly high compared to the arbitrage potential. Increasing the range of the installed system cost shows the relation between the cost and the LCOS (Figure 34):

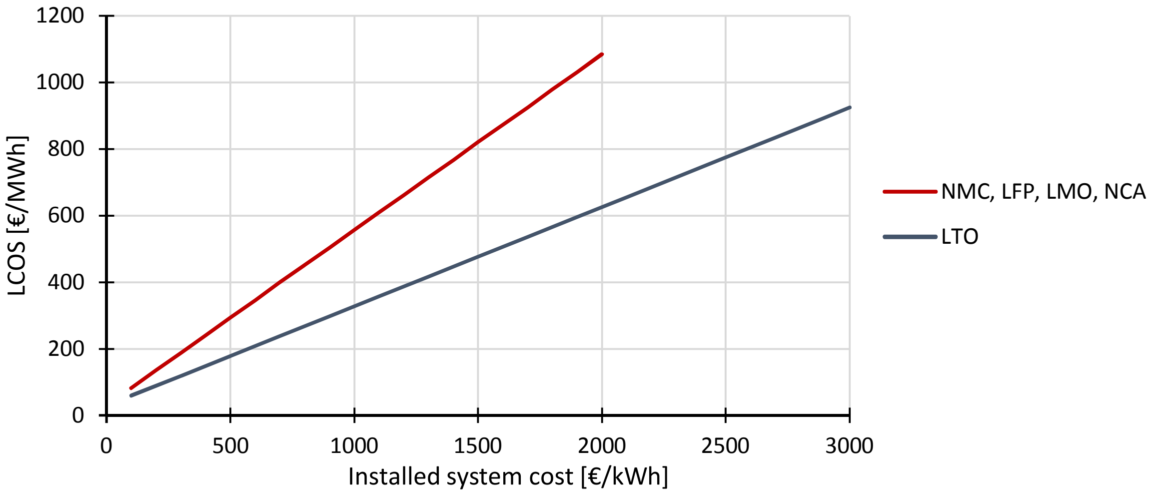


Figure 34 The sensitivity of the LCOS to the installed system cost.

Even the lowest range of installed system cost yields an LCOS of over 60 €/MWh. The value is slightly high compared to the day-ahead arbitrage potential, but quite similar to the maximum potential of intraday arbitrage. However, predicting the highest and lowest intraday price is problematic, as it is like predicting a stock market and reaching a 60 €/MWh energy arbitrage during every day seems unlikely based on chapter 4.3. Thus, even with the lowest installed system cost, the energy arbitrage suitability seems poor. However, Figure 35 suggests that reducing the P/E ratio would also improve the energy arbitrage potential.

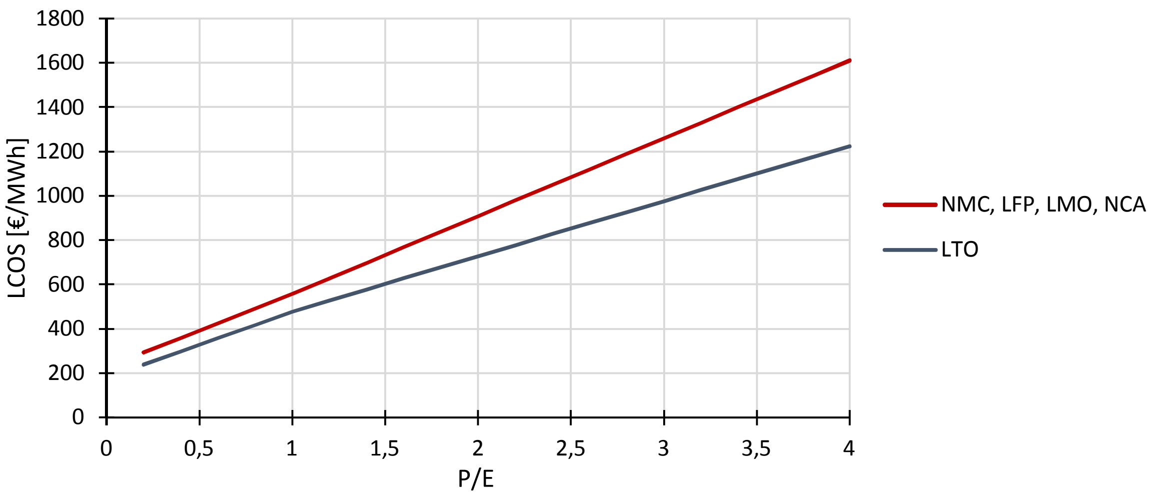


Figure 35 The sensitivity of the LCOS to power-to-energy ratio.

The figure suggests that energy arbitrage benefits from low P/E ratios. This is reasonable because energy arbitrage is related to energy and its price, not to power. However, one must note that if the P/E ratio is low, the storage cannot be charged and discharged fast. For example, four hours would be required to charge the storage entirely and another four to fully discharge it if the P/E ratio was only 0.25. The problem is that usually the peak prices last for one hour only as stated in chapter 4.2.

Finally, the sensitivity to cycle life is estimated in Figure 36. The figure does not take calendar life into account.

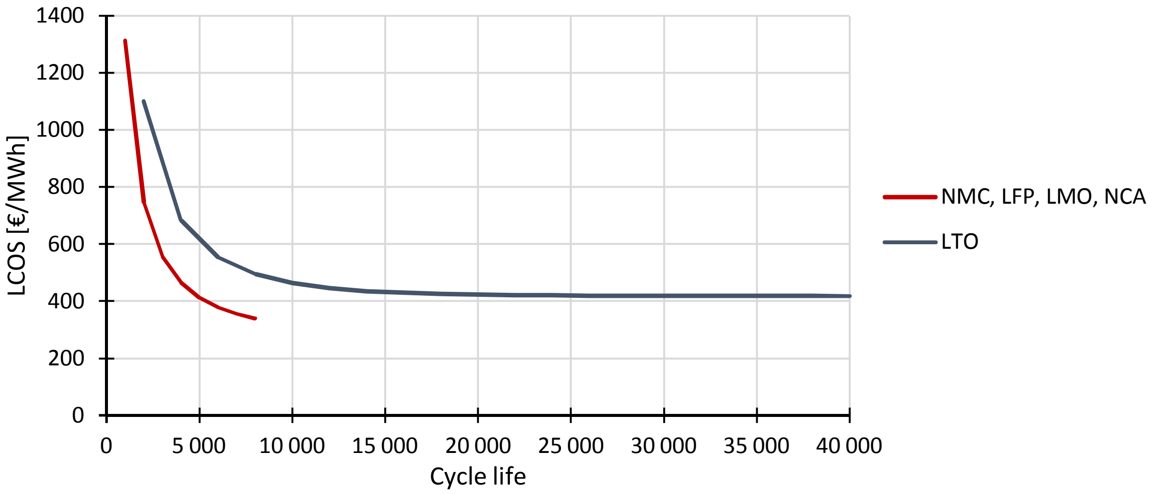


Figure 36 The sensitivity of the LCOS to cycle life.

Clearly, at about 10 000 cycles the LCOS stalls. This is because the cash flow would occur so far in the future. Moreover, it would take 33 years with 300 cycles per year to reach 10 000 cycles, which is not possible in terms of calendar life. Thus, the LCOS sensitivity supports the statement that the Li-ion EES will not be widely used in energy arbitrage applications during the next decade in Finland.

5.2 Net present value

NPV is another tool of estimating profitability. In contrast to the LCOS, the local market data is required. NPV is expressed as

$$NPV = CAPEX + \sum_{t=1}^{n} \frac{C_t}{(1+r)^t} \tag{4}$$

in which C_t is the yearly net cash flow.

NPV is calculated only for the FCR-N application as the previous chapter showed that energy arbitrage potential is poor. Moreover, other reserve markets were found to possess lower revenue potential (chapter 4.4).

First, a base setup and calculation parameters are used to establish a basis for the sensitivity analysis. The values are similar to the ones used in the LCOS calculation, however, now the approximation of the net cash flow is also used.

5.2.1 The net cash flow from the electricity markets

As the FCR-N has the highest possible potential, the total net yearly cash flow is estimated based on that. The gird frequency data of 2015 – 2017 is used as a basis of the estimation because the FCR-N reserves operate as a function of the frequency, as stated in chapter 4.4.1.

The full potential of the storage is achieved with an automatic operation, meaning that the number of working hours used to the operate the EES should be minimized. For example, if the storage holder bids in the FCR-N for the entire year with the same price, the storage holder would not need to make additional bids or estimations during the year. However, the problem is that the frequency of the grid is not symmetrical around 50 Hz. Plotting a duration curve of the frequency data of the different years reveals that most of the year the frequency is below 50 Hz (Figure 37). (113) For an EES, this means that the storage cannot independently operate in the FCR-N if the holder wants to participate in every hour of the year. Thus, the holder has to purchase additional electricity. In other words, the EES has to be discharged when the frequency is below 49.95 Hz and charged when it is over 50.05 Hz. If the frequency is below 49.95 Hz most time of the year, the storage needs to discharge more electricity than charge, which is not possible, and the difference must be matched by buying additional electricity.

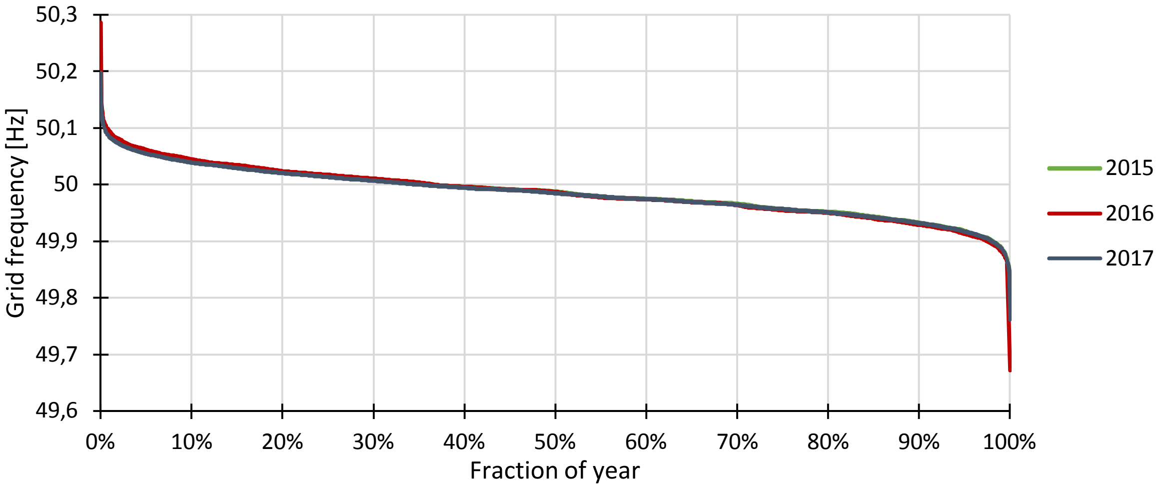


Figure 37 The duration curves of grid frequency in 2015 – 2017. The curves are almost identical.

Due to the characteristics of the frequency, a coarse model is run to estimate how much electricity must be bought and charged during a year in order to operate for the entire year in the FCR-N market. The energy flow E_i [MWh] from the battery at a specific period of time is given as

$$E_i = P_i(f)t_i \tag{5}$$

where $P_i(f)$, a function of the grid frequency, is the constant power output of the EES during the time period with a length t_i [h]. Based on the current rules of the FCR-N markets, the power is given as

$$P_i(f) = 1, f \in [0, 49.9] \tag{6}$$

$$P_i(f) = -\frac{1}{0.05}f + \frac{49.9}{0.05} + 1, f \in]49.9, 49.95[\tag{7}$$

$$P_i(f) = 0, f \in [49.95, 50.05] \tag{8}$$

$$P_i(f) = -\frac{1}{0.05}f + \frac{50.1}{0.05} - 1, f \in]50.05, 50.1[\quad (9)$$

$$P_i(f) = -1, f \in [50.1, \infty[\quad (10)$$

In other words, the battery discharges with full power when f < 49.9 Hz. The output reduces linearly when the frequency increases towards 49.95 Hz. Between 49.95 – 50.05 Hz the EES does not operate. Correspondingly, the battery starts to charge itself with the frequencies over 50.05 Hz, with the charging power increasing linearly before 50.1 Hz. At 50.1 Hz or more, the EES charges with full power.

With the power outputs, the energy content of the battery in the end of the year is given as

$$E = E_{initial} + \sum_{i=1}^{n} -P_i(f)t_i \quad (11)$$

For this model, the $E_{initial}$ is 0. The EES used in the model is infinitely large [MWh] with the rated charging and discharging power of 1 MW. A negative E refers to a situation where the EES has discharged more energy than charged. n is the amount of time steps in the frequency data. One time step is 3 min, except the summer data of 2017 has partly 5 min time steps. For 2015, n = 175 175, for 2016 n = 175 658 and for 2017 n = 154 746. The entire year has about 365 · 24 · 60 / 3 = 175 200 time steps of 3 min, and 2016 was a leap year having about 175 680 time steps of 3 min. Thus, the accuracy is quite good.

For example, on 1 Jan 2015, 0:00, the frequency was 50.105995 Hz. Thus, based on the model, the EES would charge with full power for the next three minutes, charging 0.05 MWh of energy (1 MW · (3/60) h = 0.05 MWh).

A frequency of 50.000 Hz is assumed for the missing data. The assumption does not cause large errors because the number of missing data points is small in comparison to the quantity of time steps. The largest gap in the data was 28 May 2017, 10:00 – 29 May 2017, 7:20.

Figure 38 shows the cumulative net energy that would have been charged or discharged with the current FCR-N rules in the years 2015 – 2017. For example, the value of –530 MWh means that the EES would have had discharged 530 MWh more energy than charged during 2017. This additional energy should had been bought from other electricity marketplaces, for example from day-ahead or intraday markets.

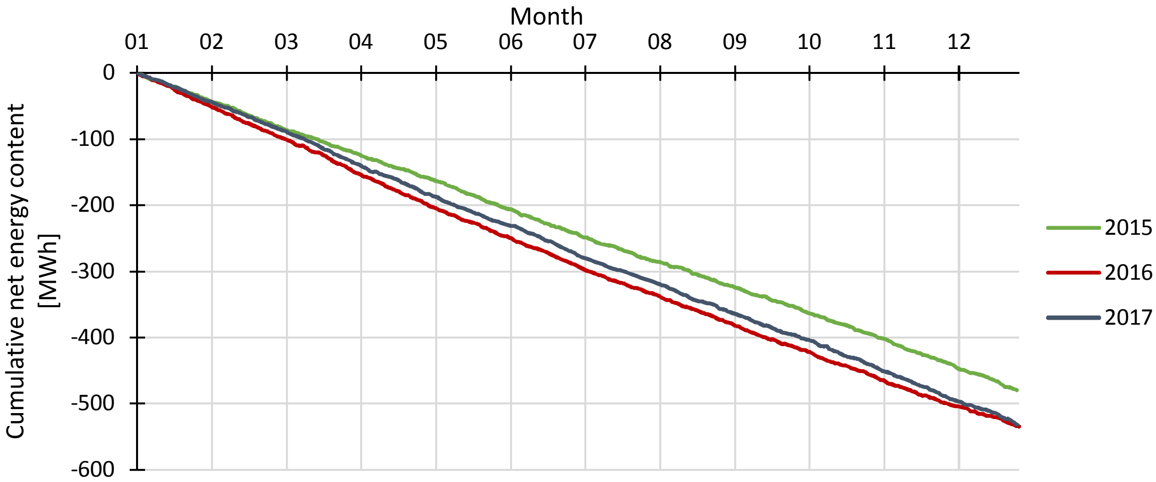


Figure 38 The cumulative amount of additional energy that would have been needed to discharge (+) or charge (-) along the year in order to be able to operate the entire year as an FCR-N reserve.

Based on the graph, the EES would have needed to buy about 480 – 530 MWh of additional electricity during one year. The average is slightly over 500 MWh. However, the required energy bought slightly decreases when taking a period of two-week maintenance into account. Thus, it is estimated the reserve holder must buy 500 MWh of electricity during one full year of operation of 1 MW reserve. Table 23 presents the other key results of the model.

Table 23 The summary of the model.

Year	2015	2016	2017	Unit
Energy Charged	233	279	196	MWh/year
Energy Discharged	713	814	728	MWh/year
Additional energy bought	480	535	532	MWh/year

The table indicates that 750 MWh is discharged yearly from the storage on average. Thus, the storage would have needed to charge at least the same amount of electricity. Hence, comparing with the total electricity cost graph in Table 21 in chapter 4.6, the EES seems to belong to class T7. The average total price of electricity bought in T7 has been 8.54 c/kWh or ~85 €/MWh during the years 2015 – 2017. As the average hourly day-ahead price has been 32 €/MWh in 2015 – 2017, the distribution costs and taxes have accounted for about 53 €/MWh (80).

To optimize the costs of the operation, the reserve holder should consider when to charge the storage. The optimization problem would be complex as the holder would have difficulties in operating on the day-ahead market and the FCR-N market on the same time. This is because the holder would not be able to charge from the day-ahead market while the frequency is below 49.95 Hz. The holder could modify the operation in a way that during an hour, the EES would always charge with full power when the frequency is above 50 Hz, using electricity from the day ahead markets between 50 – 50.05 Hz and the FCR-N markets when frequency is more than 50.05 Hz. This would be difficult in practice, as the holder cannot predict how much electricity they would need to buy from the day-ahead market and which portion would be charged automatically from the FCR-N markets because the frequency cannot be predicted that precisely.

The current FCR-N market allows an unsymmetrical dead band for the reserve, meaning that an EES could, for example, discharge when $f < 49.95$ but charge already when $f > 50.01$ (114). This would decrease the amount the electricity that should be bought from the day-ahead markets. However, if it would be useful to operate in such a way, other EES holders might start to operate similarly in the future as well increasing the amount of time when $f < 50$ Hz. If Fingrid considered this as a problem, it would probably change the FCR-N regulations. Thus, the operation and profitability of the EES should not rely on the operation plan described above.

5.2.2 Base values

Based on the simulation run in chapter 5.2.1, the operation as an FCR-N would require quite frequent cycling. This causes uncertainties because the authors cited in the cycle life estimation in chapter 3.2.2 have presented the cycle life value in full cycles. However, some authors had presented cycle equivalents, meaning with low depth of discharges, the absolute number of cycle increases while the energy stored and discharged remains the same. Simplified, an EES able to deliver 3000 full cycle equivalents, could operate 3000 cycles with a DoD of 100% and 6000 cycles with a DoD of 50%. Research conducted by Pearre & Swan also suggested that the cycle life in full cycle equivalents would remain quite stable while changing the depth of discharge (19). Thus, the full cycle equivalent approach is the method for approximation is this thesis.

The simulation in the previous chapter 5.2.1 modelled how the EES would operate as an FCR-N reserve. It measured how much additional energy would have needed to be bought in order to successfully operate as the reserve. The model also allowed to estimate how much energy flows through the storage during a year, which is used to approximate the cycle equivalents during a year. If the energy capacity of the storage is 1 MWh, 100 MWh of yearly discharge would require 100 full cycles. As discovered in Table 23, the EES would need to discharge about 750 MWh. Based on that, a value 750 full cycle equivalents per year is a good estimation for a 1 MW/1 MWh system. On average, this would mean about two full cycle equivalents per day.

When it comes to the net cash flow, the additional electricity is bought at 85 €/MWh, where the cost of energy accounts for 32 €/MWh (chapter 5.2.1). Thus, the electricity that is charged during the operation as an FCR-N reserve carries 53 €/MWh of distribution costs and tax, but no energy cost. Thus, the base values used for the NPV calculations are (Table 24):

Table 24 The base values used for the NPV calculations.

Attribute	Value	Unit
Installed system cost (LMO, NMC, LFP, NCA)	1 000 000	€/MWh
Installed system cost (LTO)	1 500 000	€/MWh
Cycle life (LMO, NMC, LFP, NCA)	3000	cycles
Cycle life (LTO)	9000	cycles
Revenue from the FCR-N	175 088	€
Cost of electricity (energy)	32	€/MWh
Distribution and taxation	53	€/MWh
Electricity discharged	750	MWh/year
Additional electricity bought	500	MWh/year
Additional electricity bought with efficiency	583	MWh/year

Full cycle equivalents	750	1/year
Hours in maintenance	336	hours
Calendar life	10 – 15	years
RTE	90	%
O&M costs	8000	€/MW-year
P/E ratio	1	
Discount rate	7	%

One must note the round-trip efficiency of 90%. In the calculations, RTE is taken into account on the charging side of the EES to simplify the calculations: When 1 MW is drawn from the grid, the EES is charged with a power of 0.9 MW. As stated earlier in chapter 5.2.1, the EES must buy 500 MWh additional electricity during the operation as an FCR-N reserve while 250 MWh is charged during the operation. If the efficiency is taken into account, only 250 MWh · 0.9 = 225 MWh is charged in the FCR-N operation while 25 MWh is lost. Thus, the amount of electricity bought equals to

$$\frac{500\ MWh + 25\ MWh}{0.9} = 583\ MWh \tag{12}$$

It is estimated, that the storage cannot attend the FCR-N markets for two weeks during the year. On average, the yearly total maximum revenue was 175 088 € in 2015 – 2017, based on the data presented in chapter 4.4.1. The absolute yearly revenue can be estimated with the approximated effect of the two-week period of maintenance or other unavailability (336 hours):

$$175\ 088\ € * \frac{8760 - 336}{8760} = 168\ 372\ € \tag{13}$$

Thus, the net cash flow for the calculation of NPV for a 1MW/1MWh system is given as:

$$\begin{aligned} C_t &= 168\ 372€ - 8000\ € - 583\ MWh * 85\frac{€}{MWh} - 250\ MWh * 53\frac{€}{MWh} \\ &= 97\ 567\ € \end{aligned} \tag{14}$$

Comparing the cycle life, yearly cycle life equivalents and the calendar life, LFP, NCM, NCA or LMO batteries operate for 3000/750 = 4 years and LTO for 9000/750 = 12 years. Thus, the base NPV for NMC, LFP, LMO or NCA system is given as

$$NPV = -1\ 000\ 000\ € + \sum_{t=1}^{4} \frac{99\ 195\ €}{(1+0.07)^t} = -669\ 519\ € \approx -670\ 000\ € \tag{15}$$

and for the LTO:

$$NPV = -1\ 500\ 000\ € + \sum_{t=1}^{12} \frac{99\ 195\ €}{(1+0.07)^t} = -725\ 054\ € \approx -730\ 000\ € \tag{16}$$

The negative NPVs suggest that the investment would be highly unprofitable even though the Li-ion EES is technically suitable to the FCR-N. The result implies that Fingrid is able to supply the necessary amount of FCR with other reserve technologies.

5.3 Net present value sensitivity analysis

The sensitivity is analyzed with the key parameters of the Li-ion EES. Even though the NPVs were remarkably low, a range of uncertainties were involved. Thus, various techno-economic variables are altered to estimate the sensitivity. The effects of taxation and distribution costs are also studied. The sensitivity analyses can also help to forecast the future performance of the Li-ion EES.

5.3.1 Installed system cost

The installed system cost was reviewed in chapter 3.3. Figure 39 reveals that the profitable investments are not expected before the installed system cost has dropped to about 300 – 400 €/kWh. The variable used is the installed system cost.

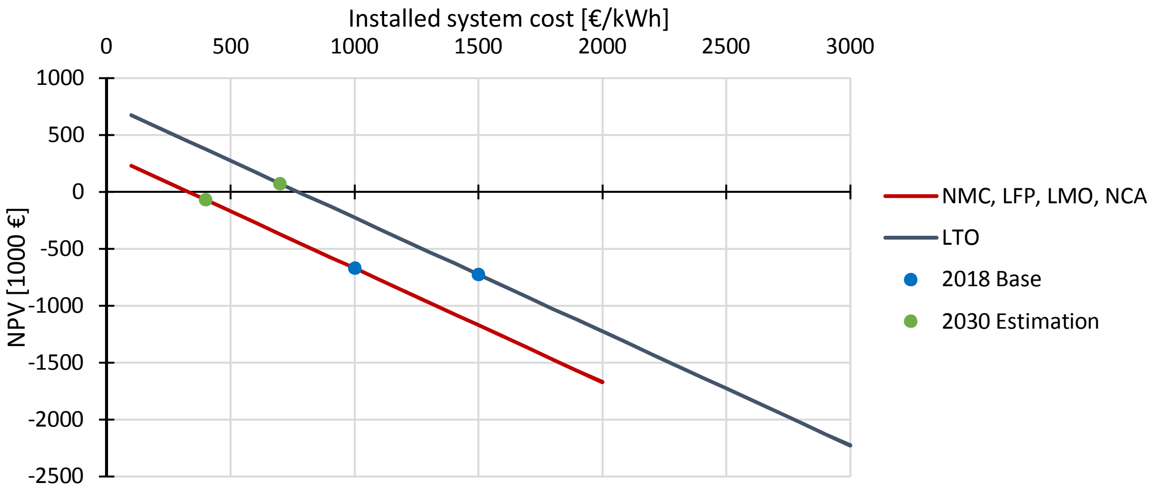


Figure 39 The sensitivity of the NPV to the installed system cost.

The dots present the NPV with the projected installed system costs in 2030 based on Figure 14 in chapter 3.3, in addition to the 2018 base value. The installed system cost sensitivity can be related to the cost development, presented in Figure 14, so the future NPV development can be forecasted (Figure 40).

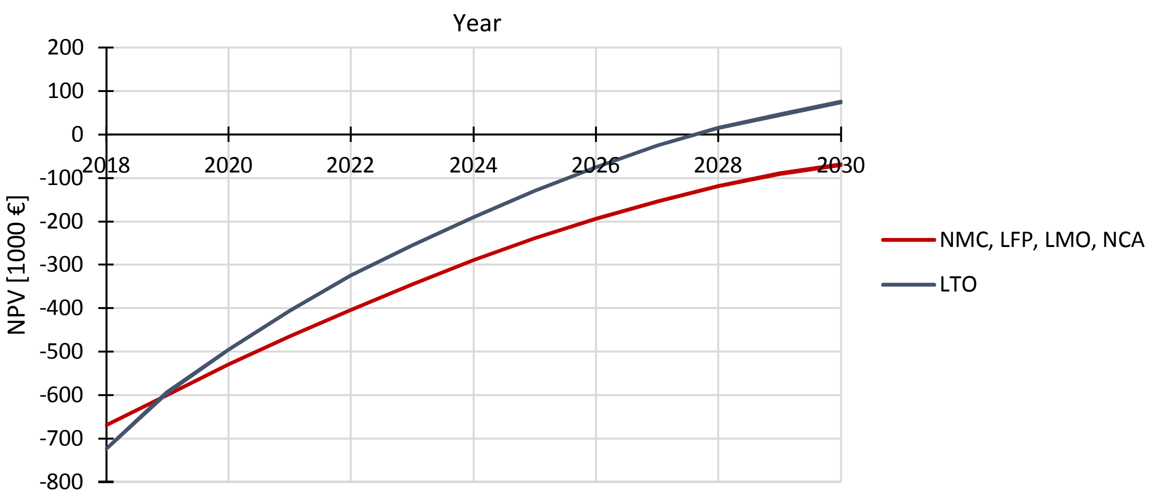


Figure 40 The future NPV development.

With the approximated installed system cost development, the Li-ion EES would break even around the end of the next decade with the current technical performance in the current market environment. Moreover, for example cycle life is also expected to increase, improving the profitability even further. Thus, the Li-ion EES will probably be more commonly utilized in the FCR-N in the end of the next decade.

5.3.2 Operation, maintenance and administrative costs

The approximations of the O&M costs mainly varied between 5 – 10 €/kW-year, but one author has predicted a range up to 30 €/kW-year. However, a large relative increase of 500% from 5 to 30 €/kW-year would only decrease the NPV with about 10% (Figure 41). With LTO, the effect is larger due to the higher cycle life.

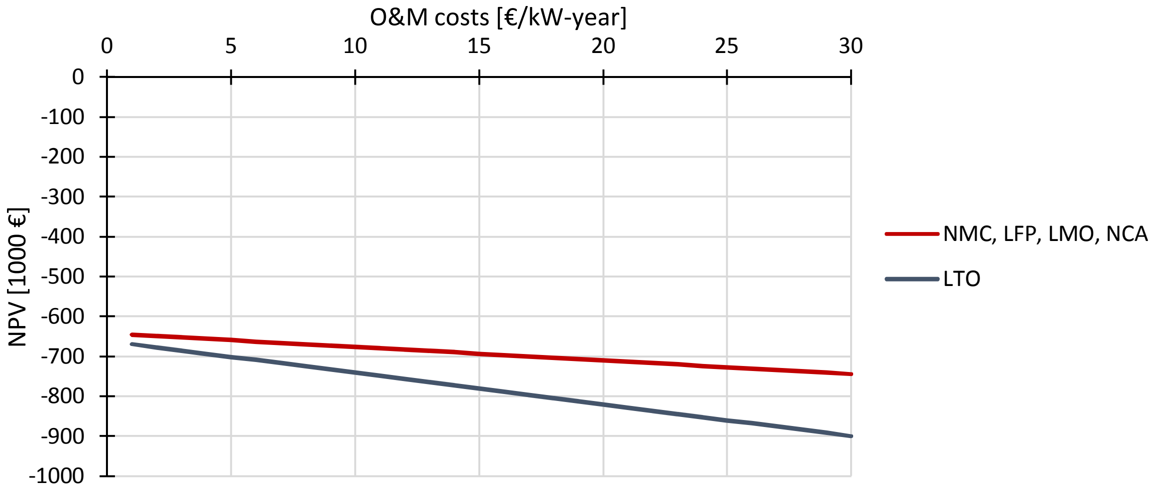


Figure 41 The sensitivity of NPV to O&M costs.

Anyway, the figure implies that the O&M costs do not have a vast effect on the profitability if they remain in the predicted range of 5 – 10 €/kW-year.

5.3.3 Cycle life

Figure 42 plots the NPV as a function of cycle life. The range is based on chapter 3.2.2. The improved cycle life allows the EES to operate more years, as long as the approximated calendar life is not reached.

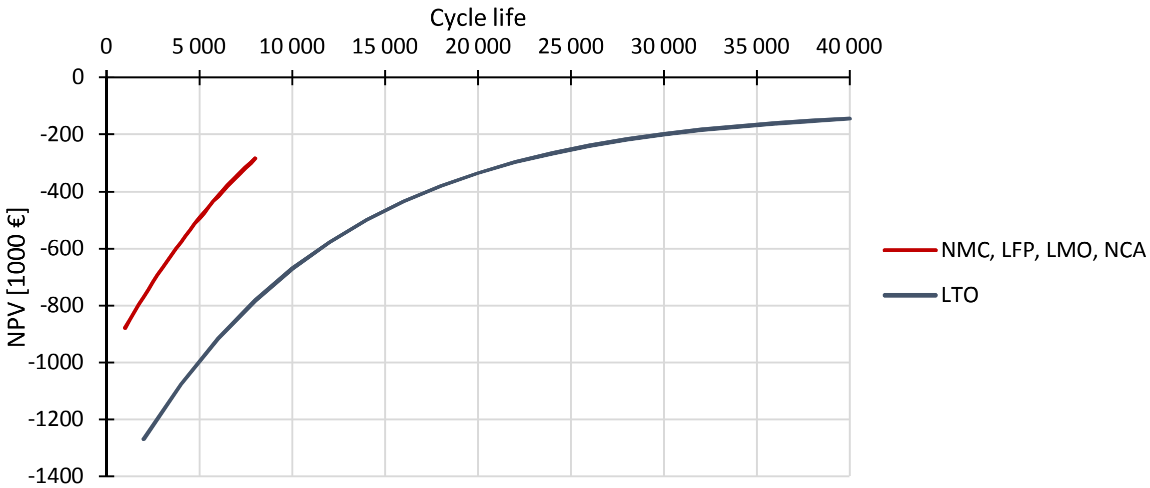


Figure 42 The sensitivity of NPV to cycle life.

The cycle life seems to have a vast effect on the profitability. Hence, the investor must consider carefully which chemistry the manufacturer is using and what kind of cycle life they can guarantee or predict in different cycling conditions. One must also note the fact that the EES is still able to partly function even after the cycle life has been reached, as stated in chapter 3.2.2, generating some revenue.

5.3.4 Round-trip efficiency

The round-trip efficiency describes the relation of usable output to usable input as stated in chapter 3.2.4. In this case, it reduces the amount of additional electricity that needs to be bought to charge the EES.

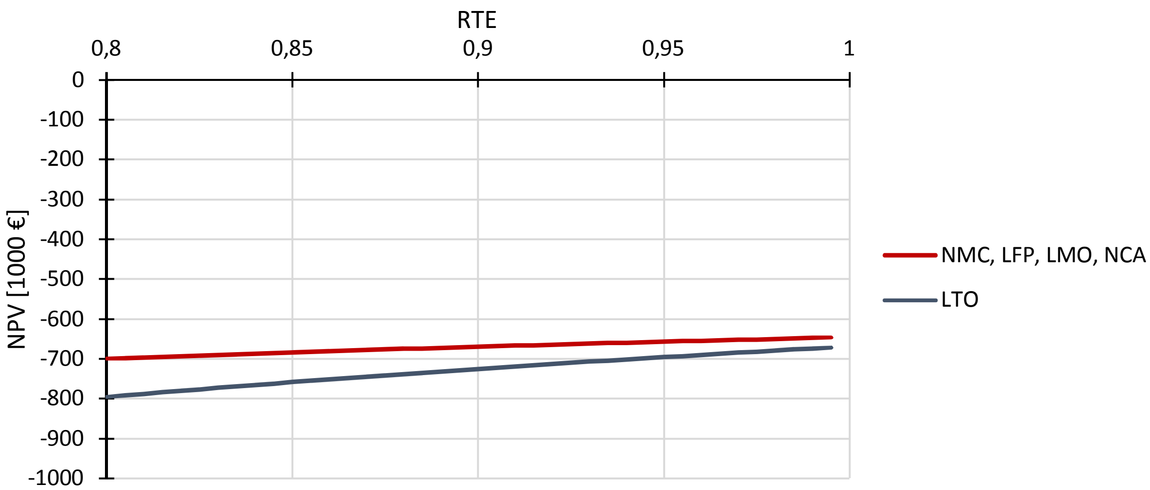


Figure 43 The sensitivity of NPV to RTE.

It is clear that the RTE does not have a significant effect compared to the total loss of the investment because the efficiency of the system is already relatively close to 1. Moreover, the revenue is gained from the FCR-N market in terms of power provided, not energy, and the RTE is a function of energy input and output.

5.3.5 Yearly revenue

The revenue is gained from the FCR-N hourly markets by selling reserve to Fingrid. In chapter 4.4, is was determined that the maximum yearly revenue varied between 148 000 – 196 000 €.

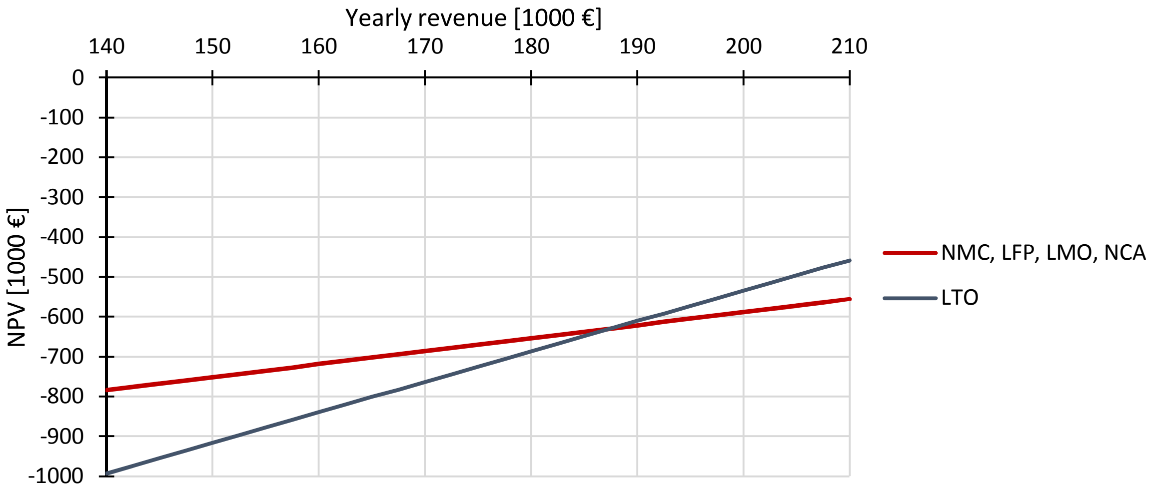


Figure 44 The sensitivity of NPV to yearly revenue.

The increase of 70 000 € in revenue (50% from 140 000 € to 210 000 €) improves the profitability by about 30%. For the LTO, the effect is more drastic as the net loss is halved.

The value of the FCR might increase in the near future with the increasing amount of wind power and decreasing inertia in the grid. However, because the reserve market rules have changed recently, the value of the FCR cannot be predicted based on the past. Moreover, Fingrid is still about to change the rules further, which is discussed in chapter 6.3.

5.3.6 Power-to-energy ratio

P/E ratio was explained in chapter 3.2.1 It compares the rated power to the energy capacity of the EES. In the model performed, the P/E ratio affects the installed system cost per kWh but also the amount of full cycle equivalents during the year. The rated power is maintained in 1 MW but the energy capacity is varied. A larger P/E ratio increases the installed system cost per kWh but also increases the amount of full cycle equivalents as the storage must be charged more often. For example, a 1 MWh EES can provide 2 MWh of energy with two full cycles but a 0.5 MWh storage requires 4 full cycles for that energy. Table 25 presents the end-points used for the estimation of sensitivity, and the values change linearly as a function of the P/E ratio based on chapter 3.3.4.

Table 25 Variables used for the determination of sensitivity of NPV to the P/E ratio. Varying the P/E ratio, the installed system cost and full cycle equivalents change linearly between the end points.

P/E ratio	Installed system cost; NMC, LFP, LMO, NCA [€/kWh]	Installed system cost; LTO [€/kWh]	Full cycle equivalents per year
0.2	500	700	150
1	1000	1500	750

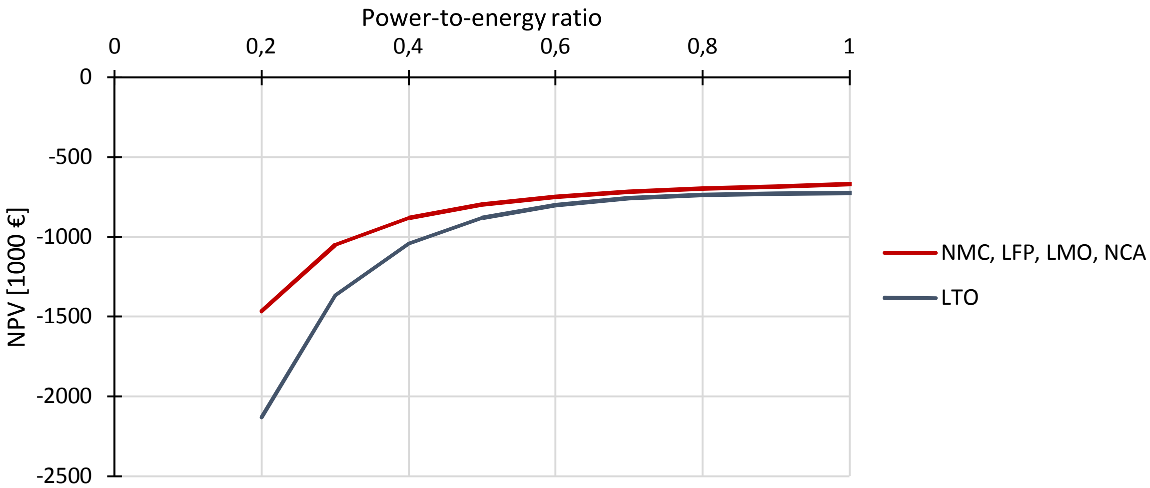


Figure 45 The sensitivity of NPV to P/E ratio. The maximum P/E ratio is 1 due to the FCR-N requirement of capability for at least 30 min of consecutive activation of the reserve.

Figure 45 implies that for the frequency containments, low P/E ratios are not favorable. This is reasonable because the FCR-N is a short-term market where the amount of delivered energy is low. Thus, it is worthwhile to invest in power rather than energy capacity. However, the P/E ratio is limited to 1 because the FCR-N rules require that a reserve has to be able to function for at least 30 minutes consecutively. For example, a 1 MW/1 MWh (P/E ratio 1) storage can charge or discharge power for 30 minutes with a state of charge of 50% but a 2 MW/1 MWh (P/E ratio 2) storage only 15 minutes if the SoC is 50%.

One must note that the evidence of the relation of the P/E ratio to the installed system costs was found questionable in chapter 3.3.4. Moreover, the P/E ratio used in the estimation only affected the amount of full cycle equivalents, in addition to the installed system cost. However, the storage must be charged more frequently as the P/E increases and the energy capacity decreases. Inevitably, at some point during the year, the storage operation must be stopped or charged outside of the FCR-N markets to buy electricity from the day-ahead or intraday markets. While charging the additional electricity, the storage is not able to fully operate as an FCR-N reserve reducing the gained revenue from the year. Still, in any case, Figure 45 implies that the investor has to clearly optimize the power and energy ratings for the particular application of the storage.

5.3.7 Interest rate

The base NPV calculation used a WACC of 0.07. The relation of WACC to the NPV is presented in the Figure 46.

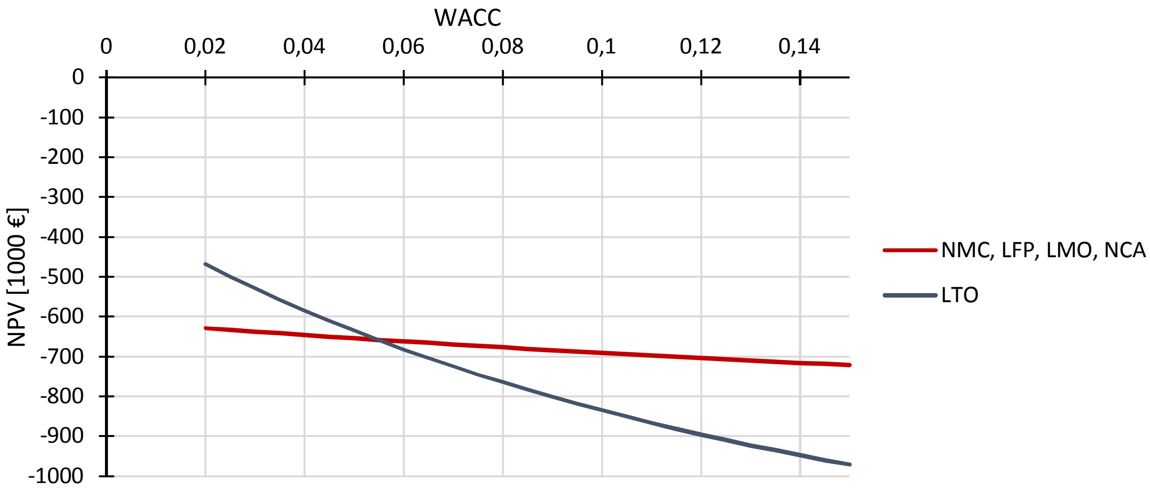


Figure 46 The sensitivity of NPV to the WACC.

The figure clearly suggest that the WACC does not drastically affect the profitability for the most of the Li-ion technologies, which is due to the low lifetime of the technologies. LTO is largely affected due to the opposite reason.

5.3.8 Electricity price

The EES has to buy additional electricity in order to maximize the hours when operating as an FCR-N reserve. Figure 47 analyzes its effect to the NPV.

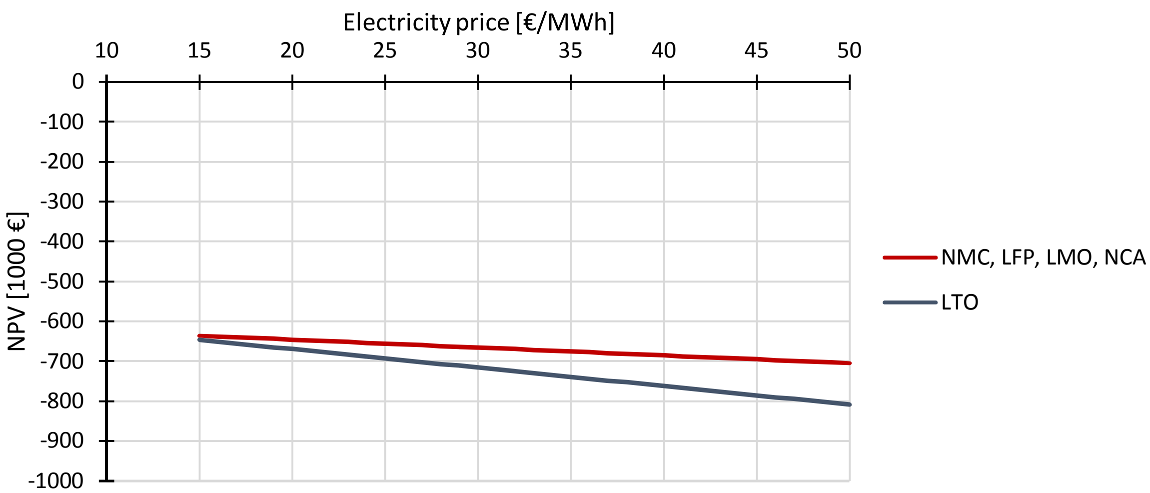


Figure 47 The sensitivity of NPV to the electricity price.

As discovered in chapter 4.2, the day-ahead prices slightly vary during the day. Table 26 gives an overview of the lowest and highest hourly prices by listing the unweighted average high price and low price of the day along the year.

Table 26 Key parameters of the day ahead markets in 2015 – 2017. (80)

Year	Average hourly price [€/MWh]	Average high price of the day [€/MWh]	Average low price of the day [€/MWh]
2015	29.66	46.63	16.77
2016	32.45	46.08	22.22
2017	33.19	44.72	24.86

If the EES investment is made, the cost of electricity bought can decreased from the average yearly price by charging the storage as much as possible at night. The hour of the lowest price is easy to guess in advance: The lowest price of a day occurred for 217 times between 02:00 and 04:00 in 2015, 232 times in 2016 and 196 times in 2017. Thus, optimal charging can bring some savings compared to the average electricity price. However, the effect seems to be rather small when reflecting the difference between the NPV with the average hourly price and the average low price.

5.3.9 Taxation and distribution costs

Figure 48 combines the effect of the taxation and distribution costs because they affect the NPV similarly by changing the cost of the electricity charged. The dots present the different policy and regulation scenarios with normal distribution costs and no taxation as well as normal taxation and no distribution costs. The X-axis is 0 €/MWh when both of those are zero.

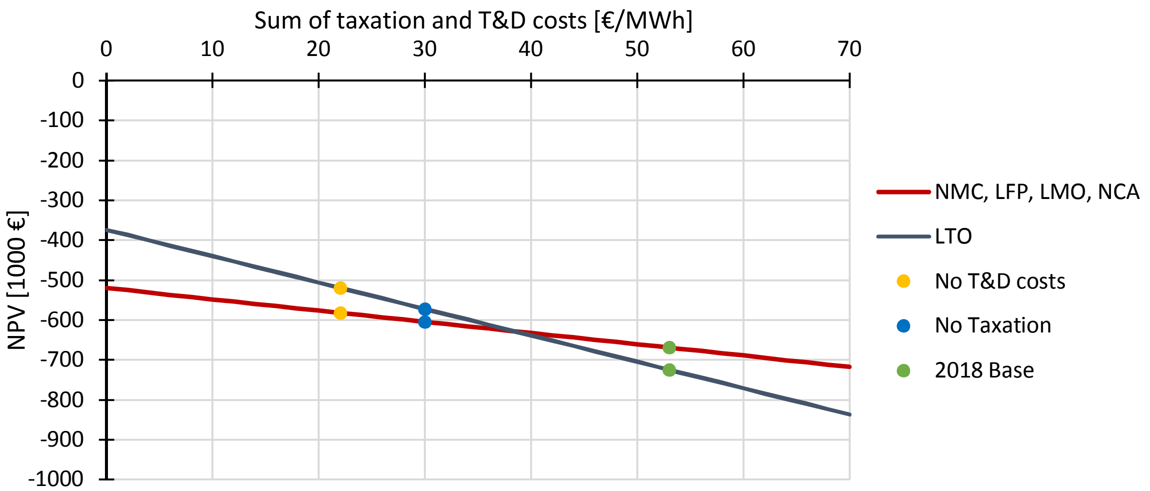


Figure 48 The sensitivity of NPV to the sum of taxation and distribution costs with dots presenting no taxation or no distribution costs in addition to the current situation.

The profitability of the LTO could be significantly increased with zero taxation due to the higher energy flow-through during the lifetime. The removal of the tax could improve the NPV of LTO systems by almost 30 %. The zero taxation is likely in the future, which is further discussed in chapter 6.4.

5.4 Summary

This chapter connected techno-economic performance of the Li-ion EES to the data from the Finnish electricity market by calculating the LCOS and NPV. The LCOS was found to be overly high compared to the energy arbitrage potential, even when taking the decreasing costs during the next ten years, and the other key parameters in the sensitivity analysis, into account. Thus, the Li-ion EES is forecasted not to be used for energy arbitrage in the next decade.

NPV was also found to be significantly negative. Its sensitivity analysis was more thorough than the one of LCOS due to the larger number of parameters. Based on the analyses, the NPV is most sensitive to the installed system cost. Still, even the lowest end of the price range would not currently induce profitable investments, even though large variations were found in the installed system cost review in chapter 3.3. However, a break-even was found to be expected in the FCR-N market in the end of the next decade.

The NPV was also heavily affected by varying the cycle life and the P/E ratio. Furthermore, the yearly revenue as well as the taxation and the distribution costs seemed to have a considerable effect. For example, the probable no-taxation policy would have greatly increased the NPV. Then again, the round-trip efficiency and the cost of electricity seemed not to have a large impact on the NPV because the RTEs are already relatively close to 100%. Moreover, the amount of generated revenue in the FCR-N market is not directly related to the energy flow through the battery. The WACC did affect the LTO profitability because of the long lifetime, while the effect was not that significant for the other technologies due to the short lifetime.

6 Possible future trends in the electricity markets

This chapter qualitatively assesses the possible changes in the electricity markets and their effects on the Li-ion EES profitability until 2030. The main trends are presented and briefly discussed. A more detailed discussion and analysis of the effects is not possible in the scope of the thesis. Thus, a reserve holder must carefully assess which of the trends are most probable and influential on the profitability of the Li-ion EES.

6.1 Changes in production capacity

The demand for storages is directly linked to the production capacity in the area and how the supply is able to match with the changing demand. The generation mix and the ramp rates of the generation units determine this capability of flexibility. Especially the intermittent renewables might cause difficulties as their production output cannot be manually controlled. The flexibility and the demand-matching is directly related to the electricity price fluctuations and the demand for reserve power. Hence, this part qualitatively assesses the changes in the production capacity.

The largest expected individual changes in the generation mix in Finland are Olkiluoto 3 and Hanhikivi 1 (115). Nuclear power is capable of ramping, but generally it is operated on a constant power output in Finland. Hence, they will induce large amounts of inflexible base generation to the grid. However, even if all of the nuclear power plants, Olkiluoto, Loviisa and Hanhikivi, would be operational simultaneously, the 4500 MW would fit to the base generation section in the electricity supply side (115). During this decade, the hourly consumption of electricity has never dropped below 5000 MWh (116). In any case, 4.5 GW is a large share of inflexible generation, certainly favoring the profitability of Li-ion EES, even though the turbine-generators are synchronized providing inertia to the grid.

The Ministry of Economic Affairs and Employment (MEAE) expects that the increasing nuclear generation would significantly decrease the yearly amount of net import in terms of energy (115). Regarding the EES, it would be problematic, as it might release more transmission capacity to be used in the balancing markets and reserve markets between the other Nordic countries. The increased amount of Nordic reserves might decrease the reserve prices in Finland.

The ban of coal in 2029 might have various effects on the CHP production in Finland. One consequence could be a slight increase in the electricity prices if coal-fired CHP plants are replaced with biomass-fueled heat-only boilers. Further discussion is unnecessary in this thesis as the ultimate effects cannot be predicted, and the market actors and politicians already debate on the effects (117) (118). Furthermore, the CHP plants are not competitors of the Li-ion EES. In other words, they do not operate in the same market segment, and thus the direct effects to the profitability of Li-ion EES might be small. However, rotating synchronous turbine-generators provide inertia to the grid. Hence, the overall effect of the ban of coal is probably positive to the Li-ion EES profitability.

As stated in chapter 2.1, hydropower can also be utilized in the reserve and balancing markets. However, the ecologically suitable rivers are already being utilized, and therefore the hydropower capacity is predicted to remain the same in the next decade. Both MEAE and Fingrid predict that the annual energy output from hydropower will remain constant during the next decade (72) (115).

The intermittent renewables are regarded as one of the core reasons for the global interest in storing electricity, as stated in the introduction. The solar power production is currently negligible in Finland but wind power capacity has increased during the last few years. Until 2030, the estimates predict moderate increases to the installed capacity, compared to the current 2.0 GW (119). OECD/IEA et al. expect 2.8 GW, while the MEAE predicts 6 TWh which corresponds to 2.3 GW with a 30 % capacity factor (115) (120). This is quite a conservative prediction, as the installed wind power capacity has grown steadily during the last few years, and currently, 3477 MW worth of wind power projects have been permitted in Finland (119). A new wind power plant with a production cost of 30 €/MWh by Tuuliwatti supports the idea of more installed capacity of wind power than the 2 – 3 GW in 2030 estimations (121). Fingrid predicts about 3 GW and 9 TWh of wind power in 2030 (72).

Currently, the installed wind power capacity does not seem to have direct impacts on the grid frequency. Figure 49 and Figure 50 plot the change in the wind power production [MW] and the change in the grid frequency during three minute time periods (113) (122). The first time period is 1 Jan 2017, 0:00 – 9 May 2017, 8:18 (n = 61 356), the latter 3 Aug 2017, 8:25 – 31 Dec 2017 23:59 (n = 67 040) due to a gap in Fingrid's wind power data in summer 2017.

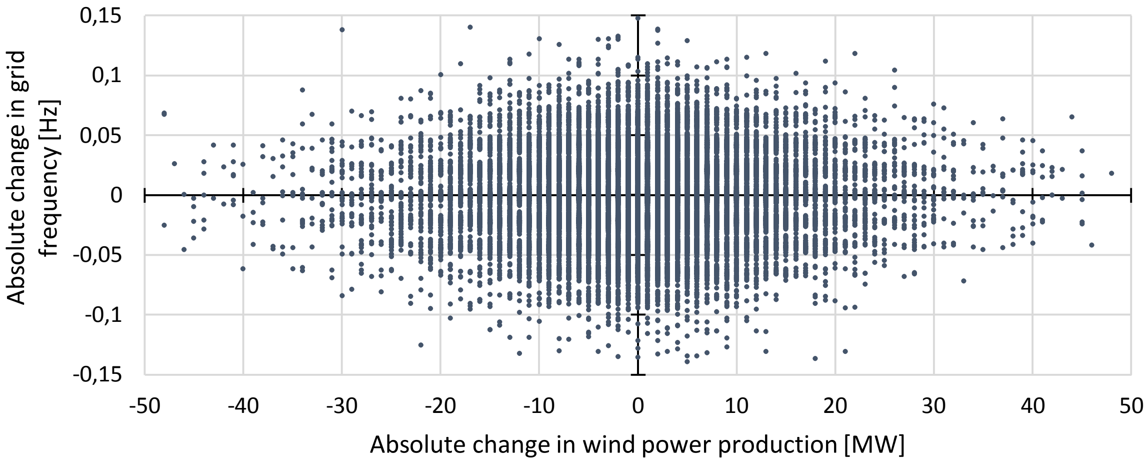


Figure 49 The absolute change of frequency as a function of the absolute change in wind power production 1 Jan 2017 – 9 May 2017. The vertical lines are caused by the 1 MW accuracy of the wind power data during this period. (113) (122)

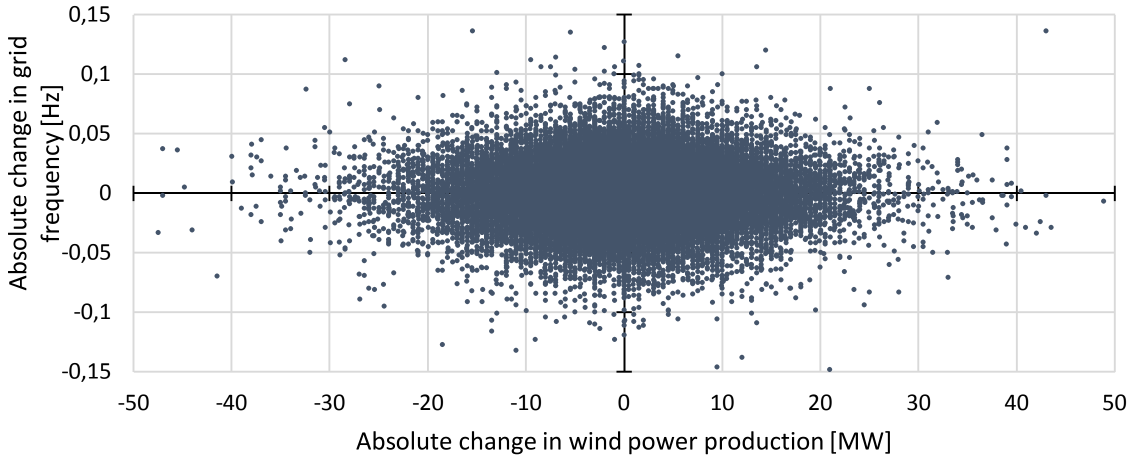


Figure 50 The absolute change of frequency as a function of the absolute change in wind power production between 3 Aug 2017 – 31 Dec 2017. (113) (122)

If there was a correlation, the point cloud would have a more diagonal form, where the dots would be positioned in the up-right and down-left corners meaning the positive changes would increase the frequency and negative changes would decrease it. One should observe that in the beginning of 2017 the total installed capacity was 1533 MW and 2044 MW in the beginning of 2018 (119).

Helistö et al. modelled the Nordic power system with different shares of wind and solar power in the annual electricity demand. Changing the levels from 22 to 60 %, the average electricity price was decreased by increasing the occurrence of rather low price levels. The volatility also increased. However, the number of high peak prices did not drastically increase, and even with the 60 % share of variable generation, the electricity prices varied between 0 and 150 €/MWh. Based on the duration curves, however, the day-ahead arbitrage potential would remain at 50 €/MWh at maximum. (123)

The shares of Helistö et al. can be compared to the IEA et al. estimation of 80 TWh wind power with total demand of 440 TWh (18 %) (120) in the Nordics in 2030. The figures are 7 TWh and 85 TWh (8.2 %) for Finland. The most optimistic scenarios state a potential of 39 TWh (46 %) in 2030 (115). Each of these values are rather small compared to the value of 60 % in the simulation run by Helistö et al. and thus, the additions to the wind power capacity in the coming decade might not significantly increase the potential for the energy arbitrage.

With high penetration levels, however, the increased intermittent production increases the risk of frequency deviations (124). If the penetration of wind power stalls to a moderate growth predicted by IEA and TEM, the effects to the profitability of Li-ion EES would likely remain modest, based on Figure 49 and Figure 50. An annual usage of 39 TWh, however, would probably drastically increase the demand for frequency containment reserves, improving the profitability. The amount of energy would correspond to about 13 GW of installed wind power capacity which would surpass the demand on most hours of the year and hence drastically increase the demand for upper but also lower frequency containment.

Nevertheless, the future trends in the capacity development increase the demand for frequency regulation. The energy arbitrage potential will also increase but probably stay on a too low level for Li-ion EES.

6.2 International transmission

International transmission aims to unify the electricity markets of different countries to reduce the number of bottlenecks and ultimately to prevent the formation of different price areas. In the near future, the Nordics will be more connected to the Central Europe and probably to the UK via Norway, Denmark and Southern Sweden (120) (6). Due to the lower electricity prices as well as high amounts of hydropower in the Nordics, it is expected that net energy flow is from the Nordics to Central Europe (120).

Fingrid and Svenska kraftnät have planned a new AC connection between Northern Finland and Sweden with 800 MW import capacity to Finland and 900 MW export capacity from Finland. The transmission system operators (TSOs) aim to commission the connection in 2025. Another investment has been proposed to the Southern Finland to replace the old 400 MW Fenno-Skan 1 DC connection. The new link has been planned for 800 MW transmission but the phase of the project is not as advanced as the AC connection. In addition to these investments, the current Swedish AC connection will be decreased by 300 MW after the commissioning of Olkiluoto 3. (72)

Currently, the Swedish imports are excessively used to balance supply and demand in Finland (77). Increased imports from Sweden and Norway to the Central Europe might limit the availability of the Swedish balancing power in Finland. On the other hand, already now the power flows from Northern to Southern Sweden, and price areas are sometimes formed in Sweden. Increased exporting from Southern Sweden to the Central Europe cannot be thus increased without improved North-South connections in Sweden. Anyway, the ultimate effects to the Li-ion EES profitability cannot be predicted reliably.

6.3 Changes in the reserve markets

In the future, Fingrid will shrink the dead band of the FCR-N from ±0.05 Hz (49.95 – 50.05 Hz) to ±0.01 Hz (49.99 – 50.01 Hz) due to the EU regulation (125) (114). Thus, the operation in the FCR-N will become technically more demanding. A Li-ion EES might benefit from this because stricter technical requirements might increase the price of the FCR-N as fewer reserve holders could fulfil the properties. Due to the new regulation, the potential effect is estimated and compared with the current operational requirements. In the new market mechanism, the power output would be given as

$$P_{new,i}(f) = 1, f \in [0, 49.9] \tag{17}$$

$$P_{new,i}(f) = -\frac{1}{0.09}f + \frac{49.9}{0.09} + 1, f \in]49.9, 49.99[\tag{18}$$

$$P_{new,i}(f) = 0, f \in [49.99, 50.01] \tag{19}$$

$$P_{new,i}(f) = -\frac{1}{0.09}f + \frac{50.1}{0.09} - 1, f \in]50.01, 50.1[\tag{20}$$

$$P_{new,i}(f) = -1, f \in [50.1, \infty[\tag{21}$$

The following result is achieved after running the model similarly to the one run in chapter 5.2.1. (Figure 51)

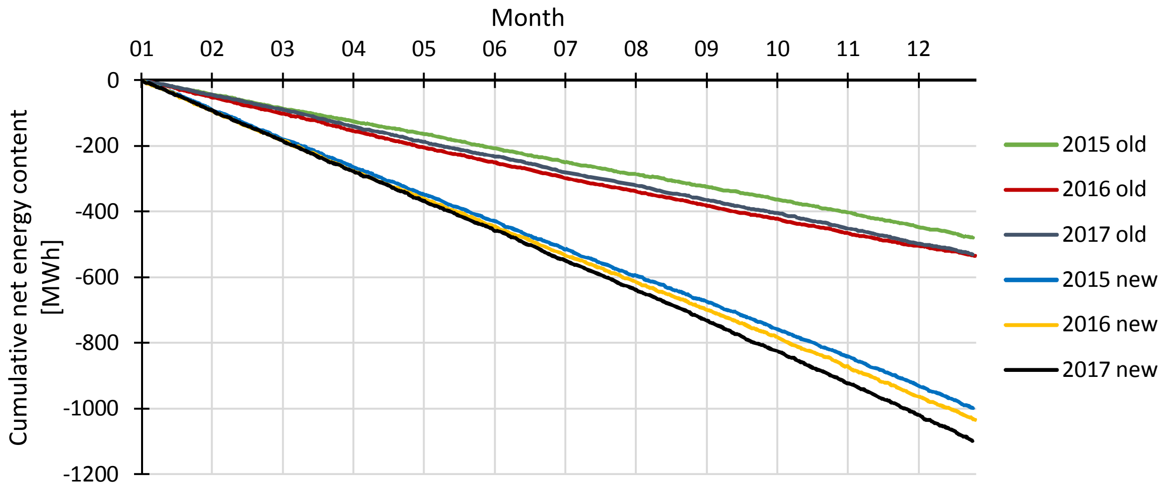


Figure 51 The cumulative amount of additional energy that would have been needed to discharge (+) or charge (-) along the year in order to be able to operate the entire year as an FCR-N reserve, based on the frequency data 2015 – 2017.

Figure 51 shows that with the stricter regulations, the EES would need to operate more, energy-wise. However, if the dead band of the FCR-N reduces from ±50 mHz to ±10 mHz, the frequency would probably remain between 49.99 – 50.01 Hz more often with the new market mechanism than with the old mechanism where the dead band is 49.95 – 50.05 Hz. Thus, the additional energy that would have been bought and charged would probably be less than the result of the model (1000 – 1100 MWh) because the model uses frequency data from the grid with old market regulation. Similarly, it is most likely that the amount of energy bought would be larger than the result modelled with old data (480 – 530 MWh) because frequency will always remain more often in the gap [49.95, 50.05] than [49.99, 50.01]. In any case, the stricter technical requirements induce more expenses for reserve holders, which most likely increases the prices of the FCR-N markets, increasing the revenue gains of the holders.

The rules of the mFRR might also alter as Fingrid has proposed changes. In addition to the current market situation, Fingrid plans to procure additional upper balancing capacity with long term contracts for 1 – 10 years. Simultaneously, adjustments are suggested to the existing balancing market mechanisms, starting from 2019. (126)

Currently, the required duration of the bid capacity is one hour in both balancing energy and capacity markets. Based on the new suggestion, the bidder of the balancing capacity markets would be required to being able to provide the bid capacity for at least three consecutive hours. The bids for the balancing capacity market would need to be given four days before the trading period. The bids for the balancing energy markets would need to be given until 9:00 (GMT+2) on the previous day. In the future, the gains from balancing energy markets would not affect the capacity fee but Fingrid has suggested sanctions for altering the capacity offer after 9:00. What is more, the capacity fee for all the bids would be determined by the highest accepted price, i.e. marginal price, unlike in the current balancing capacity market. Moreover, the reserve holders could now offer not only upper, but also lower balancing power for the capacity markets. (127) (128)

The new 1 – 10 year contracts would obligate the reserve holders to bid to the upper balancing energy markets for the contract period. As the new marketplace is only a suggestion, it is not further discussed in this thesis. The price level is unknown, and even Fingrid surveying for the supply and price levels of the capacity. (129) (130) Thus, the speculation of the price levels is not possible in the scope of this thesis.

The Nordic TSOs have also suggested changes to the reserve markets. They have stated that the resolution of the balancing market should also be changed to 15 min. (6) This would make the balancing markets more attractive for a Li-ion EES because, as stated in chapter 4.4.3, the EESs are insufficient at providing nameplate power for long periods of time. Moreover, even the storages with large P/E ratios will be able to operate successfully in the mFRR markets providing high power for short periods if Fingrid eases the requirement of the three-hour availability of the bid capacity.

The Nordic TSOs have also commented that they aim to reduce the amount of times when the frequency is outside the range [49.9 Hz, 50.1 Hz] (6). The achievement of the goal certainly requires more FCR-N reserves as they operate between the range. The increased demand would increase the prices of the FCR-N benefitting the profitability of the reserve holders.

In addition to these changes, the Nordic TSOs have presented an idea of Nordic reserve markets, including both FCR and FRR (6). Currently, only the balancing energy markets are Intra-Nordic. Already now, the net import to Finland handles a large portion of the intraday balancing of the supply and demand in Finland (77). An Intra-Nordic FCR might affect the Finnish reserve holders too if Fingrid could start buying FCR from Sweden and Norway, in addition to the balancing energy. The limit is, however, the transmission capacity of the cross-border line.

The Council of the European Union has also suggested that the capacity mechanisms applied in one member state should also be open for the reserves in other states as long as technical limitations, such as transmission capacities, are fulfilled (131). Currently, as stated in chapter 4.4.3, the balancing capacity markets in Finland are only open for Finnish reserves, but in the future, the reserves in other Nordic countries might be able to bid to Finnish markets. Similarly, a Finnish reserve could participate in other Nordic countries.

The Council has also proposed that at least 40% of the balancing capacity would be contracted for not longer than one day before the provision of the balancing capacity and the contracting period should have a maximum length of one day (131). As discussed in chapter 4.4.3, the current contracting period is one week. However, the proposal also suggests that the local TSO could be able to extend the contracting period to even a year so the time requirement is not strict and does not affect the Li-ion EES profitability (131).

For the Li-ion EES holder, it might be unfortunate that the rules of the reserve markets are complex compared to the day-ahead and intraday markets. The desirability of the market is further reduced by frequent and unclear changes by Fingrid, other Nordic TSOs or the EU. Moreover, uncertainties are induced by numerous suggestions and proposals without clear information about which of the plans will entry into force and which not. A comprehensive knowledge about the complex markets and a well-suited technology, however, could give a competitive advantage for the Li-ion EES. The balance between the risk and the reward must be assessed by the investors individually by the case.

6.4 Taxation

The Finnish Government have proposed to release large-scale electricity storage from the electricity tax. The legislation is proposed to come into force in the beginning of 2019. The aim is to get rid of the double taxation explained in chapter 4.6. While charging, the storage would not be required to carry the tax, and only the final consumer of the electricity would pay for the tax.

The new legislation will improve the NPV of grid-scale energy arbitrage if the law comes into force. However, the change of taxation of energy arbitrage will not make the Li-ion EES energy arbitrage profitable due to the high LCOS. The change will not have significant effects in the upcoming decade either, referring to Figure 33.

Selling reserve capacity to Fingrid might be different, where the final user of electricity cannot be determined, unless Fingrid will be regarded as the one. If Fingrid would carry the electricity tax from the FCR-N discharged electricity, then the storage would be probably released from the taxation, in other words.

In any case, the NPV of the operation in the FCR-N would improve tens or even hundreds of thousands of euros for a 1 MW/1 MWh system if the electricity tax is not carried from charging. Hence, the reserve holder must ensure the ultimate sections of the law if the legislation is changed.

6.5 15 min imbalance settlement period

As described in chapter 4, currently, the imbalance settlement period (ISP) in Finland is 60 minutes. However, based on the EU Electricity Balancing guideline, an ISP of 15 min should be implemented no later than Q4 2020 (132). Hence, the Nordic transmission system operators have proposed that this change should be implemented across the Nordics in the end of Q2 2020 (71). Thus, this change in the market is probable. The Nordic TSOs have even stated that the 15-min day-ahead market is also a target but in the longer run. (6)

In practice, the ISP of 15 minutes would change the settlement period of intraday markets from 60 min to 15 min. The settlement period of day-ahead markets would remain the same as now, 60 min.

Eight European countries have already implemented the ISP of 15 min (71). Unfortunately, the research on the effects of the change seems to be quite poor. What is more, long periods of market data are difficult to estimate as the intraday data is not free of charge, as mentioned in chapter 4.3. Thus, two weeks of intraday market are analyzed in Finland, Switzerland and DE/AT-market area to roughly evaluate the effects. Figure 52 and Figure 53 present the difference between the highest and the lowest price of the particular hour in the intraday markets. For example, if the highest price has been 100 €/MWh and the lowest 20 €/MWh, the difference is 80 €/MWh.

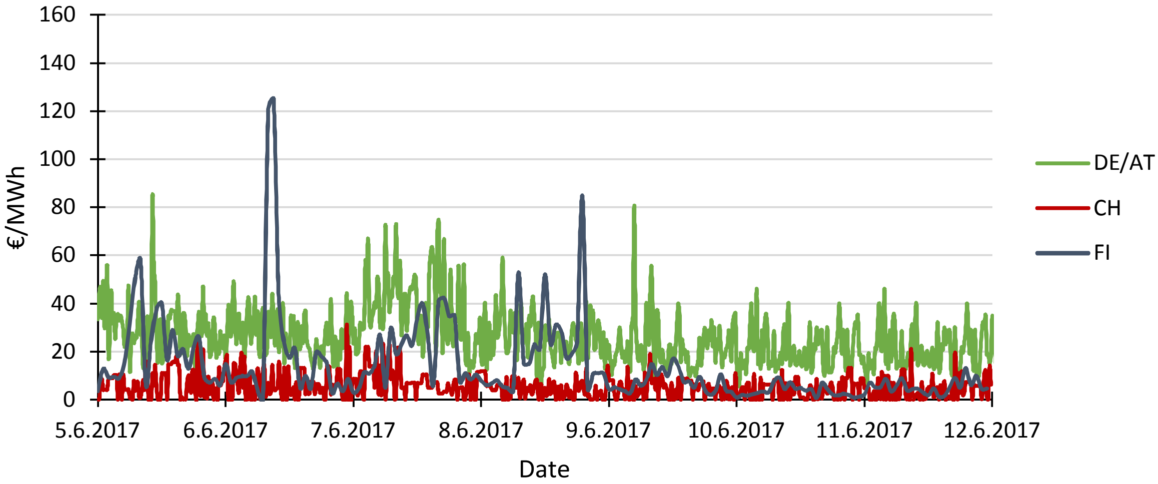


Figure 52 Intraday prices in FI, DE/AT and CH on a summer week. The highest difference peak reaches 125 €/MWh. (83) (133) (134)

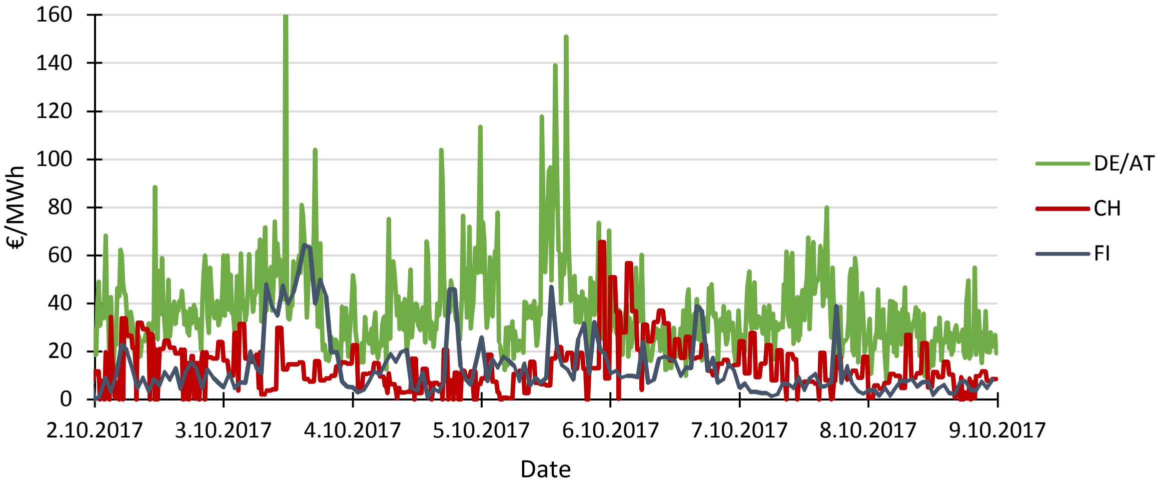


Figure 53 Intraday prices in FI, DE/AT and CH on an autumn week. The highest peak reaches 200 €/MWh. (83) (133) (134)

Based on these two weeks, it seems like the intraday electricity prices vary more in DE/AT than in FI or CH, even though both DE/AT and CH have an ISP of 15 min. It is possible that the variation caused by the high portions of solar and wind power in the German electricity mix. Thus, it is possible that the transition to 15 min ISP will not induce greater variations to intraday prices than nowadays, inducing no significant effects to the EES profitability.

6.6 Demand response

Demand response (DR) is a phenomenon where consumer reacts to the demand peaks in the grid due to some financial incentives. In other words, the system operator benefits from the smoothened peak power demand, balance responsible parties are helped by smoothing the demand curve and the consumer might save in their electricity bill.

Demand response can be regarded a competitor to not only Li-ion EES, but to all storages operating on daily or shorter periods. Effective DR would level the day-night variations in demand but also could be able to participate in frequency control. For example, controllable direct electric heating could easily be switched on and off based on the grid frequency.

Currently, the role of DR in the Finnish grid is negligible. Figure 54 presents the week 9 with the peak consumption and the peak price in 2018, showing that no significant demand response has occurred even with a fivefold price.

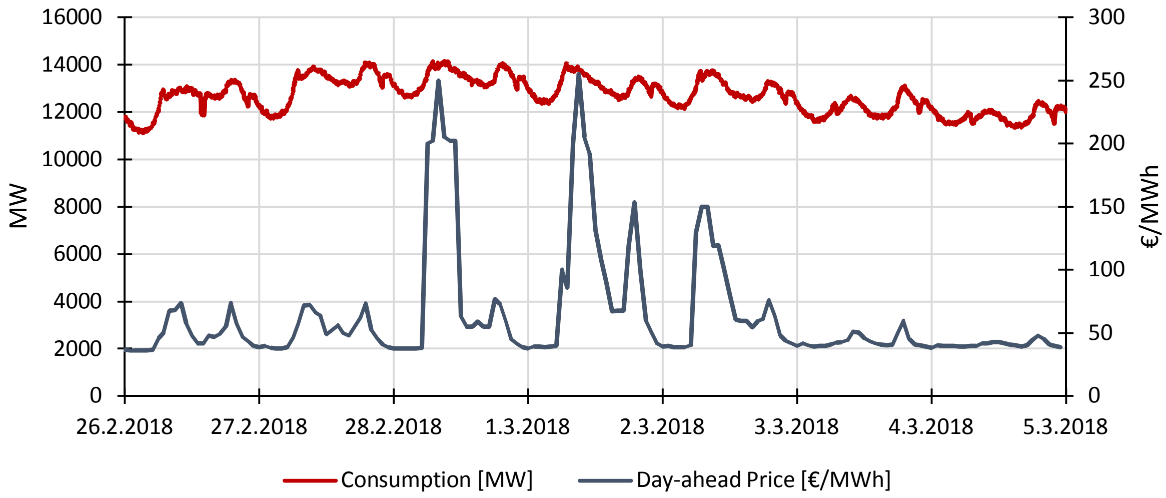


Figure 54 Total consumption of electricity and the day-ahead price in Finland on week 9 in 2018. (80) (116)

There are numerous barriers to efficient DR but the financial incentives, or the lack of them, is the largest. Leaving one hour of 10 kW electric heating with a price of 250 €/MWh, the customer would have saved 2.5 €. As most of the year the highest daily price is less than 100 €/MWh, the savings along a year would not be high. Other possible barriers for a substantial amount of DR in Finland include

- current complexity for customers to attend
- minimum sizes for attending reserve markets
- no standardized exchange of DR information between different market actors
- the regulation of distribution → the distributors do not benefit from reducing the peak demand
- the constant taxation of electricity
- the regulation of building efficiency, which does not consider the peak power demand; only the total energy consumption.
- the lack of public knowledge about the benefits of DR.

In principle, the day-ahead market follows the idea of DR. The buyer gives different bids with varying amounts of MWh and €/MWh, where the amount of energy decreases with the increasing cost. However, as Figure 54 shows, any realized amount of DR cannot be discovered.

In the future, the demand response might become an important part of the Finnish electricity system. Already now, the installed automated meter reading (AMR) is used to control consumers' electricity use between day and night. A pool from 2015 estimated that over 1000 MW of end-customer demand could be controlled via AMR fairly easily with limited additional installations, attending day-ahead market. (135) Furthermore, Fingrid estimates that during the times of peak consumption, the peak could be shaved by even gigawatts by slightly controlling the electric heating of the consumers (136).

If large amounts of DR are utilized, the volatility of the electricity prices would probably be reduced. This would cut down the potential of price arbitrage with EES, where the electricity is charged during low prices and discharged during high prices. However, as noticed earlier, the Li-ion EESs are more suitable to the reserve markets with shorter time periods so day-night DR is not a direct competitor to Li-ion EES. Moreover, with the current AMR solutions, the end-customers could not be able to attend the reserve markets and their participation would require more developed technical improvements (135). The virtual power plant (VPP) in Sello will attend the reserve markets but it is not pure utilization of DR as the VPP contains a Li-ion EES of 1.68 MW/2 MWh (137). The most recent large-scale VPP project in Finland also contains a Li-ion EES (138). Thus, it is probable that even after the demonstration phase, an aggregation of demand is also combined with an EES, at least when attending the reserve markets.

The most recent large-scale VPP project in Finland consists of 10 MW of Li-ion EES and 22 MW from building services related DR (138). The total cost of the VPP is about 24.5 M€ where 14 M€ is for the EES and 10.5 M€ for the DR, indicating that the DR could provide cost-efficiency per MW compared to the EES (63). However, Siemens and MEAE do not share further information about the investments, for example information about the technology used for DR. Moreover, Siemens does not reveal which marketplace it is attending, for example Siemens does not say if it plans to use the DR in the intraday market and the EES in the FCR-N. Thus, this example cannot prove the cost-efficiency of DR to the Li-ion EES, and further studies and demonstrations must be performed to compare the costs and benefits of DR to the Li-ion EES.

6.7 Power based distribution tariffs and capacity markets

Currently, the distribution tariff typically contains a price for the consumed amount of electrical energy and a price for the needed power. However, the energy based fees do not reflect the costs of the distribution system as the DSOs must adjust the system to the peak power demand regardless of the total energy consumption. The problem has aroused discussion about shifting from energy based fees more towards the power based fees. (105)

As an FCR-N storage, a Li-ion EES would not benefit from power based tariffs. The amount of electricity charged is rather low compared to the charging power as discovered in chapter 5.2.1. The model resulted that a 1 MW storage would need to charge 750 MWh during a year of operation. Then again, an automated industrial load of 1 MW, used 8000 hours per year, would need 8000 MWh of electricity. The distribution cost for these amounts of energy would be the same if the power based tariffs were adopted.

The power based tariffs can, however, create new market niches for the EESs. A consumer of electricity could charge their EES while their other consumption is low. Correspondingly, during those hours when power demand is high, the consumer could buy a certain amount from the grid and supply the rest of the demand by discharging the battery. In any case, chapter 5.1 showed an LCOS of over 550 €/MWh today and 250 €/MWh in 2030 for 300 cycles per year. It is very unlikely that even the combination of energy arbitrage and energy time-shift would benefit the customer 250 €/MWh or more. If 30 €/MWh is gained from the energy arbitrage with one daily cycle (chapter 5.1), the benefit from reducing the peak consumption should be at least 220 €/MW per day for a 1 MW/1 MWh EES. The value of 220 €/MW can be compared to Helen's power based tariff of 3.35 €/kW per month for medium voltage clients (139). The tariff equals to about 112 €/MW per day. Hence, the customer could benefit about 30 €/MWh + 112 €/MWh = 142 €/MWh with one daily cycle based on these values, compared to the LCOS of over 250 €/MWh.

Market-wide capacity mechanisms are quite often discussed when considering the future of the electricity market. However, MEAE does not favor a change from energy only markets to market-wide capacity mechanisms (115). Furthermore, the Nordic TSOs also prefer to limit the capacity mechanisms only to the strategic reserves (6). Thus, the market-wide capacity mechanisms are not further discussed in this thesis as the change seems unlikely in the near future.

6.8 Summary

The chapter reviewed probable trends in the Finnish electricity market. Changes in the reserve markets were found to be the most significant trend by making the FCR-N technically more demanding and probably increasing the prices, which would benefit the Li-ion EES compared to the competitors. The removal of electricity tax from EES was also found probable and would have a positive effect, ultimately depending on the precise legislation, however. Table 27 gathers the mentioned market trends.

The increasing amount of non-controllable generation in the electricity system will also support the profitability of the Li-ion EES. The effective DR was regarded as a threat but on the other hand, the recent large DR demonstrations in Finland have combined a DR with Li-ion EES. What is more, some of the DR might be applied in the day-ahead markets rather than the reserve markets. Furthermore, the ultimate magnitude of the introduced DR seems uncertain. A shift towards more power based distribution tariffs might have a minor negative effect on the profitability.

Continuously changing policy causes uncertainties and risks which cannot be predicted. Even if the effects of policy changes can be modelled, however, the ultimate impacts cannot be ensured in advance. Still, the overall view on the future market trends seems positive to the Li-ion EES.

Table 27 Possible future market trends considering the Li-ion EES profitability. The second column describes the occurrence probability of the market change, where (XX) = very probable, (X) = probable. The third column describes the effect on the profitability, where (+) = positive, (±) = neutral, (?) = uncertain and (–) = negative.

Market trend	Probability	Effect on the profitability
More inflexible and intermittent generation	XX	+ +
More demanding reserve markets	XX	+ +
Removal of storage taxation	XX	+
More international transmission	XX	?
15 min ISP	XX	±
More power based distribution tariffs	X	–
Increased demand response	X	?

7 Further research

The further research regarding the Li-ion EES should focus on the techno-economic performance and the market area of the EES. For example, high uncertainties are related to the cycle life and O&M costs as discovered in chapter 3 which evaluated the techno-economic aspects of the grid-scale Li-ion storage. Moreover, the sensitivity of the cycle life to the profitability is high while the O&M costs did not have drastic effect. Thus, in the further research, it would be vital to gain a more improved view on the cycle life. Especially, how the cycle life changes with different applications and cycling and how it affects the amount of delivered energy during the lifetime of the Li-ion EES.

Unfortunately, the current pilot Li-ion projects in Finland, which have received support from the government, are owned by private companies, and thus the information from the operation is not entirely publicly available. The companies are required to share information about different steps of the project but are given right hold details which can be considered trade secrets (140). As a result, little benefit is gained in the EES field when the all information is not open. This is because the large uncertainties are related to operation of the EES as seen in chapter 5, for example to cycle life. Thus, releasing all the key data from the government supported projects should be crucial.

For a reliable estimation of the EES operation, a publicly funded project would be required, e.g. a university project, where the data would become available for further studies. The suitability to the Finnish electricity market could be then studied more carefully, and the cycle life could be assessed with different cycling.

As stated in chapter 3, global standards should be required for the testing of the EES, not only the Li-ion, but all battery storages, in order to make them comparable. While testing, the standards would require to maintain some of the test variables constant. For example, the cycle life would be measured in a pre-determined depth of discharge and ambient temperature.

Currently, industry and media use the term Li-ion battery, even though the chemistries vary a lot. The differentiation between the chemistries should be important in the future research, clearly separating the values of LFP, NMC, LMO and NCA cathodes as well as LTO and graphite anodes.

When it comes to the market environment in Finland, a more comprehensive study on the grid frequency and reserve markets should be conducted. In other words, which factors affect the grid frequency the most and which circumstances make Fingrid to procure FCR, aFRR or mFRR reserves. Other topics related to the market environment include DR and its cost-performance and applicability in Finland to estimate DR's competitiveness to the Li-ion EES.

To summarize, further research is required to increase the knowledge and benefits of the Li-ion EES. This supports the adoption and public awareness of the grid-scale but also EV Li-ion batteries.

8 Conclusions

This thesis evaluated the feasibility of the grid-scale Li-ion EES in the Finnish electricity markets. The evaluated Li-ion chemistries were LMO, NMC, LFP, NCA and LTO. A common Li-ion chemistry, LCA, was excluded due to its main usage in portable electronics. Pooling numerous studies, reviews and analyses, the techno-economic attributes of the Li-ion storages could be estimated as the pooling allowed to find a reliable range for the different performance characteristics. The features reviewed included the installed system cost and its breakdown, O&M costs, cycle life, calendar life, round-trip efficiency and power-to-energy ratio. LTO was found to technically outperform other chemistries while being the most expensive, though.

The current cost of a grid-scale installed system was estimated to about 1000 €/kWh for a system with power-to-energy ratio of 1 for chemistries LMO, NMC, NCA and LFP, on average. It was noted that, however, LFP lies on the expensive side of the cost range and NCA on the opposite side, while NMC and LMO seem to be in the middle range. LTO was found to cost approximately 1500 €/kWh with a P/E ratio of 1. For all chemistries, a minor relationship with the P/E ratio was found, where a higher P/E ratio resulted in higher costs per kWh due to advanced technologies required for higher power outputs.

Cycle life approximations had a large variance between authors and chemistries, ranging from few hundreds to even 40 000, while the round-trip efficiency of 90% of grid-scale Li-ion EES was found to be somewhat reliable. O&M costs of 8 €/kW-year came by during the review. During the next decade, the most significant development was found to be expected in the installed system cost and cycle life, whereas the other performance characteristics were predicted to stay about the same.

The Finnish electricity market was reviewed to estimate the market conditions of the Li-ion EES. The day-ahead and intraday markets were found unattractive due to the relatively low price volatility. The potential for energy arbitrage was found to be about 20 – 25 €/MWh per cycle in the day-ahead market and less than 80 €/MWh per cycle in the intraday markets. Instead, the reserve markets possessed the largest revenue potential. The mFRR markets were found technically unsuitable and the aFRR economically unfavorable for Li-ion EES leaving the FCR, especially the FCR-N, as the most potential reserve marketplace. The reserve holder could be able to generate approximately 175 000 € yearly revenue per MW if the reserve is operated every hour of the year.

The feasibility of the Li-ion EES was evaluated with LCOS and NPV methods after gathering the key data from the Li-ion techno-economic review and the electricity market review. The LCOS calculation resulted in about 560 €/MWh for NMC, LMO, LFP and NCA and 640 €/MWh for LTO. The amount was found excessively large compared to the price volatility in the day-ahead and intraday markets. Even though the costs are lowering, the EESs are not expected to be widely used in energy arbitrage applications during the next decade in Finland due to the high LCOS.

The FCR-N market was used for the NPV calculation, as it was found to be the most attractive marketplace. The operation in the FCR-N market was modelled to approximate the energy flow in and out of the EES. Finally, taxation and T&D-costs were included in addition to the yearly O&M costs. None of the technologies were found profitable by using the base values, as the calculations yielded highly negative NPV values. However, the sensitivity analysis revealed that the uncertainties related to the cycle life might drastically change the NPV of the system. Then again, the RTE seemed not to have a great effect on the profitability as the efficiency is already quite high. Nevertheless, the installed system cost analysis predicted a break-even in the end of the next decade suggesting a positive future for the Li-ion EES in the frequency containment.

In the near future, the Finnish electricity system is going through changes with new nuclear capacity, additional wind power and retiring coal. The effects are favorable for Li-ion EES bringing more inflexible and intermittent generation to the grid and reducing grid inertia, thus raising the demand for reserves, especially for the frequency containment. Some wind power capacity forecasts were presented, where the most conservative scenarios adding about 1 GW of cumulative wind power capacity in the coming decade. If the scenarios come true, the effects on the Li-ion EES remain moderate. However, the most optimistic projections forecasted over 10 GW of wind power, which would induce interest for storing electricity. Still, for pure energy arbitrage solutions, grid-scale Li-ion does not seem that potential, at least with the forecasted Li-ion EES cost development. Instead, the excessive wind power would highly increase the demand for reserves.

The upcoming FCR-N rules were found promising to the Li-ion EES, while the most uncertainties were related to the frequent and unpredictable policy changes, however. Furthermore, the current legislation was found not to be favoring the Li-ion EES, but a change in the taxation legislation is expected in 2019.

Demand response was not considered as a threat as the recent large-scale DR demonstration projects in Finland have accompanied a Li-ion EES. Furthermore, DR is first expected to attend technically less demanding marketplaces, such as day-ahead markets, making DR compete in different markets than the Li-ion EES.

All things considered, the overall market conditions and trends seem favorable for the Li-ion EES. The Li-ion EES is well suited for the frequency containment, while the market trends are favorable. While the energy arbitrage applications are not expected, combining with the fact of the decreasing installed costs of the Li-ion EES and the improving technical performance, the Li-ion EES might become a key part of the frequency regulation in the electricity system in the next decade while the share of intermittent and inflexible generation increase.

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