Techno-economic analysis of the deployment potential of energy storage for grid connected applications

Niklas Sebastian Günter

Thesis to obtain the Master of Science Degree in

Energy Engineering and Management

Supervisors: Prof. Duarte de Mesquita e Sousa

Prof. João José Esteves Santana

Examination Committee

Chairperson: Prof. José Alberto Falcão de Campos

Supervisor: Prof. Duarte de Mesquita e Sousa

Members of Committee: Prof. Pedro Manuel Santos de Carvalho

December 2015
Acknowledgment

This thesis has been completed during my time at the ABB Corporate Research Center in Västerås, Sweden. I would like to thank ABB for giving me the opportunity to work at their facilities among world class scientists and for the insightful experience during these six months in the world of industrial research.

I would like to express my deepest gratitude to my supervisor Dr. Antonis Marinopoulos for his guidance and patience during the process of finding a suitable thesis topic and developing this thesis and for giving me the freedom to explore and follow my interests. It would not have been possible to complete this thesis without your assistance. Thank you to my supervising professors at the Instituto Superior Técnico, Lisbon, Prof. João José Esteves Santana and Prof. Duarte de Mesquita e Sousa, for your helpful feedback and comments and the support in overcoming administrative obstacles. Furthermore, I would like to thank Tomas Tengnér, Dr. Stefan Thorburn, Dr. Giovanni Velotto, Dr. Lars Gertmar, and Dr. Theodore Soong for sharing their extensive knowledge through fruitful discussions and encouraging me to think outside the box. Learning from the best these past six months has been such an eye-opener and I am deeply thankful for the opportunity to learn more about the subject I am passionate about.

Many warm thanks go out to all my fellow master’s thesis colleagues and the temporary employees from around the world for their friendship and support, fun fikas and after work activities, for sharing the thesis writing experience, intercultural exchange and Swedish lessons, for being amazing flatmates, and providing endless laughter. Thank you Ilka Jahn, Theo Soong, Alexandra Kapidou, Daniele Petrili, Herman Hornequist, Matilda Ornkloo, Maja Grubisic, Ziwei Li, Ashkan Nami, Minos Beniakar, Diana Beccherelli, Asad Raja, Maura Gallarotti, and Joydeep Mukherjee for becoming such great friends and making my experience in Sweden so memorable. All of you added so much color to my life and I feel very blessed to have met you all.

Last but definitively not the least, my dearest family, thank you for being so supportive and always believing in me. Thank you for being my pillars of strength and always being there for me.
Abstract

Electric energy storage can provide several services and is used in a variety of applications today. New and improved technologies and decreasing cost of batteries make electric energy storage already competitive in certain applications and with increasing share of renewable energy resources the need for energy storage increases.

This thesis defines and examines services that can be provided by grid connected energy storage and presents the applications in which these services can be deployed, including several examples of projects that have been realized. Five current and potential future markets have been studied and the deployment potential for grid connected energy storage in these markets has been analyzed. From the combination of services, applications, and markets a value proposition can be derived. This value proposition is used for the development of metrics for measuring the benefits of deployment cases of energy storage.

A methodology for the definition of a deployment case of energy storage has been developed as well as a cost-benefit model which analyzes the sensitivity of the cost-efficiency of the deployment case towards certain sensitivity parameters. Deployment cases have been defined for frequency regulation in the eastern United States and peak limiting in California and examined in cost-benefit and sensitivity analyses. The results show that energy storage is cost-efficient for these deployment cases even if frequency regulation market prices and subsidies drop below today’s level. Furthermore, it could be shown that the combination of compatible services can offer additional revenue streams.

From the analyses conducted in this thesis it can be concluded that energy storage offers valuable alternatives to current grid resources and can help integrate fluctuating generation and demand if market structures are in place that treat energy storage and the services it offers in a fair way.

Keywords:

energy storage; battery; cost-benefit analysis; market analysis; frequency regulation; peak limiting
Resumo

O armazenamento de energia eléctrica está, hoje em dia, associada ao fornecimento de diversos serviços e a várias aplicações. Os desenvolvimentos tecnológicos mais recentes conjuntamente com a redução do preço das baterias têm contribuído para que o armazenamento de energia eléctrica seja uma solução competitiva em determinadas aplicações. Por outro lado, a crescente geração de energia a partir de fontes renováveis requer soluções para armazenamento da energia eléctrica.

Esta tese define e investiga serviços que podem ser prestados através dos sistemas de armazenamento de energia integrados nas redes eléctricas e descreve as aplicações em que estes serviços podem ser implantados, incluindo vários exemplos de projetos que têm sido realizados. Partindo de cinco mercados já existentes foi analisado o potencial futuro de integração de sistemas de armazenamento de energia nestes mercados. A partir da combinação de serviços, aplicações e mercados é possível propor soluções economicamente viáveis. Estas propostas foram utilizadas para o desenvolvimento de métricas para medir os benefícios da implementação de soluções para armazenamento de energia.

Neste trabalho foi desenvolvida uma metodologia para a definição de solução com armazenamento de energia, assim como como um modelo de análise de custos-benefícios com análise de sensibilidade a determinados parâmetros. Para esta abordagem foram usadas soluções para regulação da frequência no leste dos Estados Unidos, limitações de pico na Califórnia, tanto na análise custo-benefício como na sensibilidade a parâmetros. Os resultados mostram que o armazenamento de energia é vantajoso em termos de custo, mesmo que os preços da energia e os subsídios se venham a situar abaixo dos níveis actuais. Além disso, ficou demonstrado que a combinação de serviços compatíveis pode conduzir a receitas adicionais.

A partir das análises realizadas nesta dissertação, pode-se concluir que o armazenamento de energia constitui desde já uma alternativa válida como recurso para integração nas redes eléctricas. Por outro lado, o armazenamento de energia desempenha um papel importante em redes que integram soluções de geração de energia e de carga intermitentes se o mercado reconhecer a sua importância e do serviço que oferece.

Palavras-chave: armazenamento de energia; bateria; análise de custo-benefício; análise de mercado; regulação de frequência; limitação de pico
# Table of Contents

Abbreviations ........................................................................................................... I

List of Figures ............................................................................................................. II

List of Tables .............................................................................................................. VI

1 Introduction ............................................................................................................. 1

1.1 Status quo and Research Challenges ...................................................................... 1

1.2 Objective and Approach ....................................................................................... 2

2 Background .............................................................................................................. 5

2.1 Services ............................................................................................................... 5

2.1.1 Large Scale Energy Time-Shift ........................................................................ 6

2.1.2 Electric Supply Capacity .................................................................................. 7

2.1.3 Reserves ........................................................................................................... 7

2.1.4 Frequency Regulation ...................................................................................... 9

2.1.5 Load Following ................................................................................................ 11

2.1.6 Black Start Capability ..................................................................................... 13

2.1.7 Load Leveling ................................................................................................ 13

2.1.8 Transmission and Distribution (T&D) Congestion Relief and Investment Deferral .... 14

2.1.9 Voltage Support .............................................................................................. 16

2.1.10 Power Quality ................................................................................................ 17

2.1.11 Electric Service Reliability ............................................................................ 18

2.1.12 Peak Limiting ................................................................................................ 18

2.1.13 Time-of-Use Shifting .................................................................................... 19

2.1.14 Renewable Energy Capacity Firming ............................................................ 20

2.1.15 Renewable Energy Ramp Rate Control .......................................................... 21

2.1.16 Renewable Energy Time-Shift ...................................................................... 22

2.2 Applications ....................................................................................................... 23

2.2.1 At Generation Site .......................................................................................... 24

2.2.2 In the Transmission Grid ............................................................................... 26

2.2.3 In the Distribution Grid .................................................................................. 26
5.1 Deployment Case 1 – Frequency Regulation in PJM .......................................................... 55
  5.1.1 Case Definition ........................................................................................................... 55
  5.1.2 Cost-Benefit Analysis ............................................................................................... 56
  5.1.3 Sensitivity Analysis .................................................................................................. 59

5.2 Deployment Case 2 – Peak Limiting in California ......................................................... 65
  5.2.1 Case Definition ........................................................................................................ 65
  5.2.2 Cost-Benefit Analysis .............................................................................................. 67
  5.2.3 Sensitivity Analysis .................................................................................................. 70

6 Conclusion and Future Research ....................................................................................... 77

References .......................................................................................................................... 80

A. Appendix .......................................................................................................................... 86
  A1. Energy Storage Mind Map ............................................................................................ 87
  A2. Services Compatibility Matrix ....................................................................................... 88
  A3. Cost-Benefit Calculation for Deployment Case 1 – Frequency Regulation in PJM ......... 89
  A5. Sensitivity Results Case 2 – Peak Limiting: Food Processor ........................................ 91
  A6. Sensitivity Results Case 2 – Peak Limiting: Office Building ........................................ 94
### Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC</td>
<td>Alternating Current</td>
</tr>
<tr>
<td>ACE</td>
<td>Area Control Error</td>
</tr>
<tr>
<td>BCR</td>
<td>Benefit/Cost Ratio</td>
</tr>
<tr>
<td>BOP</td>
<td>Balance of Plant</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>Commercial and Industrial</td>
</tr>
<tr>
<td>CBA</td>
<td>Cost-Benefit Analysis</td>
</tr>
<tr>
<td>EAA</td>
<td>Equivalent Annual Annuity</td>
</tr>
<tr>
<td>ESS</td>
<td>Energy Storage System</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>IPP</td>
<td>Independent Power Producer</td>
</tr>
<tr>
<td>IRR</td>
<td>Internal Rate of Return</td>
</tr>
<tr>
<td>ISO</td>
<td>Independent System Operator</td>
</tr>
<tr>
<td>LCODE</td>
<td>Levelized Cost of Discharged Energy</td>
</tr>
<tr>
<td>LMP</td>
<td>Locational Marginal Price</td>
</tr>
<tr>
<td>MIRR</td>
<td>Modified Internal Rate of Return</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>PB</td>
<td>Payback Period</td>
</tr>
<tr>
<td>PCS</td>
<td>Power Conversion System</td>
</tr>
<tr>
<td>PJM</td>
<td>Pennsylvania-New Jersey-Maryland Interconnection LLC</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>RE</td>
<td>Renewable Energy</td>
</tr>
<tr>
<td>RMCCP</td>
<td>Regulation Market Capability Clearing Price</td>
</tr>
<tr>
<td>RMCP</td>
<td>Regulation Market Clearing Price</td>
</tr>
<tr>
<td>RMPCP</td>
<td>Regulation Market Performance Clearing Price</td>
</tr>
<tr>
<td>RTO</td>
<td>Regional Transmission Organization</td>
</tr>
<tr>
<td>SOC</td>
<td>State of Charge</td>
</tr>
<tr>
<td>T&amp;D</td>
<td>Transmission and Distribution</td>
</tr>
<tr>
<td>TOU</td>
<td>Time-of-Use</td>
</tr>
<tr>
<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
</tr>
<tr>
<td>η_sys</td>
<td>System Efficiency</td>
</tr>
</tbody>
</table>
List of Figures

Figure 1-1 Approach to develop metrics for measuring ESS benefits .................................................. 3
Figure 2-1 Energy storage services and their application groups (pictures from [ABB 2012; Texas
Electricity Alliance 2011]) .............................................................................................................. 5
Figure 2-2 Energy storage for energy time-shift [Energy Storage Association (ESA) 2015] ............... 6
Figure 2-3 ESS for electric supply capacity substituting a conventional peak power plant (source: AES
Energy Storage cited in [Energy Storage Coalition 2014]) ............................................................... 7
Figure 2-4 ESS used for reserve capacity [Akhil et al. 2013] ............................................................. 9
Figure 2-5 Frequency regulation provided by ESS: System load (top) and ESS power (below) [Akhil
et al. 2013] ...................................................................................................................................... 10
Figure 2-6 Load following in the daily load cycle [Eyer & Corey 2010] ................................................. 11
Figure 2-7 Possible ESS operations for load following [Eyer & Corey 2010] ........................................ 12
Figure 2-8 Ideal load leveling by an ESS over a period of one day [Sabihuddin et al. 2015] ........... 14
Figure 2-9 Transmission line congestion relieved by an ESS [Akhil et al. 2013] ................................. 15
Figure 2-10 ESS used for T&D investment deferral [Akhil et al. 2013] ............................................. 16
Figure 2-11 ESS providing voltage support [Akhil et al. 2013] ............................................................ 17
Figure 2-12 ESS providing power quality services by smoothing grid voltage (adapted from [Akhil
et al. 2013]) .................................................................................................................................. 18
Figure 2-13 Peak limiting using an ESS discharging during peak power consumption (adapted from
[Sharp 2015]) .................................................................................................................................. 19
Figure 2-14 Typical Time-of-Use rate structure [Southern California Edison (SCE) 2015] .............. 20
Figure 2-15 RE capacity firming of short term intermittancy [Energy Storage Association (ESA) 2015]
............................................................................................................................... 21
Figure 2-16 RE ramp rate control with an ESS for a photovoltaic power plant (adapted from [Wood
2012]) ................................................................................................................................................ 22
Figure 2-17 RE time-shift with an ESS for increased self-consumption [Bosch 2015] ....................... 23
Figure 2-18 Overview of locations of ESS applications ................................................................. 24
Figure 2-19 Categories of policy actions approaching a working energy storage market [Stanfield &
Vanega 2015] ................................................................................................................................ 29
Figure 2-20 Transmission zones in the USA according to FERC Order 1000 [FERC 2014] .............. 30
Figure 2-21 Process of the development of market rules in the US ...................................................... 31
Figure 2-22 Frequency regulation signals RegA (blue) and RegD (green) in PJM [PJM 2013] .......... 33
Figure 2-23 Regulation market clearing process in PJM [PJM 2015b] ............................................... 34
Figure 2-24 Legislation process in California ...................................................................................... 35
Figure 3-1 Metrics development process with the input parameters service, market and application.. 40
Figure 4-1 Main section of ESS and energy losses [Zakeri & Syri 2015] .......................................... 44
Figure 4-2 Process of developing an ESS deployment case................................................................. 45
Figure 4-3 Decision flow for step 1: Opportunity definition................................................................. 45
Figure 4-4 Decision flow for step 2: Solution requirements ................................................................. 45
Figure 4-5 Decision flow for step 3: Validation of services................................................................. 46
Figure 4-6 The value of stacking services [KEMA 2012]................................................................. 47
Figure 4-7 Decision flow for step 4: ESS characteristics................................................................. 47
Figure 4-8 Layers of effects of infrastructure projects [Think 2013]............................................. 48
Figure 4-9 Calculation flow for Cost-Benefit Analysis ................................................................. 48
Figure 5-1 AES Laurel Mountain ESS providing frequency regulation in PJM [Shelton 2013]......... 55
Figure 5-2 Locational marginal prices and assigned regulation power on a typical day (data from [PJM
2015a])........................................................................................................................................ 58
Figure 5-3 NPV in dependence on Power-to-Energy ratio................................................................. 60
Figure 5-4 Rates of return in dependence on Power-to-Energy ratio................................................ 60
Figure 5-5 NPV in dependence on PCS lifetime................................................................................. 61
Figure 5-6 Rates of return in dependence on PCS lifetime ............................................................. 61
Figure 5-7 NPV in dependence on battery lifetime......................................................................... 61
Figure 5-8 Rates of return in dependence on battery lifetime........................................................... 61
Figure 5-9 NPV in dependence of PCS cost .................................................................................... 62
Figure 5-10 Rates of return in dependence of PCS cost................................................................. 62
Figure 5-11 NPV in dependence of battery cost............................................................................ 62
Figure 5-12 Rates of return in dependence of battery cost............................................................. 62
Figure 5-13 NPV in dependence on the available energy capacity for time-shifting.................... 63
Figure 5-14 Rates of return in dependence on the available energy capacity for time-shifting ...... 63
Figure 5-15 NPV in dependence of the RMCP ............................................................................. 64
Figure 5-16 Rates of return in dependence of the RMCP ............................................................. 64
Figure 5-17 Difference of NPVs without and with time-shifting in dependence on the RMCP...... 64
Figure 5-18 Difference of rates of return without and with time-shifting in dependence on the RMCP
....................................................................................................................................................... 64
Figure 5-19 ESS at Gills Onions for peak limiting and TOU shifting [Department of Energy 2015].. 65
Figure 5-20 Load Profile: Food Processor [EnerNOC 2013].............................................................. 66
Figure 5-21 Load Profile: School [EnerNOC 2013]........................................................................ 66
Figure 5-22 Load Profile: Office Building [EnerNOC 2013]............................................................ 66
Figure 5-23 TOU electricity prices for deployment case 2 – Peak limiting in California.............. 69
Figure 5-24 NPV in dependence on an increased energy capacity .................................................. 70
Figure 5-25 Payback period in dependence on an increased energy capacity ................................ 70
Figure 5-26 NPV in dependence on the PCS lifetime ..................................................................... 71
Figure 5-27 Payback period in dependence on the PCS lifetime .................................................... 71

III
Figure 5-28 NPV in dependence on the battery lifetime .......................................................... 71
Figure 5-29 Payback period in dependence on the battery lifetime ........................................... 71
Figure 5-30 NPV in dependence on PCS cost ..................................................................... 72
Figure 5-31 Payback period in dependence on PCS Cost ......................................................... 72
Figure 5-32 NPV in dependence on battery cost ................................................................... 72
Figure 5-33 Payback period in dependence on battery cost ...................................................... 72
Figure 5-34 NPV in dependence on peak load reduction .......................................................... 73
Figure 5-35 Payback period in dependence on peak load reduction .......................................... 73
Figure 5-36 NPV in dependence on the number of limited values .............................................. 74
Figure 5-37 Payback period in dependence on the number of limited values ............................. 74
Figure 5-38 NPV in dependence on the electricity tariff ........................................................... 75
Figure 5-39 Payback period in dependence on the electricity tariff .......................................... 75
Figure 5-40 NPV in dependence on the subsidies ................................................................. 75
Figure 5-41 Payback period in dependence on the subsidies ..................................................... 75
Figure A-1 Energy storage mind map ..................................................................................... 87
Figure A-2 Compatibility of different services according to [Eyer & Corey 2010] p. 121 ........ 88
Figure A-3 Cost-Benefit Calculation for Deployment Case 1 – Frequency Regulation in PJM ... 89
Figure A-4 Cost-Benefit Calculation for Deployment Case 2 – Peak Limiting in California: School. 90
Figure A-5 NPV in dependence on an increased energy capacity ............................................... 91
Figure A-6 Payback period in dependence on an increased energy capacity .............................. 91
Figure A-7 NPV in dependence on the PCS lifetime ............................................................... 91
Figure A-8 Payback period in dependence on the PCS lifetime ............................................... 91
Figure A-9 NPV in dependence on the battery lifetime .......................................................... 91
Figure A-10 Payback period in dependence on the battery lifetime .......................................... 91
Figure A-11 NPV in dependence on PCS cost ...................................................................... 92
Figure A-12 Payback period in dependence on PCS Cost ....................................................... 92
Figure A-13 NPV in dependence on battery cost ................................................................. 92
Figure A-14 Payback period in dependence on battery cost .................................................... 92
Figure A-15 NPV in dependence on peak load reduction ......................................................... 92
Figure A-16 Payback period in dependence on peak load reduction ......................................... 92
Figure A-17 NPV in dependence on the number of limited values .............................................. 93
Figure A-18 Payback period in dependence on the number of limited values ............................. 93
Figure A-19 NPV in dependence on the electricity tariff .......................................................... 93
Figure A-20 Payback period in dependence on the electricity tariff .......................................... 93
Figure A-21 NPV in dependence on the subsidies ................................................................. 93
Figure A-22 Payback period in dependence on the subsidies .................................................... 93
Figure A-23 NPV in dependence on an increased energy capacity ............................................. 94
Figure A-24 Payback period in dependence on an increased energy capacity ................................................. 94
Figure A-25 NPV in dependence on the PCS lifetime ................................................................................... 94
Figure A-26 Payback period in dependence on the PCS lifetime ................................................................. 94
Figure A-27 NPV in dependence on the battery lifetime .............................................................................. 94
Figure A-28 Payback period in dependence on the battery lifetime ............................................................ 94
Figure A-29 NPV in dependence on PCS cost ............................................................................................ 95
Figure A-30 Payback period in dependence on PCS Cost ........................................................................... 95
Figure A-31 NPV in dependence on battery cost ....................................................................................... 95
Figure A-32 Payback period in dependence on battery cost ....................................................................... 95
Figure A-33 NPV in dependence on peak load reduction ........................................................................... 95
Figure A-34 Payback period in dependence on peak load reduction ........................................................... 95
Figure A-35 NPV in dependence on the number of limited values ............................................................. 96
Figure A-36 Payback period in dependence on the number of limited values ............................................. 96
Figure A-37 NPV in dependence on the electricity tariff ............................................................................. 96
Figure A-38 Payback period in dependence on the electricity tariff ............................................................ 96
Figure A-39 NPV in dependence on the subsidies ....................................................................................... 96
Figure A-40 Payback period in dependence on the subsidies ....................................................................... 96
List of Tables

Table 4-1 Financial boundary conditions: general values ................................................................. 49
Table 4-2 Total capital cost: typical values .................................................................................. 50
Table 4-3 Operation and maintenance cost: typical values ......................................................... 50
Table 4-4 Disposal Costs: Typical values ..................................................................................... 51
Table 5-1 Input values: Deployment case 1 - Frequency regulation ........................................... 56
Table 5-2 Input data for benefit calculation: Deployment case 1 - Frequency regulation .......... 59
Table 5-3 Results of CBA: Deployment Case 1 - Frequency regulation ..................................... 59
Table 5-4 Input values: Deployment case 2 - Peak Limiting in California ............................... 68
Table 5-5 Yearly electricity bill of the three cases in deployment case 2 – Peak limiting in California
...................................................................................................................................................... 69
Table 5-6 Results of CBA: Deployment Case 2 - Peak limiting in California ............................ 69
Table 5-7 Electricity tariffs for sensitivity analysis ...................................................................... 74
1 Introduction

Electric energy storage has been deployed for well over two centuries since Volta built the first electrochemical battery in 1800 and has always been a part of the electricity system [Clifford 2013; Whittingham 2012]. Due to their limited power and energy capacities though, until recently batteries have been used mainly in small scale and mobile applications.

The need for energy storage has been in existence since the start of the first locally isolated grids a century ago to today’s internationally interconnected grids. This need is a result of the variable demand from the consumer side in the electrical grid and an increasing deployment of fluctuating renewable energy sources. This problem of trying to meet a varying load with a variable supply could only partly be solved by pumped hydro storage plants [Vassallo et al. 2015]. Most of the energy storage capability needed to meet flexibility requirements, however, has been provided in the form of stored chemical energy in fossil fuels like coal or natural gas, allowing thermal power plants to ramp up or down their generation following demand.

1.1 Status quo and Research Challenges

With increasing deployment of renewable energy resources such as wind and solar photovoltaic (PV) adding variability at the generation side as well, the need for flexible grid resources like electric energy storage is increasing. Several energy storage projects have been realized to support the integration of renewable energy sources, but also as stand-alone resources providing grid services. Commercial and industrial consumers use energy storage solutions for reliability purposes, to increase efficiency and to lower their electricity bill [Department of Energy 2015]. In residential applications home owners with rooftop solar photovoltaic increase their self-consumption of renewable energy with the help of small scale energy storage systems. Depending on the application, energy storage systems (ESSs) are capable of providing different valuable services. When placed on the transmission level in the grid, ESSs can participate in the wholesale market and supply ancillary services, such as frequency regulation or black start capability. On the distribution level further ancillary services like power quality and voltage support can be provided, behind the meter at the customer side reliability and energy management can be offered. In combination with renewable energy power plants, ESSs can serve in firming power output and matching it to the forecasted generation.

In this context it is important to note that the definitions of the terms “service” and “application” vary among the reviewed literature and are sometimes used interchangeably. Within this thesis the term “service” describes the electrical operation that is fulfilled by the energy storage system including its power conversion system. A service could for example be frequency regulation. The term “application” describes the location within the grid and the connection and functionality of the ESS in relation to its surrounding infrastructure as well as its technical characteristics. An example for an
application is an ESS located at a renewable power plant and used to avoid curtailment. The term “benefit”, which in the literature also often describes a service, is used in this thesis exclusively for financial benefits, e.g. savings achieved in $/kWh per year. While the term “energy storage” can generally refer to the storage of all forms of energy, in this thesis only storage technologies for storage and discharge of electricity are considered, i.e. mainly electrochemical batteries. For the purpose of electrical energy storage different technologies and battery chemistries may be applicable. However, the scope of this thesis does not include a differentiation or comparison of these technologies.

Technological advancements in battery research and manufacturing in combination with increasing demand for electric vehicles have caused a cost reduction that can make the use of energy storage in stationary applications profitable today [Tweed 2015a]. Whether or not energy storage is profitable in a specific application strongly depends on several factors that will be identified and examined in this thesis. Market structures and their respective legislation and regulations can have a prohibitive influence on the economic feasibility of energy storage deployment. While in some countries there is a proper valuation and competitive market for some services provided by ESSs, in others this market structure is missing and energy storage is not considered in the current legislation resulting in more costly solutions and effectively a market failure [Castillo & Gayme 2014]. This thesis will present exemplary markets in the USA, Germany, Australia, and Japan and analyze the challenges that legislative authorities and regulatory entities are facing regarding the recognition of energy storage.

Further difficulties lie in the effective valuation of ESSs. Universally applicable metrics are missing, partly due to the fact that different combinable services are generating different revenue streams and benefiting different entities. This raises the questions “Who should own and operate an energy storage system?” and “How will the services it provides be paid for?” These problems currently addressed in literature have been insufficiently covered in regulation until today, resulting in inadequate compensation for ESSs in grid applications [Castillo & Gayme 2014]. In this thesis metrics for several services and applications are developed and presented, focusing mainly on grid applications and commercial and industrial (C&I) applications.

1.2 Objective and Approach

The objective of this thesis is to analyze the deployment potential of grid connected energy storage systems (ESS) in dependence on the services provided, the application that employs the ESS, and the respective market in which the ESS participates. Therefore services, applications, and a selection of markets are presented and analyzed thoroughly in order to identify possible dependencies, business cases and metrics. In order to obtain a better overview over services, applications, and markets, a mind map has been created which is presented in appendix A1. The services, application, and markets are then used to develop appropriate metrics to measure the benefits that ESSs are able to offer, illustrated in Figure 1-1.
Methodologies for the definition of clear deployment cases of ESSs and for a cost-benefit analysis including a sensitivity analysis are developed. These methodologies are then employed to analyze two exemplary deployment cases of ESSs and the dependencies of their economic feasibility on certain sensitivity parameters.

Figure 1-1 Approach to develop metrics for measuring ESS benefits
2 Background

There is a great variety of services provided by energy storage systems in a wide range of applications. These applications cover the whole energy supply chain from generation through the transmission and distribution network to the end-consumers. In some markets, services are recognized as market products which can be traded between market participants, whereas in other markets most of the possible services that ESSs can offer are internalized in the existing electricity system and cannot be valuated. In this chapter, different services provided by ESSs are defined and described, energy storage applications are introduced and exemplified by projects that have been realized around the world, and different potential markets for ESSs in the USA, Germany, Australia and Japan are presented including their legislation and regulation.

2.1 Services

Depending on the application, an ESS can provide multiple services, although it is important to consider whether or not these services can be called upon at the same time.

<table>
<thead>
<tr>
<th>Generation side</th>
<th>T&amp;D System</th>
<th>End-Consumer</th>
<th>Renewables integration</th>
</tr>
</thead>
<tbody>
<tr>
<td>• (Large scale) Energy time-shift</td>
<td>• Load leveling</td>
<td>• Electric service reliability</td>
<td>• RE Capacity firming</td>
</tr>
<tr>
<td>• Electric supply capacity</td>
<td>• T&amp;D Congestion relief and upgrade deferral</td>
<td>• Peak limiting</td>
<td>• RE Ramp rate control</td>
</tr>
<tr>
<td>• Reserves</td>
<td>• Voltage support</td>
<td>• Time-of-Use shifting</td>
<td>• RE Time-shift</td>
</tr>
<tr>
<td>• Frequency regulation</td>
<td>• Power quality</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Black start capability</td>
<td>• Load following</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Load following</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Figure 2-1 Energy storage services and their application groups* (pictures from [ABB 2012; Texas Electricity Alliance 2011])

The definitions for services vary throughout the literature and can be somewhat arbitrary since each service is derived from the simple storage operations of energy charging (power absorption) or energy discharging (power injection) over a certain period of time. In this thesis the following services are
considered according to the definitions in this section and are roughly grouped according to their most common applications as shown in Figure 2-1. It is important to note that the services as they are defined here do not always match market products.

2.1.1 Large Scale Energy Time-Shift

Energy time-shift generally describes the transfer of electric energy from one time period to another. On the generation side of the grid this service is performed by large scale storage facilities with energy discharge capacities ranging from several MWh to several GWh, e.g. pumped hydro storages (PHS), compressed air energy storages (CAES) and large battery banks [Akhil et al. 2013; Poullikkas 2013]. For large scale energy time-shift the storage typically participates in the wholesale market and is charged during low load periods (off-peak) when the electricity price is low and discharged during high load periods (peak) when the electricity price is high as shown in Figure 2-2. Revenue is generated due to the price difference between the charging and discharging price. Often this is referred to as arbitrage which is, from a financial point of view, not entirely correct since the meaning of arbitrage in finance is the simultaneous purchase and sale of a commodity [Eyer & Corey 2010]. For energy time-shifting, however, charging and discharging occur by definition at separate time points, often several hours or days apart. The goal of large scale energy time-shift is usually the maximization of profit gained by trading electricity on the wholesale market. Potential storage operators for this service are independent power producers (IPPs) and also utilities.

Figure 2-2 Energy storage for energy time-shift [Energy Storage Association (ESA) 2015]

ESSs providing large scale energy time-shift services require a discharge duration of one to several hours in order to accommodate a utility’s daily peak demand period with a power capacity ranging from one MW to hundreds of MW. The round-trip efficiency of the storage is an especially critical characteristic of this service as it influences the profitability of the ESS (Eyer & Corey 2010).
2.1.2 Electric Supply Capacity

Electric supply capacity is a service that is very similar to large scale energy time-shift, being provided on the generation side of the grid with a power capacity in the range of one MW to hundreds of MW and discharge durations of up to several hours depending on the specific application and market [Akhil et al. 2013]. ESSs for electric supply capacity are charged during off-peak periods and discharged during peak periods thus reducing the overall system peak. This service lowers the need for expensive conventional peak power plants and helps to avoid inefficient part load operation of conventional power plants. Utilities benefit by having to purchase less generation capacity on the wholesale market and from deferred or avoided investments in new peak power plants. IPP may also profit from bidding their ESS into the capacity market if such market mechanisms exists in the respective country.

The advantage of ESS over conventional peak power plants lays in their flexibility, including fast ramp rates, no minimum run time or operating point, and full dispatchability of their power capacity in positive as well as in negative direction. This flexibility is illustrated in Figure 2-3.

![Figure 2-3 ESS for electric supply capacity substituting a conventional peak power plant](source: AES Energy Storage cited in [Energy Storage Coalition 2014])

2.1.3 Reserves

As there are many different definitions for the term of reserves among the literature and in different markets, the service of providing reserves is defined here generally as the capacity to inject active power into the grid in order to cover unexpected deviations in generation and demand. This stands in contrast to frequency regulation which covers expected deviations and will be addressed in section 2.1.4.
Reserves are commonly grouped according to response time [Pearre & Swan 2014], whether or not they are synchronized to the grid frequency, and whether they respond to a control signal or automatically [Kirschen & Rebours 2005]. Most of the literature uses the terminology of the North American markets referring to spinning reserve (synchronized), non-spinning reserve (non-synchronized) and supplemental reserve [NERC 2013]. Here the reserves cover at least the power capacity of the single largest resource serving the respective system of the responsible regional transmission organization (RTO) or independent system operator (ISO) [Akhil et al. 2013]. In Europe the reserves are divided according to the ENTSO-E (European network of transmission system operators for electricity) terminology into primary control reserve, secondary control reserve, and tertiary control or minute reserve [ENTSO-E 2015]. The reserve capacity has to be able to cover the simultaneous outage of at least the two largest generating resources in the ENTSO-E area [Beck et al. 2013].

Energy storage systems are capable of providing all categories of reserves. However, due to their limited energy capacity and high flexibility batteries are best suited to provide reserves which cover a short time frame and require fast reaction times such as spinning reserve and primary control reserve. Currently reserves are mainly provided by PHS and thermal power plants running in inefficient part load operation in order to be available quickly. An ESS used for reserves only has to be ready to discharge if necessary. During the time of charging, storage can even provide twice its interconnected power capacity for reserves: once its capacity rating by decreasing the load when it stops charging and once its capacity rating by providing power when it starts to discharge instead [Eyer & Corey 2010]. This case is comparable with the flexibility shown in Figure 2-3. Typical ESS power capacity values for reserve services range from 10 to 100 MW with discharge durations up to one hour depending on the market regulations [Akhil et al. 2013]. The graphs in Figure 2-4 show an exemplary reaction of an ESS providing spinning reserves to a loss of generation capacity. The upper graph depicts the system generation capacity including a generation outage on Wednesday morning. The lower graph shows the quick response of the ESS discharging for 30 minutes until additional generation capacity can take over followed by a longer charging period.
2.1.4 Frequency Regulation

The service of frequency regulation suits especially well to the characteristics of energy storage. Frequency regulation serves the purpose of balancing expected short term deviations of generation and loads in order to maintain the grid frequency within a tolerance band around a certain level, 50 Hz in Europe and 60 Hz in North America. Differences in generation and loads are reflected in the change of grid frequency. If generation exceeds demand (overproduction), the frequency increases. Conversely if generation is lower than demand (underproduction), the frequency decreases. These differences are dampened by frequency regulation resulting in a smoothed load curve as shown in the top graph in Figure 2-5. The thin line in the top graph is an exaggerated representation of the load without frequency regulation while the thick line depicts the load after frequency regulation. The lower graph in Figure 2-5 shows the response of an ESS to the regulation signal, either charging or discharging to absorb or inject active power into the grid.

Frequency regulation is traditionally provided by generation resources like thermal power plants that are online and increase (up regulation) or decrease (down regulation) their power output as needed. Most of these thermal generation units, however, are not particularly well-suited for frequency regulation as they are not designed to operate at partial load or with quickly varying output. In partial load operation their efficiency decreases while emissions per kWh increase. Fast ramp rates and varying power output result in increased wear and tear of the plant equipment [Eyer & Corey 2010]. Other frequency regulation resources include demand response resources like variable speed pumps and ceramic thermal storage, behind-the-meter energy storage like water heaters and plug-in (hybrid) electric vehicles, and ESSs in the grid that are addressed here [PJM 2013].
Figure 2-5 Frequency regulation provided by ESS: System load (top) and ESS power (below) [Akhil et al. 2013]

The quick response time and fast ramp rates are advantages of ESSs that make them very valuable for frequency regulation. Due to their flexibility, ESSs can follow regulation signals very closely and can thus reduce the overall need for frequency regulation services in the system [Tweed 2013]. Additionally, efficient storage can act as a regulation resource with twice its interconnected power rating, discharging for up regulation and charging for down regulation as has been shown in Figure 2-3. When the storage is charging it absorbs energy from the grid for which the ESS operator has to pay. This must be considered when evaluating the economic benefits of providing frequency regulation, especially for storage technologies with low efficiency [Eyer & Corey 2010].

ESSs for frequency regulation have power capacities in the range of 10 to 40 MW with discharge durations between 15 and 60 minutes and are located on the generation side of the grid [Akhil et al. 2013]. The minimum values for these characteristics are strongly market dependent. An ESS providing frequency regulation needs to be able to follow the automatic generation control (AGC) signal from the system operator or react to the area control error (ACE), the difference between scheduled and actual generation within the respective control area of the grid. When operating an ESS for frequency regulation, it must be considered that most ESSs cannot provide other services simultaneously. Nevertheless other (more valuable) services could be provided at any time instead of frequency regulation [Eyer & Corey 2010].

The remuneration for frequency regulation is highly market and country dependent. In some markets there are rules and compensation mechanisms which take into account the special capabilities and needs of storage, and regulation capacities are tradable commodities [PJM 2015b]. In other markets,
frequency regulation is an obligation fulfilled by generators who receive a fixed compensation regardless of the actual performance of the service provided [Chanoine 2013]. Frequency regulation as it is defined here is included in the primary control reserve under the ENTSO-E definition mentioned in section 2.1.3 and is thus not treated as a separate product in the European markets.

2.1.5 Load Following
Load following is another service that maintains the balance in the system reacting to fluctuations in generation and demand. It is mainly needed to follow the load in the so called “shoulder hours” in the morning when demand increases and in the evening when demand decreases. Following increasing demand is also called “load following up” while following decreasing demand is called “load following down” [Eyer & Corey 2010]. The working principle of load following is depicted in Figure 2-6.

To provide load following, generation resources have to ramp up or down their power output. This requires part load operation which entails lower efficiency and higher emissions per unit energy generated when using thermal power plants. Variable output also increases wear and tear and thus leads to reduced lifetime of the equipment and higher maintenance costs [Akhil et al. 2013].

The utilization of energy storage allows generation resources like thermal power plants to run at a constant output level, ideally the design output, and to be started only when operation at a constant level can be assured. Most storage technologies are very suitable for the supply of load following services since they hardly face any constraints when running in part load operation. ESSs can react quickly to changes in demand and can provide load following by charging and discharging. Figure 2-7 shows two possible ESS operations each for providing load following up and load following down.
Load following up can be provided by reducing charging while a generation resource is operating at constant level until the additional load equals the power output of the generation resource (top left). Another way to provide load following up with an ESS involves an increase in discharging power until the design output of a generation resource is met which is then kept at a constant output level (top right). For load following down the charging power can be increased while a generation resource delivers constant output until it can be switched off (bottom left). Load following down can also be provided by reducing the discharging power of the ESS until the load following requirement drops under the design output of a generation resource which then can be switched off (bottom right).

Figure 2-7 Possible ESS operations for load following [Eyer & Corey 2010]

When providing load following services with an ESS, it is important to note that the energy required for charging and discharging must be bought and sold on the wholesale market at market prices. This might limit the profitability of less efficient ESSs and has to be taken into account when evaluating benefits from load following.

Depending on the market, there may be a fixed remuneration for the provision of load following capacity; it may be tradable between market participants, or procured via bilateral contracts. If there are sufficient fast ramping resources in the system load following might not be a separate service but instead included in the energy price at the energy spot market [Kirby 2007]. Hence, an ESS for load following can be operated by an IPP or a utility.
2.1.6 Black Start Capability

Black start capability is the service of re-energizing the grid after a major power outage has occurred and is thus located on the generation side of the grid. It is needed to provide electricity for restarting other generation resources, since most power plants depend upon electricity from the grid for start-up operations [Electric Power Research Institute (EPRI) 2010]. The active and reactive power capability of resources providing black start capability must be sufficient to energize transmission lines and restart generators. Other important requirements include fast ramping capability, a wide operating load range, and the ability to control frequency and voltage [Kirby 2007].

The service of black start capability can be provided by large ESSs with power capacities between 5 to 50 MW and discharge durations up to one hour. ESSs can fulfill all the requirements of a black start resource especially due to their fast response time and ramp rates as well as their good part load operation capability. However, providing black start capability with an ESS is economically only feasible in combination with other services in order to improve reliability of electricity supply in remote places as it has been achieved in Fairbanks, Alaska, with a 27 MW ESS [Department of Energy 2015]. For black start capability only, ESS are not very well suited due to the limited necessary number of cycles [Normark & Faure 2014].

Today black start capability is mainly provided by hydroelectric resources, PHS, and thermal power plants which employ onsite distributed generation. In addition, CAES is able to supply black start power. System operators procure black start capability and ensure that the resources are strategically well placed in order to keep transmission distances to the next generation resources as short as possible. In general providers of black start capability are compensated by the system operator for their service. This may happen through bilateral agreements or competitive tender processes which are usually cost based [Electric Power Research Institute (EPRI) 2010][Australian Energy Market Operator (AEMO) 2013].

2.1.7 Load Leveling

Load leveling is a service related to electric supply capacity. However, it is generally applied in the distribution network and thus located closer to the loads, which the ESS serves during high demand periods by discharging power. During periods with low demand, the ESS is charged. Due to this operation it helps to smooth or level the load curve of the area it serves. The cycling time of demand for this service may be anywhere in the range from minutes to seasons. If applied on a large scale, load leveling reduces the overall system peak demand and thereby the need for peak power plants [Whittingham 2012]. At the same time it also lowers the stress on transmission and distribution (T&D) infrastructure resulting from load fluctuations and peak loads [ABB 2012].

ESSs for load leveling are mainly deployed by utilities in order to decrease stress on their infrastructure like transformers and substations. As load leveling is usually not a market product,
utilities are the main stakeholders to which the benefits of this service accrue. Load leveling may also be performed by large industrial consumers with their own connection equipment to the grid, combining the service with peak limiting and time-of-use energy shifting as addressed later in sections 2.1.12 and 2.1.13 [Department of Energy 2015].

Figure 2-8 shows how ESSs can be used for load leveling, charging the storage during low demand periods and discharging it during high demand periods. While the completely leveled resulting load in Figure 2-8 is an exaggerated depiction of what load leveling can provide, it can be regarded as the ultimate goal of energy storage [Sabihuddin et al. 2015].

![Figure 2-8 Ideal load leveling by an ESS over a period of one day](Sabihuddin et al. 2015)

## 2.1.8 Transmission and Distribution (T&D) Congestion Relief and Investment Deferral

Transmission and distribution (T&D) congestion relief and investment deferral is a service that can be provided to owners and operators of infrastructure like utilities and transmission system operators (TSOs).

Transmission congestion arises when the delivery of available energy at the marginal price to all or some loads is constrained by insufficient transmission infrastructure. This situation may occur when the peak demand exceeds the capacity of transmission facilities. As a consequence electricity needs to be supplied from other more expensive sources and/or via more expensive transmission infrastructure which is reflected in higher costs for the consumer in the form of congestion charges or locational marginal prices (LMPs) for wholesale electricity at the affected transmission nodes [Akhil et al. 2013]. Congestion in the distribution network results in higher load on the distribution infrastructure and in utilization of more expensive distribution equipment leading to higher costs for the utility which will be paid by the utility customers in the end.

As a response to T&D congestion, system operators often react by investing in an upgrade of the congested infrastructure. In a different situation, high loading and load fluctuations may lead to a
reduced lifetime of T&D equipment and thus to the need of an investment in new equipment replacing the old facilities. These investments are often large lump-sum investments for additional T&D equipment. An important point to consider regarding T&D congestion and equipment replacement is the fact that the system only experiences the highest loads on a few days or a few hours per year [Eyer & Corey 2010]. The Electric Power Research Institute (EPRI) estimates that 25% of the distribution and 10% of the transmission assets are needed less than 400 hours a year [Electric Power Research Institute (EPRI) 2010]. Hence, during the majority of its operating hours the T&D infrastructure is significantly oversized.

With the help of ESSs, costs due to T&D congestion such as congestions charges can be substantially reduced and investments in new or additional equipment can be deferred or completely avoided by reducing high loads and thus extending the lifetime of existent equipment. In order to provide this service, the ESS should be installed electrically downstream of the congested or overloaded part of the T&D system. The storage would be discharged during high load periods reducing the electrical strain on the T&D equipment and charged during low load periods [Eyer & Corey 2010].

The event of T&D congestion and the response of an ESS for congestion relief are shown in Figure 2-9, where the top graph indicates four exceedances of the power capacity of a transmission line. The lower plot illustrates how an ESS can compensate the need for additional transmission infrastructure during these events [Akhil et al. 2013].

![Figure 2-9 Transmission line congestion relieved by an ESS](Akhil et al. 2013)

Figure 2-10 shows how ESSs can be used to defer or avoid an investment in additional T&D infrastructure. The upper plot displays the load of a transmission line whose maximum capacity is almost reached on Wednesday afternoon. The load exceeds the threshold at which investment in additional T&D equipment is considered. This load peak can be covered by an ESS such that the load on the transmission line remains below the investment threshold. The energy storage is discharged during the high load period and charged afterwards during a period with lower load. It is important to note that investing in a small amount of storage can provide sufficient capacity to defer or avoid a
large lump-sum investment in T&D infrastructure. This avoided cost reduces electricity rates for the consumers and increases the capacity factor of T&D equipment [Eyer & Corey 2010].

![Figure 2-10 ESS used for T&D investment deferral](Akhil et al. 2013)

### 2.1.9 Voltage Support

The maintenance of the voltage level within certain limits and of the power factor, which represents the phase shift between phase angles of voltage and current, is a requirement for electric grid operators. The service of voltage support fulfills this requirement. In contrast to all other services presented in Figure 2-1, voltage support is not an active power service. It is rather used to manage reactance caused by grid equipment and consumers that display characteristics of inductors or capacitors [Eyer & Corey 2010].

Voltage support is provided by injecting or absorbing reactive power into or from the grid and thus keeping the voltage stable. Traditionally this is done by specifically allocated power plants, preferably with synchronous generators. Today however, several technologies can act as a source or sink for reactive power such as static synchronous compensators (STATCOM) or ESSs [Kirby 2007].

In order to be capable of providing voltage support services, the power conversion system (PCS) of an ESS must be able to operate at a power factor different from one, which is the case in almost all of today’s ESSs [Akhil et al. 2013]. Depending on the location in the grid, the reactive power rating for an ESS providing voltage support ranges between 1 to 10 MVAR. It is advantageous to locate voltage support equipment close to the load as it is not possible to transport reactive power effectively over large distances [Eyer & Corey 2010].
An ESS would provide voltage support mainly with its PCS to correct the power factor and inject or absorb reactive power. During this operation no charging or discharging of the storage is required. Since voltage drops due to reactive power demand often occur when the loading on the grid is high, ESSs can support grid stability additionally by discharging active power [Eyer & Corey 2010]. Figure 2-11 shows different ways of operation of an ESS providing voltage support: injection of reactive power while discharging active power, injection of reactive power while charging with active power, and injection of reactive power without any active power operation.

ESSs for voltage support would mainly be operated by system operators at substations and utilities in the distribution grid. Large C&I consumers could also take advantage of the voltage support capability of ESSs since in most markets there is a charge for the consumption of reactive power exceeding a certain threshold which can be avoided using ESSs [E.ON Mitte AG 2013].

2.1.10 Power Quality
The quality of electric power delivered to the customers may vary due to variations in voltage magnitude, variations in the primary frequency, a low power factor, harmonics, interruptions in service and other phenomena that are caused by events in the T&D system. These power quality impairments can be corrected by ESSs located in the distribution system or directly at the customer. In order to provide power quality services, the ESS monitors the grid power and in case of any disturbance discharges with a smooth power output.

ESSs for power quality may be employed by utilities, but are mainly used by C&I facilities with critical and sensitive processes that depend on a high power quality. The response time for such an ESS has to be very short, in the range of milliseconds. Depending on the application the power capacity ranges from 100 kW to 10 MW with discharge durations from a few seconds up to 15 minutes.
An example of how an ESS can ensure the power quality for a sensitive load is shown in Figure 2-12. The upper plot displays the grid voltage with a short spike of 50 V. This spike is fully absorbed by the ESS as shown in the middle plot, leading to a smooth voltage arriving at the load presented at the lower plot.

2.1.11 Electric Service Reliability

Electric service reliability is related to the power quality service and ensures uninterrupted power supply to the load in case of a complete power outage from the grid. Energy storage is especially well suited for this service due to its quick response time and is generally used on-site of C&I consumers to protect must-run equipment and ensure flawless operation. In order to provide this electric service reliability the ESS needs to be able to operate in islanding mode and resynchronize to the grid once the grid is re-energized.

The discharge duration depends on whether the ESS is used to bridge the time needed to start on-site generation resources or to provide power for an orderly shutdown of operation processes and can last between 15 minutes and 1 hour. The power rating of the ESS is very dependent on the load that it serves.

2.1.12 Peak Limiting

The service of peak limiting is used by end consumers, mainly C&I customers, to keep their maximum power draw from the grid below a certain limit. This helps them to reduce the so called demand charges, a fee that depends on the peak power draw of a customer within a defined time and which exists in most markets. Demand charges are denominated in $/kW and charged for each month for the
highest power demand averaged over a certain period, usually 15-minutes. In many tariffs the charges depend on the season, day of the week, and time of the day [Neubauer & Simpson 2015].

For many C&I customers demand charges represent a major part of their electricity bill. Using energy storage for peak limiting by discharging it during peak consumption and charging it during off-peak periods can reduce demand charges significantly, up to 50%. Since demand charges apply for the single largest peak in a month the reliability of the employed ESS is of high importance. Often the service of peak limiting is also provided by demand response measures, which can be combined with the deployment of an ESS [Green Charge Networks 2015].

There are different ownership models for ESSs used for peak limiting. The customer can own and operate the ESS completely by himself and profit from the savings due to the reduced demand charges, the ESS can be owned by a utility operating it in an optimized way for the system and sharing the savings from reduced demand charges with the customer, or it can be owned and operated by an independent service provider who is also sharing the benefits with the customer [Navigant Research 2015][stem 2015].

Figure 2-13 shows an exemplary load profile and indicates how an ESS can limit the maximum power drawn from the grid. The demand charges could be reduced by approximately 40% in this case.

![Maximum power draw with peak limiting](image)

**Figure 2-13 Peak limiting using an ESS discharging during peak power consumption** (adapted from [Sharp 2015])

### 2.1.13 Time-of-Use Shifting

Time-of-use (TOU) shifting is a service closely related to (large scale) energy time shift described in section 2.1.1 since it also involves storing energy during a time when it is not needed and discharging it when the demand is high. The main difference to (large scale) energy time shift, however, is the scale of the ESS, as it is deployed at the end-consumer’s site, and the rates on which energy prices are based. While (large scale) energy time-shift uses wholesale energy prices, the rates for time-of-use shifting are based on the customer’s retail tariff [Eyer & Corey 2010].
In market with existing TOU energy tariffs end consumers can save money by charging their ESS during off-peak periods at low energy prices and consuming the stored energy during more expensive peak periods. Usually, TOU energy tariffs are applicable for small and medium sized companies, in rare cases also for private consumers. TOU rates can depend on the season, day of the week, and hour of the day. A typical TOU rate structure is depicted in Figure 2-14, showing different rates for summer and winter with on-peak, mid-peak, and off-peak periods depending on the day of the week and time of the day.

The power capacity of an ESS providing time-of-use shifting depends on the energy consumption of the customer and can lay between 1 kW and 1 MW with discharge durations from 1 to 6 hours depending on the tariff [Akhil et al. 2013].

2.1.14 Renewable Energy Capacity Firming

The power output of most renewable energy resources, especially wind and solar power, is inherently fluctuating. The objective of the service of renewable energy (RE) capacity firming is to reduce the peaks and valleys in the generation profile and thus produce a nearly constant power output, similar to load leveling for a fast varying load profile.

Energy storage is particularly well-suited for RE capacity firming as it responds quickly to variations in generation and can absorb peaks by charging as well as suppress valleys in generation by
discharging as shown in Figure 2-15. The resulting firmed capacity can act as a generation resource with nearly constant power output and thereby reduces the need for additional supply capacity and capacity payments as mentioned in section 2.1.2. RE capacity firming can help to avoid the need for curtailing by buffering unexpected peaks in production. Another benefit may arise from compensating the need for transmission and distribution infrastructure [Eyer & Corey 2010].

RE capacity firming is especially beneficial for the overall system if it is provided during peak demand periods since it reduces the need for additional generation capacity. This is particularly the case for solar power resources as their output usually coincides with peak demand [Eyer & Corey 2010].

The technical requirements for ESSs providing RE capacity firming are similar to those of load leveling presented in section 2.1.7. The power rating and discharge duration of the ESS are dependent on the resource and on the location, and can vary from a few hundred kW to several tens of MW for the discharging power. The discharging duration may range from 30 minutes to 2 hours for short duration intermittency and up to several hours for daily intermittency firming the capacity over a 24-hour period. For participation in the wholesale market the ESS should also be reliable since there are significant financial fines if offered constant power is not firm [Eyer & Corey 2010]. ESSs serving for RE capacity firming are best operated by the RE resource operator, which can be an IPP or a utility.

2.1.15 Renewable Energy Ramp Rate Control

Another challenge in connection to intermittent RE-sources is the fast ramping occurring with clouds passing by for solar or in gusty conditions for wind power resources. In some markets there are regulations for ramping rates, the change of power output over time. A solution to this challenge is the service of RE ramp rate control provided by ESSs which requires a similar operation as the service of load following introduced in section 2.1.5 [Akhil et al. 2013].
Energy storage deployed for RE ramp rate control is charged during fast ramping up in order to keep the change in overall power output below a defined maximum ramp rate. When the RE resource’s output drops rapidly the energy storage discharges to fulfill the ramping requirements. This operation is shown in Figure 2-16 with the data of a photovoltaic (PV) power plant for which a battery provides RE ramp rate control. In the case of a rapid increase of power generation by the PV plant the battery is charged to keep the overall ramp rate at certain level. At a sudden drop of power output from the PV system the battery discharges energy keeping overall ramp rate at an acceptable level.

![Figure 2-16 RE ramp rate control with an ESS for a photovoltaic power plant](adapted from [Wood 2012])

ESSs for RE ramp rate control have to be designed for many cycles and quick response times. Depending on the technology, size and location of the RE power plant being served the power capacity of the ESS can range from hundreds of kW to several MW with discharge durations of 15 minutes to 1 hour [Electric Power Research Institute (EPRI) 2010]. The services of RE ramp rate control and RE capacity firming are related and usually provided together in the same energy storage application operated by the RE power plant operator.

If there is no ramp rate control at a RE power plant, the rapid changes in power output have to be absorbed by load following power plants with the effects accompanying load following by conventional dispatchable generation described in section 2.1.5, or, in case of ramping up only, they can be curtailed [Eyer & Corey 2010]. Benefits can be achieved by saving investment costs in grid upgrades and possibly new dispatchable generation resources, and by avoiding curtailment and inefficient operation of load following generation resources [Wood 2012].

### 2.1.16 Renewable Energy Time-Shift

Renewable energy time-shift is a service closely related to (large scale) energy time-shift and time-of-use shifting and works with the same operating principle: storing energy when it is abundantly and cheaply available and discharging energy when it is needed and at economically favorable times.
RE time-shift may be used in different applications for different purposes. Large scale RE facilities like wind turbines and utility scale photovoltaic facilities are sometimes forced to curtail their production due to congested T&D systems. This results in a lost opportunity of generating and selling energy. Using an ESS for RE time-shift, the excess energy that would have been curtailed otherwise can be stored, and discharged and sold later at a possibly better price. Even at periods when curtailment is not required storing energy during low demand periods and discharging it during peak periods can increase the profitability of an RE power plant participating in the wholesale market. Furthermore RE time-shift with an ESS may serve to ensure fulfillment of energy supply contracts and for hedging against forecast errors [Ibrahim & Ilinic 2013].

For smaller scale RE-resources located behind the meter at the consumer site RE time-shift is often used to increase the self-consumption of the generated energy, e.g. shifting solar energy generated during midday to peak demand in the evening hours as depicted in Figure 2-17. Customers with TOU tariffs may also store the energy generated from their RE resource to use during expensive peak hours or, if net-metering is in place, to feed it into the grid during hours when it is most valuable [Pearre & Swan 2014].

The power capacity range of ESSs for RE time-shift is very application dependent and reaches from 1 kW for small residential PV applications to several MW for large wind farms. The discharge duration mainly depends on the duration of the locational off-peak and peak periods and ranges from 2 to 6 hours [Eyer & Corey 2010; Electric Power Research Institute (EPRI) 2010].

![Diagram](image)

*Figure 2-17 RE time-shift with an ESS for increased self-consumption [Bosch 2015]*

### 2.2 Applications

An application is a use case of one or multiple services and specifies, as defined in section 1.1, the location of the ESS within the grid and the connection and its functionality in relation to its
surrounding infrastructure as well as its technical characteristics. The applications for ESSs can be divided according to Figure 2-18 into grid and off-grid applications, with subdividing the grid applications into applications located at the generation site, in the transmission grid, in the distribution grid, and behind the meter at the customer site.

Off-grid applications include mobile generation and storage facilities as well as physical and electrical islands, i.e. electrical systems on the mainland which are not connected to the grid such as broadcast antennas, remote farms, and villages in less developed countries. ESSs have been deployed in off-grid applications for decades and provide most of the services introduced in section 2.1, since ESSs are often the most economical option in these cases [Sterner et al. 2014].

In this thesis however, only grid applications are examined and exemplified.

### 2.2.1 At Generation Site

ESSs can be applied to provide services in support of or instead of other generation resources like thermal power plants or RE power plants. Supporting power plants with services like reserves, frequency regulation and load following increases their efficiency and lifetime, resulting in less fuel consumption and less emissions per generated kWh. ESSs offering electric supply capacity can replace thermal power plants. ESSs located close to large RE resources providing RE capacity firming, RE ramp rate control, RE time-shift, and possibly frequency regulation help integrating RE and ensure system stability. In the following, some examples for applications of ESSs at generation sites are presented.
**AES Angamos Storage Array**
A 20 MW/5MWh lithium-ion battery storage system has been installed in 2011 at the Angamos coal fired power plant in northern Chile. The ESS replaces the reserves and frequency regulation obligations of two of the power plant’s units comprising a capacity of 544 MW to maintain stability of the electric grid in northern Chile, which mainly serves the mining industry. Due to the ESS taking over the reserves and frequency regulation services, the power plant can operate more smoothly and at increased load. This results in decreased wear and tear of equipment, a higher efficiency and a 4% higher energy production. The ESS was developed by AES Energy Storage with batteries from A123 and a power conversion system from ABB [Energy Storage Association (ESA) 2015; Department of Energy 2015].

**AES Alamitos Energy Storage Array**
A 100MW/400MWh lithium-ion battery storage system has been contracted to be built at the Alamitos Power Center in Long Beach, California. It will accompany several combined cycle power plants and provide electric supply capacity. Due to the flexibility of ESSs explained in section 2.1.2 it will be able to replace the equivalent of traditional peaking plants of twice its power capacity. Additionally the ESS could provide other services such as load following and providing reserves helping to ensure system stability and reliability. The ESS must be completed by the end of 2020 and provides service under a 20 year power-purchase agreement with the utility Southern California Edison (SCE). The project is being developed by AES Energy Storage [Wesoff 2014; AES Energy Storage 2014].

**Rankin Substation Energy Storage Project**
A 402 kW/282 kWh sodium nickel chloride battery system has been installed in 2011 at a substation in Mount Holly, North Carolina, near a 1.2 MW rooftop solar project nearby. In this region the variability of the large amounts of distributed solar generation has caused voltage drops and fast ramp rates leading to problems in the distribution grid. In some cases passing clouds caused 80% of the solar output to drop within a few seconds. The ESS provides RE capacity firming, RE ramp rate control, and voltage support smoothing the voltage profile of the distribution circuit and thus supporting the grid infrastructure. The ESS is operated by the utility Duke Energy, using batteries from FIAMM and power electronics from S&C Electric Company [Department of Energy 2015; Duke Energy 2013].

**AES Laurel Mountain**
A 32 MW/8 MWh lithium-ion battery storage system has been installed in 2011 at Elkins, West Virginia, near a 97.6 MW wind farm along Laurel Mountain. The ESS and the wind farm have been developed together as one project, where the ESS provides RE ramp rate control to smooth the wind farm’s output. Additionally the ESS offers fast frequency regulation in the PJM market and thus generates revenue independently from the wind farm. This project was developed by AES Energy
storage with batteries from A123 and power electronics from Parker SSD [Department of Energy 2015; Geinzer 2012].

This project will be examined more closely in a case study in section 5.1.

2.2.2 In the Transmission Grid
ESSs located in the transmission grid can reduce transmission congestion and support transmission infrastructure to extend equipment lifetime and defer investments. Similar to applications at the generation site, ESSs in the transmission grid are able to provide ancillary services such as reserves, frequency regulation, load following, black start capability, and voltage support. This enhances system reliability and reduces the need for additional generation resources or existing generation to operate in part load. Below, some exemplary applications of ESSs in the transmission grid are shown.

**GVEA Battery Energy Storage System**
A 27 MW/6.75 MWh nickel-cadmium battery storage system has been installed in 2003 in Fairbanks, Alaska. The ESS is used to ensure electric service reliability in case of a generation or transmission related outage. It provides reserves for up to 15 minutes at rated power and black start services for local generation to come online. Additionally, it provides voltage support services delivering reactive power in case of a failure in transmission or generation. The ESS was developed by ABB with batteries from Saft and power electronics from ABB, and is operated by the local utility Golden Valley Electric Association (GVEA) [Department of Energy 2015; ABB 2012].

**Duke Energy Beckjord Energy Storage Project**
A 2 MW/0.8 MWh lithium-ion battery storage system is currently being installed at the retired W.C. Beckjord coal-fired power plant in New Richmond, Ohio, in addition to an existing 2 MW ESS. It is placed at the old power plant in order to make use of the existing infrastructure and will provide frequency regulation in the PJM market to increase stability of the power grid. The project is developed by and for Duke Energy with batteries from LG Chem, power electronics from Parker Hannifin, and system integration by Greensmith Energy Management Services [Department of Energy 2015; Tweed 2015b].

2.2.3 In the Distribution Grid
Energy storage in the distribution grid close to the demand side can provide important ancillary services like load leveling, voltage support, and power quality and is able to relieve distribution equipment and defer investments. If placed closely to a renewable energy source it can additionally support RE integration by RE capacity firming, RE ramp rate control, and RE time-shift as mentioned in section 2.2.1 about ESS located at the generation site.


**Falköping Substation Smart Grid**

A 75 kW/75 kWh lithium-ion battery storage system has been installed in 2011 at an existing substation in Falköping, Sweden. The ESS offers RE time-shift as well as RE capacity firming and thus stabilizes the grid since there is a high proportion of wind power connected to grid in this region. Due to its location at a substation in the distribution grid the ESS is used additionally for load leveling keeping generation and demand balanced. Furthermore, it takes part in a study providing auxiliary power for charging electric vehicles. The ESS was built by ABB for the local utility Falbygdens Energi [Department of Energy 2015].

**WEMAG Younicos Battery Park**

A 5 MW/5 MWh lithium-ion battery storage system has been installed in 2014 next to an existing substation in Schwerin, Germany. It offers frequency regulation in the German primary control reserve market and thus supports the integration of large amounts of wind power installed in this region of Germany by providing RE capacity firming at the same time. In addition the ESS provides black start capability and voltage support. The ESS was built for the green utility WEMAG AG, with development and integration by Younicos, and Samsung SDI providing the batteries including a 20 year warranty [Department of Energy 2015; Younicos 2014].

### 2.2.4 Behind the Meter

ESSs installed at the consumer behind the meter can help to reduce the electricity bill by peak limiting and thus reducing demand charges or by time-of-use shifting to shift the power draw from the grid to cheaper time periods. ESSs are also used to ensure electric service reliability and power quality for sensitive equipment, for example in data centers, hospitals or airports. This is a very established application with a market size of 2 billion euros in Europe alone [Sterner et al. 2014]. In combination with renewable energy sources behind the meter ESSs can increase the self-consumption of the generated energy or feed the energy into the grid at the economically best time. Examples for common applications of behind the meter ESSs are presented in the following paragraphs.

**Prudent Energy VRB-ESS – Gills Onions**

A 600 kW/3.6 MWh vanadium redox flow battery storage system has been installed in 2012 at Gills Onions, a food processing plant in Oxnard, California. A large proportion of the energy consumed by the processing plant is generated by fuel cells onsite use methane from processed waste products. The ESS provides time-of-use shifting respectively RE time-shift to consume this energy predominantly during peak hours in the afternoon when electricity in Southern California Edison’s TOU tariff is most expensive. Additionally, the ESS is used for peak limiting to reduce demand charges caused by spikes in consumption during startup of large equipment. The ESS was developed and built by Prudent Energy [Department of Energy 2015; Energy Storage Association (ESA) 2015].

Applications similar to this including peak limiting will be examined in a case study in section 5.2.
Willis-Knighton Medical Center UPS

A 3500 kW/60 kWh lead-acid battery storage system has been installed in 2009 as part of the uninterruptable power supply (UPS) at the Willis-Knighton Medical Center in Shreveport, Louisiana. It provides power quality and electric service reliability services in case of voltage sags or short term interruptions of the feeder power supply. High power quality is not only necessary for critical equipment but also reduces costs for rescheduling procedures, overtime for professional staff, and maintenance for medical and lab equipment. In case of power outages longer than 60 seconds additional on-site generation is started. The UPS was developed and integrated by S&C Electric Company [S&C Electric Company 2015].

Residential PV Storage in Germany

In Germany, homeowners installing a photovoltaic array on their rooftop are supported by government subsidies if they combine their PV system with an ESS. These ESSs are mainly used to increase self-consumption by RE time-shifting. The majority of the installed batteries are lithium-ion or lead-acid batteries with power capacities of 1-4 kW and energy capacities 2-10 kWh [Kairies et al. 2015]. A more detailed elaboration regarding the German subsidization of residential PV storage systems can be found in section 2.3.4 about the energy storage market in Germany.

2.3 Markets

Before focusing on markets for energy storage it is important to understand that energy markets, and electricity markets in specific, have always been heavily regulated with regulatory rules historically grown according to traditional generation and transmission infrastructure. These regulatory rules often created artificial markets that made the profitability of projects strongly rely on the currently applicable legislation. Energy storage entering the market poses new challenges for regulators trying to integrate this relatively new technology into market regulations. One challenge arises for example if generation, transmission, distribution, and loads are overseen by different entities, as it is the case in the US. Then regulators need to address first the classification of energy storage as it can fulfill all of these roles [Castillo & Gayme 2014]. More issues regarding the integration of energy storage into the energy markets and regulation will be discussed in detail in chapter 6.

As the market for energy storage is still in an early stage, its development needs to be accompanied by new regulations and proactive policies that are created in accordance with the potential of ESSs to provide multiple services. In the approach towards a working energy storage market, the policy actions performed by a country pass through different steps that Stanfield and Vanega summarized in four general categories depicted in Figure 2-19 [Stanfield & Vanega 2015].
Many countries fall into the first category demonstrating interest in energy storage and exploring its possible potential considering costs, benefits, services, and regulatory issues. Interest in storage may be expressed with studies, working groups, workshops, and pilot programs. Policy actions in the second category focus on reviewing existing rules and regulation to clarify whether and how they apply to energy storage in order to ensure that interconnection requirements and standards are clearly defined. In the third category countries directly influence the market by stimulating the deployment of energy storage through financial incentives, other subsidies, and mandates. The fourth and most advanced category of policy actions deals with including energy storage in planning processes for grid modernization and the future of the electricity sector where it can also serve as a tool for the expansion of RE deployment [Stanfield & Vanega 2015].

The economic feasibility of ESSs deployment strongly depends on the applicable market and regulatory structures as well as the remuneration mechanisms. Markets differ between countries and even within a country between different transmission zones and states. The term market used in this thesis refers to an area in which market rules, market structure and remuneration mechanisms are equal for a service offered by an ESS. That means that for different services the geographic area of a market may be different since transmission zones and their respective wholesale markets may stretch across borders while subsidies are limited to countries or states and electricity tariffs to utilities’ serving zones. In order to understand how a market can influence the profitability of ESSs and of the services provided, the markets of the PJM Interconnection and of California in the United States, and of Germany, Australia, and Japan are examined and possible applications for energy storage are identified.

2.3.1 USA

In the US there exist several markets which are separated according to states and transmission zones. On a national level they are under supervision of the Federal Energy Regulatory Commission (FERC) while each state has its own Public Utilities Commission (PUC) regulating the energy market within
its competences on a state level. System operators in the US are called Regional Transmission Organization (RTO) or Independent System Operator (ISO) which operate a certain region’s electricity grid and wholesale market while also being responsible for reliability planning. The transmission zones in the US are shown in Figure 2-20.

![Transmission zones in the USA according to FERC Order 1000](image)

**Figure 2-20 Transmission zones in the USA according to FERC Order 1000** [FERC 2014]

**Policy Making**

As mentioned above, market areas for different services correspond to different geographic areas, such that markets for services on the distribution or load level match the utility’s service area while markets for products traded in the wholesale market usually match the transmission zones. These wholesale markets are regulated by FERC, a federal agency within the Department of Energy responsible for nationwide energy matters including the regulation and oversight of interstate electricity trading and wholesale electricity markets [FERC 2014]. FERC acts on new laws or changes of laws coming from congress, develops orders that are binding for market operators and participants, and enforces these orders. Figure 2-21 illustrates the development process of new market rules from the introduction of a new bill to the actual implementation of the rules.
In order to understand the creation of new market rules it is important to recognize that the initial phase of rule development is a highly political process. For a new a law to be established or an existing law to be changed a member of congress needs to introduce a bill into his or her respective legislative chamber (i.e. Senate or House of Representatives). After introduction of the bill a committee reviews the bill and decides whether it proceeds in the process, needs to be changed or amended, or whether it should be stopped. If it proceeds to the chamber, it is considered and discussed further, possibly changed, and if it passes, referred to the other chamber. There the process is repeated, including possible changes or amendments after which the bill would have to be referred back to the first chamber. Once the bill has passed Senate and House of Representatives in the same version, it is referred to the president to be enforced. The president may sign the bill and thus make it a law, but also has the right to veto it [U.S. House of Representatives 2015].

After a law affecting the energy market has been enforced by legislation, FERC develops an order translating the law into regulation and mandates. Following the acceptance of the order by a federal court, the RTOs and ISOs have to adapt their market rules or implement organizational changes in compliance with the regulations and mandates introduced by the order. Finally, market participants and utilities active in the respective wholesale markets have to act and adjust their businesses according to the changes of rules imposed by the FERC order.

Figure 2-21 Process of the development of market rules in the US

<table>
<thead>
<tr>
<th>Step</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Bill Introduction</td>
</tr>
<tr>
<td></td>
<td>Member of Congress (House of Representatives or Senate) introduces a bill</td>
</tr>
<tr>
<td>2.</td>
<td>Referral to Committee</td>
</tr>
<tr>
<td></td>
<td>The respective committee changes, amends or stops the bill</td>
</tr>
<tr>
<td>3.</td>
<td>Passed by House (or Senate)</td>
</tr>
<tr>
<td></td>
<td>The bill is accepted by the House of Representatives (or Senate)</td>
</tr>
<tr>
<td>4.</td>
<td>Passed by Senate (or House)</td>
</tr>
<tr>
<td></td>
<td>The bill is accepted by the Senate (or House of Representatives)</td>
</tr>
<tr>
<td>5.</td>
<td>Signed by President</td>
</tr>
<tr>
<td></td>
<td>The bill is signed by the President and it becomes a law</td>
</tr>
<tr>
<td>6.</td>
<td>FERC Order</td>
</tr>
<tr>
<td></td>
<td>FERC analyses the law and develops an order</td>
</tr>
<tr>
<td>7.</td>
<td>RTO/ISO</td>
</tr>
<tr>
<td></td>
<td>The RTO / ISO implements the order in its market rules</td>
</tr>
<tr>
<td>8.</td>
<td>Market</td>
</tr>
<tr>
<td></td>
<td>Market participants and utilities act according to new rules</td>
</tr>
</tbody>
</table>
Regulation for markets on the distribution and load site of the grid is managed on a state level which will be explained with the example of California in section 2.3.3.

**Current Energy Storage Market**

The current energy storage market in the US is constantly growing, with growth rates of 40% in 2014 and an expected growth of 250% in 2015 according to GTM Research [Munsell 2015]. However, most of the growth takes place in two regional markets, namely PJM Interconnection and California, where 79% or 99 MW out of 115 MW of installations since 2013 have been deployed [Munsell 2015]. Reasons for this lie in the market rules for frequency regulation in PJM and mandates and utility tariffs in California which will be explained in more detail in the following sections.

From a legislative point of view there have been several FERC orders affecting energy storage and its recognition regarding planning processes and market rules. According to FERC Order 890 wholesale markets are obliged to consider non-generation resources like energy storage as grid services to prevent undue discrimination in transmission services. Another order targeting the transmission system is FERC Order 1000 which requires the consideration of non-transmission alternatives during transmission planning. This means that whenever there is a need for grid upgrades or new transmission lines other options like energy storage have to be taken into account during the planning process. FERC Order 755, introduced in 2011, had a major impact on the compensation of frequency regulation services by requiring ISOs and RTOs to compensate resources for capacity offered and actual performance of operation, i.e. accuracy and response and ramping time. Faster ramping resources such as energy storage benefit from this rule because of their much better performance than traditional frequency regulation resources [Castillo & Gayme 2014].

2.3.2 **PJM Interconnection (Eastern United States)**

The PJM Interconnection, LLC (PJM = Pennsylvania - New Jersey - Maryland) is a regional transmission organization (RTO) in the eastern United States (dark blue in Figure 2-20). PJM operates one of the largest competitive wholesale electricity markets in the world with a generating capacity of more than 180 GW and 945 members. It serves several states in the eastern US providing electricity to more than 61 million people [Monitoring Analytics LLC 2015].

The energy storage market in PJM is mainly based on providing frequency regulation. PJM was the first RTO or ISO to implement FERC Order 755 into its market rules. While other RTOs and ISOs have also been developing or are still developing programs for performance based frequency regulation, the market rules in PJM are still more lucrative for ESSs than in other markets because the signal type and compensation mechanism in PJM are specifically designed to meet the needs and capabilities of ESSs. Most other ISOs and RTOs adjusted their existing market rules to comply with FERC Order 755 without taking energy storage into account. However, there seems to be a shift towards including energy storage into market rules as the New England system operator (ISO NE) and
the Southwest Power Pool (SSP) adopted similar compensation and market rules as PJM [Trabish 2015].

There are two signals for frequency regulation in PJM, a slow moving signal (RegA) derived from the low-pass filtered area control error (ACE) which is sent to traditional regulating resources like combined cycle or coal power plants, and a fast moving, dynamic signal (RegD) derived from the high-pass filtered ACE which is sent to dynamic resources such as energy storage or demand response resources. These two signals are differentiated by the ramp rate they request from the resource and by the mileage they travel as depicted in Figure 2-22. Mileage in this context is defined as the accumulated change of the signal within one hour and shows how much a resource ramps up and down per assigned MW. Its unit is ΔMW/MW.

![Figure 2-22 Frequency regulation signals RegA (blue) and RegD (green) in PJM](image)

Following FERC Order 755 which separates capability and performance of a resource, there is a two-part bidding and a two-part payment process. The bidding process is cost based and takes into account the capability cost, performance cost, and lost opportunity cost of a resource. ESSs and demand response resources, however, are allowed to bid into a market with an offer cost of zero which is advantageous as offers of available regulation resources are ranked and called upon in merit order. From the costs of the marginal resource, the regulation requirement (about 0.7% of expected peak load), and historical performance data a regulation market capability clearing price (RMCCP) and a regulation market performance clearing price (RMPCP) is calculated [PJM 2015b]. Figure 2-23 summarizes this process.
The credits that the market participant receives for providing frequency regulation are calculated for every hour from the regulation market clearing prices, the resource’s historical performance score and the mileage ratio between RegD and RegA signals. The performance score reflects the accuracy with which the resource follows the regulation signal and lies between 0 and 1. Thus, the RMCCP Credit \( C_{RMCCP} \) is the product of the assigned regulation power \( P_R \) in MW, the actual performance score \( PS \) and the RMCCP:

\[
C_{RMCCP} [\$] = P_R [MW] \times PS \times RMCCP[\$/MW]
\]  

(1)

The RMPCP Credit \( C_{RMPCP} \) is the product of the assigned regulation power in MW, the actual performance score \( PS \), the mileage ratio \( RM \) and the RMPCP:

\[
C_{RMPCP} [\$] = P_R [MW] \times PS \times MR [\Delta MW/\Delta MW] \times RMPCP[\$/MW]
\]  

(2)

The final Regulation Market Clearing Price (RMCP) Credit \( C_{RMCP} \) is the sum of the RMCCP Credit and the RMPCP Credit:

\[
C_{RMCP} [\$] = C_{RMCCP} [\$] + C_{RMPCP} [\$]
\]  

(3)

[PJM 2015c]

In order to be eligible for participation as RegD resource, the performance score has to be larger than 0.75. Typical performance scores of ESS are between 0.96 and 0.98 [East Penn Manufacturing 2014]. In 2014 the average RMCCP was about 39 \$/MW and the average RMPCP 4\$/MW with an average mileage ratio of 2.9 \( \Delta MW/\Delta MW \) [PJM 2015a].
Since the rule changes leading to performance based compensation have only happened recently, it is important to note that PJM continues to develop and improve market rules in order to provide fair treatment of all market participants. This may again change compensation mechanisms in the near future [Monitoring Analytics LLC 2015].

Another important point to consider is the limited market size of the frequency regulation market which comprised an average of 663 MW in 2014 [Monitoring Analytics LLC 2015]. With increasing deployment of ESSs for frequency regulation the market size and also the compensation prices may decrease as provision of frequency regulation becomes more efficient. For these reasons there have been proposals to open PJM’s capacity market for energy storage and adjust the market rules accordingly. Although participation in the capacity market may be less profitable its size is approximately 150 times the size of the frequency regulation market [Engerati 2014].

2.3.3 California

California is the other big market for energy storage in the US besides PJM. In California, however, most of the ESSs are deployed behind the meter at the end-consumer side of the grid. This is due to favorable electricity tariffs with large differences between peak and off-peak prices as well as subsidies by the state.

Tariffs and subsidies are strongly influenced by state legislation which resembles the national legislative processes explained in section 2.3.1. In California a bill is introduced by a member of one of the legislative chambers (State Assembly or Senate), is evaluated by a committee, and then has to pass both chambers. After it is approved by the governor it becomes a law and the California Public Utilities Commission (CPUC) develops guidelines and mandates from it. These guidelines and mandates affect the market for energy related products and utilities’ decisions regarding electricity tariffs and investments for the future. An overview of the process is shown in Figure 2-24.

![Figure 2-24 Legislation process in California](image)

One outcome of the legislative process is the Self-Generation Incentive Program (SGIP) which initially started in 2001 and has been modified several times by bills to change its focus. It subsidizes the installation of distributed generation resources which also includes energy storage. The current incentive for an ESS is 1.46 $/W [California Public Utilities Commission 2015].

Electricity tariffs for commercial and industrial customers in California usually consist of time-of-use energy charges and relatively high demand charges for the peak power drawn from the grid in a
month. ESSs that are supported by the SGIP incentive and reduce demand charges by peak limiting offer an interesting value proposition. Additional savings can be earned by exploiting the TOU tariff by shifting consumption to the cheaper off-peak hours. Different business models have arisen in this market. Customers may own and operate the ESS on their property themselves and benefit from the complete savings generated. More commonly though, an ESS integrator and operator installs and owns the ESS at the customer site and shares the benefits with the customer, while also being able to aggregate several ESSs to one asset and participate in the wholesale market [Burger 2015]. In another business model the local utility owns and operates the ESS, which is placed behind the meter at the customer’s property and shares the benefits with the customer [Navigant Research 2015].

The energy storage market is projected to grow rapidly in the next few years due to a state law from 2010, Assembly Bill 2514, which instructed CPUC to set targets for load serving entities for the procurement of “viable and cost-effective energy storage systems” to be reached by the end of 2015 and 2020, for public utilities by 2016 and 2021 [Skinner 2010]. Following this law CPUC developed a mandate which requires the three biggest utilities to procure 1325 MW of energy storage until 2020. The first utility to announce procurements under this mandate was Southern California Edison (SCE) contracting 261.1 MW of energy storage, which is more than 5 times the required amount. 100 MW of the energy storage SCE bought will be grid scale and on the utility side of the meter, and 160.6 MW will be located at the customer side behind the meter with benefits shared as mentioned above. The other two big investor owned utilities Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E) are expected to make similar announcements before the end of the year [Navigant Research 2015].

California is also one of the most progressive states regarding renewable energy integration requiring that by 2020 at least 33 percent of its electricity will be generated by renewable energies. This mandate has recently been increased to 50 percent by 2030. Although there is a large amount of residential rooftop solar installations, this has not benefited ESS deployment since there is a net-metering policy in place leaving no financial incentive for energy storage, as renewable energy can be fed into the grid at retail prices. This policy is currently reviewed with open outcome. Besides California, net-metering exists in 43 other states of the US [Pyper 2015].

Irrespective of the result of the net-metering revision, CPUC ordered time-of-use tariffs for retail customers to be implemented by 2019. Depending on the difference between peak and off-peak prices, these tariffs may open a new market for ESSs at residential customers [Hansell 2015].

2.3.4 Germany
The energy storage market in Germany is mainly based on RE time-shifting for increased self-consumption of solar energy from residential rooftops. Until 2012 there had not been any financial incentive for storing excess energy from PV systems as the feed-in tariff had been higher than the
retail prices for electricity [Sterner et al. 2014]. In 2013 the feed-in tariff fell below the retail rates and is currently at about 0.12 €/kWh, while the retail price has been constantly growing to an average of 0.29 €/kWh today [Kairies et al. 2015]. This price difference offers a value proposition for storing excess energy for later use.

The German parliament assigned the federal government to develop a market incentive program for decentralized energy storage for PV systems to increase self-consumption and contribute to grid stabilization. The incentive program developed in collaboration with the state bank KfW started in May 2013 and offers low-interest loans and a repayment bonus. For new PV installations in combination with an ESS the repayment bonus equals 30% of the ESS cost with a maximum of 600 €/kW\textsubscript{PV}. For existing PV systems which have been built in 2013 or later the maximum repayment bonus is 660 €/kW\textsubscript{PV}. It is important to note that the repayment bonus depends on the rated PV peak power and not on the ESS power capacity [German Federal Ministry for Economic Affairs and Energy (BMWi) 2014].

In order to be eligible for participation in the incentive program, the connected PV system must not be larger than 30 kW and the feed-in power must be limited to 60% of the PV peak power. This is to ensure that ESSs are installed in a beneficial way for the grid, reducing strain on grid equipment during peak generation. Furthermore, the ESS must be equipped with an open interface to enable possible future remote controlling and voltage support services. Until the end of March 2015 the KfW has granted support within the scope of this program to 9500 ESSs with an average energy capacity of 6.45 kWh [Kairies et al. 2015]. Installing an ESS in combination with a PV system offers substantial savings to end-consumers. Additional returns for the ESS owner are offered by some storage suppliers who operate many behind-the-meter ESSs and aggregate them to a virtual power plant which participates in the wholesale market [Sonnenbatterie 2015].

Except for storing solar energy for self-consumption, it is difficult to find a profitable business model for ESSs in Germany. As mentioned in section 2.2.3 there is the possibility to participate in the primary control reserve providing frequency regulation, but this is only cost effective for integrated utilities that are able to stack several services of the ESS to benefit from multiple revenue streams [Younicos 2014].

The German government regards ESSs as a tool for the integration of renewable energies and for stabilizing the electricity grid, however, only in the future. Currently, the focus lies on developing rules for fair competition of different flexibility options such as demand response, energy storage and grid upgrades. Energy storage in general is viewed as being too expensive at the moment and most supportive activities are aiming at research and development for cost reduction and technology advancement [German Federal Ministry for Economic Affairs and Energy (BMWi) 2014].
2.3.5 Australia

The Australian energy storage market is currently in a phase of uncertainty. Most of the ESS deployment in the past has been focused on smart grid research projects or off-grid applications. In fact, the off-grid market is offering great potential containing over 6% of Australia’s energy consumption and large areas having no grid connection. Energy storage in combination with renewable energy sources can supply a large proportion of this market, which is forecasted to grow to over 200 MW in the short to medium term and to over 1 GW in the long term [Chambers & Rozali 2013].

The most promising market, however, is the residential rooftop solar sector. With increasing electricity retail prices and decreasing costs for solar PV, residential rooftop solar installations have become more and more common which in turn has caused fixed network costs to increase the average electricity price even further. With very low feed-in tariffs for solar energy at 0.06 AU$/kWh and peak period prices for households at 0.525 AU$/kWh energy storage offers an appealing value proposition. Households can reduce their electricity bill significantly by utilizing ESSs for RE time-shifting to increase self-consumption of their generated solar energy [Vassallo et al. 2015].

Unlike in Germany though, there is no incentive program for residential ESSs in place. In order to become a business case, the costs for ESSs must be low enough to be covered by the savings that potential operators can achieve. According to various analyses this is the case now in many regions of Australia or will be the case in the near future. The Australian Energy Market Operator (AEMO) forecasts almost 8 GWh of storage capacity in combination with PV for 2035 which translates roughly to 4 GW of storage power capacity [Australian Energy Market Operator (AEMO) 2015]. Other forecasts are more optimistic predicting 33 GWh of storage by 2040 [Stone 2015b]. Investment banks also see large growth for the residential storage market in the near future: Morgan Stanley predicts half of the Australian households installing a solar storage which at 2.4 million households creates a market size of 24 billion AU$ [Parkinson 2015] while UBS also finds business case of residential solar with storage profitable suggesting a market size of 20 billion AU$ [Parkinson 2014].

Of course, these predictions have to be treated with caution especially since there is a great uncertainty from the regulatory side which may influence future electricity prices and utilities’ planning. One point among others to be considered is the expiry of solar feed-in tariffs for 250 000 households in 2016 and another 400 000 households in 2020 [Parkinson 2015]. However, the numbers show that there is a serious market for ESSs emerging in Australia which might take off fully once prices for ESSs in Australia approach those in the United States. Currently, costs of comparable ESSs are two to four times higher in Australia than in the US [Parkinson 2014].

The market for ancillary services in Australia is currently unattractive for ESS as prices are low due to sufficient supply and limited demand. In the transmission and distribution network, energy storage is
usually not considered as there is little experience by the staff in operating it and asset management practices of utilities would have to be changed. This shows that the company culture of utilities can also be a barrier for the deployment of ESSs [Marchment Hill Consulting 2012].

2.3.6 Japan

Japan’s electricity market is currently undergoing big changes as it is facing impactful deregulation measures. Besides these changes, Japan has quite a unique electrical system with two different frequency zones, consisting of many islands which are connected by transmission lines with limited capacity and a strong growth of renewable energy deployment, especially since the Fukushima nuclear accident in 2011 [Ministry of Economy Trade and Industry 2015].

With new solar PV installations of 9.4 GW in 2013 and 8 GW in 2014, Japan has become one of the fastest growing solar markets in the world [Ferris 2014; Deign 2015]. Most of these solar installations are residential, but since the feed-in tariffs are far above retail electricity prices and price differences between day and night are small, there is no incentive for private households to invest in ESSs [Iwafune 2014].

Despite this limitation, the energy storage market in Japan is just starting to grow, mainly due to large subsidy programs. In 2014 the Japanese government announced a program supporting homeowners and businesses willing to install lithium-ion batteries with a total of 10 billion yen (74 million €) by covering up to 66% of the costs of the ESS [Ferris 2014]. Furthermore, there is an additional support package for ESSs announced in 2015 providing a total of 81 billion yen (600 million €) for ESS funding [Deign 2015]. The details for these subsidies are not clear yet although there have been announcements by Japanese utilities about significant financial support for large scale ESSs projects such as a 300 MWh ESS by utility Kyushu Electric Power to facilitate the integration of large amounts of renewable energy [Stone 2015a].

Another reason for Japan’s government to subsidize growth of energy storage deployment is based on the intention to support domestic battery manufacturers and thus securing a significant share of the growing energy storage market for the Japanese economy [Stone 2015a].
3 Metrics Development

In order to assess the economic value of the benefits of energy storage in an application, appropriate metrics are necessary, which need to be selected in dependence of the individual case. It is important to choose a metric that takes into account the value proposition of the respective ESS. Therefore good knowledge of the service provided, of the market in which the ESS participates, and of the application in which the ESS is installed is required for the development process of metrics which has been designed here. The first input arguments are the service, market, and application from which the necessary details will be derived as illustrated by Figure 3-1.

![Figure 3-1 Metrics development process with the input parameters service, market and application](image)

Once the service, the market, and the application are identified, a value proposition can be derived which should usually be known beforehand as it is the reason for installation and operation of the ESS. The value proposition is either a market product, which can be traded and has a market price, or it is
valued as a system support, supporting the operation of the system in which it is installed. In the latter case, the system size may range from a single residential customer to the whole grid.

3.1 ESS Based Metrics

ESS based metrics measure the monetary value of the benefits generated directly by the ESS. The services that the ESS provides can be translated directly into one or several market products which can be traded on the wholesale market and are priced according to the market. Thus, the benefits are generated directly by the ESS.

ESS based metrics can be divided into power based and energy based metrics, depending on the discharge duration necessary for the respective service or market product. For short discharge durations, power based metrics are used, since the value is generated by the provision of power while the amount of charged or discharged energy is relatively small. The compensation in the market is based on the provision of power and does not take into account the energy that is charged or discharged. The power to energy ratio of ESSs operating this way is typically larger than one. For long discharge durations, energy based metrics are used since the value is generated by charging or discharging relatively large amounts of energy over a long time period at little power. Here, the compensation in the market is based only on the amount of energy, regardless of the power at which it is provided. The power to energy ratio of ESSs operating this way is typically smaller than one.

3.1.1 Energy based metrics

Energy based metrics can be used, e.g. to measure the benefits generated by participation in the wholesale energy market by providing large scale time shifting. The benefits are derived from the difference of the energy price, thus the unit is [$/kWh]. Costs can be measured in a similar way. An example for an energy based cost metric is the widely used levelized cost of discharged energy (LCODE) which has the unit [$/kWh]. LCODE, sometimes also called revenue requirement, represents the total life cycle costs of the ESS divided by the total energy discharged during its lifetime. A similar metric, which does not include the cost for charging, is the added cost by storing electricity [$/kWh] [Zakeri & Syri 2015]. The corresponding metric for measuring the benefits is the added value by storing electricity [$/kWh].

3.1.2 Power based metrics

Power based metrics may measure the benefit gained from availability, e.g. for reserves or capability in frequency regulation, or the benefit gained from performance and actual operation, e.g. for actively providing frequency. Availability describes the offer of keeping a certain amount of power capacity at stand-by for a period of time during which it can be called upon. This power capacity can be positive, thus offering to provide power, or negative, i.e. offering to absorb power. An example for a power
based availability metric is the levelized benefit of capacity quantified in dollars per kilowatt and hour [$/kW/h].

The benefit gained from performance and actual operation is generated by charging and discharging with the required power at the requested time. Depending on the market, the compensation for the performance may or may not be dependent on the accuracy with which the service is provided. An example for a power based performance metric is the levelized benefit of mileage expressed in dollars per change of kilowatt output during one hour [$/\Delta kW/h].

### 3.2 System Based Metrics

If the value proposition of the ESS is regarded as system support, i.e. the ESS supports the operation of the system in which it is installed, system based metrics can be applied.

System based metrics refer to the added value to the system regardless of the system size. The revenue stream described by system based metrics results from saved costs, which are either payable costs or lost opportunity costs.

#### 3.2.1 Saving payable costs

In supporting the system, the ESS can reduce the costs that the system operator has to pay for system operation. The metrics for the benefits generated by the ESS are the same metrics as for the costs, since the benefits are equal to the money saved by avoiding these costs.

Payable costs can be market product charges or asset related costs. Market product charges are costs that usually accrue on the consumer side, e.g. the costs that appear on the electricity bill like demand charges [$/kW], energy charges [$/kWh] or VAR charges for reactive power [$/kVar]. Transmission congestion charges [$/kW] also fall into this category, although they do not directly accrue at the consumer side but in the transmission network. They do, however, affect indirectly the customers’ electricity bill in the energy and demand charges.

Asset related costs are derived from investments in permanent or consumable elements of the system. Investments in permanent elements such as T&D infrastructure can be deferred or avoided using an ESS. The benefits from saving the investment costs can be measured in [$] or [$/kW]. Consumable elements of the system include fuel such as gas, diesel, or coal. Fuel costs can be reduced by a steadier operation of a power plant or avoiding operation at all. The benefits from reducing the fuel consumption can be measured in [$/kWh] or [$/L].

#### 3.2.2 Saving lost opportunity costs

Lost opportunity costs accrue when an element of the system is not allowed to generate the value that it would be capable of generating in optimal conditions. This is usually related to a reduced capacity factor of the element.
An ESS can increase the capacity factor of equipment like power plants, RE sources, and transmission and distribution facilities by providing several services. A thermal power plant can operate more steadily and at a higher capacity factor if an ESS is used for load following, reserves, and frequency regulation instead of the power plant. RE sources may avoid curtailment and increase their forecasting accuracy using RE time-shifting and RE ramp rate control. T&D infrastructure do not need to be designed for peak load if an ESS is placed electrically downstream of the equipment. The benefits from an increased capacity factor and the reduced lost opportunity costs can be measured using the metric of the respective product value, usually either [$/kW/h] or [$/kWh].
4 Methodology

Whenever a decision over an investment has to be made, be it in the public sector, private industry, or even personal life, usually the potential benefits of making the investment are compared to its cost in a cost-benefit analysis and only if the benefits exceed the costs, the project proceeds. This is also the case in the energy sector regarding the deployment of ESSs. In this chapter, methodologies for the definition process of ESS deployment cases, for the cost-benefit analysis, and the corresponding sensitivity analysis have been developed which are tested in the analysis of two different deployment cases of ESSs in chapter 5.

A generic methodology for defining clear deployment cases of ESS as well as for analyzing these cases regarding costs and benefits, and their sensitivity to certain parameters is developed. For this purpose the ESS is modeled to consist of a power conversion system and a storage section which can be characterized and priced independently from each other. Both sections have inherent efficiencies which are taken into account in the overall system efficiency $\eta_{Sys}$. The model is illustrated in Figure 4-1.

![Figure 4-1 Main section of ESS and energy losses](Zakeri & Syri 2015)

4.1 Case Definition

The process of developing a clear deployment case for an ESS is divided into four steps which are shown in Figure 4-2. It is adapted from EPRI’s approach of evaluating ESSs for grid services which can be found in EPRI’s Electricity Storage Handbook [Akhil et al. 2013].
4.1.1 Step 1: Opportunity definition

In order to develop a clear deployment case for an ESS, the intention of the operator or problem to be solved needs to be clearly defined which happens in the beginning of the process as illustrated in Figure 4-3.

The questions of who operates the storage and which is the target market are important to understand which opportunities for market participation arise and to get an impression of the operator’s priorities. Now the intention for deploying an ESS or the problem to be solved needs to be well defined. This may not be as straightforward as the question suggests since especially in grid operation often only the symptoms of a problem become obvious while the actual cause stays unknown. Only once this is clearly defined, it should be evaluated whether or not an ESS can help to solve the problem or meet the intention. If the outcome of this evaluation is positive, the process is continued with step 2.

4.1.2 Step 2: Solution Requirements

In step 2 the technical requirements for a successful implementation of the solution with an ESS are defined according to Figure 4-4.

Figure 4-2 Process of developing an ESS deployment case

Figure 4-3 Decision flow for step 1: Opportunity definition

Figure 4-4 Decision flow for step 2: Solution requirements
After the intention or problem has been identified, the necessary measures to solve the situation have to be defined in the form of technical criteria such as, e.g., active or reactive power injection, limiting power flow at a certain value or a minimal response time. These criteria, though related to ESS characteristics, focus only on what is necessary to solve the problem. Next appropriate metrics for measuring the success of the solution are determined. At this point alternative solutions that do not require an ESS should be considered and compared to the ESS solution using the chosen metrics. In case another solution is more cost effective, it should be evaluated further and potentially implemented instead of the ESS solution. If the ESS solution continues to be the best solution, the technical requirements for the ESS need to be defined which should comply with the technical criteria of the solution and also include other storage specific characteristics like power and energy capacity, ramp rate, and response time. These characteristics are then used for defining the services in step 3.

4.1.3 Step 3: Validation of Services

For the adequate provision of the solution, the ESS needs to provide at least one service which may potentially be combined with other services by stacking in order to increase the benefits. The process of selecting and validating the correct services is performed in step 3, shown in Figure 4-5.

![Figure 4-5 Decision flow for step 3: Validation of services](image)

First, one anchor service is defined, which is the service solving the problem or addressing the intention and usually a service that generates disproportional high benefits in the particular case. To increase the profitability of the ESS, compatible secondary services can be added. These should require similar characteristics as the anchor service of the ESS which is checked next together with the timing of services, i.e. whether or not services are needed identical, overlapping or different time. Depending on the compatibility and the values of the services, they can be arranged in order of the priority with which they are called upon. It is important to note that lower ranked services will not be able to offer as much benefit as if they were top ranked since their utilization factor is lower as illustrated in Figure 4-6.
After generating this order, additional benefits generated and possible additional costs (e.g. for increased power or energy capacity) must be reviewed. The additional benefits and costs can be optimized iterating the process from step 2c where the technical ESS requirements are defined. Once this has been completed to a sufficient degree the process can be continued with step 4.

4.1.4 Step 4: ESS Characteristics
Step 4 finishes the development process with the definitions shown in Figure 4-7.

The ESS requirements resulting from the iteration in step 3 are now transferred into the final ESS properties. From these properties a storage technology and the features of the power conversion system that best suit the requirements are chosen. This is the last step of the development process for a deployment case of an ESS, which is now defined in terms of market, application, services, and metrics.

4.2 Cost-Benefit Analysis
As mentioned above, all costs and benefits should be considered in a cost-benefit analysis (CBA). Generally, these cost and benefits include all positive and negative effects caused by the project and are not necessarily given in monetary terms. The difficulty in performing a comprehensive CBA lies in
assigning monetary values to these effects in order to make them comparable [Layard & Glaister 1994]. The different layers of possible effects in energy infrastructure project are the impact within the power system, externalities, and macroeconomic effects as shown on the left in Figure 4-8. The effects within the power system can be categorized into production (generation), infrastructure (transmission), consumption, and other activities presented on the right. The main effects regarding externalities are CO₂ emissions reductions, integration of renewable energy, derived local environmental and social costs, and benefits resulting from early deployment [Think 2013].

![Figure 4-8 Layers of effects of infrastructure projects](Think 2013)

Depending on the project some of the effects might not be relevant, especially regarding projects in the private sector, and can thus be neglected. As the CBA in this thesis is performed from the ESS operator’s and owner’s point of view, only the monetary effects of investment and operating costs, as well as the benefits generated by the ESS and the system in its immediate surrounding are considered.

After the deployment case for the ESS has been clearly defined according to section 4.1, the CBA can be carried out following the steps presented in Figure 4-9.

![Figure 4-9 Calculation flow for Cost-Benefit Analysis](unnamed.png)
4.2.1 Financial Boundary Conditions

Before starting with the actual calculation of cost and benefits, the financial boundary conditions must be clarified. They are dependent on the owner of the ESS, the market in which it is operated and of the project itself and include the applicable discount rate \( r \), the reinvestment rate which is considered here to be the weighted average cost of capital \( WACC \), the inflation rate \( i \), the lifetime of the project \( T \), and the tax \( t \). The values for these conditions used in this thesis are presented in Table 4-1.

<table>
<thead>
<tr>
<th>Name</th>
<th>Abbreviation</th>
<th>Value</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount rate</td>
<td>r</td>
<td>10%</td>
<td>[Eyer &amp; Corey 2010]</td>
</tr>
<tr>
<td>Weighted average cost of capital</td>
<td>WACC</td>
<td>8%</td>
<td>[Cutter et al. 2014]</td>
</tr>
<tr>
<td>Inflation rate</td>
<td>i</td>
<td>2%</td>
<td>[Kaun &amp; Chen 2013]</td>
</tr>
<tr>
<td>Tax rate</td>
<td>t</td>
<td>42%</td>
<td>[Cutter et al. 2014]</td>
</tr>
<tr>
<td>Project lifetime</td>
<td>T</td>
<td>20 years</td>
<td>General assumption</td>
</tr>
</tbody>
</table>

4.2.2 Total Capital Cost

The total capital cost \( C_{Cap} \) includes all costs for the purchase, delivery and installation of the ESS. These can be divided into costs for the power conversion system \( C_{PCS} \), the storage section \( C_{stor} \), and balance of plant costs \( C_{BOP} \). The PCS costs typically include the costs for power interconnections and power electronics like rectifiers and inverters and are dependent on the power capacity \([$/kW]\). Storage section costs describe the battery costs which depend on the energy capacity \([$/kWh]\). The balance of plant costs contain all other expenses necessary to set up the ESS, such as project engineering and design, system integration, land and buildings, monitoring and control systems, and shipment and installation. These costs can either be measured per unit of power capacity \([$/kW]\) of unit of energy capacity \([$/kWh]\) [Zakeri & Syri 2015]. In order to use identical units for calculation, all costs will be converted to be described as per unit of power capacity \([$/kW]\), thus cost per unit of energy capacity \([$/kWh]\) will be multiplied by the charging/ discharging time \( t_c \). Therefore the total capital cost can be calculated the following way:

\[
C_{Cap} = C_{PCS} + C_{stor} \times t_c + C_{BOP} \quad [$/kW] \tag{4}
\]

with

\[
t_c = \frac{Energy\ Capacity}{Power\ Capacity} \quad [h] \tag{5}
\]

Typical values for the components of the capital costs are shown in Table 4-2.
Table 4-2 Total capital cost: typical values

<table>
<thead>
<tr>
<th>Name</th>
<th>Abbreviation</th>
<th>Value</th>
<th>Unit</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power conversion system</td>
<td>$C_{PCS}$</td>
<td>150</td>
<td>$/kW</td>
<td>[Sterner et al. 2014]</td>
</tr>
<tr>
<td>(low)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power conversion system</td>
<td>$C_{PCS}$</td>
<td>410</td>
<td>$/kW</td>
<td>[Zakeri &amp; Syri 2015]</td>
</tr>
<tr>
<td>(high)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Storage system (low)</td>
<td>$C_{stor}$</td>
<td>200</td>
<td>$/kWh</td>
<td>[Sabihuddin et al. 2015]</td>
</tr>
<tr>
<td>Storage system (high)</td>
<td>$C_{stor}$</td>
<td>850</td>
<td>$/kWh</td>
<td>[Zakeri &amp; Syri 2015]</td>
</tr>
<tr>
<td>Balance of plant</td>
<td>$C_{BOP}$</td>
<td>85</td>
<td>$/kW</td>
<td>[Zakeri &amp; Syri 2015]</td>
</tr>
</tbody>
</table>

4.2.3 Operating Cost

The operating and maintenance (O&M) costs ($C_{O&M}$) are the costs that accrue continuously during the lifetime of the ESS. Costs that have to be paid independently of operation are fixed O&M costs ($C_{O&M,f}$) [$/kW]. Variable O&M costs ($C_{O&M,v}$) are dependent on the operation throughput of the ESS and thus expressed per unit of energy discharged [$/kWh]. The number of full discharge cycles per year ($n$) is used to annualize the variable O&M costs.

The costs accounting for losses ($C_L$) due to efficiency are treated separately here, but could also be included in the variable O&M costs. They also occur per unit of energy discharged [$/kWh$] and are dependent on the electricity price and the overall system efficiency ($\eta_{Sys}$). The yearly total O&M costs are calculated using the following equation:

$$C_{O&M} = C_{O&M,f} + (C_{O&M,v} + C_L) \times n \times t_c \ [$/kW]$$  \hspace{1cm} (6)

with

$$C_L = \eta_{Sys} \times Electricit\text{y price} \ [$/kWh]$$  \hspace{1cm} (7)

Typical values for operation and maintenance costs are given in Table 4-3.

Table 4-3 Operation and maintenence cost: typical values

<table>
<thead>
<tr>
<th>Name</th>
<th>Abbreviation</th>
<th>Value</th>
<th>Unit</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed O&amp;M (low)</td>
<td>$C_{O&amp;M,f}$</td>
<td>7.5</td>
<td>$/kW</td>
<td>[Zakeri &amp; Syri 2015]</td>
</tr>
<tr>
<td>Fixed O&amp;M (high)</td>
<td>$C_{O&amp;M,f}$</td>
<td>25</td>
<td>$/kW</td>
<td>[Cutter et al. 2014]</td>
</tr>
<tr>
<td>Variable O&amp;M (low)</td>
<td>$C_{O&amp;M,v}$</td>
<td>2.3</td>
<td>$/kWh</td>
<td>[Zakeri &amp; Syri 2015]</td>
</tr>
<tr>
<td>Variable O&amp;M (high)</td>
<td>$C_{O&amp;M,v}$</td>
<td>5</td>
<td>$/kWh</td>
<td>[Cutter et al. 2014]</td>
</tr>
</tbody>
</table>
4.2.4 Replacement and Disposal Costs

If the project lifetime is longer than the lifetime of the components of the ESS, they will have to be replaced. Here the replacement costs of the PCS ($C_{R,PCS}$) [$/kW$] and of the storage section ($C_{R,stor}$) [$/kWh$] are considered. Importantly, the replaced components need to be disposed of (or recycled) at the same time as the replacement takes place. Furthermore, the whole ESS must be disposed of at the end of the project lifetime which creates additional disposal and recycling costs for the PCS ($C_{D,PCS}$) [$/kW$] and the storage section ($C_{D,stor}$) [$/kWh$]. These are not negligible since most batteries require a special treatment at the end of their lifetime, which can be expensive. Depending on the time of replacement, the costs occur separately or can be added up:

For replacement:

\[
C_{R,PCS} = C_{PCS} + C_{D,PCS} \quad [$/kW]
\]

\[
C_{R,stor} = C_{stor} + C_{D,stor} \quad [$/kWh]
\]

At the end of life:

\[
C_D = C_{D,PCS} + C_{D,stor} \times t_c \quad [$/kW]
\]

It is important to note that all costs used here are considered at the time that they accrue and might need to be discounted later. Also, depending on the tool used for calculation it might be useful to convert the cost into absolute values [$\]$ at this point. Table 4-4 shows typical values for the disposal costs.

<table>
<thead>
<tr>
<th>Name</th>
<th>Abbreviation</th>
<th>Value</th>
<th>Unit</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disposal of PCS</td>
<td>$C_{D,PCS}$</td>
<td>5.5</td>
<td>$/kW$</td>
<td>[Narula et al. 2011]</td>
</tr>
<tr>
<td>Disposal of storage section</td>
<td>$C_{D,stor}$</td>
<td>5.5</td>
<td>$/kWh$</td>
<td>[Narula et al. 2011]</td>
</tr>
</tbody>
</table>

4.2.5 Benefits

The benefits of the project are either generated directly by the ESS or by its surrounding system. They can be assigned to their respective services such that the anchor service generates $B_A$ and the secondary services $B_{sec,i}$ with $i$ being the respective service out of $k$ total secondary services. The benefits of the services can be measured in [$$/kW], [$$/kWh], [$$/ΔkW] or other metrics introduced in chapter 3. For ease of calculation they should either be converted to [$$/kW] or into absolute values [$\]$. The yearly total benefits can then be summed up:

\[
B = B_A + \sum_{i=1}^{k} B_{sec,i} \quad [$] \text{or} \quad [$/kW]
\]
The benefits are considered at the time they are generated and then discounted when applying the metrics for evaluation. If there are subsidies available for the ESSs, they should be considered here as well.

4.2.6 Metrics

Several metrics can be applied to describe the results of a CBA. Six very common metrics have been chosen and are presented here.

Net Present Value (NPV)

The net present value (NPV) determines whether or not a project is profitable. If the NPV is positive, the project is profitable. If it is negative, the investor is losing money. To calculate the NPV, the cash-flows \( CF_j \) representing costs and benefits of the year \( j \) are discounted to present time using the discount rate \( r \) and then summed up:

\[
NPV = \sum_{j=0}^{T} \frac{CF_j}{(1+r)^j}
\]

Equivalent annual annuity

The equivalent annual annuity (EAA) represents the annual cash-flow a project would generate if all cash-flows were distributed equally over the projects lifetime. This is helpful when comparing projects with different lifetimes. It is calculated by annualizing the NPV using the capital recovery factor (CRF):

\[
EAA = CRF \times NPV
\]

with

\[
CRF = \frac{r}{1-(1+r)^{-T}}
\]

Benefit / Cost Ratio

The benefit/cost ratio (BCR) shows the relative profitability of a project compared to its costs. Benefits and costs are discounted to the present value and directly compared. Like the NPV, it shows whether or not a project is profitable. If the BCR is greater than 1, it is profitable; if it’s smaller than 1, it is unprofitable.

\[
BCR = \frac{PV(B)}{PV(C)} = \frac{\sum_{j=0}^{T} B_j}{\sum_{j=0}^{T} C_j} \left(\frac{1}{1+r}\right)^j
\]
**Payback Period**

The payback period (PB) is the time that is needed for a project to recover its initial investment. The cash-flows of the individual years are added up starting from the start of the project until the accumulated cash-flow equals the initial investment. The years necessary to equalize the investment represent the payback period. If the annual cash-flows stay constant over the lifetime of the project, the payback period can be calculated by dividing the annual cash-flow ($CF_j$) by the initial investment ($Inv_0$):

$$PB = \frac{CF_j}{Inv_0} \quad (16)$$

**Internal Rate of Return (IRR)**

The internal rate of return is a common metric used to decide whether or not to proceed with a project or to decide between alternative projects. If it is higher than the applicable discount rate the project is profitable and the alternative with the highest IRR is chosen. The IRR represents the discount rate that would make the NPV equal to zero and is usually computed iteratively:

$$NPV = 0 = \sum_{j=0}^{T} \frac{CF_j}{(1 + IRR)^j} \quad (17)$$

**Modified Internal Rate of Return (MIRR)**

The modified internal rate of return (MIRR) aims at solving two problems that arise with the use of the IRR. One problem is the possibility of multiple IRRs in case cash-flows after the initial investment are negative. The other problem lies in the assumption of the IRR that positive cash-flows are reinvested at the IRR which is generally not true. These problems are solved with the use of the MIRR. The MIRR is calculated in a similar way as the IRR, however, using a different reinvestment rate, usually the WACC, for the benefits. The costs are discounted using the discount rate while the benefits are compounded to the end of the project lifetime using the new reinvest rate and then discounted using the MIRR that makes the NPV equal to zero:

$$NPV = 0 = \sum_{j=0}^{T} \frac{C_j}{(1 + r)^j} + \sum_{j=0}^{T} B_j \times \frac{(1 + WACC)^{T-j}}{PV(B_j)} \times \frac{1}{(1 + MIRR)^j} \quad (18)$$

$$MIRR = \sqrt[\tau]{\frac{\sum PV(B_j)}{\sum PV(C_j)}} - 1 \quad (19)$$
**4.3 Sensitivity Analysis**

While the cost-benefit analysis is a good tool to measure the profitability of a project, it is limited to one specific deployment case. In order to take uncertainties into account and to test the dependencies of the deployment case on certain input parameters, a sensitivity analysis must be performed. For this purpose a tool has been developed during the preparation of this thesis using Matlab and MS Excel with which sensitivity parameters can be modified individually and a CBA can be performed for each individual case.

The selection of sensitivity parameters depends on the deployment case, especially regarding the generation of benefits. However, there are certain general parameters that occur and may be varied in every ESS deployments cases. These include power-to-energy ratio of the capacities, the lifetime of the PCS and the batteries, and their costs. In addition to these sensitivity parameters deployment case specific parameters are varied in the following two cases presented in chapter 5.
5 Results and Discussion

Two deployment cases have been defined and analyzed according to the methodology in chapter 4. In this chapter the definition of the deployment cases and the results of the cost-benefit analyses and the sensitivity analyses are presented and discussed.

5.1 Deployment Case 1 – Frequency Regulation in PJM

This deployment case is based on the ESS deployment AES Laurel Mountain mentioned in section 2.2.1 which is a 32 MW/8 MWh lithium-ion battery ESS, shown in Figure 5-1, located close to a wind farm and provides RE integration services. The main benefits, however, are generated by providing frequency regulation in the PJM market.

5.1.1 Case Definition

The definition of this deployment case follows the methodology introduced in section 4.1 and is based on the deployment AES Laurel Mountain mentioned above, though it may be different in some parts, since not all information is publicly available and several assumptions are made to reach a clearly defined deployment case.

The owner and operator of this ESS is an IPP operating in the PJM market with the intention to generate profits by providing frequency regulation. This purpose can be fulfilled by an ESS. The technical criteria for providing frequency regulation in PJM consist of a minimum power capacity of 0.1 MW, a power-to-energy ratio for ESS of 4 or smaller, a fast reaction time of maximal two seconds, and the ability to receive and react to an automatic generation control (AGC) signal [PJM 2015b].

Metrics to measure the success of the project are chosen to be a positive NPV and an IRR of more than 20%. The technical criteria for the ESS require a fast ramp rate of few milliseconds to ramp up to 100% output power with a response time of less than 100 milliseconds and active power injection of the amount bid into the market. Furthermore, about 330 equivalent full cycles per year are required.
according to an evaluation made using the RegD signal of 2014 which can be downloaded from the PJM website [PJM 2015a].

The anchor service in this case is frequency regulation. Only few secondary services can be provided in combination together with frequency regulation which requires sophisticated control software. Since there is no operation data available about the wind farm close by, the profits from RE integration are difficult to measure and RE integration services are neglected here. Instead, large scale time-shifting has been chosen as secondary service which requires only two short term interruptions of frequency regulation per day. Because the services are provided separately from each other there is no problem regarding compatibility while frequency regulation has the highest priority. Added costs may accrue if the energy capacity is increased for large scale time-shifting. This is analyzed in the sensitivity analysis as well as the question whether or not there are additional benefits from providing large scale time-shifting while stopping frequency regulation.

The ESS properties are equal to the technical requirements mentioned in the paragraph above with charging and discharging efficiency of 95% each, thus $\eta_{\text{Sys}} = 90.25\%$ since the efficiency of the storage section is assumed to be 100%. The battery technology utilized is lithium-ion, specifically lithium iron phosphate (LiFePO₄) batteries.

### 5.1.2 Cost-Benefit Analysis

The CBA for this case uses the financial boundary conditions specified in section 4.2. For the total capital costs, operating costs, and replacement and disposal costs typical values within the ranges given also in section 4.2 are used. The lifetime of the PCS and the storage system is assumed to be ten years which is a realistic value [Pearre & Swan 2014]. The technical data needed to perform the CBA are taken from the case definition in the previous section 5.1.1. The costs and benefits are calculated for the first year of operation and increased using the inflation rate for following years. The input values are summarized in Table 5-1.

<table>
<thead>
<tr>
<th>Input parameter</th>
<th>Abbreviation</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power capacity</td>
<td>P_cap</td>
<td>32</td>
<td>MW</td>
</tr>
<tr>
<td>Energy capacity</td>
<td>E_cap</td>
<td>8</td>
<td>MWh</td>
</tr>
<tr>
<td>Yearly equivalent full cycles</td>
<td>cycles</td>
<td>330</td>
<td>-</td>
</tr>
<tr>
<td>System efficiency</td>
<td>$\eta_{\text{Sys}}$</td>
<td>90.25</td>
<td>%</td>
</tr>
<tr>
<td>Discount rate</td>
<td>r</td>
<td>10</td>
<td>%</td>
</tr>
<tr>
<td>Weighted average cost of capital</td>
<td>WACC</td>
<td>8</td>
<td>%</td>
</tr>
<tr>
<td>Inflation rate</td>
<td>i</td>
<td>2</td>
<td>%</td>
</tr>
</tbody>
</table>
## Table

<table>
<thead>
<tr>
<th>Description</th>
<th>Symbol</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tax rate</td>
<td>$t$</td>
<td>42</td>
<td>%</td>
</tr>
<tr>
<td>Project lifetime</td>
<td>$T$</td>
<td>20</td>
<td>years</td>
</tr>
<tr>
<td>PCS lifetime</td>
<td>$T_{PCS}$</td>
<td>10</td>
<td>years</td>
</tr>
<tr>
<td>Storage section lifetime</td>
<td>$T_{stor}$</td>
<td>10</td>
<td>years</td>
</tr>
<tr>
<td>PCS cost</td>
<td>$C_{PCS}$</td>
<td>150</td>
<td>$/kW$</td>
</tr>
<tr>
<td>Storage section costs</td>
<td>$C_{stor}$</td>
<td>300</td>
<td>$/kWh$</td>
</tr>
<tr>
<td>Balance of plant cost</td>
<td>$C_{BOP}$</td>
<td>85</td>
<td>$/kW$</td>
</tr>
<tr>
<td>Fixed O&amp;M cost</td>
<td>$C_{O&amp;M,f}$</td>
<td>7.5</td>
<td>$/kW$</td>
</tr>
<tr>
<td>Variable O&amp;M Cost</td>
<td>$C_{O&amp;M,v}$</td>
<td>2.3</td>
<td>$/kWh$</td>
</tr>
<tr>
<td>Disposal and Recycling cost (PCS)</td>
<td>$C_{D,PCS}$</td>
<td>5.5</td>
<td>$/kW$</td>
</tr>
<tr>
<td>Disposal and Recycling cost (storage section)</td>
<td>$C_{D,stor}$</td>
<td>5.5</td>
<td>$/kWh$</td>
</tr>
</tbody>
</table>

The benefits in this case result from the regulation market clearing price (RMCP) credits which are calculated according to equations (1) - (3) in section 2.3.2 and from participation in the wholesale market. The metrics of the benefits are levelized cost of capacity [$/kW$] and levelized cost of mileage [$/$ΔkW] for frequency regulation and added value by storing energy [$/kWh$] for large scale time-shifting. These metrics are, however, converted into pure monetary terms [$] during the calculation.

For the purpose of participation in the wholesale market the hourly values of the locational marginal prices (LMP) of the day ahead market for the year 2014 have been exported from PJM’s online tool Data Miner for the pricing node *LEADSVIL.34.5 KV LAURMTBT* (Pnode ID 123901511) which is the node that the ESS is connected to [PJM 2014]. The lowest LMP in the early morning and the highest LMP in the evening peak hours of every day have been identified. During these hours the ESS stops providing frequency regulation for the time it needs for charging or discharging until a predefined state of charge (SOC). This is illustrated in Figure 5-2 for a typical day. The analysis of the RegD signal of the year 2014 showed that the minimum SOC at the beginning of a day must be at least 10.7% of the energy capacity multiplied by the power-to-energy ratio. The energy capacity available for charging at the beginning of a day must not exceed 2.2% of the energy capacity also multiplied by the power-to-energy ratio. This assumption requires the storage to be charged or discharged at the end of a day if these limits have been crossed. Due to efficiency losses it usually needs to be charged which generates additional costs that have to be accounted for.
In this base case the maximum SOC limits are considered using the power-to-energy ratio of 4 which results in a minimum SOC of 42.8% (=3.424 MWh) and a maximum SOC of 91.2% (=7.296 MWh). Therefore, the energy capacity available for large scale time-shifting is $E_{TS} = 3.872$ MWh. The benefit from large scale time-shifting $B_{TS}$ is the product of the difference of the two LMPs and the available energy capacity $E_{TS}$:

$$B_{TS} = E_{TS} \times \Delta LMP$$  \hspace{1cm} (20)$$

The necessary data to calculate the benefits from frequency regulation, namely the hourly values of 2014 for the RMCCP, the RMPCP, and the mileage ratio, is also available on the PJM website [PJM 2015a]. The assigned regulation power is the full power capacity of the ESS and the performance score is assumed to be 95%. Table 5-2 summarizes the input data for the benefit calculation.
### Table 5-2 Input data for benefit calculation: Deployment case 1 - Frequency regulation

<table>
<thead>
<tr>
<th>Benefit category</th>
<th>Name</th>
<th>Abbreviation</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time-shifting</td>
<td>Locational Marginal Price</td>
<td>LMP</td>
<td>Various</td>
<td>$/MWh</td>
</tr>
<tr>
<td></td>
<td>State of charge range</td>
<td>SOC range</td>
<td>42.8 – 91.2</td>
<td>%</td>
</tr>
<tr>
<td>Frequency Regulation</td>
<td>RMCCP</td>
<td>RMCCP</td>
<td>Various</td>
<td>$/MW</td>
</tr>
<tr>
<td></td>
<td>RMPCP</td>
<td>RMPCP</td>
<td>Various</td>
<td>$/MW</td>
</tr>
<tr>
<td></td>
<td>Mileage ratio</td>
<td>m_ratio</td>
<td>Various</td>
<td>ΔMW/ΔMW</td>
</tr>
<tr>
<td></td>
<td>Performance score</td>
<td>performance</td>
<td>95</td>
<td>%</td>
</tr>
</tbody>
</table>

### Results of Cost-Benefit Analysis

For this specific case with the input data presented above, the results show that the project is highly profitable. This is described by the metrics introduced in section 4.2 and presented in Table 5-3 along with additional information about the costs and benefits. The detailed calculation of the results can be found in appendix A3.

### Table 5-3 Results of CBA: Deployment Case 1 - Frequency regulation

<table>
<thead>
<tr>
<th>Metric</th>
<th>Abbreviation</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial investment cost</td>
<td>C\textsubscript{cap}</td>
<td>9,920,000 $</td>
</tr>
<tr>
<td>Frequency regulation benefit (1\textsuperscript{st} year)</td>
<td>RMCP Credits</td>
<td>13,552,500 $</td>
</tr>
<tr>
<td>Frequency regulation cost (due to losses)</td>
<td>C\textsubscript{l}</td>
<td>16,133 $</td>
</tr>
<tr>
<td>Large-scale time-shifting benefit (1\textsuperscript{st} year)</td>
<td>B\textsubscript{sec}</td>
<td>45,990 $</td>
</tr>
<tr>
<td>Life cycle cost (before tax)</td>
<td>LLC</td>
<td>16,010,819 $</td>
</tr>
<tr>
<td>Life cycle benefits (before tax)</td>
<td>LLB</td>
<td>132,436,270 $</td>
</tr>
<tr>
<td>Net present value</td>
<td>NPV</td>
<td>67,147,995 $</td>
</tr>
<tr>
<td>Equivalent annual annuity</td>
<td>EAA</td>
<td>7,887,179 $</td>
</tr>
<tr>
<td>Benefit / Cost ratio</td>
<td>BCR</td>
<td>8.3</td>
</tr>
<tr>
<td>Payback period</td>
<td>PB</td>
<td>0.83 years = 10 months</td>
</tr>
<tr>
<td>Internal rate of return</td>
<td>IRR</td>
<td>101 %</td>
</tr>
<tr>
<td>Modified internal rate of return</td>
<td>MIRR</td>
<td>21 %</td>
</tr>
</tbody>
</table>

#### 5.1.3 Sensitivity Analysis

For this sensitivity analysis the sensitivity parameters power-to-energy, lifetime of PCS and batteries, and costs of PCS and batteries have been chosen as mentioned above. Furthermore, the sensitivity of the profitability towards the available energy for large scale time-shifting is evaluated and the
influence of the RMCPs is analyzed since these prices are derived from historical data of one particular year which may not be representative. In each sensitivity case only the respective parameters are varied while all other input parameters are kept constant at the values of the base case presented in the cost-benefit analysis above. The results of the sensitivity analysis for this deployment case are presented and discussed in the next paragraphs. For the sensitivity analysis only the NPV and IRR and MIRR are used to evaluate the profitability, as these metrics are often most important for decision makers in companies such as IPPs. The graphs are marked with a yellow star to indicate the base case scenario introduced in the CBA.

**Sensitivity Results: Power-to-Energy ratio**

The power-to-energy ratio has been varied by keeping the power capacity value constant and varying the energy capacity between 4 MW to 128 MW, thus varying the power-to-energy ratio between ¼ and 8. The NPV is shown in Figure 5-3, the IRR and the MIRR are shown in Figure 5-4.

![Figure 5-3 NPV in dependence on Power-to-Energy ratio](image1)

![Figure 5-4 Rates of return in dependence on Power-to-Energy ratio](image2)

The results show that the profitability increases with increasing power-to-energy ratio. This is due to the fact that the major part of the benefits is gained from providing frequency regulation which is dependent on the power capacity. A higher power-to-energy ratio results in proportionately lower costs for the storage section which generates benefits from large scale time-shifting only; however it does not contribute significantly to the overall benefits. It should be noted, that the cooling requirements of the ESS would increase with increasing power-to-energy ratio, which would lead to higher balance of plant costs and thus to a maximum profitability at a certain power-to-energy ratio. This has not been considered here, since only one sensitivity parameter is varied at a time.

**Sensitivity Results: Lifetime of PCS and Storage Section**

The lifetime of the components of the ESS can influence the profitability of the project due to replacement and disposal costs. The lifetimes of the PCS and the Storage Section are varied independently from each other in the range from 1 to 20 years.
First, the lifetime of the PCS is varied and the lifetime of the storage section is kept constant at 10 years. The graph in Figure 5-5 shows the NPV and the graph in Figure 5-6 shows the IRR and the MIRR.

The influence of the PCS lifetime on the profitability is especially visible at short lifetimes less than 5 years. The NPV as well as IRR and MIRR show sublinear growth approaching the values that would result from an infinite lifetime. In fact, the NPV and the rates of return only change marginally for lifetimes longer than 10 years since the number of replacements and thus the costs stay constant. The minor growth that still exists is due to the change of replacement and disposal costs with inflation.

A similar effect can be seen when varying the lifetime of the storage section while keeping the PCS lifetime constant, as shown by the NPV in Figure 5-7 and IRR and MIRR in Figure 5-8.

As the overall cost of the storage section is smaller than that of the PCS, the influence of a change in its lifetime on the profitability is smaller as well.

**Sensitivity Results: Costs of PCS and Storage Section**

The costs of the components of the ESS, especially battery costs, are often seen as the prohibiting factor when considering ESS deployment. They influence directly the capital costs and thus the initial investment. The graphs of the NPV in Figure 5-9 and the IRR and MIRR in Figure 5-10 show the
impact of changes in PCS costs from 100-800 $/kW on the NPV, the IRR and the MIRR while keeping the costs of the storage section constant.

With increasing PCS costs the NPV as well as IRR and MIRR decrease since the profitability is reduced by higher initial costs. The same is true for the influence of an increase in battery costs shown by the NPV in Figure 5-11 and by the IRR and MIRR in Figure 5-12 below. The battery costs have been varied from 100-600 $/kWh while keeping the PCS costs constant.

As mentioned above at the lifetime sensitivity, the effect of a change in battery costs is smaller than the effect of a change in PCS costs because the battery costs represent a smaller portion in the overall costs. Although the profitability decreases with increasing costs, it should be noted that even with high component costs the project stays profitable.

**Sensitivity Results: Available Energy Capacity for time-shifting**

The available energy capacity for time-shifting is the portion of the overall energy capacity that generates benefits from participation in the wholesale market. This energy capacity has been varied between 0-55% of the overall energy capacity and represents the requested available energy capacity for time-shifting. The actual available energy capacity for time-shifting is equal to the requested energy capacity as long as the predefined limits are respected. If the requested available energy capacity exceeds the limits, the actual available energy capacity is defined as the maximum possible energy capacity within the limits. The development of the NPV for the varying available energy
capacity for time-shifting is shown in the graph in Figure 5-13 and the IRR and MIRR are shown in Figure 5-14.

![Figure 5-13 NPV in dependence on the available energy capacity for time-shifting](image1)

![Figure 5-14 Rates of return in dependence on the available energy capacity for time-shifting](image2)

Both the decreasing NPV and the decreasing IRR indicate that the profitability decreases with increasing available energy capacity for time-shifting until a certain point. This means, that the more energy is traded at the wholesale market, the less profit is generated, even though the differences are not very large. This seems remarkable since the ESS is expected to produce additional benefits by providing a secondary service. However, the important point to consider here is that the ESS requires time for charging and discharging during which it cannot provide frequency regulation. Therefore, it loses the opportunity to generate benefits from frequency regulation during this time. These lost opportunity costs are larger than the additional benefits gained from large scale time-shifting and they grow with the time that the ESS is not able to provide frequency regulation, which is proportional to the available energy capacity for time-shifting.

The available energy capacity for time-shifting above which the profitability stays constant is 48.4%, which is the maximum energy capacity that still allows the ESS to operate within the limits required for frequency regulation introduced in the cost-benefit analysis, section 5.1.2.

**Sensitivity Results: Regulation Market Clearing Prices (RMCPs)**

The provision of frequency regulation is the main source of benefits for the ESS. These benefits are calculated from the RMCCP and the RMPCP, thus their values have a major influence on the profitability of the ESS which is tested by varying them between 10-150% of their original values. The mean of the original RMCCP is 39.63 $/MW and the mean of the original RMPCP is 4.07 $/MW. The dependency of the profitability on the RMCPs is shown by the NPV in Figure 5-15 and the IRR and MIRR in Figure 5-16.
It is obvious that the profitability increases with increasing price factor, i.e. the factor that the RMCPs have been multiplied by. The zero-crossing of the NPV represents the price factor that makes the project profitable and is found by linear interpolation to be 13.7%. This price factor is also the point at which the IRR is equal to 10% which is the applied discount rate. The equivalent mean values of the RMCCP and the RMPCP are 5.44 $/MW and 0.56 $/MW respectively.

Below certain RMCPs, participation in the wholesale market by large scale time-shifting becomes more valuable than providing frequency regulation during the time of charging and discharging. This has been analyzed by comparing the profitability metrics of the base case, which provides the maximum possible amount of large scale time shifting, with a case without any large scale time-shifting. The graph in Figure 5-17 shows the difference in NPV (ΔNPV) of the two cases as shown in equation (21). Figure 5-18 shows the difference of the IRR and MIRR of the two cases.

\[ \Delta NPV = NPV_{with\ TS} - NPV_{without\ TS} \]  

In this case the zero-crossing of the ΔNPV represents the price factor, below which participation in the wholesale market is more profitable than providing frequency regulation during the time of charging and discharging. By linear interpolation this point is found to be 32.8% of the original RMCPs. The
zero-crossing of the IRR confirms this number. The equivalent mean values of the RMCCP and the RMPCP are 12.99 $/MW and 1.33 $/MW respectively.

5.2 Deployment Case 2 – Peak Limiting in California

This deployment case addresses behind-the-meter ESSs at a commercial or industrial (C&I) site providing peak limiting for demand charge reduction, similar to the ESS deployment Prudent Energy VRB-ESS – Gills Onions mentioned in section 2.2.4. The ESS with the tanks of the vanadium redox flow battery in the front is shown in Figure 5-19.

![ESS at Gills Onions for peak limiting and TOU shifting](Department of Energy 2015)

5.2.1 Case Definition

This deployment case consists in fact of three individual cases, considering data of three different sites. All other boundary conditions are comparable. The energy consumption data of several C&I sites have been reviewed and three representative sites have been chosen for further investigation. The anonymized data is provided in increments of five minute intervals for the year 2012 and can be downloaded freely from the EnerNOC website [EnerNOC 2013].

The ESS owners and operators are a food processor (EnerNOC site 771), a school (EnerNOC site 100), and an office building (EnerNOC site 9). All three of them are located in California in the area of the utility Southern California Edison (SCE) where there are time-of-use tariffs with demand charges and subsidies for energy storage. They face the problem of short and high peak loads and the intention is to limit these peaks in order to reduce demand charges. Therefore an ESS is deployed to mitigate the problem. The load profiles of the food processor (Figure 5-20), the school (Figure 5-21), and the office building (Figure 5-22) are shown below for a representative week.
The solution requires active power injection in the order of 25% of the monthly peak load for the time of the respective peak. The success of the solution is measured by whether or not it manages to reduce the peak load by 25% and by the overall savings it provides, i.e. the demand charge reduction must be larger than the cost for the solution, leading to a positive NPV of the project. The technical criteria for the ESS require active power injection with a power capacity of 25% of the highest peak during the year. This corresponds to power capacities of 140 kW for the food processor, 100 kW for the school, and 240 kW for the office building. The energy capacities must be large enough to cover multiple
peaks, since their might not be enough time to recharge between peaks. The minimum required energy capacity has been calculated such that all peaks can be compensated which leads to possible discharge times of several hours. The energy capacity for the food processor is 500 kWh, for the school 270 kWh, and for the office building 700 kWh. The power and energy capacities have been rounded up to the next multiple of 10 kW or 10 kWh respectively.

As the intention is to reduce demand charges, the anchor service has been defined to be peak limiting. Possible secondary services include RE time-shifting for self-consumption, power quality, and TOU shifting. Since there are no available data about local RE generation or power quality requirements only TOU shifting has been considered. However, to keep the complexity of the algorithm simulating the state of charge (SOC) at an acceptable level and to stay within the scope of this thesis, TOU shifting has only been performed for the energy that needs to be charged or discharged for peak limiting. That means that, if possible, the ESS charges during off-peak hours and not during peak hours. This secondary service is fully compatible with the anchor service of peak limiting. Priority is given to peak limiting. The secondary service generates additional benefits by saving energy charges, but does not cause additional costs.

The ESS properties are equal to the requirements mentioned above with ramp rates and response times of few seconds. The number of yearly equivalent full cycles is 1260 for the food processor, 400 for the school, and 900 for the office building. The storage section consists of lithium-ion batteries.

5.2.2 Cost-Benefit Analysis

A cost-benefit analysis is performed for each of the three cases with the technical parameters defined in the previous section 5.2.1. The financial boundary conditions remain the same as defined in the introduction to the CBA in section 4.2. However, as the benefits in this deployment case result from savings of demand and energy charges, there are no taxes applied to the earnings.

In California, energy storage is subsidized by the state. For this case the subsidies are assumed to be 1000 $/kW of power capacity which is less than the actual subsidies of 1460 $/kW (see section 2.3.3). The influence of subsidies is analyzed later in a sensitivity analysis. Here, these subsidies are subject to the following two conditions: they are only applicable to the minimal, required power capacity and they may not exceed 75% of the total capital cost. However, they may also be applied to possible replacements at the end of the component lifetime. These conditions have been implemented to prevent the unnecessary increase of the power capacity and to demand a certain investment by the owner. The total subsidies for a year are calculated according to the following equation:

\[
Subsidies = \min\{0.75 \times Total\ inv\ Costs;\ 0.75 \times Minimum\ required\ power\ capacity\} \tag{22}
\]
The lifetime of the PCS and the storage section are defined to be 10 years. All cost and benefit values are calculated for the first year and then increased by the inflation rate for the following years. Table 5-4 summarizes the input parameters for the CBA.

<table>
<thead>
<tr>
<th>Input parameter</th>
<th>Abbreviation</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power capacity</td>
<td>P_cap</td>
<td>100</td>
<td>kW</td>
</tr>
<tr>
<td>Energy capacity</td>
<td>E_cap</td>
<td>270</td>
<td>kWh</td>
</tr>
<tr>
<td>Yearly equivalent full cycles</td>
<td>cycles</td>
<td>406</td>
<td>-</td>
</tr>
<tr>
<td>System efficiency</td>
<td>n_sys</td>
<td>90</td>
<td>%</td>
</tr>
<tr>
<td>Discount rate</td>
<td>r</td>
<td>10</td>
<td>%</td>
</tr>
<tr>
<td>Inflation rate</td>
<td>i</td>
<td>2</td>
<td>%</td>
</tr>
<tr>
<td>Subsidies</td>
<td>sub</td>
<td>1000</td>
<td>$/kW</td>
</tr>
<tr>
<td>Demand charge summer</td>
<td>d_charge_s</td>
<td>25</td>
<td>$/kW</td>
</tr>
<tr>
<td>Demand charge winter</td>
<td>d_charge_w</td>
<td>13</td>
<td>$/kW</td>
</tr>
<tr>
<td>Project lifetime</td>
<td>T</td>
<td>20</td>
<td>years</td>
</tr>
<tr>
<td>PCS lifetime</td>
<td>T_PCS</td>
<td>10</td>
<td>years</td>
</tr>
<tr>
<td>Storage section lifetime</td>
<td>T_stor</td>
<td>10</td>
<td>years</td>
</tr>
<tr>
<td>PCS cost</td>
<td>C_PCS</td>
<td>150</td>
<td>$/kW</td>
</tr>
<tr>
<td>Storage section costs</td>
<td>C_stor</td>
<td>300</td>
<td>$/kWh</td>
</tr>
<tr>
<td>Balance of plant cost</td>
<td>C_BOP</td>
<td>85</td>
<td>$/kW</td>
</tr>
<tr>
<td>Fixed O&amp;M cost</td>
<td>C_O&amp;M,f</td>
<td>7.5</td>
<td>$/kW</td>
</tr>
<tr>
<td>Variable O&amp;M Cost</td>
<td>C_O&amp;M,v</td>
<td>2.3</td>
<td>$/kWh</td>
</tr>
<tr>
<td>Disposal and Recycling cost (PCS)</td>
<td>C_D_PCS</td>
<td>5.5</td>
<td>$/kW</td>
</tr>
<tr>
<td>Disposal and Recycling cost (storage section)</td>
<td>C_D_stor</td>
<td>5.5</td>
<td>$/kWh</td>
</tr>
</tbody>
</table>

The benefits result from savings on the electricity bill and thus depend on the electricity tariff. For the purpose of this case study an electricity tariff has been created which is adapted from PG&E’s Schedule A-10 B¹ and SC&E’s TOU-GS-2² tariff. It is different for summer and winter and consists of a demand charge and time-of-use electricity charges. The demand charge is 25 $/kW in summer and 13 $/kW in winter with summer dating from May 1 until October 31. The TOU electricity charges are shown in Figure 5-23 indicating the time periods for peak, part-peak, and off-peak pricing. These are valid Monday through Friday. Weekends and public holidays are considered off peak periods.

¹ Available at http://www.pge.com/tariffs/ERS.SHTML
² Available at https://www.sce.com/wps/portal/home/regulatory/tariff-books/rates-pricing-choices/business-rates
The yearly electricity bill without energy storage for the three cases is derived from this tariff and is shown in Table 5-5.

Table 5-5 Yearly electricity bill of the three cases in deployment case 2 – Peak limiting in California

<table>
<thead>
<tr>
<th></th>
<th>Food Processor</th>
<th>School</th>
<th>Office Building</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand charges</td>
<td>105,492 $</td>
<td>76,490 $</td>
<td>176,322 $</td>
</tr>
<tr>
<td>Energy charges</td>
<td>190,281 $</td>
<td>82,879 $</td>
<td>333,604 $</td>
</tr>
</tbody>
</table>

Results of Cost-Benefit Analysis

The cost-benefit analysis shows that all three cases are profitable using the input parameters presented above. The detailed calculation is shown in appendix A4 for the exemplary case of the school. The results of the CBA in terms of the metrics introduced in section 4.2 for all three cases are shown in Table 5-6.

Table 5-6 Results of CBA: Deployment Case 2 - Peak limiting in California

<table>
<thead>
<tr>
<th>Metric</th>
<th>Abbreviation</th>
<th>Value Food Processor</th>
<th>Value School</th>
<th>Value Office Building</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial investment cost</td>
<td>C_Cap</td>
<td>182,900 $</td>
<td>$104,500 $</td>
<td>266,400 $</td>
</tr>
<tr>
<td>Initial subsidies</td>
<td>sub</td>
<td>97,901 $</td>
<td>72,877 $</td>
<td>173,914 $</td>
</tr>
<tr>
<td>Annual demand charge savings</td>
<td>d_savings</td>
<td>18,220 $</td>
<td>14,944 $</td>
<td>39,734 $</td>
</tr>
<tr>
<td>Energy charge savings</td>
<td>e_savings</td>
<td>157 $</td>
<td>-56 $</td>
<td>-277 $</td>
</tr>
<tr>
<td>Life cycle cost</td>
<td>LCC</td>
<td>153,667 $</td>
<td>59,813 $</td>
<td>175,152 $</td>
</tr>
<tr>
<td>Life cycle benefits</td>
<td>LCB</td>
<td>178,978 $</td>
<td>145,000 $</td>
<td>384,270 $</td>
</tr>
<tr>
<td>Net present value</td>
<td>NPV</td>
<td>87,114 $</td>
<td>85,186 $</td>
<td>209,118 $</td>
</tr>
<tr>
<td>Equivalent annual annuity</td>
<td>EAA</td>
<td>2,973 $</td>
<td>10,006 $</td>
<td>24,563 $</td>
</tr>
<tr>
<td>Benefit / Cost ratio</td>
<td>BCR</td>
<td>1.16</td>
<td>2.42</td>
<td>2.19</td>
</tr>
<tr>
<td>Payback period</td>
<td>PB</td>
<td>8.81 years</td>
<td>2.25 years</td>
<td>2.51 years</td>
</tr>
<tr>
<td>Internal rate of return</td>
<td>IRR</td>
<td>14.4%</td>
<td>44.3%</td>
<td>39.1%</td>
</tr>
<tr>
<td>Modified internal rate of return</td>
<td>MIRR</td>
<td>9.9%</td>
<td>14.9%</td>
<td>14.3%</td>
</tr>
</tbody>
</table>

Figure 5-23 TOU electricity prices for deployment case 2 – Peak limiting in California
5.2.3 Sensitivity Analysis

The sensitivity parameters analyzed in this sensitivity analysis include the available energy capacity, the lifetime and the cost of the PCS and the storage section, the percentage by which the monthly peak load is reduced, the number of peak values that are limited, the electricity tariff as well as the subsidies. In each sensitivity case only the respective parameters are varied while all other input parameters are kept constant at the values of the base case presented in the cost-benefit analysis above. The results of the sensitivity analysis for the deployment case of the school are presented and discussed in the following paragraphs. The results of the other two cases, the food processor and the office building, are presented in the appendix. All results are shown by the NPV and the payback period, as this metric is more important to most owners of behind-the-meter energy storage than the IRR or the MIRR. The star in the graphs represents the base case scenario examined above in the cost-benefit analysis in section 5.2.2.

Sensitivity Results: Energy Capacity

The energy capacity has been varied from 100-160% of the minimal required energy capacity to investigate whether it is economically beneficial to increase the energy capacity available for TOU shifting in order to move the period of charging to the off-peak hours. The NPV and the payback period are shown in Figure 5-24 and Figure 5-25 respectively.

The NPV and the payback period show that the profitability decreases with increasing energy capacity. This means that the costs for additional energy capacity exceed the additional savings achieved from TOU shifting.

Sensitivity Results: Lifetime of PCS and Storage Section

Both the lifetimes of the power conversion system (PCS) and the battery have been varied between 2-20 years. The lifetime can have a strong influence on the profitability of the installed ESS due to high replacement costs for the components. The NPV and payback period for the dependency on the PCS lifetime are shown in the graphs in Figure 5-26 and Figure 5-27 respectively.
The graphs show that even for short lifetimes of the PCS the project can be profitable. However, for a short lifetime, the payback period increases because the growth of accumulated capital amortization becomes slower. For a lifetime of 4 years or more, the payback period stays constant as it only calculates the payback time for the initial investment and not for reoccurring investments.

The graph of the NPV shows a drop at a PCS lifetime of 10 years which is unexpected since the NPV should be constantly rising with increasing lifetime. The cause for this drop lies in the design of the subsidies. Since the total subsidies consist of 75% of either the total investment costs in a year and 1000 $/kW for the minimum required power capacity, it is more beneficial to replace PCS and storage section in different years than in the same year.

This effect also appears in the case of varying the battery lifetime shown in Figure 5-28 and Figure 5-29. Due to the strong overall increase of profitability with increasing battery lifetime, it is not as obvious as in Figure 5-26 above.

It can be seen that the project becomes unprofitable for a battery lifetime of less than 2.4 years. This value has been determined by linear interpolation. However, this is less than most commercial batteries are able to offer and the NPV increases strongly with additional battery lifetime. The payback period stays constant for a lifetime of 4 years and longer. It is not shown for shorter battery lifetimes.
as the next lower value has been calculated for a battery lifetime of two years which is shorter than the possible payback period.

**Sensitivity Results: Costs of PCS and Storage Section**

The costs of the PCS have been varied between 100-800 $/kW and the profitability is shown by the NPV in Figure 5-30 and the payback period in Figure 5-31.

![Figure 5-30 NPV in dependence on PCS cost](image)

![Figure 5-31 Payback period in dependence on PCS Cost](image)

As expected, the profitability decreases with increasing PCS cost shown by a decreasing NPV and an increasing payback period. The project is profitable up to PCS cost of 733 $/kW where the NPV becomes negative which has been found by linear interpolation. There is still a payback period existent for unprofitable case because the project only becomes unprofitable with the replacement of the components after 10 years.

The battery costs have been varied between 100-600 $/kW and the profitability is shown by the NPV in Figure 5-32 and the payback period in Figure 5-33.

![Figure 5-32 NPV in dependence on battery cost](image)

![Figure 5-33 Payback period in dependence on battery cost](image)

The profitability of the project decreases with increasing battery cost as shown by the decreasing NPV and increasing payback period. The project is profitable up to a battery cost 516 $/kW where the NPV becomes negative. This has been calculated using linear interpolation. The bend in the two graphs at a battery cost of 260 $/kW is caused by the change of the subsidy limit at this value. While at 260 $/kW...
the subsidies are limited by 75% of the investment costs, the subsidy limit at 280 $/kW is defined as 75% of the minimum required power capacity times the subsidies in $/kW.

**Sensitivity Results: Reduction of Peak Load**

The dependence of the profitability on the reduction of the peak load has been examined by varying the reduction of the peak load between 5-50% of the monthly peak value, i.e., the percentage by which the monthly maximum power draw is reduced. It is shown by the NPV in Figure 5-34 and the payback period in Figure 5-35. It is important to note that in this particular case multiple parameters have been varied at the same time. A change in peak load reduction requires a change in power and energy capacity to ensure that the load will not exceed the assigned limit. This in turn affects the costs.

![Figure 5-34 NPV in dependence on peak load reduction](image)

![Figure 5-35 Payback period in dependence on peak load reduction](image)

The NPV illustrates that there is a maximum of profitability at 35% reduction of the peak load. Thus, the assumed base case with 25% reduction of peak load is not the most profitable. The project becomes unprofitable for peak load reduction of less than 7.1% and more than 48.6% of the monthly peak load. The values of the zero-crossings have been obtained by linear interpolation. The maximum of the profitability exists because savings on the electricity bill increase with increasing reduction of the peak load, however, with increasing reduction of peak load the required power and energy capacity of the ESS increase as well, which leads to higher costs, and thus to a longer payback period. On the other hand, a small peak load reduction requires a smaller power and energy capacity, which keeps the costs low, but it also leads to smaller savings on the electricity bill since the demand charges are not reduced significantly.

**Sensitivity Results: Method of Peak Load Reduction**

Another method of reducing the peak load has been tested in order to examine the sensitivity towards the peak load values that are limited. Unlike in all other cases, here the amount by which the peak load is limit does not only depend on the highest value in a month, but on the difference between the highest value that is limited and the highest value that is not limited anymore. Therefore, a percentage of the number of peak values in each month is defined to be limited to the load of the highest value that does not belong to this percentage. For example, if there are 1000 values in a month and the top
percentage is defined as 1%, then the 10 highest values are limited to the 11th highest value. The NPV for this approach is shown in Figure 5-36 and the payback period in Figure 5-37.

![Figure 5-36 NPV in dependence on the number of limited values](image)

![Figure 5-37 Payback period in dependence on the number of limited values](image)

The profitability has a maximum when the 3% of the values with the highest load are limited. If more than 8% of the values are limited, the profitability decreases rapidly and the project becomes unprofitable if more than 10.4% of the values are limited. This is also shown by a strongly increasing payback period. The maximum of the NPV lies at 99,676 $ which is less than the maximum obtained above, thus here this method of peak load reduction is less profitable than the method of reducing the monthly peak load by a certain percentage. This holds true for this case and in general for cases with few peaks in the load profile and a small range of load values. In other cases with large peaks this method might be more profitable than reducing the monthly peak load by a certain percentage as for example in the case of the food processor shown in appendix A5.

**Sensitivity Results: Electricity Tariff**

Since the benefits are generated from savings of demand charges and energy charges, the profitability strongly depends on the electricity tariff applied. The tariff has been varied by changing the prices for demand charges and the difference between TOU electricity prices as shown in Table 5-7. The timing of the peak, part-peak and off-peak period as well as the dates for summer and winter remain unchanged. The NPV and the payback period for each tariff are shown in Figure 5-38 and Figure 5-39, respectively.

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Very high</th>
<th>High</th>
<th>Medium</th>
<th>Low</th>
<th>Very low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand charge summer</td>
<td>[$/kW]</td>
<td>35</td>
<td>25</td>
<td>20</td>
<td>15</td>
</tr>
<tr>
<td>Demand charge winter</td>
<td>[$/kW]</td>
<td>15</td>
<td>13</td>
<td>10</td>
<td>7.5</td>
</tr>
<tr>
<td>Peak electricity price</td>
<td>[$/kWh]</td>
<td>0.20</td>
<td>0.20</td>
<td>0.18</td>
<td>0.14</td>
</tr>
<tr>
<td>Part-peak electricity price</td>
<td>[$/kWh]</td>
<td>0.15</td>
<td>0.14</td>
<td>0.12</td>
<td>0.12</td>
</tr>
<tr>
<td>Off-peak electricity price</td>
<td>[$/kWh]</td>
<td>0.5</td>
<td>0.07</td>
<td>0.08</td>
<td>0.10</td>
</tr>
</tbody>
</table>

Table 5-7 Electricity tariffs for sensitivity analysis
The profitability is highest with highest demand charges and the largest difference between TOU electricity prices and it decreases with decreasing demand charges and small differences between TOU electricity prices. The payback period increases with decreasing profitability and exists even for the very low priced tariff since the project only becomes unprofitable with the replacement of components after 10 years.

**Sensitivity Results: Subsidies**

Subsidies reduce the initial investment costs and the replacement costs and thus influence the overall profitability of the project. The subsidies have been varied between 0-1600 $/kW to assess this influence. This is shown by the NPV in Figure 5-40 and the payback period in Figure 5-41.

The NPV shows that the profitability increases with increasing subsidies until the subsidies reach the limit of 75% of the investment cost at 1075 $/kW. The payback period decreases until the subsidy limit is reached, after which it stays constant at 1 year and 10 months. The project becomes unprofitable if the subsidies fall below 152 $/kW. This value has been obtained by linear interpolation. There is a payback period even for the unprofitable case since it only becomes unprofitable with the replacement of components after ten years.

These results show that the current subsidies in California at 1460 $/kW are at a level that is much higher than needed for many projects to operate profitably. Although there is still a need for subsidies
in many cases for a profitable deployment of ESS for peak limiting, this need is decreasing with further technological development and further price reduction of the components of ESSs, especially of batteries. Therefore current and future subsidies, not only in California, but in any market, should take into account the ongoing development of technology and prices. Thus, they should be adapted to a minimum level that is required in order to ensure fair support of a technology.
6 Conclusion and Future Research

ESSs are capable of providing a variety of different services to the different stakeholders in the electricity grid. The value of these services and whether or not there is a monetary value to them is strongly dependent on the market and the application where the ESS is deployed.

It has been shown that ESSs can be deployed profitably in certain applications, such as providing frequency regulation in the PJM market in the US or reducing the electricity bill for C&I customers, by limiting their peak load, in California. The cost-benefit and sensitivity analysis of these two applications demonstrated that ESS deployment can be profitable even with less beneficial market structures. Even with lower regulation market clearing prices the case of frequency regulation in PJM is economically feasible. The case of peak limiting and demand charge reduction in California showed that current subsidies are higher than necessary for ESSs to be operated profitably while it also showed that subsidies are still necessary to a certain extent. The dependence on subsidies is very much related to the individual deployment case and its load profile. In many cases, such as the ones presented in this thesis, subsidies in the range from 100-800 $/kW will make the deployment of ESSs for peak limiting profitable. Furthermore, the structure of the electricity tariff plays an important role regarding the economic feasibility of ESS deployment for the reduction of the electricity bill.

Several other applications have been introduced and examples of actual ESS deployments around the world that operate profitably have been presented. This shows that energy storage can be a cost effective solution in many applications already today. Additional benefits may be generated by ESSs by offering secondary services, which create new revenue streams.

Further decreasing prices, especially for batteries as observed in recent years, will result in an increase of the profitability of existing applications of ESSs and open up new opportunities for other services and applications.

With the analysis of present and possible future markets for ESSs it has become obvious that current market rules and regulations across markets are not consistent and have a strong influence on whether or not ESS deployment is economically feasible. The case of PJM in the US shows that if regulating orders, which are applicable for the whole US, are transferred into market rules considering energy storage, ESSs are able to participate competitively in the open market and improve the overall system stability. While PJM was the first system operator to implement frequency regulation rules with a fair treatment of energy storage, other RTOs, such as the New England System Operator (ISO NE) and the Southwest Power Pool (SPP), are following the PJM example thus increasing the market size for the ESSs providing frequency regulation [Trabish 2015].

It can further be concluded that markets and market rules around the world are changing in favor of energy storage. However, since electricity markets are highly regulated and rule making is a very
political process, changes are happening slowly and require a change of mindset of policy makers. ESSs can provide several valuable services, which are not recognized and compensated in the current market. Also, current market structures are often not clear about how to treat energy storage, as a load or as a generation resource. The question of who may own energy storage, which in turn is dependent on the type of resource that energy storage is regarded as, is another important issue to be addressed by policy makers.

In order to create a suitable market structure, policies must be changed carefully to avoid loopholes as could be seen in the deployment case 2 in section 5.2.3, where the design of the subsidies was insufficient regarding the different replacement times of PCS and storage section. This example shows the importance of careful policy design to provide a fair treatment of all market participants.

A process for the development of metrics to measure benefits of ESSs has been created in this thesis in order to evaluate the value of ESSs in an appropriate manner. This is important in order to understand the value that the benefit streams of different services entail disregarding the corresponding market structures which might still be missing.

In conclusion it can be said that energy storage offers valuable alternatives to current grid resources, as well as services that help integrate fluctuating generation and demand. This can be done profitably already today, as shown in this thesis by the examples of frequency regulation and peak limiting, especially with market structures that recognize the value of energy storage and the services it can provide.

The markets and market regulations concerning energy storage are constantly changing. Future research in this field may examine the deployment potential in other arising markets such as different European countries and South Korea, as well as different transmission zones in the US. An analysis of the implementation of the frequency regulation order (FERC Order 755) by different RTOs and ISOs across the US and its effect on the profitability of ESSs in the respective transmission zones could lead to interesting results.

The influence of the financial boundary conditions on the cost-benefit analyses has not been studied in this thesis, but could be an important point to consider, especially for deployment cases that are close to economically feasible. This must be kept in mind when analyzing the economics of a concrete project.

In order to assess the complete value of ESSs it is necessary to find combinations of services that are technically compatible and also complement each other regarding possible benefits. The economic compatibility is market dependent and needs to be analyzed carefully as could be seen in the combination of frequency regulation and large scale time shifting in section 4.3.
Furthermore, other deployment cases should be investigated in which the overall system benefits are taken into account which are generated by services like T&D congestion relief and upgrade deferral, as well as services in support of thermal power plants like load following and reserves. Also, deployment cases supporting the integration of renewable energies should be examined. Another possible scenario is the utilization of energy storage in combination with demand response programs which could offer synergies leading to additional revenue streams.

Additional research examining the best technology options for different services as well as for the combination of services in different applications should be conducted since different services have different technical requirements.
References


“Mogelijkheden om elektrische energie onrechtstreeks op te slaan.”


E.ON Mitte AG, 2013. Preisblatt Netzsentgelte Strom der E . ON Mitte AG.


Geinzer, J., 2012. AES Laurel Mountain Overview. Available at:


Poullikkas, A., 2013. A comparative overview of large-scale battery systems for electricity storage. Renewable and Sustainable Energy Reviews, 27, pp.778–788. Available at:
84

http://dx.doi.org/10.1016/j.rser.2013.07.017.


Southern California Edison (SCE), 2015. Rate Schedule TOU-GS-2-B for Medium-Sized Businesses. Available at: https://www.sce.com/wps/wcm/connect/c07b114a-b2a6-4d0e-a097-e9afeb255fa1/Business_2_TOU_Fact_Sheet_OptionB.pdf?MOD=AJPERES.


Texas Electricity Alliance, 2011. Chaos in the CO-OP’s. Available at:


A. Appendix
A1. Energy Storage Mind Map

Figure A-1 Energy storage mind map
## A2. Services Compatibility Matrix

![Compatibility Matrix]

Figure A-2 Compatibility of different services according to [Eyer & Corey 2010] p. 121
## A3. Cost-Benefit Calculation for Deployment Case 1 – Frequency Regulation in PJM

### Figure A-3 Cost-Benefit Calculation for Deployment Case 1 – Frequency Regulation in PJM
## Cost-Benefit Calculation for Deployment Case 2 – Peak Limiting in California

### Boundary Conditions:

| Power capacity | 150 MW |
| Project lifetime | 30 years |
| Energy capacity | 270 kWh |
| Battery lifetime | 16 years |
| Discharging time (full cycle) | 2.7 h |
| Yearly MWh output | 400 |
| Required min. power capacity | 27,999 kW |

### Cost-Benefit Analysis

| Category | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 |
|----------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| Capital Cost System | $15,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Storage | $10,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Balance of Plant | $5,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Replacement Cost POCS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Replacement Cost Batteries | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Subsidies | $35,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Capital Cost (CCC) | $50,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total O&M Cost | $0 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 | $700 |

### Figure A-4 Cost-Benefit Calculation for Deployment Case 2 – Peak Limiting in California: School
A5. Sensitivity Results Case 2 – Peak Limiting: Food Processor

*Sensitivity Results: Energy Capacity*

Figure A-5 NPV in dependence on an increased energy capacity

Figure A-6 Payback period in dependence on an increased energy capacity

*Sensitivity Results: Lifetime of PCS and Storage Section*

Figure A-7 NPV in dependence on the PCS lifetime

Figure A-8 Payback period in dependence on the PCS lifetime

Figure A-9 NPV in dependence on the battery lifetime

Figure A-10 Payback period in dependence on the battery lifetime
**Sensitivity Results: Costs of PCS and Storage Section**

**Figure A-11** NPV in dependence on PCS cost

**Figure A-12** Payback period in dependence on PCS Cost

**Figure A-13** NPV in dependence on battery cost

**Figure A-14** Payback period in dependence on battery cost

**Sensitivity Results: Reduction of Peak Load**

**Figure A-15** NPV in dependence on peak load reduction

**Figure A-16** Payback period in dependence on peak load reduction
Sensitivity Results: Method of Peak Load Reduction

Figure A-17 NPV in dependence on the number of limited values

Figure A-18 Payback period in dependence on the number of limited values

Sensitivity Results: Electricity Tariff

Figure A-19 NPV in dependence on the electricity tariff

Figure A-20 Payback period in dependence on the electricity tariff

Sensitivity Results: Subsidies

Figure A-21 NPV in dependence on the subsidies

Figure A-22 Payback period in dependence on the subsidies
A6. Sensitivity Results Case 2 – Peak Limiting: Office Building

Sensitivity Results: Energy Capacity

Figure A-23 NPV in dependence on an increased energy capacity

Figure A-24 Payback period in dependence on an increased energy capacity

Sensitivity Results: Lifetime of PCS and Storage Section

Figure A-25 NPV in dependence on the PCS lifetime

Figure A-26 Payback period in dependence on the PCS lifetime

Figure A-27 NPV in dependence on the battery lifetime

Figure A-28 Payback period in dependence on the battery lifetime
Sensitivity Results: Costs of PCS and Storage Section

Figure A-29 NPV in dependence on PCS cost

Figure A-30 Payback period in dependence on PCS Cost

Figure A-31 NPV in dependence on battery cost

Figure A-32 Payback period in dependence on battery cost

Sensitivity Results: Reduction of Peak Load

Figure A-33 NPV in dependence on peak load reduction

Figure A-34 Payback period in dependence on peak load reduction
**Sensitivity Results: Method of Peak Load Reduction**

NPV

![Graph showing NPV in dependence on the number of limited values.](image)

Payback Period [years]

![Graph showing Payback period in dependence on the number of limited values.](image)

Figure A-35 NPV in dependence on the number of limited values

Figure A-36 Payback period in dependence on the number of limited values

**Sensitivity Results: Electricity Tariff**

NPV

![Graph showing NPV in dependence on the electricity tariff.](image)

Payback Period [years]

![Graph showing Payback period in dependence on the electricity tariff.](image)

Figure A-37 NPV in dependence on the electricity tariff

Figure A-38 Payback period in dependence on the electricity tariff

**Sensitivity Results: Subsidies**

NPV

![Graph showing NPV in dependence on the subsidies.](image)

Payback Period [years]

![Graph showing Payback period in dependence on the subsidies.](image)

Figure A-39 NPV in dependence on the subsidies

Figure A-40 Payback period in dependence on the subsidies