Techno-economic and life cycle assessment of large energy storage systems

by

Sahil Kapila

A thesis submitted in partial fulfillment of the requirements for the degree of

Master of Science

in

Engineering Management

Department of Mechanical Engineering

University of Alberta

Abstract

Energy storage systems (ESSs) play a key role in the implementation of sustainable energy. However, the life cycle cost, energy use, and greenhouse gas (GHG) emissions, which are important decision factors for their implementation, has received limited attention. For this reason, the economic and environmental implications of implementing ESSs were explored in this thesis.

In this study, life cycle assessment models were developed to determine the economic feasibility, net energy ratio (NER), and GHG impact of ESSs. ESSs here refer to pump hydro storage (PHS) and compressed air energy storage (CAES). The PHS stores energy in the form of gravitational potential energy of water by using height differential between two reservoirs whereas CAES stores energy in compressed air. The life cycle assessment (LCA) models were developed using data-intensive bottom-up methods for capacity ranges of 98–491 MW, 81–404 MW, and 60–298 MW for PHS, conventional CAES (C-CAES), and adiabatic CAES (A-CAES), respectively. For CAES systems, cost models were developed for storage in salt caverns, hard rock caverns, and porous formations. The NER was calculated as a ratio of net energy output to the total net energy input, while LCA was conducted based on the direct emissions factor (DEF) and total emissions factor (TEF) of the ESS. The DEF is the amount of emissions associated with the storage systems per kWh of electricity produced. DEF does not include upstream emissions from electricity generation whereas TEF incorporates the upstream emissions from electricity generation in addition to the direct GHG emissions. The results show that the levelised cost of electricity is \$69–\$121 for PHS, \$58–\$70 for C-CAES, and \$96–\$121 per MWh for A-CAES. C-CAES is economically attractive at all capacities, PHS is economically attractive at higher capacities, and A-CAES is not attractive compared to PHS and C-CAES. The NER for PHS, C-CAES, and A-CAES is 0.778, 0.543, and 0.702, respectively. The NER is highest for PHS, followed by A-CAES and then C-CAES. The DEF (gCO_2e/KWh) for PHS, C-CAES, and A-CAES,

was 7.79, 264.36, and 4.96, respectively. The DEF for C-CAES is significantly higher due to the consumption of natural gas during the production of electricity. The uncertainty results for PHS, C-CAES, and A-CAES are $8.05^{+0.89}_{-1.43}$, $3.84^{+0.23}_{-0.25}$, and $4.92^{+0.30}_{-0.31}$ for the LCA and $0.777^{+0.0035}_{-0.0036}$, $0.543^{+0.0015}_{-0.0018}$, and $0.704^{+0.0063}_{-0.0064}$ for the NER.

The information developed is helpful to those making investment and policy decisions related to large energy storage systems.

Preface

This thesis is original work by Sahil Kapila under the supervision of Dr. Amit Kumar. Chapter 2 of this thesis has been published as Kapila, S., A.O. Oni, and A. Kumar, “The development of techno-economic models for large-scale energy storage systems”, Energy, 2017. Chapter 3 is expected to be submitted as Kapila, S., A.O. Oni, and A. Kumar, “Development of Net Energy Ratio over Life Cycle of Large-Scale Energy Storage Systems”, to Applied Energy. I was responsible for the concept formulation, data analysis, model improvement, and manuscript composition. Dr. O. A. Oni contributed by reviewing the papers and providing useful insight. Dr. A. Kumar was the supervisory author and was involved with the concept formation, results analysis, and manuscript composition.

Acknowledgements

I would like to acknowledge my supervisor, Dr. Amit Kumar, for his continuous guidance and support throughout my research project. His insight, expertise, and persistent feedback played a vital role in the completion of this work. I would also like to express my gratitude to the NSERC Energy Storage and Technology (NEST) Network and the University of Alberta for providing financial support for this project.

It is my pleasure to thank Dr. Abayomi Olufemi Oni for his continuous encouragement and support throughout the work. He reviewed and provided valuable suggestions to immensely improve this research work. I am also thankful to Dr. Mahdi Vaezi, Dr. Eskinder Gemechu, and Madhumita Patel for reviewing and providing feedback as well as to Astrid Blodgett for her editorial assistance. Last but not the least, I would like to recognize my colleagues in the Sustainable Energy Research Group for their support and useful discussions that helped widen my knowledge on energy research and create a productive research environment.

I am greatly thankful to my parents, family, and friends for their endless support and encouragement that helped me achieve this level of knowledge and perform this research work.

Table of Contents

List of Tables

List of figures

List of abbreviations

ALCC	Annual Levelized Capital Cost
A-CAES	Adiabatic Compressed Air Energy Storage
C-CAES	Conventional Compressed Air Energy Storage
CAES	Compressed Air Energy Storage
CLP	Climate Leadership Plan
DEF	Direct emission factor
ESS	Energy storage system
GHG	Greenhouse gasses
IEA	International Energy Agency
kW	Kilowatt
kWh	Kilowatt hour
LCA	Life cycle analysis
LCC	Life cycle cost
LCOE	Levelised Cost of Electricity
LCOS	Levelised Cost of Storage
MW	Megawatt
MWh	Megawatt hour

NER	Net energy ratio
NG	Natural gas
O&M	Operation and Maintenance
PHS	Pumped hydro storage
SC	Storage cost
TEC	Total equipment cost
TIC	Total investment cost
TEF	Total emission factor

Chapter 1

1 Introduction

1.1 Background

The world's heavy consumption of fossil fuels has increased greenhouse gas (GHG) emissions, which has in turn contributed to global warming and climate change [1, 2]. The need to protect our environment by confronting climate change has led governments, research agencies, and various industries to come together to achieve sustainable energy goals. At the Paris Convention in 2016, leaders across the globe reached a consensus to keep a global temperature increase well below two degrees above pre-industrial levels [3].

The electricity sector is one of the main contributors to GHG emissions. Electricity and heat production made up 25% of global GHG emissions in 2010 [4, 5]. Most of the emissions come from the use of fossil fuels (coal, natural gas, etc.), as they dominate the power sector [6]. Renewable sources of energy such as wind and solar are widely recognized alternatives that will play an important role in reducing GHG emissions [7, 8]. Renewable sources contribute considerably fewer GHGs than conventional sources [9, 10]. To achieve the International Energy Agency's (IEA) two-degree target, renewable energy production needs to meet 74% of global electricity demand by 2060 [11]. To that point, the installed capacity of combined solar and wind energy production has grown by more than 200% in recent years, from 183 GW in 2009 to 665 GW in 2014, as shown in Figure 1 [12].

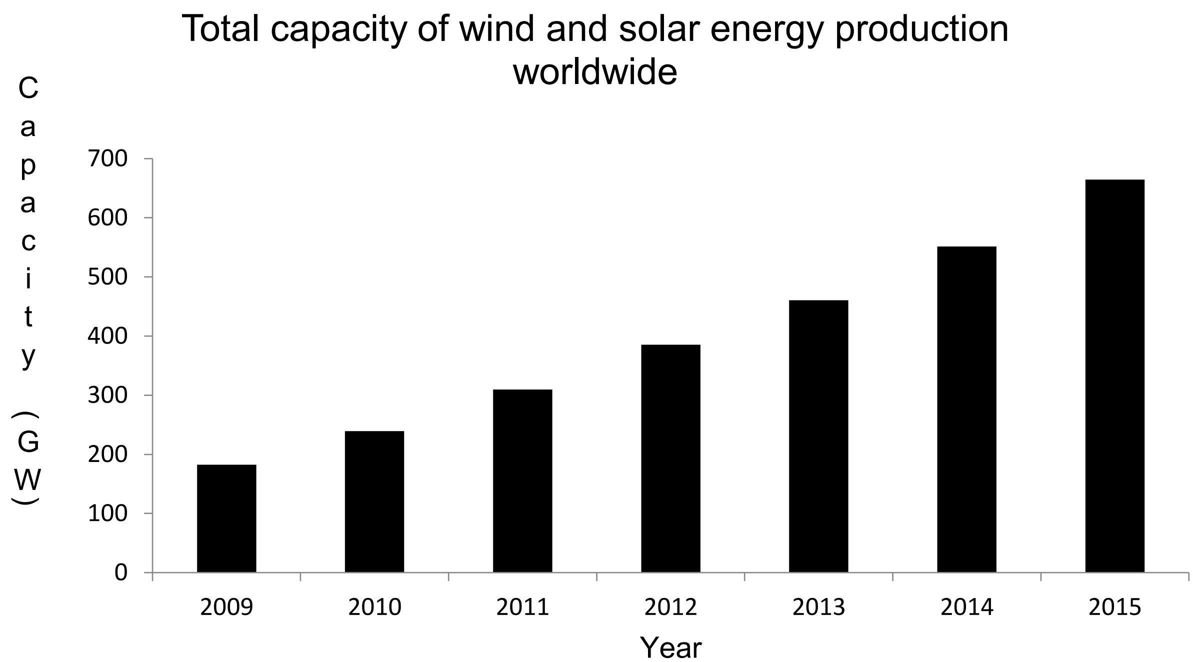

Figure 1: Growth in global installation of wind and solar renewables [12]

Although renewable energy sources have many advantages, they also present challenges [13]. They do not generate the quantities produced by traditional fossil fuels and depend heavily on weather. These are intermittent, changing in intensity quickly as clouds pass over the sun or wind velocity changes [14]. The irregularity in wind and solar energy production leads to large disruptions in electricity generation and poses challenges to balance of load, grid stability, and reliability to the energy network. Currently, power and demand balance in the grid network is maintained by storing conventional sources of fuels such as coal and natural gas. Because of their sporadic nature, wind and solar energy demand flexibility [14, 15], which restrains their market penetration above a certain threshold. In general, no more than 20% of an area's electricity demand can be met by renewables on their own [16]. But significant development in energy storage systems (ESSs) in recent years has enabled these renewables to break this threshold and penetrate the electricity market to the full extent [9].

In Alberta, a western province in Canada, the electricity sector depends enormously on coal power plants, which were responsible for 17% of Alberta's GHG emissions in 2013 [17]. Under existing federal regulations, 12 of Alberta's 18 coal power plants will retire by 2030. However, the Climate Leadership Plan (CLP) adopted by the Government of Alberta calls for the phase-out of coal power plants and introduces carbon pricing. There is an imminent need for a reliable source of energy that reduces GHG emissions and thus protects the environment. Thus, under the CLP, all coal power plants will be retired by 2030 and replaced by renewable and natural gas-fired power plants [18].

ESSs can play a key role in achieving the IEA's two-degree target and reducing the dependence on the fossil fuel power plants. These provide flexibility and facilitate the integration of renewable energy sources in the grid network by storing energy at a time of surplus generation and releasing it at a time of deficiency and thus helping lower overall GHG emissions [19]. These storage technologies can act as shock absorbers in the grid network and improve its efficiency, reliability, and security [20].

However, the lack of adequate information on the economics and environmental performance of ESSs hinders the development of feasible business models for EESs. Although there are a few ESSs around the world, there is not enough information in the public domain on their economic sustainability and environmental footprints needed for the decision makers in the industry and the government globally. Therefore, it is imperative to conduct a comprehensive study that will provide more insight into the economics and life cycle environmental impacts of an EES, which in turn will inform decision-making.

1.2 Literature review and research gap

Energy storage is not a new concept. It has been around from the beginning of the 20th century. The total installed capacity of ESSs across the globe is 143 GW [21, 22]. Pumped hydroelectric storage (PHS) and compressed air energy storage (CAES) have more than 99% of installed ESS capacity globally [21, 22]. Both PHS and CAES are bulk energy storage systems and are the market leaders in storage technologies serving applications like load shifting, peak shaving and spinning reserves [23]. These large storage systems serve the grid network by load leveling and peak shaving. Baseload production plants only need to build for average electric demand instead of peak demand, thereby saving on construction investments. ESSs also allow the transmission and distribution network to operate at full capacity, thus new and upgraded lines are not required. This study focuses on large, mechanical storage systems such as PHS and CAES. PHS and CAES have the potential to integrate renewable technologies to the utility grid in large quantities.

Storage systems have been described extensively in the literature. Several studies address technical features such as defining characteristics, system sizes, and applications [1, 13, 15, 19, 24-27]. However, the economic assessment and life cycle analysis have received little attention.

Most of the studies provide information on the unit capacity capital cost (dollar per kW or dollar per kWh) without any detailed information on the development, life cycle cost, or economic feasibility of an ESS. The research by Schoenung et al. [28-30] on storage system costs uses a top-down approach to estimate the benefits and cost of storage technologies for applications such as bulk storage, distributed generation, and power quality. These studies, moreover, were limited to point estimates with the use of aggregated capital cost data. Data were collected from various suppliers and thus are generalized. Beaudin et al. [19] reviewed energy storage for mitigating renewables' variability and presented tabulated ranges of capital cost data based on earlier studies. No additional information was provided on equipment cost breakdown, operating cost, etc. Akhil et al. [31] calculated the present worth and life cycle costs of discrete energy storage technology scenarios. Four scenarios were considered based on capacity and discharge time for PHS. The data were collected from suppliers and real-life projects. However, that study's methodology lacks transparency and reproducibility. Viswanathan et al. [32] provided a qualitative and quantitative summary of capital cost and O&M cost data in existing literature. They provided a range of values rather than discrete numbers and estimated the future cost of an ESS. Bozzolani [33] did a detailed study on cost model development for compressed air energy storage. However, the study was limited to that system and did not compare it with other storage systems. Zakeri et al. [34] reviewed existing cost data and performed a comparative life cycle cost analysis of an ESS as well as an uncertainty analysis. Neither Bozzolani nor Zakeri et al. considered the economic viability of storage technologies or scale of storage systems.

The economy of scale is vital to determine the optimal plant size. Locatelli et Al. [35] assessed the economics of large storage plants through a top-down methodology using capital investment data from the literature. Denholm and Kulcinski [23] did a pioneering LCA study of ESSs. They developed life cycle energy requirements, GHG emissions, and net energy ratios (NERs) of utility-scale applications ESSs such as pumped hydroelectric storage (PHS), compressed air energy storage (CAES), and battery energy storage systems. Hiremath et al. [36] and Rydh et al. [37] conducted comparative assessments of battery energy storage systems for stationary applications. Their results show that the use stage of batteries increases the overall emissions significantly. Jing et al. [38] focused on thermal energy storage systems for combined cooling, heating, and power system applications. The system operated following the thermal load operational strategy wherein excess electricity produced is stored for future use, and this strategy has a fewer pollutants and more energy-saving potential than operating the system following the electrical load operational strategy. Eduard et al. [39] did a comparative assessment of thermal energy storage systems for solar power plants. A system using solid media (i.e., concrete) has fewer environmental impacts than a system using liquid media (i.e., molten salt). A few other studies considered a bundle of storage technologies together [40-42] and showed that compared to other storage systems, batteries have higher impacts during their construction and end-of-life phases and lower impacts during operation. Akhil et al. [43] comprehensively reviewed and compared life cycle GHG emissions from different hydro facilities including pumped hydroelectric plants. Bouman et al. [44] conducted a life cycle assessment of a CAES plant integrated with offshore wind plants through a cradle-to-grave approach. The results show that integrating conventional compressed air energy storage (C-CAES) with a wind plant significantly increases the environmental impacts whereas adiabatic compressed air energy storage (A-CAES) only moderately increases these impacts. Oliveira et al. [40] carried out a comparative LCA on a range of storage technologies.

Most of the above studies are recent and consolidate the increasing interest in renewables and storage technologies. The earlier studies used data from vendors or existing literature and used a top-down approach to evaluate life cycle costs. These studies did not: define system boundaries with respect to storage system capacity; develop bottom-up cost models; perform economic assessments; and report capital cost changes with changes in storage system capacity. In addition, there are wide variations and discrepancies in economic and cost data since storage facility size and location are rarely considered in these analyses. For an LCA, the storage system size, a key parameter, was not considered; the software used to perform analyses provided point estimates of emissions, which is inadequate considering the various assumptions in the studies. In some studies, no explicit methodology was provided, while in others decommissioning emissions were not considered.

To address these knowledge gaps, this study developed data-intensive comprehensive techno-economic and life cycle models for large energy storage systems using the bottom-up approach. A holistic evaluation of initial investments, life cycle costs, GHG emissions, and NERs was carried out to understand the overall financial and environmental performance of storage systems for the Canadian electricity in various provinces.

The study provides valuable information to policymakers, governments, and environmental activists, assisting them in making informed energy decisions on storage technologies.

1.3 Research motivation

The following statements best summarize the factors that motivated this research:

1. There has been little work done on the economic feasibility and environmental impacts of storage systems.
2. A detailed bottom-up data-intensive model is needed to understand the economic feasibility of storage systems.
3. A cradle-to-grave life cycle analysis is required to understand the environmental footprint of energy storage systems.
4. To formulate new policies, either economic or environmental, it is necessary to quantify the investment and GHG emissions of ESSs.

1.4 Research objectives

The overall objective of this research is to develop a life cycle model to access the economic feasibility and determine the environmental footprint of large energy storage systems. The specific objectives are to:

1. Develop simulation models to assess several PHS and CAES scenarios of different storage facility sizes.
2. Estimate the investment cost of a storage plant using a bottom-up methodology.
3. Develop economies of scale and scale factors for estimating the capital cost of PHS and CAES.
4. Evaluate the life cycle net energy ratio (NER) for PHS and CAES.
5. Conduct life cycle GHG emissions assessments of PHS and CAES.
6. Conduct sensitivity and uncertainty analyses to identify important input parameters and provide range of estimates

1.5 Scope and limitations of the thesis

This research focuses only on large-scale mechanical storage systems, PHS and CAES. The study evaluates the costs of PHS and CAES in Alberta, Canada. Only the major greenhouse gases like CO_2, CH_4, and N_2O are considered to calculate GHG emissions. In the uncertainty analysis, only the more sensitive parameters are considered. The scope and limitations of this study are discussed further in chapters 2 and 3.

1.6 Organization of the thesis

This thesis is paper-based and was written in such a way that each chapter can be read independently. Due to this, some background information is repeated in the chapters. There are four chapters. Chapters 2 and 3 are independent papers.

Chapter 2, The development of techno-economic models for mechanical energy storage systems: In this chapter, a data-intensive process simulation model, developed based on a bottom-up approach, is described. The assumptions involved in the technical simulations and the resultant storage capacity obtained are presented. The chapter also describes how an ESS's economy of scale is obtained from the calculation of investment costs of storage plants of different capacities.The model used to calculate the levelised cost of electricity based on Alberta's energy market is presented. In addition, the chapter gives the results of the sensitivity and uncertainty analyses. This chapter has already been published in a peer-reviewed journal.

Chapter 3, Development of Net Energy Ratio over Life Cycle of Large-Scale Energy Storage Systems: This chapter summarizes the cradle-to-grave emissions of the storage systems considered. It describes the calculation of NER-based energy flows over the life cycle of ESSs. The methodology and assumptions are presented. Both direct and indirect GHG emissions are calculated. In addition, the chatper gives the results of the sensitivity and uncertainty analyses. This chapter will be submitted for publication in a peer-reviewed journal.

Chapter 4, Conclusions and recommendations for future work: This chapter concludes the thesis with key findings and notable observations. The last subsection identifies areas where further investigation can be conducted along with some suggestions to improve the current model.

1.7 References

1. Kousksou, T., et al., *Energy storage: Applications and challenges.* Solar Energy Materials and Solar Cells, 2014. **120, Part A**: p. 59-80.
2. Poullikkas, A., *Implementation of distributed generation technologies in isolated power systems.* Renewable and Sustainable Energy Reviews, 2007. **11**(1): p. 30-56.
3. Rogelj, J., et al., *Paris Agreement climate proposals need a boost to keep warming well below 2 C.* Nature, 2016. **534**(7609): p. 631-639.
4. *Climate Change 2014: Mitigation of Climate Change* in *Climate Change*. 2014. p. 1246.
5. *National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada*. 2016: Canada.
6. *World Energy Resources* 2016: England and Wales.
7. Aneke, M. and M. Wang, *Energy storage technologies and real life applications – A state of the art review.* Applied Energy, 2016. **179**: p. 350-377.
8. Luo, X., et al., *Overview of current development in electrical energy storage technologies and the application potential in power system operation.* Applied Energy, 2015. **137**: p. 511-536.
9. Xu, Y. and C. Singh, *Adequacy and economy analysis of distribution systems integrated with electric energy storage and renewable energy resources.* IEEE Transactions on power systems, 2012. **27**(4): p. 2332-2341.

10. Hertwich, E.G., et al., *Integrated life-cycle assessment of electricity-supply scenarios confirms global environmental benefit of low-carbon technologies.* Proceedings of the National Academy of Sciences, 2015. **112**(20): p. 6277-6282.
11. Gielen, D., *Energy technology perspectives.* Paris: International Energy Agency, 2017.
12. Martinot, E., *Renewables 2015: Global status report.* REN21 Renewable Energy Policy Network/Worldwatch Institute, 2015: p. 251.
13. Hadjipaschalis, I., A. Poullikkas, and V. Efthimiou, *Overview of current and future energy storage technologies for electric power applications.* Renewable and Sustainable Energy Reviews, 2009. **13**(6–7): p. 1513-1522.
14. Decourt, B. and R. Debarre, *Electricity Storage*, in *Leading the energy transition*. 2013. p. 98.
15. Chen, H., et al., *Progress in electrical energy storage system: A critical review.* Progress in Natural Science, 2009. **19**(3): p. 291-312.
16. Cavallo, A.J., *Energy storage technologies for utility scale intermittent renewable energy systems.* Journal of solar energy engineering, 2001. **123**(4): p. 387-389.
17. Rahimi, E., *Alberta Climate Leadership Plan*. 2016.
18. Leach, A., et al., *Climate leadership: Report to minister*. 2015: Department of Environment Alberta and Climate Change Advisory Panel.
19. Beaudin, M., et al., *Energy storage for mitigating the variability of renewable electricity sources: An updated review.* Energy for Sustainable Development, 2010. **14**(4): p. 302-314.
20. Ferreira, H.L., et al., *Characterisation of electrical energy storage technologies.* Energy, 2013. **53**: p. 288-298.
21. *Technology Roadmap Energy storage*. 2014: France.
22. Rastler, D., *Electricity energy storage technology options: a white paper primer on applications, costs and benefits*. 2010: Electric Power Research Institute.

23. Denholm, P. and G.L. Kulcinski, *Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems.* Energy Conversion and Management, 2004. **45**(13–14): p. 2153-2172.
24. Ibrahim, H., A. Ilinca, and J. Perron, *Energy storage systems—Characteristics and comparisons.* Renewable and Sustainable Energy Reviews, 2008. **12**(5): p. 1221-1250.
25. Connolly, D., *A review of energy storage technologies: For the integration of fluctuating renewable energy*. 2010.
26. Palizban, O. and K. Kauhaniemi, *Energy storage systems in modern grids—Matrix of technologies and applications.* Journal of Energy Storage, 2016. **6**: p. 248-259.
27. Mahlia, T.M.I., et al., *A review of available methods and development on energy storage; technology update.* Renewable and Sustainable Energy Reviews, 2014. **33**: p. 532-545.
28. Schoenung, S.M. and W.V. Hassenzahl, *Long-vs. short-term energy storage technologies analysis. a life-cycle cost study. a study for the doe energy storage systems program.* Sandia National Laboratories, 2003.
29. Schoenung, S.M. and J. Eyer, *Benefit/cost framework for evaluating modular energy storage.* SAND2008-0978, 2008.
30. Schoenung, S., *Energy Storage Systems Cost Update* 2011.
31. Akhil, A.A., et al., *DOE/EPRI 2013 electricity storage handbook in collaboration with NRECA*. 2013: Sandia National Laboratories Albuquerque, NM.
32. Viswanathan, V., et al., *National Assessment of Energy Storage for Grid Balancing and Arbitrage, Phase II, Volume 2: Cost and Performance Characterization.* Report PNNL-21388, Pacific Northwest National Laboratory, Richland, WA, 2013.
33. Bozzolani, E., *Techno-economic analysis of compressed air energy storage systems.* 2010.
34. Zakeri, B. and S. Syri, *Electrical energy storage systems: A comparative life cycle cost analysis.* Renewable and Sustainable Energy Reviews, 2015. **42**: p. 569-596.

35. Locatelli, G., E. Palerma, and M. Mancini, *Assessing the economics of large Energy Storage Plants with an optimisation methodology.* Energy, 2015. **83**: p. 15-28.

36. Hiremath, M., K. Derendorf, and T. Vogt, *Comparative life cycle assessment of battery storage systems for stationary applications.* Environmental science & technology, 2015. **49**(8): p. 4825-4833.

37. Rydh, C.J., *Environmental assessment of vanadium redox and lead-acid batteries for stationary energy storage.* Journal of Power Sources, 1999. **80**(1): p. 21-29.

38. Jing, Y.-Y., et al., *Life cycle assessment of a solar combined cooling heating and power system in different operation strategies.* Applied Energy, 2012. **92**: p. 843-853.

39. Oró, E., et al., *Comparative life cycle assessment of thermal energy storage systems for solar power plants.* Renewable Energy, 2012. **44**: p. 166-173.

40. Oliveira, L., et al., *Environmental performance of electricity storage systems for grid applications, a life cycle approach.* Energy conversion and management, 2015. **101**: p. 326-335.

41. Sternberg, A. and A. Bardow, *Power-to-What?–Environmental assessment of energy storage systems.* Energy & Environmental Science, 2015. **8**(2): p. 389-400.

42. Ma, T., H. Yang, and L. Lu, *Feasibility study and economic analysis of pumped hydro storage and battery storage for a renewable energy powered island.* Energy Conversion and Management, 2014. **79**: p. 387-397.

43. Kadiyala, A., R. Kommalapati, and Z. Huque, *Evaluation of the life cycle greenhouse gas emissions from hydroelectricity generation systems.* Sustainability, 2016. **8**(6): p. 539.

44. Bouman, E.A., M.M. Øberg, and E.G. Hertwich, *Environmental impacts of balancing offshore wind power with compressed air energy storage (CAES).* Energy, 2016. **95**: p. 91-98.

Chapter 2

2 The Development of Techno-economic Models for Large-Scale Energy Storage Systems[1]Introduction

The use of fossils fuels to meet energy demands leads to greenhouse gas (GHG) emissions that cause environmental pollution and climate change [1-4]. The concerns of the public were recently addressed by reinforcing, in the Paris Agreement, the target to keep the global temperature increase well below 2°C above pre-industrial levels [5]. To achieve this target, there is the need for a reliable source of energy production that reduces GHG emissions, thereby improving the quality of the environment. Renewable sources of energy production such as wind and solar are widely recognized alternatives that will play a vital role in reducing GHG emissions [6, 7]. There has been a growth of more than 200% in the installed capacity of combined solar and wind energy production in recent years, from 183 GW in 2009 to 665 GW in 2014 [8]. Although these sources of renewable energy have many advantages, they also present some challenges [9]. They do not generate quantities of energy as large as those produced by traditional fossil fuels, and they are weather-dependent. Furthermore, they are intermittent, changing in intensity quickly as clouds pass over the sun or wind velocity changes [10]. The irregularity in wind and solar energy production leads to huge disruptions in electricity generation and poses challenges of load balance, grid stability, and reliability to energy network. Currently power and demand balance in the grid network is maintained by storing conventional fuels such as coal and natural gas. But wind and solar energy production demands additional flexibility in the system because of their sporadic nature [10, 11]. Energy storage systems can provide this flexibility and facilitate the integration of renewable energy sources in the grid network by storing energy at a time of surplus

[1] https://doi.org/10.1016/j.energy.2017.08.117

generation and releasing it at a time of deficiency [12]. These storage technologies can act as shock absorbers in the grid network and improve its efficiency, reliability, and security [13]. Thus, the introduction of an ESS in the energy network can address the aforementioned problem.

Energy storage is a vital link in the energy supply chain. In general, no more than 20% of an area's electricity demand can be met by renewables without the help of an ESS [14]. An ESS can lead to renewables' deployment in large quantities and thus is critical for a low carbon sustainable future. Lack of adequate information is a hindrance to the development of feasible business models for an EES. Although there are few ESSs around the world, they do not provide sufficient information on the economic sustainability of the systems. Therefore, it is imperative to conduct a comprehensive study that will provide more insight into the economics of an EES and develop the costs based on bottom-up approach.

Several studies address technical features such as the defining characteristics, system sizes, and applications of ESS [1, 9, 11, 12, 15-18]. However, the economic assessment remains obscure in most of the studies. Most of the studies provide information on the unit capacity capital cost (dollar per kW or dollar per kWh) without any detailed information on the development, life cycle cost and economic feasibility of ESS. The research by Schoenung et al. [19-21] on storage system costs use a top-down approach to estimate the benefits of storage technologies compared to costs for application categories such as bulk storage, distributed generation, and power quality. These studies, moreover, were limited to point estimates with the use of aggregated capital cost data. Data were collected from various suppliers and thus are generalized. Beaudin et al. [12] reviewed energy storage for mitigating renewables' variability and presented tabulated ranges of capital cost data based on earlier studies. No additional information was provided on equipment cost break-down, operating cost, etc. Akhil et al. [22] calculated the present worth and life cycle costs of discrete energy storage technology scenarios. Four scenarios were considered based on capacity and discharge time for Pumped Hydro Storage. The data were collected from suppliers and real-life projects. However, that study's methodology lacks transparency and reproducibility. Viswanathan et al. [23] provided a qualitative and quantitative summary of capital cost and O&M cost data in existing literature. They provided a range of values rather than discrete numbers and estimated the future cost of an ESS. Bozzolani [24] did a detailed study on cost model development for Compressed Air Energy Storage. However, the study was limited to only this system and does not show its comparison with other large scale storage systems. Zakeri et al. [25] reviewed existing cost data and performed a comparative life cycle cost analysis of an ESS as well as an uncertainty analysis. Neither Bozzolani [24] nor Zakeri et al. [25] considered the economic viability of storage technologies or storage scale. The economy of scale is vital to determine the optimal plant size. Locatelli et al. [26] assessed the economics of large storage plants through a top-down methodology using capital investment data from the literature.

Most of these earlier studies used data from vendors or existing literature and used a top-down approach. They did not define system boundaries with respect to storage system capacity, develop bottom-up cost models, show economic assessment, nor report capital cost changes with changes in storage system capacity. In addition, there are wide variations and discrepancies in cost data since storage facility size and location are rarely considered in these analyses.

To address the aforementioned gap, the objective of this study is to develop data-intensive comprehensive techno-economic models for large energy storage systems. Pumped Hydro Storage (PHS) and Compressed Air Energy Storage (CAES) were considered in this study as they are prime candidates for large-scale storage application [27]. A detailed economic analysis was performed to investigate the economic feasibility of both systems in Alberta's (a province in Western Canada) electricity market. The specific objectives of the study are to:

1. Develop and model scenarios for PHS and CAES of different storage facility sizes.

2. Use a bottom-up methodology with the help of equipment cost relations to calculate the capital cost of a storage plant.
3. Assess the total investment required to build a storage plant of a specific size and operating cost.
4. Develop economies of scale and scale factors for PHS and CAES.
5. Estimate the selling price of the electricity produced by ESS in order to recover capital investment.
6. Conduct sensitivity and uncertainty analyses to identify important inputs.

The study will enable investors and policy makers to make informed decisions on investments and future policies for PHS and CAES.

2.2 Process Description

2.2.1 Pumped Hydro Storage

PHS is a method of storing and generating electricity using two water reservoirs at different elevations. Presently, it is the most mature and commercially available technology and has more than 99% of installed ESS capacity [28, 29]. Figure 2 is a schematic diagram of a pump hydro system. The key components of a PHS plant are the pump turbine, motor, generator, penstock, inlet valve, penstock valve, upper reservoir, and lower reservoir. When the demand for electricity is low, the water in the lower reservoir is pumped to the upper reservoir. When the demand for electricity is high, the water from the upper reservoir flows to the lower reservoir, initiating the turbine to generate electricity. Two system valves regulate the flow of the water. The surge chamber facilitates the changes in water pressure.

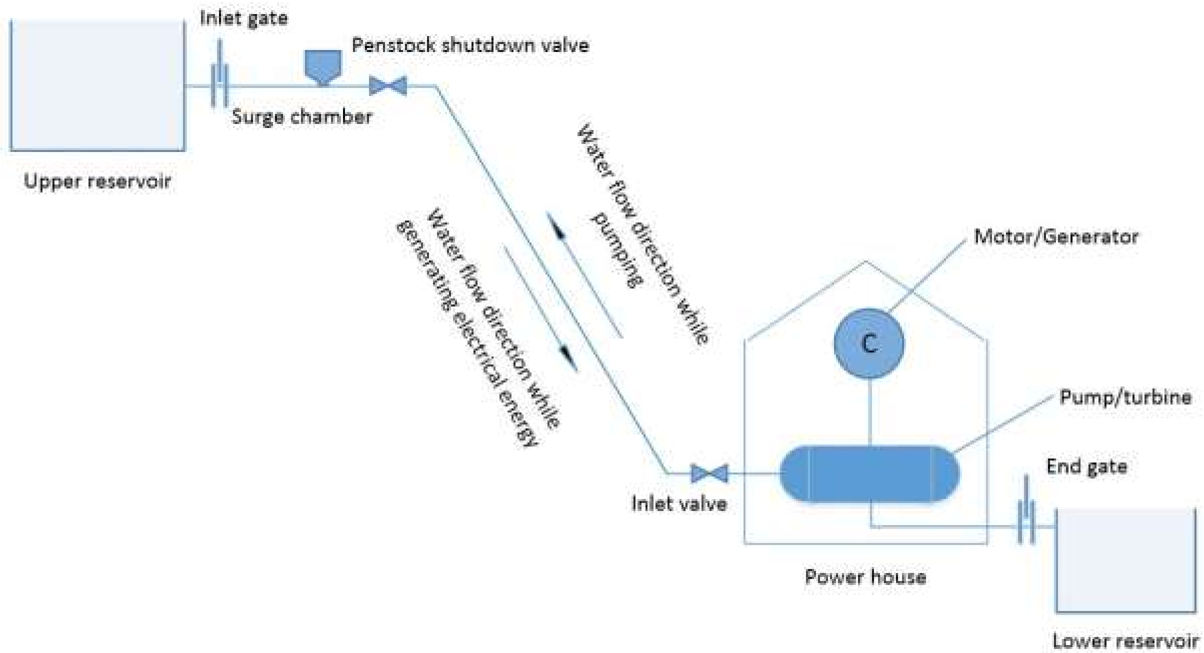

Figure 2: Pumped hydro storage schematic

2.2.2 Compressed Air Energy Storage

CAES is a method of storing electricity in the form of the potential energy of compressed air. It is the second commercially proven technology with a worldwide installed capacity of 440 MW [15]. CAES systems are of two types: conventional compressed air energy storage (C-CAES) and adiabatic compressed air energy storage (A-CAES).

2.2.2.1 Conventional Compressed Air Energy Storage

The main components of a C-CAES plant are the compressor, intercooler, valve, underground storage, recuperator, and turbine. Figure 3 presents a schematic of a conventional CAES system. During a period of low power demand, the excess electricity is supplied to compressors 1 to 3 to compress the air and convert electrical energy into potential air energy. The compressed air is then stored in an underground cavern, i.e., a salt cavern, porous formation, or hard rock cavern. During periods of high power demand, the air is supplied with energy by burning natural gas in combustors 1 and 2 and released through turbines 1 and 2 to produce electricity. The recuperator is installed just before the combustor to pre-heat the air with energy from exhaust gases and thereby increase overall system efficiency. The valves at the inlet and outlet of the underground storage maintain constant pressure. Constant pressure ensures the turbines are operating at optimum points all the time, resulting in a more efficient system.

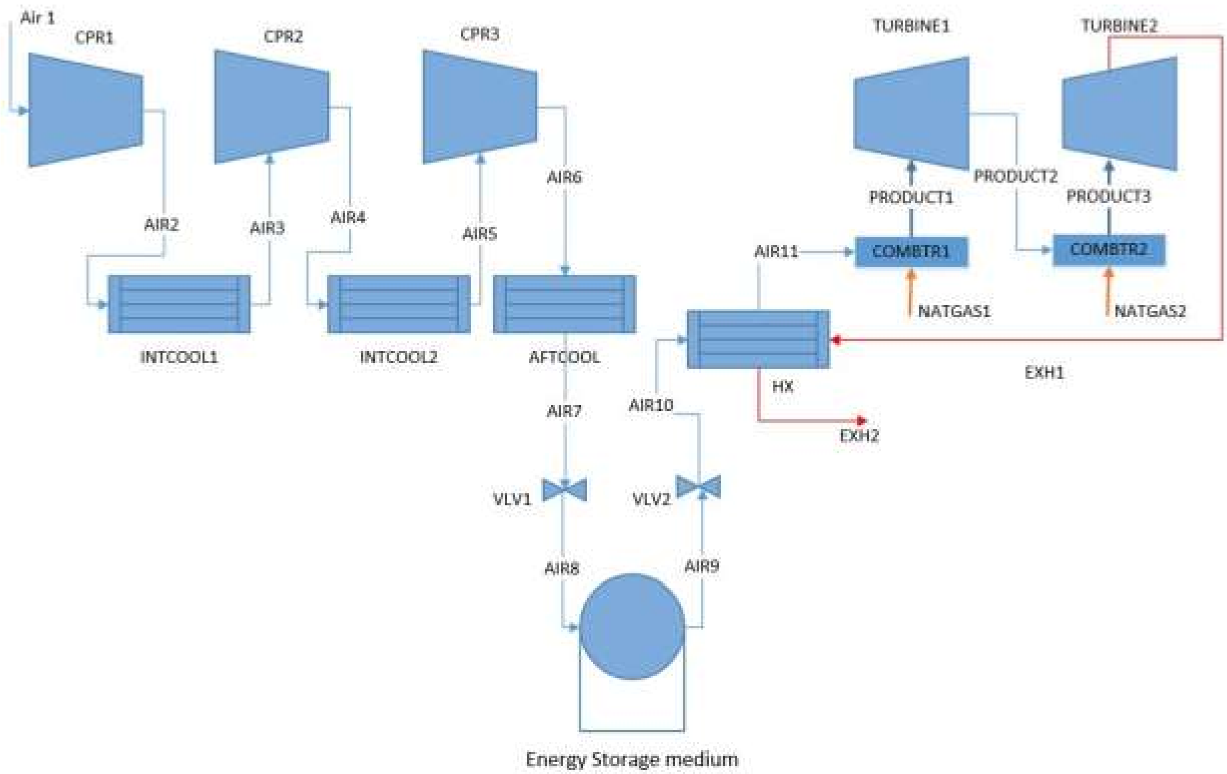

Figure 3: Conventional compressed air energy storage schematic

2.2.2.2 Adiabatic Compressed Air Energy Storage

The A-CAES system is the integration of CAES and a thermal energy storage system. The main components of the A-CAES system are the compressor, heat exchanger, underground storage, heat storage fluid, and turbine. Figure 4 is a schematic of the adiabatic CAES system. As for C-CAES, during periods of low power demand, excess electricity is supplied to compressors 1 and 2 to compress the air. The heat generated during compression is extracted from the compressed air with heat exchangers 1 and 2 and stored in working thermal fluid. The working fluid can be hot oil or a molten salt solution [26]. The compressed air is stored in an underground cavern. During periods of high power demand, the stored heat is recalled to heat the compressed air and then the air is released through turbines 1 and 2 to produce electricity. The heat storage powers the turbine to run without any help of fuel or gas.

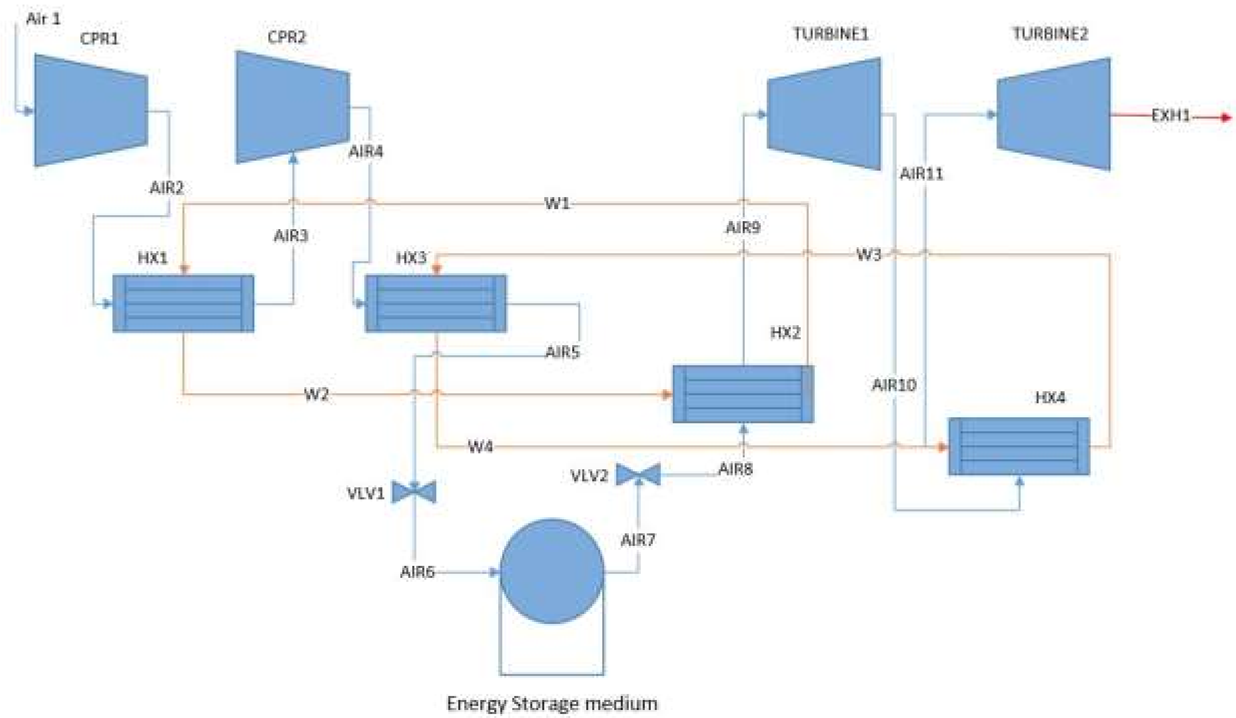

Figure 4: Adiabatic compressed air energy storage schematic

2.3 Model Development

2.3.1 Pumped Hydro Storage

The available head and the flow rate of water through the turbine are the essential input parameters in defining the power output from the PHS facility. As the head and flow rate increase, the power output of the PHS plant increases. The power output (P) is directly proportional to the head (h) and the flow rate (Q), as defined in equation 1. The head is the available height differential of the reservoirs. The flow rate will depend on the size of the penstock. The energy output (E) of the PHS plant is directly proportional to the amount of water stored in the reservoir

(V). The energy output of the PHS plant is calculated by equation 2. Generally, one cubic meter of water falling from a height of 100 m has the potential to produce 0.272 kWh of electricity [15].

$$P = \eta * \rho * g * Q * h \tag{1}$$

$$E = \frac{\eta_g * \rho * g * V * h}{3.6 * 10^9} \tag{2}$$

Where η is the overall efficiency of a PHS plant, η_g is the efficiency of PHS in generation mode, ρ is the mass density of water (1000 kg/m^3), and g is the acceleration due to gravity (m/s^2).

The output electrical energy from PHS was modeled using the parameters presented in Table 1. The data available from various operating PHS plants in the U.S were compiled [30, 31]. The important input parameters of a PHS plant were selected from the compiled data. The head and flow rate of a PHS plant base case were taken as 500 m and 60 m^3/s, respectively. The efficiency of the pump turbine is an important defining characteristic of a PHS plant as the power output depends on it. The efficiency of the pump turbine both in pumping and generation mode was taken as 0.9 [30]. Losses due to evaporation and frictional losses in penstock are negligible compared to losses in components [15] and thus were not included in the technical analysis. The PHS base case was modeled for a capacity of 294 MW. The developed PHS model is flexible enough to handle different plant capacities depending on unit operations. Scenarios of different plant capacities were created by varying input parameters.

Table 1: Input parameters for the pumped hydro storage model

Component	Type	Parameters	Value	Units	Reference
		Head	500	m	[31]
Pump turbine	Francis	efficiency (pumping)	0.9		[32]
		efficiency (Generation)	0.9		[32]
		No of units	1		
		Flow rate	60	m^3/s	[31]
		Velocity of flow	5	m/s	[31]
		Hours of operation (pumping)	8	hr	
Upper Dam	Concrete Dam	Dam height	35	m	Assumed
		Dam width	80	m	Assumed
Lower Dam)	Concrete Dam	dam height	25	m	Assumed
		Dam width	60	m	Assumed
Surge chamber		Height	100	m	Assumed

2.3.2 Compressed Air Energy Storage

The individual components of a CAES plant were modeled separately. The model used in this study was based on engineering thermodynamics equations.

The efficiency of the compressor (η_c) was calculated using equation 3 [33]. The outlet temperature of the compressor ($T_{out,comp}$) was determined using the ideal gas polytropic relation. The relation is presented in equation 4 [34, 35]. The required compressor power (W_{comp}) can be estimated based on air mass flow rate ($\dot{m}_{air}$) and the temperature difference across the compressor, as shown in equation 5.

$$\eta_c = 0.91 - \frac{r_c - 1}{300} \tag{3}$$

$$T_{out,comp} - T_{in,comp} = T_{in,comp} * (r_c^{\frac{\gamma-1}{\gamma*\eta_c}} - 1) \tag{4}$$

$$W_{comp} = C_{p,air} * \dot{m}_{air} * (T_{out,comp} - T_{in,comp}) \tag{5}$$

Where, r_c is the compressor pressure ratio and γ is the specific heat ratio of air.

The specific heat of air ($C_{p,air}$) was evaluated at an average compressor temperature using the relationship presented by McDonald and Magande [43]:

$$C_{p,air} = \frac{(28.11+0.1967*10^{-2}*\Delta T+0.4802*10^{-5}*\Delta T^2-1.966*10^{-9}*\Delta T^3)}{28.97} \tag{6}$$

where, ΔT is the temperature difference across the equipment.

The pressure drop (ΔP) through the intercooler is a function of heat exchanger effectiveness (ε) and inlet pressure (P_{in}) and was calculated using equation 7 [33]. The rate of heat exchange ($\dot{Q}$) through the intercooler or recuperator was calculated using equation 8 [38, 44]. The area of intercooler or after-cooler (A) required was calculated with the heat balance equation (9):

$$\Delta P = 0.0083 * \frac{\varepsilon}{1-\varepsilon} * P_{in} \tag{7}$$

$$\dot{Q} = \varepsilon * (\dot{m} * C_p)_{min} * (T_{hot,in} - T_{cold,in}) \quad (8)$$

$$A = \frac{\dot{m}_{air} * C_{p,air} * \Delta T}{U * LMTD} \quad (9)$$

where $T_{hot,in}$ is the inlet temperature of the hot stream, $T_{cold,in}$ is the inlet temperature of the cold stream, U is overall heat transfer coefficient, and $LMTD$ is logarithmic mean temperature difference.

The cavern volume (V_c) required to store the air was calculated by equation 10:

$$V_c = \frac{\gamma * R * \dot{m}_{air} \ * T_{cavern}}{\frac{dp}{dt}} \quad (10)$$

where R is the specific gas constant taken, T_{cavern} is temperature of the storage cavern, and $\frac{dp}{dt}$ is the pressure differential required to fill the cavern.

The flow rate of natural gas $(\dot{m}_{NG})$ required in the combustor was measured using equation 11:

$$\dot{m}_{NG} = \frac{\dot{m}_{air} * C_{p,air} * \Delta T}{LHV} \quad (11)$$

where LHV is heating value of natural gas (KJ/kg).

The efficiency of the turbine (η_t) was evaluated using equation 12 [41]. The outlet temperature of the turbine $(T_{out.turb})$ was also determined using the ideal gas polytropic relation. The relation is presented in equation 13 [34, 36]. The power delivered by the turbine $(W_{turbine})$ was calculated by equation 14.

$$\eta_t = 0.9 - \frac{r_t - 1}{250} \tag{12}$$

$$T_{out.turb} = T_{in,turb} - T_{in,turb} * (1 - r_t^{\frac{\eta_t*(1-\gamma)}{\gamma}}) \tag{13}$$

$$W_{turbine} = C_{pa} * \dot{m}_{air} * (T_{in} - T_{out}) \tag{14}$$

Five scenarios of different power output capacities were developed for both conventional and adiabatic CAES by varying unit operations. The flow rate was varied along with all linked parameters to accommodate the change in flow rate such as compressor power, storage cavern volume, amount of natural gas or heat storage fluid required, area of recuperator or heat exchanger, etc.

2.3.2.1 Conventional Compressed Air Energy Storage

The energy output from C-CAES was modeled using the parameters presented in Table 2. The air enters the system at 15°C and 1 bar of pressure. The air flow rate for the CAES base case was taken to be 300 kg/s. The compressed air is stored in an underground cavern at a pressure in the range of 45-70 bars [37]. To reach this pressure range, the system has three compressors each with a compressor ratio of 4.3. The effectiveness of intercoolers was taken to be 0.8 [38]. Two turbine systems were used to generate electrical energy, a high-pressure and a low-pressure turbine, with discharge pressures of 10 bars and 1 bar, respectively. The C-CAES plant base case was modeled for a capacity of 242 MW.

Table 2: Input parameters for the conventional compressed air energy storage model

Stream/Component	Parameter	Value	Units	Reference
Air	Inlet temperature	288.15	K	
	Pressure	1	bar	
	Flow rate	300	kg/s	
	Specific heat ratio	1.4		[39]
	Specific gas constant	287	J/kg K	[40]
Natural gas 1	Inlet temperature	288.15	K	
	Pressure	1	bar	
Natural gas 2	Inlet temperature	288.15	K	
	Pressure	1	bar	
	Lower heating value	48120	KJ/kg	[41]
Compressor 1	Compression ratio	4.3		[24]
Compressor 2	Compression ratio	4.3		[24]
Compressor 3	Compression ratio	4.3		[24]
Intercooler 1	Effectiveness	0.8		[38]
Intercooler 2	Effectiveness	0.8		[38]
	U value (Air to Water)	200	$W/(m^2K)$	[42, 43]
Aftercooler	Effectiveness	0.8		[38]
Storage Cavern	Inlet pressure	70	bar	[37]
	Outlet pressure	45	bar	[37]
	Temperature	303.15	K	
Recuperator	Effectiveness	0.8		[38]
	U value (Air to Air)	150	$W/(m^2K)$	[42, 43]
Combustor 1	Operating temperature	823.15	K	[44]
Combustor 2	Operating temperature	1098.15	K	[44]

Stream/Component	Parameter	Value	Units	Reference
Turbine 1	Turbine discharge pressure	10	bar	[44]
Turbine 2	Turbine discharge pressure	1	bar	[44]

2.3.2.2 Adiabatic Compressed Air Energy Storage

The energy output from A-CAES was modeled using the parameters listed in Table 3. The air enters the system at 15°C and one bar of pressure. The airflow rate for the CAES base case was taken as 300 kg/s. The compressed air is stored in an underground cavern at a relatively high pressure of 140-160 bar. A two-compressor system is used with a compressor ratio of 13.1. The effectiveness of heat exchangers was taken to be 0.9 [38]. Two turbine systems, high-pressure turbine and low-pressure, are used to generate electrical energy with discharge pressures of 15 bars and 1 bar, respectively. The discharge pressure of the high-pressure turbine was selected based on optimizing the total electrical output for the system. The A-CAES plant base case was modeled for a capacity of 179 MW.

Table 3: Input parameters for the adiabatic compressed air energy storage model

Stream/ Component	Parameter	Value	Unit	Reference/ Remark
Air	Inlet temperature	288.15	K	
	Pressure	1	bar	
	Flow rate	300	kg/s	
	Specific heat ratio	1.4		[39]
Dowtherm T 1	flow rate (kg/s)	120	kg/s	
	Initial Temperature	288.15	K	

Stream/ Component	Parameter	Value	Unit	Reference/ Remark
Dowtherm T 2	flow rate (kg/s)	120	kg/s	
	Initial Temperature	288.15	K	
Storage Tank 1	Number of Units	3		Assumed
Storage Tank 2	Number of Units	3		Assumed
Pump	Efficiency	0.7		[45]
	Head	20	m	Assumed
Compressor 1	Compression ratio	13.1		
Compressor 2	Compression ratio	13.1		
Heat exchanger 1	Effectiveness	0.9		[38]
Heat exchanger 2	Effectiveness	0.9		[38]
Heat exchanger 3	Effectiveness	0.9		[38]
Heat exchanger 4	Effectiveness	0.9		[38]
	U value	200	$W/(m^2K)$	[42, 46]
Storage Cavern	Inlet pressure	160	bar	[47]
	Outlet pressure	140	bar	[47]
	Temperature	298.15	K	
Turbine 1	Turbine discharge pressure	15	bar	[47]
Turbine 2	Turbine discharge pressure	1	bar	

2.4 Development of Techno-economic Models

2.4.1 Evaluation of Total Equipment Cost

The total equipment cost (TEC) is the sum of the cost of individual equipment required for the energy storage system. It comprises the power-related costs including the purchase and installation costs of all the power equipment in the storage system. Individual equipment costs were calculated using the cost functions of equipment found in the literature [48-50]. A list of equipment for PHS and CAES and their cost functions is presented in Appendix A[2]. These cost functions are adjusted to incorporate location factor and exchange rate.

2.4.2 Evaluation of Storage Cost

The storage cost (SC) evaluates the energy-related costs for the storage systems including the construction cost of reservoirs for PHS and the underground air storage reservoir for CAES.

For PHS, the reservoir cost (C_r) is calculated through an equation from Dawes and Wathne [51].

$$C_r = 5.5663 * (196.22 * V_r^{0.54} + 0.001 * V_r^{0.87} * k) \tag{15}$$

Where V_r is the reservoir volume and k is the land unit cost ($ per acre).

The land unit cost was taken to be $10,000 per acre [52]. This figure is based on the upper range of land cost in Alberta and was selected in order to have conservative estimates.

Three CAES storage media were considered in this analysis: salt, porous formation, and hard rock cavern. The cost of each was calculated based on construction materials. For a salt cavern, the total storage cost was broken down into four components: drilling, piping, water supply, and labor cost. For porous formations, drilling, piping, and labor costs were considered. The drilling depth (L) required for both salt caverns and porous formations was taken as 800 m based on existing CAES plants [53]. The per meter drilling cost was taken as $150/foot [54]. Steel was selected as the material for the construction of air channels. The piping cost was calculated based

[2] All costs are in 2014 U.S. dollars

on the mean diameter of piping and pipe length. The mean diameter of the pipe (x) was taken as 20 inches [53]. The piping cost (C_{pipe}) was calculated as follows [50]:

$$C_{pipe} = 1.3129 * x^{1.1052} * L \tag{16}$$

About fifty gallons of water are required per cavern unit volume [52]. Water is available free of charge as it is assumed that there is an unlimited source of water nearby like a river or lake. But this water needs to be transported to the cavern site. Thus, transportation costs will be incurred. The average distance between the water source and the cavern is assumed to be 2 km. Pipes and pumps are required to transport the water, and electricity is needed to operate the pumps. For the construction of the cavern, the labor cost was calculated assuming 10 laborers working for $35/hour [55]. It normally takes about two years to construct a salt cavern [37].

For hard rock formation, a limestone mine was considered. For underground mining, a room and pillar were selected for the creation of a hard rock cavern. Related costs were derived from Shinobe [27]. The construction time was taken as 300 days, and a 50% capital recovery factor was assumed. In addition, the gains from limestone are assumed to contribute one-third of the investment and operation cost.

2.4.3 Calculation of Total Investment Cost

The total investment cost (TIC) includes all power- and energy-related costs, and the balance of plant. This cost indicates the amount required upfront to build the storage facility. The TIC is derived from the total equipment cost following the methodology shown in Figure 5 [48, 56]. The method used is a standard method present in existing literature and generally acceptable for new plant construction. The TIC has four components: total direct cost, indirect cost, contingency, and storage cost. The total direct cost is further divided into the sub-components equipment cost, an additional 5% for accounted components, building, site development, and initial working capital. The indirect cost includes the contractor fee owner and insurance. The contingency is taken to be

10% of the total direct cost, while decommissioning cost is assumed to be zero [57]. The cost of the power conditioning system (PCS), which facilitates the integration of the plant to the grid, was not considered in the analysis.

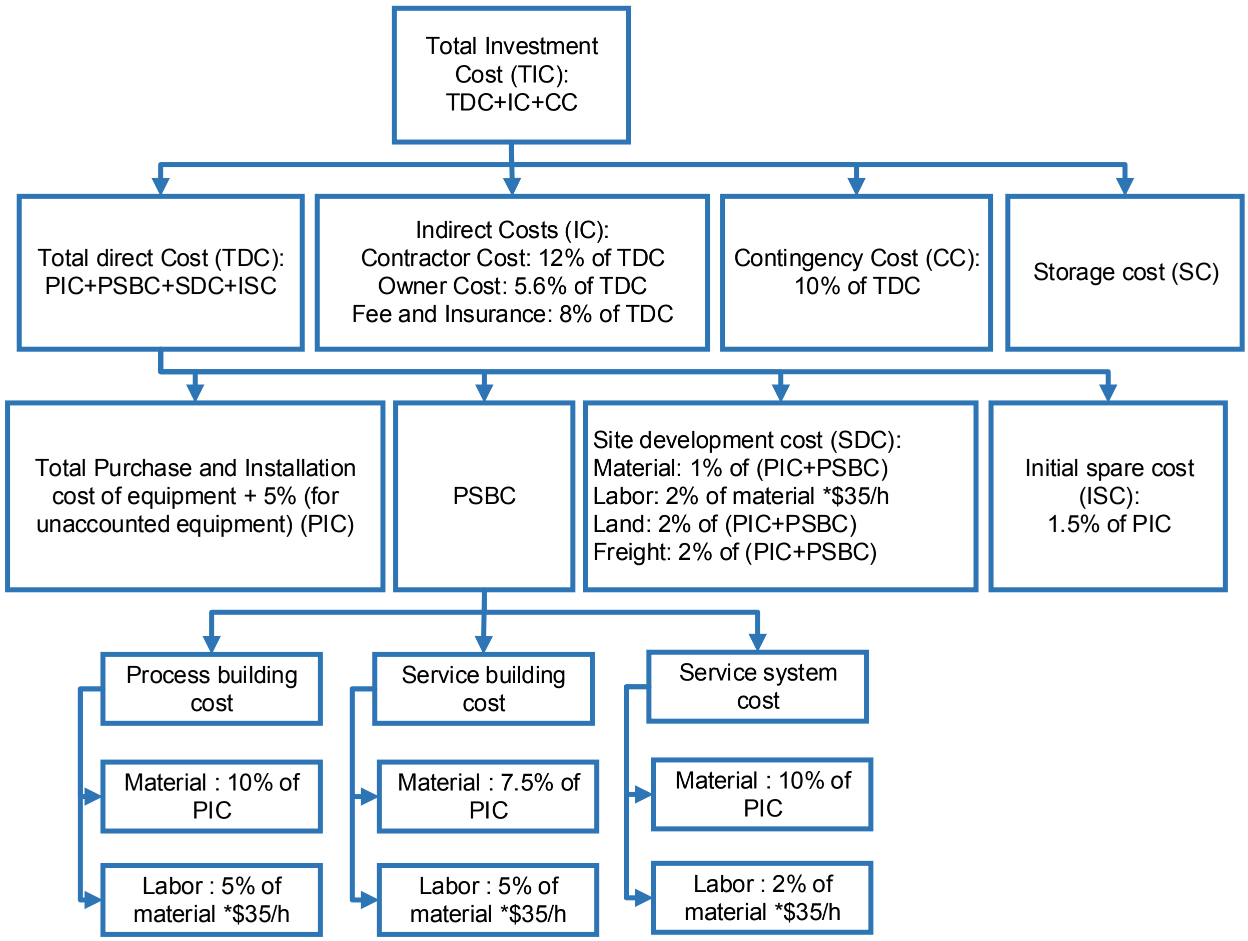

Figure 5: Methodology for the total investment cost calculation

2.4.4 Development of scale factor

The scale factor shows the effect of plant capacity on the TIC and defines the cost of one plant size relative to another. The scale factor (f) for an EES is determined by curve fitting the TIC to the plant capacity. It is defined through the following equation [49]:

$$f = \frac{\log\left(\frac{Cost_A}{Cost_B}\right)}{\left(\frac{Capacity_A}{Capacity_B}\right)} \quad (17)$$

where $Cost_A$ is the cost of the required plant, $Cost_B$ is the base case plant cost, $Capacity_A$ is the capacity of the required plant, and $Capacity_B$ is the base case plant capacity.

2.4.5 Operation & Maintenance Costs

For PHS, it is assumed that there are 20 employees working at an average salary of $65,000, which is incorporated in the operation and maintenance (O&M) cost. Other office supplies involve 10% of employee wages [58]. Annual maintenance and replacement costs are 2% of the TIC [59]. Overhaul cost is considered to be part of maintenance and replacement costs. The same methodology was used as for CAES to have uniformity and consistency in comparison.

2.4.6 Annual life cycle cost

The annual life cycle cost ($ALCC$) refers to the yearly payment to cover upfront costs and loan repayment if any [25] and is expressed in $/kW-year. The ALCC includes the TIC and O&M costs (including replacement costs) and annual fuel cost (electricity and other fuels such as natural gas). Both the TIC and O&M are annualized to calculate the ALCC. Before the ALCC is calculated, the capital recovery factor (CRF) needs to be defined. The capital recovery factor converts the total investment in annual installation over the life of the project based on the interest rate. The CRF is calculated with equation 18. The interest rate (i) selected for the ALCC analysis is 10%. Once we have the CRF, the ALCC is calculated by equation 19.

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1} \quad (18)$$

$$ALCC = (TIC * CRF + O\&M + Fuel_{price} * N * Fuel_{consumed}) \quad (19)$$

where N is the number of cycles in a year.

2.4.7 Levelised Cost of Electricity

The levelised cost of electricity ($LCOE$) is the price at which the electricity produced by an ESS should be sold at the given conditions to cover all the costs related to the ESS over its lifetime. The LCOE can be expressed in $/kWh or $/MWh. The plant life ($n$), number of operation cycles per year (N), and electricity input cost (Ein_{price}) are required to calculate the LCOE. The required assumptions to calculate the LCOE for both PHS and CAES are presented in Table 4. For the energy arbitrage application, the LCOE is compared with off-peak and on-peak electricity prices in Alberta. Alberta's electricity market is a deregulated market managed by the Alberta Electric System Operator. Electricity prices are set in real time. The dynamic of this market and high price fluctuation create ideal conditions for energy arbitrage [15]. The Alberta Electricity System Operator separates each day into two periods: on-peak and off-peak [60]. The on-peak period starts at 7:00 am and ends at 11:00 pm. The off-peak period is the remaining eight hours. Electricity demand is higher during the on-peak period than the off-peak period and so are the electricity prices; thus, there is an opportunity for energy arbitrage. The average values of on-peak and off-peak electricity prices in Alberta over the last 10 years (2005-2014) were calculated [60]. It is assumed that storage facilities go through a full charge and a discharge cycle once a day, 350 days a year. A two-week maintenance period per year is assumed, and the plant is shut down during this time. The system charging time is 10 hours for both PHS and CAES plants. Both PHS and CAES are leaders on the storage technology maturity curve [10]. Though PHS has a few decades of early maturity over CAES, the equipment required for CAES is used in other developed industries such as conventional gas turbine plants. Thus, it is assumed that risk associated with both technologies is the same, and a discount rate of 10% is used for both technologies for consistency. A discount rate of 10% is within the range of values present in existing literature [20, 21, 25]. Furthermore, the impact of discount rate on the overall cost was also investigated by performing a sensitivity analysis.

Table 4: Data for the LCOE calculation

	PHS	CAES	Reference	Comments
Construction time (years)	7	2	[30, 37, 58]	
No. of cycles in a year	350	350		One cycle per day, two weeks for annual maintenance
Life (years)	50	40	[10, 12]	Average life based on different sources
Off-peak pool price ($/MWh)	28.18	28.18	[60]	Average calculated for years 2005-14
On-peak pool price ($/MWh)	77.84	77.84	[60]	Average calculated for years 2005-14
Discount rate (d)	10%	10%		Assumed
Average inflation (i)	2%	2%	[61]	Average rate of inflation in Canada

The LCOE was calculated as:

$$LCOE = \frac{\left(\dfrac{TIC}{\dfrac{\frac{1+i}{1+d} * \left(\left(\frac{1+i}{1+d}\right)^{n} - 1\right)}{\frac{1+i}{1+d} - 1}} + O\&M + Ein_{price} * N * E_{consumed}\right)}{(N * E_{produced})} \tag{20}$$

where $E_{consumed}$ is the electricity consumed in one cycle and $E_{produced}$ is the electricity produced in one cycle.

2.4.8 Levelised Cost of Storage

The levelised cost of storage (LCOS) was derived by subtracting the system charging cost from the LCOE. The LCOS includes all the net internal costs except the cost of charging the system. The LCOS is calculated as:

$$LCOS = LCOE - \frac{Price\ of\ charing\ fuel}{Overall\ efficiency} \tag{21}$$

2.5 Results and discussion

2.5.1 Development of technical scenarios

2.5.1.1 Pumped Hydro Storage

The simulation results from five PHS scenarios are reported in Table 5. The scenarios were generated by varying the water flow rate in equally spaced intervals from 20 to 100 cubic meters. The plant's power capacity output in each scenario is 98, 196, 294, 392, and 491 MW. The energy output of one cycle for different scenarios ranges from 795 to 3973 MWh. As the water rate increases, the power input and energy output from the plant also increase. The water requirement ranges from 0.72 to 3.6 million cubic meters.

Table 5: Technical results for pumped hydro storage

		Scenarios				
	Parameter	**1**	**2**	**3**	**4**	**5**
Simulation Input	Water flow rate (m^3/s)	20	40	50	60	100
	Head (m)	500	500	500	500	500

Simulation Output	Water volume (thousand m^3)	720	1440	2160	2880	3600
	Power capacity (MW)	98	196	294	392	491
	Energy output in one cycle (MWh)	795	1589	2384	3178	3973

2.5.1.2 Compressed Air Energy Storage

2.5.1.2.1 Conventional Compressed Air Energy Storage

The simulation results from five C-CAES scenarios are reported in Table 6. These scenarios were generated by varying the air flow rate in equally spaced intervals from 100 to 500 cubic meters. The plant's power capacity output in each scenario is 81, 162, 242, 323, and 404 MW. The C-CAES plant's power output increases with an increase in air flow rate. The compressor efficiency is constant and is equal to 0.86 for all scenarios. The input power required by each compressor is also listed in Table 6. The minute difference in the power requirement by the three compressors is because they operate at different temperatures and the specific heat capacity of air changes slightly with temperature. The intercooler and the recuperator areas were also calculated and found to increase with an increase in power output. For any one scenario, the intercooler area required decreases from intercooler 1 to intercooler 3. This happens because of the increase in air pressure from intercooler 1 to intercooler 3. The total flow rate of natural gas varies from 2.03 to 10.15 kg/s. The efficiency of the high- and the low-pressure turbines is 0.90 and 0.89, respectively, and is the same for all scenarios. The individual output of each generator is included in the table.

Table 6: Simulation results for conventional compressed air energy storage

		Scenarios				

	Parameter	1	2	3	4	5
Simulation Input	Air flow rate (m^3/s)	100	200	300	400	500
	Compressor efficiency	0.86	0.86	0.86	0.86	0.86
	Compressor 1 power (MW)	17.25	34.50	51.75	69.01	86.26
	Compressor 2 power (MW)	17.57	35.14	52.71	70.28	87.85
	Compressor 3 power (MW)	17.89	35.78	53.66	71.55	89.44
	Intercooler 1 area (m^2)	2182	4365	6547	8730	8730
	Intercooler 2 area (m^2)	1757	3513	5270	7027	7027
	Intercooler 3 area (m^2)	1521	3042	4563	6084	6084
	Recuperator area (m^2)	2,362	4724	7085	9447	9447
	Natural gas flow rate (kg/s)	2.03	4.06	6.09	8.12	10.15
	Efficiency of turbine 1	0.9	0.9	0.9	0.9	0.9
	Efficiency of turbine 2	0.89	0.89	0.89	0.89	0.89
Simulation Output	Generator 1 Output (MW)	28	56	84	112	140
	Generator 2 Output (MW)	53	106	158	211	264
	Output capacity (MW)	81	162	242	323	404

2.5.1.2.2 Adiabatic Compressed Air Energy Storage

The simulation results from five A-CAES scenarios are reported in Table 7. The scenarios were generated by varying the air flow rate in equally spaced intervals from 100 to 500 cubic meters. The plant's power capacity output in each scenario is 60, 119, 179, 239, and 298 MW. The A-CAES base case has a capacity output of 179 MW. The A-CAES plant's power increases with an increase in air flow rate. The compressor efficiency is constant and is equal to 0.87 for all scenarios. The input power required by each compressor is also listed in Table 7. Here, the difference between the power requirements of compressor 1 and compressor 2 is significant because of the high variation in the operating temperature of the two compressors. The heat exchanger area was also calculated and found to increase with an increase in power output. For any given scenario, the area of heat exchangers 3 and 4 is less than that of heat exchangers 1 and 2 as heat exchangers 3 and 4 operate at higher pressure. The efficiency of the high- and the low-pressure turbines is 0.87 and 0.85 respectively and is same for all scenarios. The individual output of each generator is included in Table 7.

Table 7: Simulation results for adiabatic compressed air energy storage

		Scenarios				
	Parameter	**1**	**2**	**3**	**4**	**5**
Simulation Input	Air flow rate (m^3/s)	100	200	300	400	500
	efficiency of compressor	0.87	0.87	0.87	0.87	0.87
	Compressor 1 Power (MW)	39.69	79.39	119.08	158.78	198.47
	Compressor 2 Power (MW)	45.36	90.72	136.08	181.44	226.81
	Heat exchanger 1 Area (m^2)	5814	11627	17441	23254	29068
	Heat exchanger 2 Area (m^2)	8109	16218	24327	32435	40544
	Heat exchanger 3 Area (m^2)	4885	9771	14656	19542	24427
	Heat exchanger 4 Area (m^2)	3289	6577	9866	13154	16443
	efficiency of turbine 1	0.87	0.87	0.87	0.85	0.87
	efficiency of turbine 2	0.85	0.85	0.85	0.00	0.85
Simulation Output	Output of Generator 1 (MW)	26	52	79	105	131
	Output of Generator 2 (MW)	33	67	100	134	167
	Output Capacity (MW)	60	119	179	239	298

2.5.2 Total Investment Cost and Scale factor

The total investment cost is comprised of power cost and energy cost. The power cost is the cost of the equipment that determines the plant's power capacity (i.e., the pump). The energy cost is simply storage cost and relates to the energy output capacity of the plant. The units of power cost and energy cost are dollar per kW and dollar per kWh of one cycle respectively.

The power and energy costs for different PHS scenarios are shown in Table 8. For each scenario, two energy cost sub-scenarios were created, one for two-reservoir and one for one reservoir. The PHS energy cost includes the reservoir construction cost. In the two-reservoir scenario, it is assumed that both reservoirs (lower and upper) need to be built. For the one reservoir scenario, it is assumed one of the reservoirs exists and only one needs to be built. The PHS power cost ($ per kW) is from $800 to $2000. The energy cost ($ per kWh) for the two-reservoir scenario is from $40 to $55 and for the one reservoir scenario, $20 to $27. Both the power cost and the energy cost decrease with an increase in plant capacity because of economies of scale. The TIC for the PHS ranges from 200 to 550 million, as shown in Figure 6. In addition, the plot of the total investment with respect to the storage plant's power capacity has a scale factor 0.52. This means that the investment cost increases at a much lower rate than the increase in storage plant power output capacity, thus ensuring a higher return on investment for plants of higher power capacities. The scale factor established a strong economy of scale for PHS, i.e., an increase in capacity drastically reduces unit capital cost.

Table 8: Power and energy costs and plant capacities for pumped hydro storage

Plant capacity (MW)	Power cost ($/kW)	Energy cost ($/kWh)	
		Two-reservoir	One reservoir
98	2005	55	27
196	1245	49	24

294	1039	45	23
392	894	43	22
491	801	42	21

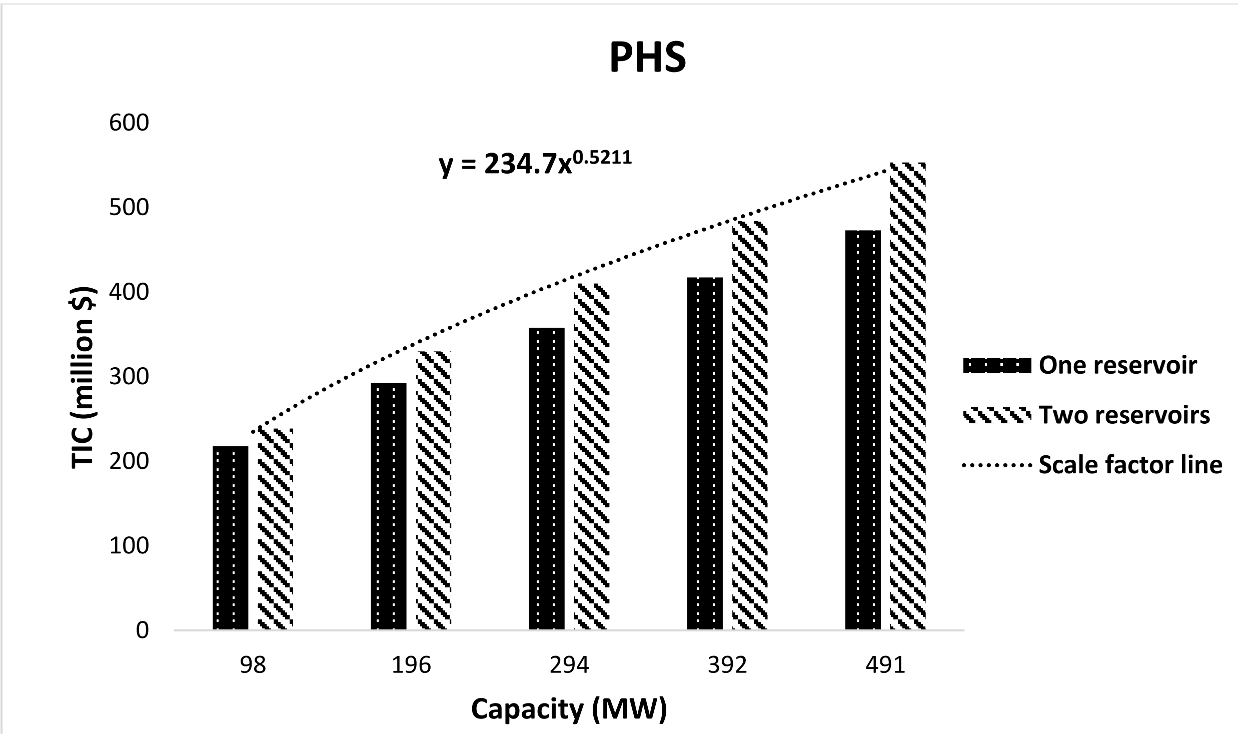

Figure 6: Total investment cost for pumped hydro storage

The power and energy costs for different C-CAES and A-CAES scenarios are presented in Table 9 and 10 respectively. The scenarios are divided into three categories depending on storage type (salt, porous formation, or hard rock cavern). For C-CAES, the power cost is in the range of $600 to $710/kW. Energy costs are in the range of $3 to $7/kWh for the salt cavern, $1 to $3/kWh for the porous formation, and around $30 for the hard rock formation. For A-CAES, the power cost is in the range of $1880 to $2230. Energy costs are in the range of $4 to $11/kWh for the salt cavern, $1 to $4/kWh for the porous formation, and around $50/kWh for the hard rock formation. The TIC for C-CAES and A-CAES ranges from 60 to 270 and 140 to 700 million, as shown in Figure 7 and

Figure 8, respectively. In addition, the plot of the total investment with respect to the storage plant's power gives a scale factor of 0.87 for C-CAES and 0.88 for A-CAES. There are economies of scale established for C-CAES and A-CAES, but they are not as strong as for PHS.

Table 9: Power and energy cost variations with plant capacity for conventional compressed air energy storage

Plant Capacity (MW)	**Power cost ($/kW)**	**Energy cost ($/kWh)**		
		Salt cavern	**Porous formation**	**Hard rock cavern**
81	707	7	3	30
162	657	5	1	30
242	633	4	1	30
323	619	3	1	31
404	609	3	1	31

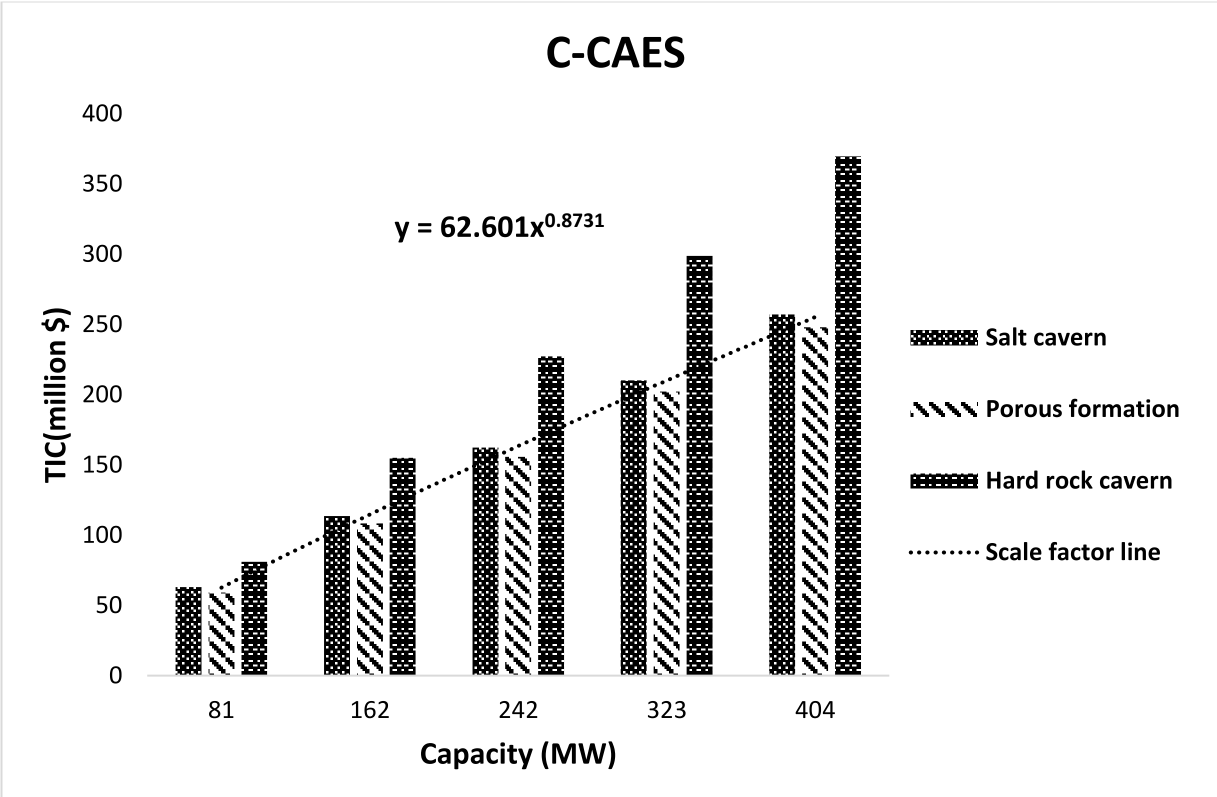

Figure 7: Total investment costs for conventional compressed air energy storage

Table 10: Power and energy cost variations with plant capacity for adiabatic compressed air energy storage

Plant Capacity (MW)	Power cost ($/kW)	Energy cost ($/kWh)		
		Salt cavern	Porous formation	Hard rock cavern
60	2228	11	4	50
119	2060	7	2	51
179	1976	5	1	51
239	1923	5	1	51
298	1884	4	1	51

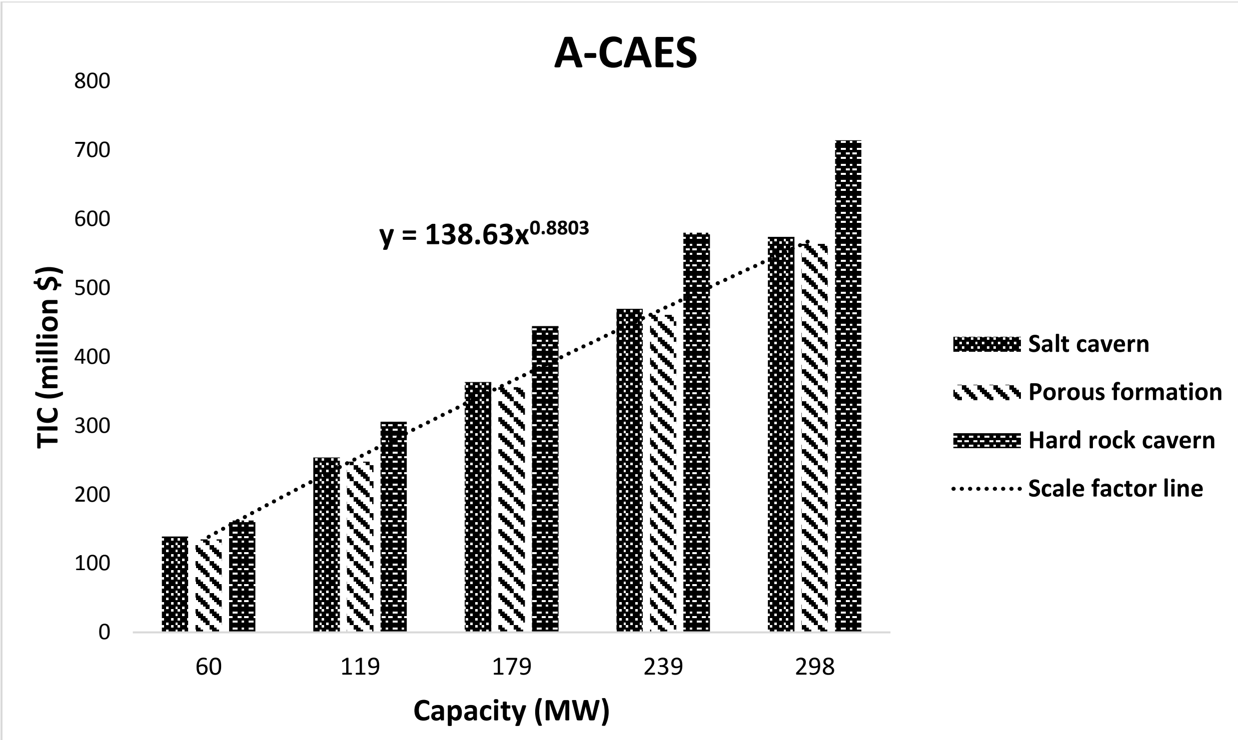

Figure 8: Total investment costs for adiabatic compressed air energy storage

The investment cost ranges are lowest for C-CAES, followed by PHS and then A-CAES. As the plant size increases, the capital cost per unit capacity decreases, showing the economy of scale benefits. The scale factor established a strong economy of scale for PHS. The energy cost for CAES is lowest for the porous formation, followed by the salt cavern. The hard rock formation is expensive to develop compared to other types of storage. As there are fewer elements involved in the construction of a porous formation, the cost is less. The above-surface air storage in pipes is currently being researched, but it is expensive and can be as high as $120 per kWh, according to Shoenung and Eyer [20].

2.5.3 Annual life cycle cost

The annual life cycle cost for PHS is shown in Figure 9. The ALCC is the indicator of annual loan repayments to cover the lifecycle costs of storage systems. Figure 9 includes the contributing components of the ALCC. The ALCC for PHS with two-reservoir can be from $235 to $400 per kW-year and with one reservoir from $220 to $375 per kW-year. The ALCC is lower for a single reservoir as less investment is required as less capital cost is involved for one reservoir. The main component of the ALCC is the capital cost; it is more than 60% of the costs.

The ALCCs for C-CAES and A-CAES are presented in Figure 10 and 11, respectively. For C-CAES, the ALCC is from $215 to $265 per kW-year and for A-CAES, from $345 to $480 per kW-year. The major contributor for C-CAES is the annual fuel cost (electricity and natural gas) and for A-CAES is capital cost. The ALCC is highest for a hard rock formation, followed by a salt cavern; it is lowest for a porous formation. The investment cost is highest to build a hard rock cavern, followed by a salt cavern and a porous formation. The ALCC decreases with increases in a storage plant's power capacity for all storage plants because of economies of scale.

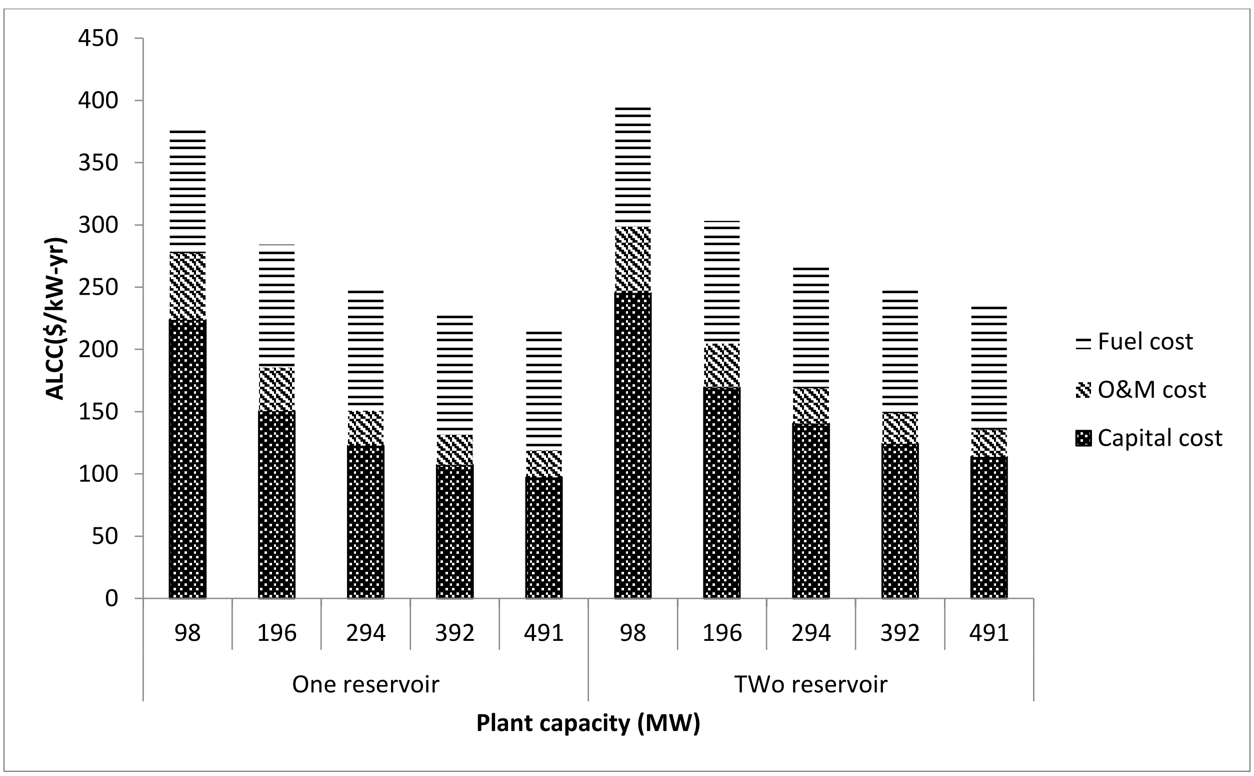

Figure 9: Annual life cycle cost for pumped hydro storage

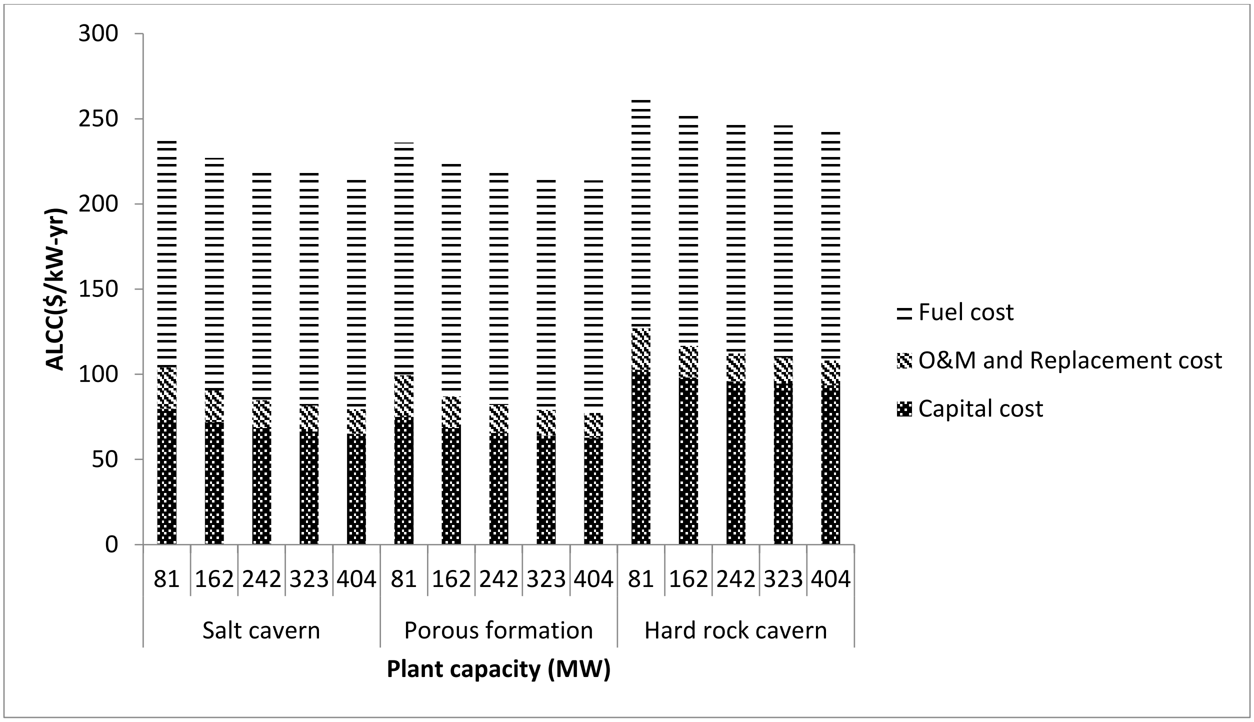

Figure 10: Annual life cycle cost for conventional compressed air energy storage

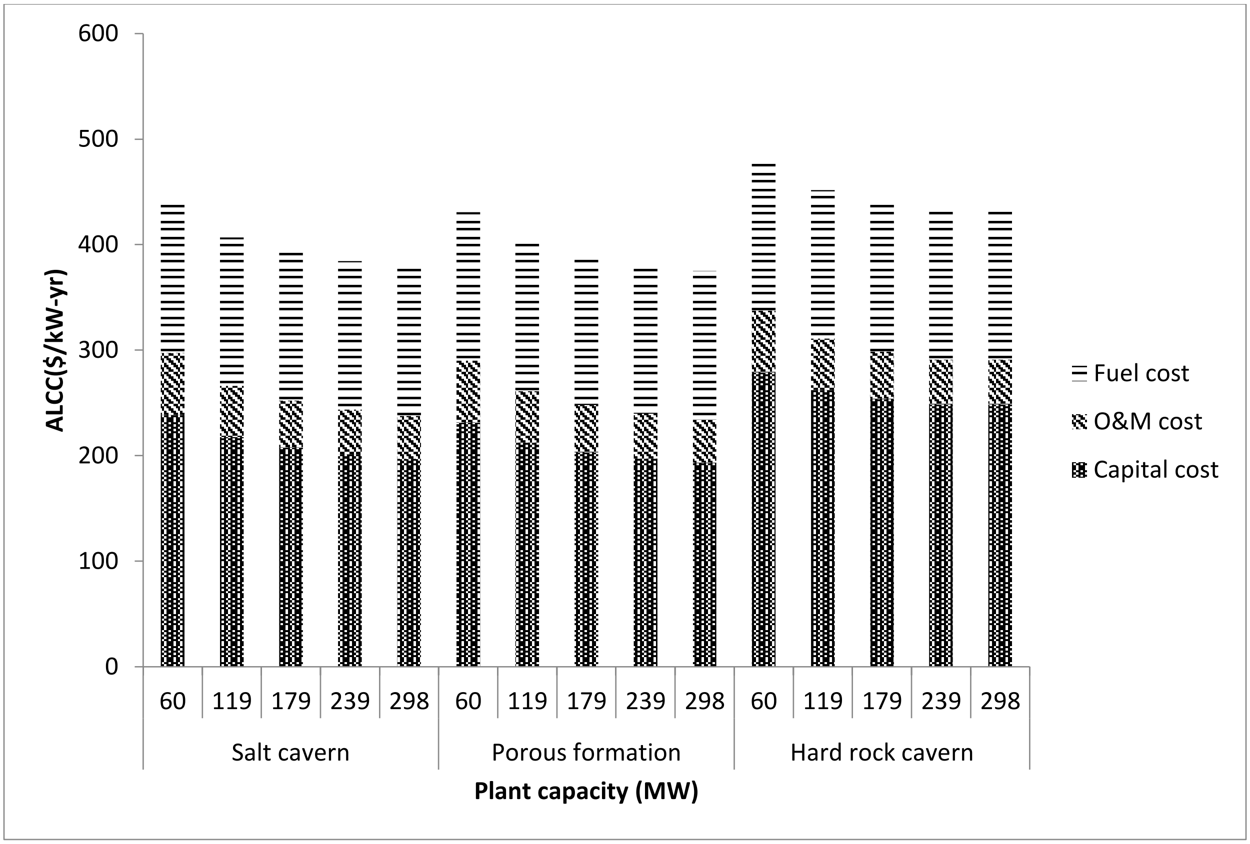

Figure 11: Annual life cycle cost for adiabatic compressed air energy storage

2.5.4 Levelised Cost of Electricity

The variations in the levelised cost of electricity with plant capacity for PHS are shown in Figure 12. The LCOE is from $69 to $114 MWh for the single reservoir scenario and from $73 to $121 per MWh for the two-reservoir scenario. The LCOE decreases with an increase in plant power capacity due to economies of scale, as shown in the figure. The unit capital cost decreases with an increase in plant capacity; thus, the LCOE is lower for higher capacities. The average on-peak electricity price in Alberta is $77.84 per MWh. The LCOE for a plant with a higher power capacity, such as 392 or 490 MW, is less than Alberta's on-peak electricity price. For lower plant capacities, the LCOE is more than the average on-peak price in Alberta.

The LCOE for C-CAES and A-CAES is presented in Figure 13 and 14. The LCOE for C-CAES is \$58 to \$64 per MWh for the salt cavern, \$58 to \$63 per MWh for the porous formation, and \$65 to \$70 per MWh for the hard rock cavern. The LCOE for A-CAES is \$97 to \$112 per MWh for the salt cavern, \$96 to \$110 per MWh for the porous formation, and \$108 to \$121 per MWh for the hard rock cavern. The LCOEs for the salt cavern and porous formation are similar. The hard rock cavern scenario has a higher LCOE than the other scenarios because of the higher storage cost component. The LCOE for the C-CAES for all three storage types is lower than the average on-peak electricity price in Alberta. The LCOE for A-CAES for all storage types is higher than the average on-peak electricity price in Alberta.

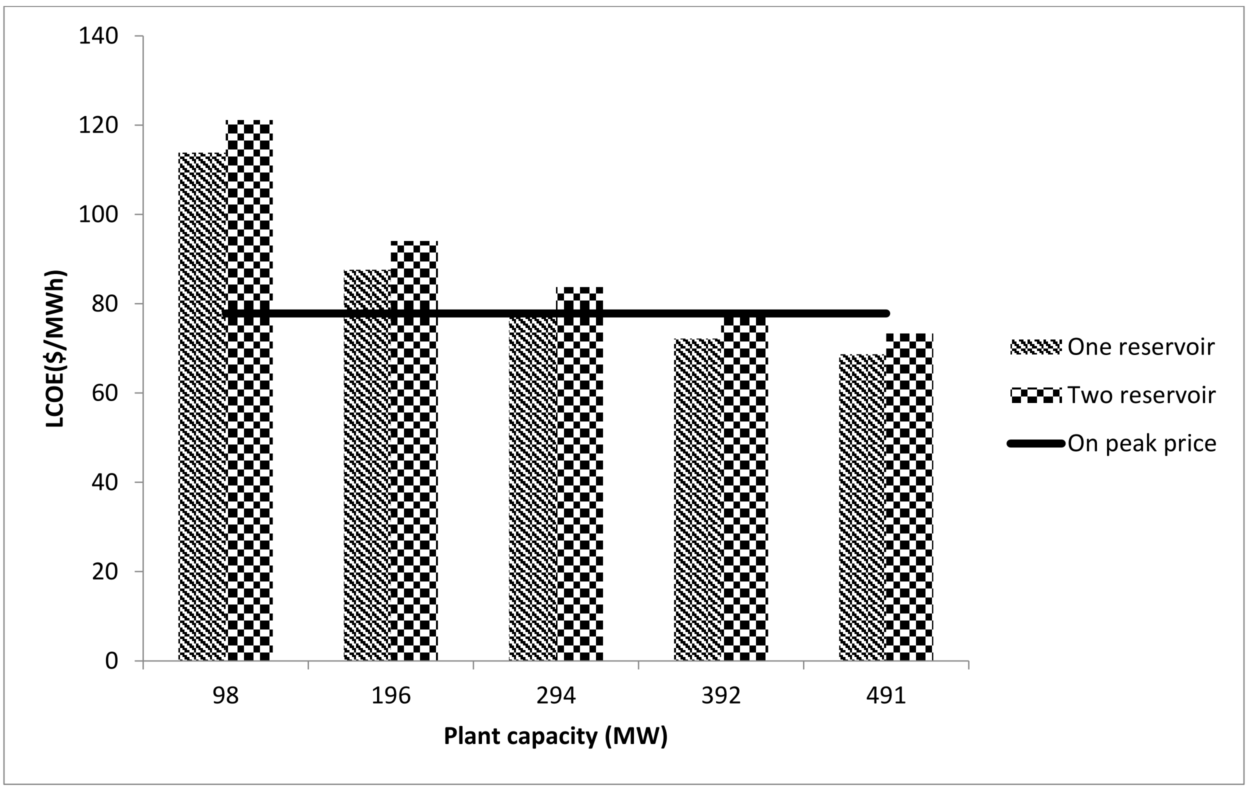

Figure 12: Variations of the levelised cost of electricity with plant capacity for pumped hydro storage

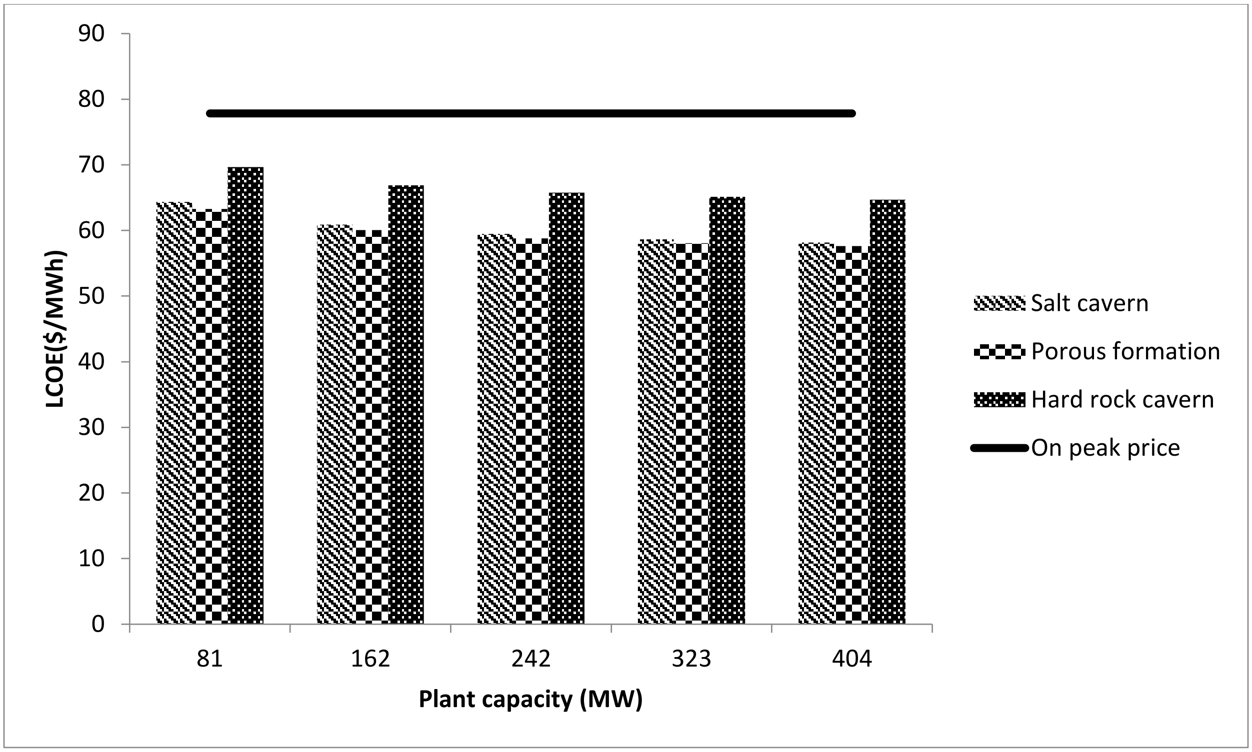

Figure 13: Variations of levelised cost of electricity with plant capacity for conventional compressed air energy storage

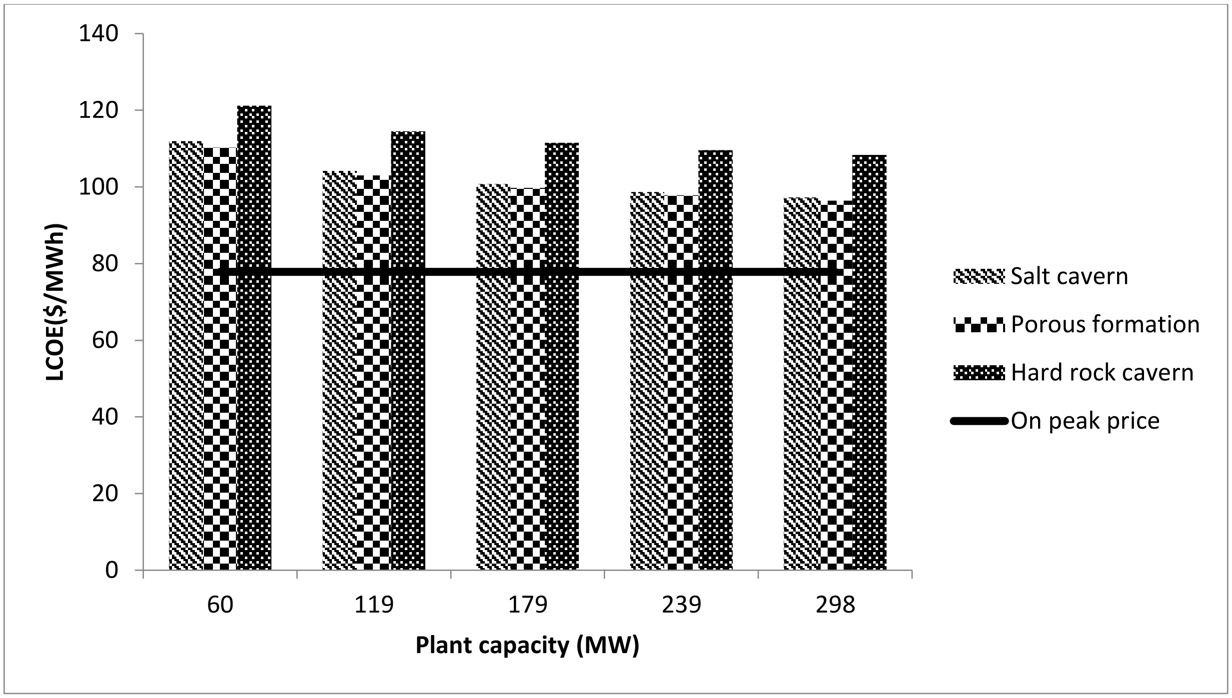

Figure 14: Variations of levelised cost of electricity with plant capacity for adiabatic compressed air energy storage

2.5.5 Levelised Cost of Storage

The variations in levelised cost of storage (LCOS) with plant capacity for PHS are presented in Figure 15. The LCOS is as low as $34 per MWh for a plant capacity of 491 MW and as high as $86 per MWh for a plant capacity of 98 MW. Again, the variation is due to decreases in unit capital cost with increases in plant capacity. As the unit capital cost is lower for higher capacities, the LCOS is less. The LCOS decreases with an increase in plant power capacity through economies of scale. The LCOS is from $34 to $79 per MWh for the one reservoir scenario and $39 to $86 per MWh for the two-reservoir scenario. The results of the LCOS were compared with the differences between on-peak and off-peak electricity prices in Alberta, otherwise known as the opportunity cost. The LCOS for PHS is lower than the opportunity cost for plant capacities of 294 MW, 392 MW, and 491 MW.

The LCOS for C-CAES and A-CAES is presented in Figure 16 and Figure 17, respectively. The LCOE for C-CAES ranges from $19 to $25 per MWh for the salt cavern, $19 to $24 per MWh for the porous formation, and $25 to $31 per MWh for the hard rock cavern. The LCOE for A-CAES ranges from $57 to $72 per MWh for the salt cavern, $56 to $70 per MWh for the porous formation, and $68 to $81 per MWh for the hard rock cavern. The LCOS for C-CAES is lower than the opportunity cost for all storage types and thus favorable. The LCOS for A-CAES is higher than the opportunity cost and thus not promising at all.

The greater the difference in unit capital cost the wider spread the LCOS. Thus, the variation in LCOS is greater for PHS than for CAES.

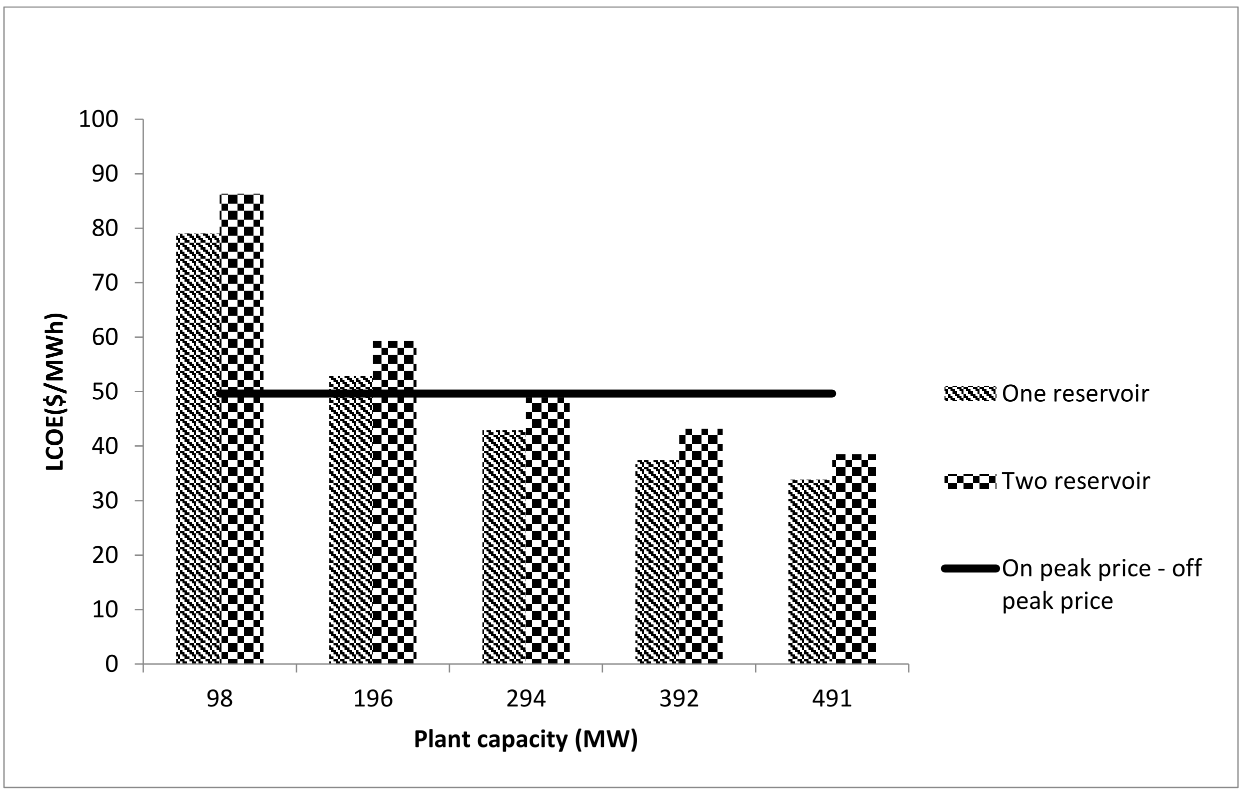

Figure 15: Variations of levelised cost of storage with plant capacity for pumped hydro storage

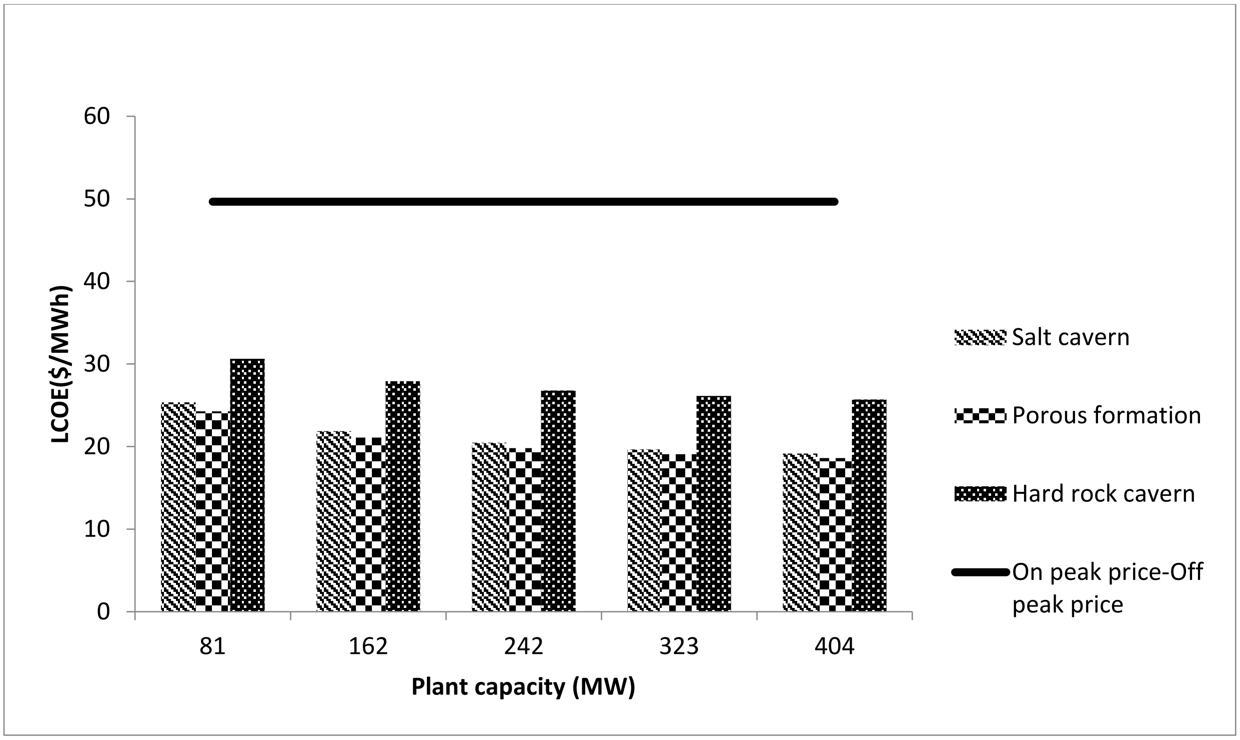

Figure 16: Variations of levelised cost of storage with plant capacity for conventional compressed air energy storage

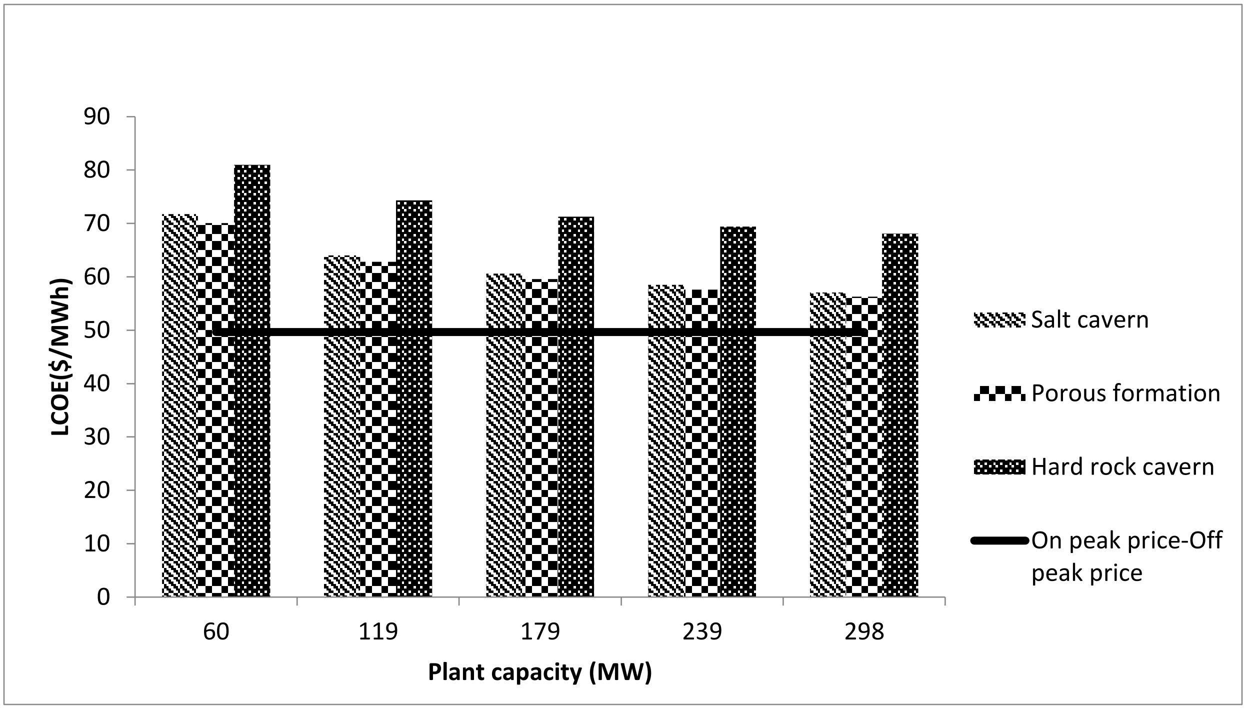

Figure 17: Variations of levelised cost of storage with plant capacity for adiabatic compressed air energy storage

2.5.6 Sensitivity Analysis

A sensitivity analysis was conducted to determine the influence of key process and cost parameters on the cost of electricity produced from the storage plant. The parameters selected are in one of three categories: technical, cost, and economic parameters. The technical parameters selected for PHS are head, water flow rate, hours of operation, and pump turbine efficiency. The technical parameters selected for CAES are turbine efficiency, hours of operation, airflow rate, and turbine inlet temperature. As equipment costs are derived from the literature, it is important to study their effect on the LCOE to build confidence in cost numbers. Cost parameters include the TIC, O&M cost, and high-cost equipment. Based on the classification provided by the Association for the Advancement of Cost Estimating International, the estimated costs for technologies are class 4 preliminary estimates and have an accuracy range of ±30%

[62]. This range was used in the sensitivity analysis. In addition, economic parameters such as fuel cost, electricity cost, inflation, and discount rate were included to study their impact on the LCOE.

The PHS base case has a capacity of 294 MW with two-reservoir and an LCOE of $83.76 per MWh. The sensitivity analysis results for PHS are presented in Figure 18. The LCOE is most sensitive to the efficiency of the pump turbine. An increase in pump turbine efficiency reduces system energy losses, thus increasing the electricity output from the system. The capital cost of the pump turbine increases with an increase in efficiency, though the overall impact on the entire system is relatively insignificant. As there is more energy output from the PHS plant, the LCOE decreases. A 5% increase in pump turbine efficiency will decrease the LCOE by 4.8%. Other highly sensitive parameters for PHS are hours of operation and discount rate.

The C-CAES base case has a capacity of 242 MW with salt cavern storage and an LCOE of $59.46 per MWh. The results of the sensitivity analysis for C-CAES are presented in Figure 19. The LCOE is most sensitive to the inlet temperature of the second turbine. If the inlet temperature of the second turbine increases by 5%, the LCOE goes down by 1.9%. The turbine inlet temperature is directly proportional to the energy output from the CAES plant, thus leading to a decrease in the LCOE. Other highly sensitive parameters are hours of operation and the TIC.

The A-CAES base case has a capacity of 179 MW with salt cavern storage and an LCOE of $100.78 per MWh. The results of the sensitivity analysis for A-CAES are presented in Figure 20. For A-CAES, the most sensitive parameter is air flow rate. The plant capacity is dependent on air flow rate and, a decrease in air flow rate results in a smaller plant size. Further, due to economies of scale, the LCOE increases. A 5% decrease in air flow rate increases the LCOE by 3.8%. Other sensitive parameters are air inlet temperature and the TIC.

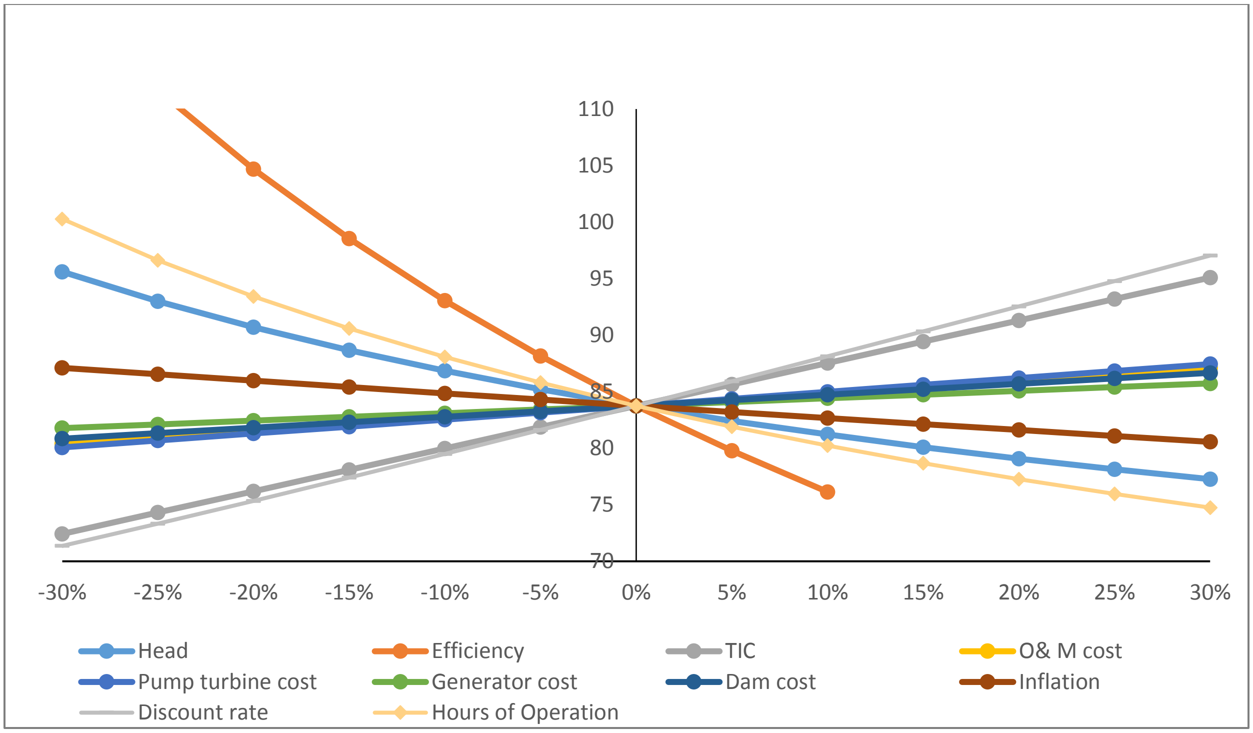

Figure 18: Effect of variations of different parameters on the levelised cost of electricity for pumped hydro storage

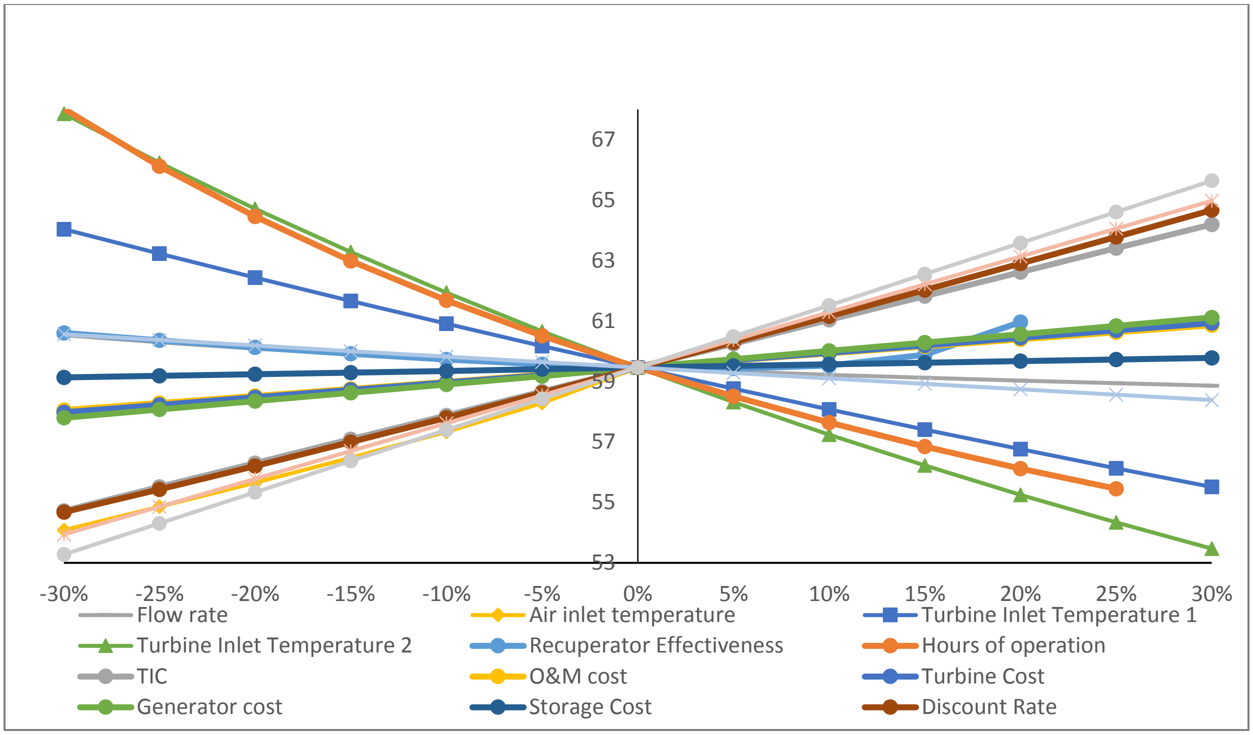

Figure 19: Effect of variations of different parameters on the levelised cost of electricity for conventional compressed air energy storage

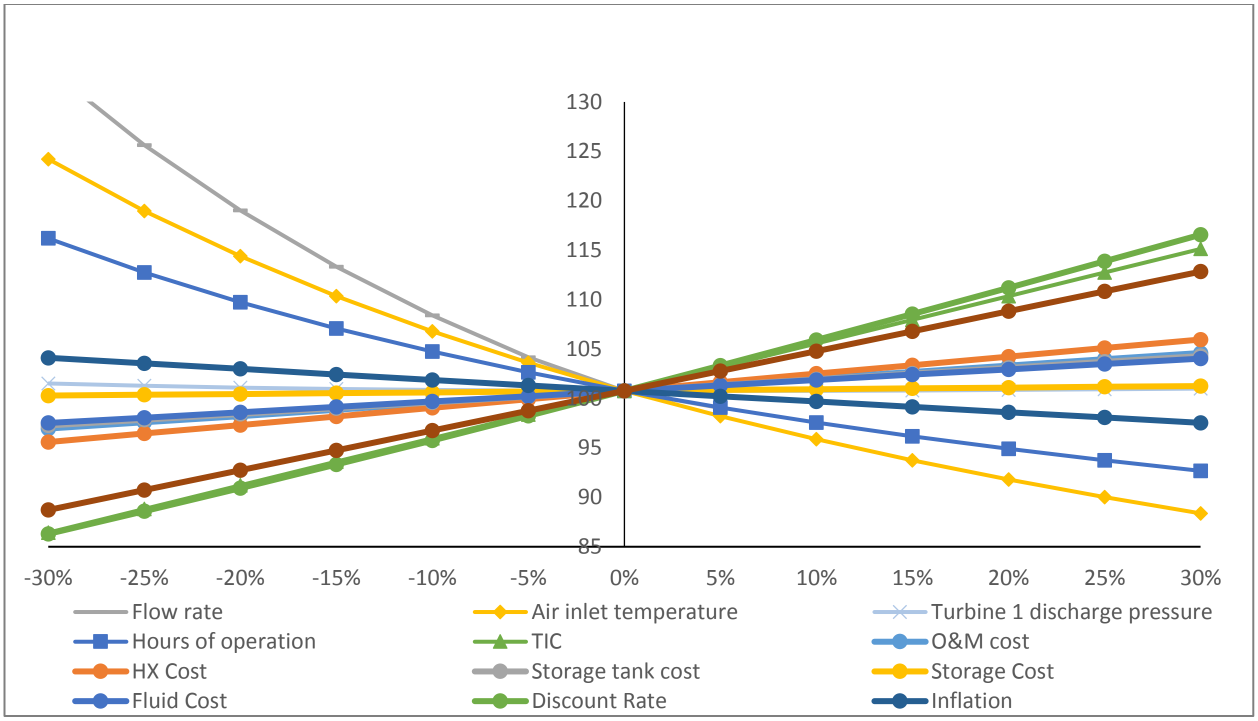

Figure 20: Effect of variations of different parameters on the levelised cost of electricity for adiabatic compressed air energy storage

2.5.7 Uncertainty Analysis

An uncertainty analysis was performed to evaluate the effect of simultaneous change in input variable on final output. An uncertainty analysis was also conducted to understand the risks and impacts of uncertainties in input process parameters on the LCOE. The Monte Carlo simulation technique and ModelRisk software were used to perform the analysis. A random value was selected from the range of input variables that have an impact on the final output. The process is iterated a number to times, taking random input values every time to obtain a range of values for the final output. The Monte Carlo simulation was performed for the PHS, C-CAES, and A-CAES base cases by identifying the input parameters and quantifying the uncertainty in the LCOE with 50,000 iterations each. The various input variables selected for uncertainty analysis and their ranges are reported in Table 11. The results of this analysis are presented in Figure 21. The mean

LCOE for PHS is $96.82 per MWh and for C-CAES and A-CAES is $57.87 and $104.48 per MWh, respectively.

Table 11: Uncertainty analysis parameters

	Parameter	Minimum value	Base value	Maximum value	Unit	Reference
PHS						
	Head	100	500	1200	m	[30, 31]
	efficiency (pump)	0.8	0.9	0.95		[30, 31]
	efficiency (Turbine)	0.8	0.9	0.95		[30, 31]
	Hours of operation	6	8	10	h	[30, 31]
	Flow rate (m^3/s)	20	60	120	m^3/s	[30, 31]
	Velocity of flow	4	5	10	m/s	[30, 31]
C-CAES						
	Flow rate	285	300	315	m^3/s	
	Air Inlet temperature	273.15	288.15	298.15	K	
	Turbine 1 temperature	810.15	823.15	823.15	K	[37, 44]
	Turbine 2 temperature	1073.15	1073.15	1144.15	K	[37, 44]
	Electricity Cost	21.29	28.18	36.55	$/MWh	[60]
	NG cost	0.125	0.23	0.26	$/kg	
A-CAES						

Flow rate	285	300	315	m^3/s	
Air Inlet temperature	273.15	288.15	298.15	K	
Electricity Cost	21.29	28.18	36.55	$/MWh	[60]

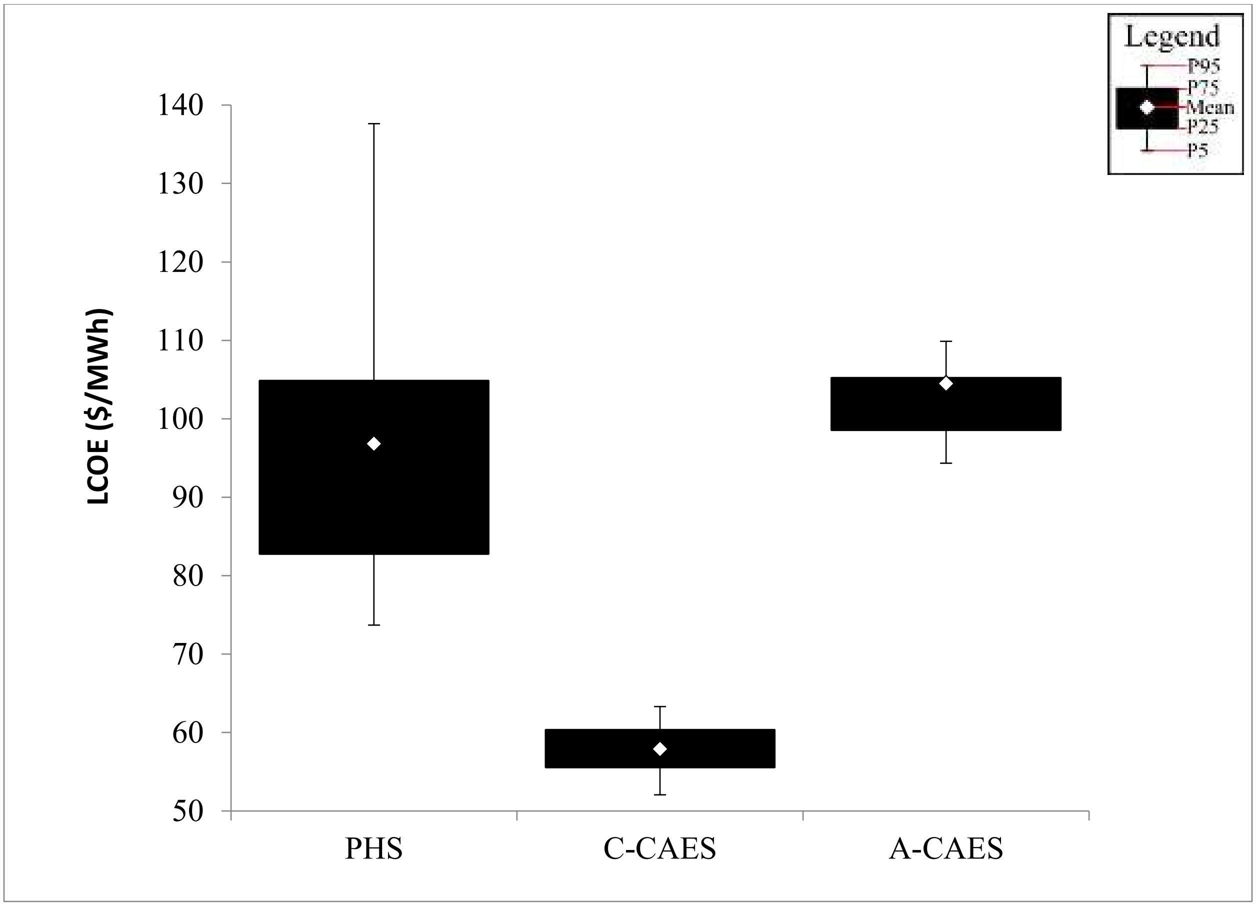

Figure 21: Results of uncertainty analysis

In this study, the LCOEs for PHS and CAES are $69-121 per MWh and $58-70 per MWh, respectively. These results were compared with the values reported by Zakeri et al. [25] and the DOE/EPRI report [22]. The LCOEs for PHS and CAES reported by Zakeri et al. [25] are in the range of $125-150 per MWh and $130-160 per MWh, respectively, while the values reported by DOE/EPRI [22] are $150-220 per MWh for PHS and $120-210 per MWh for CAES. The values presented by Zakeri et al. are higher due to the high cost of the storage medium and the location factor. The price of electricity input to the system is strongly influenced by jurisdiction and thus is higher in this case. In this study, by considering a salt cavern as a storage medium, capital cost is significantly lowered, i.e., by $2-5/kWh. On the other hand, it is difficult to compare the values reported by DOE/EPRI [22] because the details of the plant components and system boundaries were not stated.

2.6 Conclusion

The objective of the study was to develop data-intensive comprehensive cost models, calculate lifecycle costs for PHS and CAES, and evaluate the economic feasibility of ESS. To that end, equipment parameters and costs for PHS and CAES were estimated using a detailed bottom-up cost calculation methodology. A techno-economic model was developed to investigate the power output of the storage plant. Five scenarios for each EES technology considered were modeled encompassing different plant storage capacities ranging from 98 to 491 MW, 81 MW to 404 MW, and 60 to 298 MW for PHS, C-CAES, and A-CAES, respectively. The TIC of these scenarios was calculated using the equipment cost relation and compared. The TIC decreases with increases in plant capacity due to economies of scale. The developed scale factors for PHS, C-CAES, and A-CAES are 0.5, 0.9, and 0.91, respectively. The scale factors show that the additional unit investment cost falls sharply with increases in capacity for PHS and thus it is beneficial to build plants in higher capacities. The unit output capital cost is lowest for C-CAES, followed by PHS and then A-CAES.

For CAES, three storage types were considered. The cost is lowest for a porous formation, slightly higher for a salt cavern, and highest for a hard rock formation. The LCOEs for the PHS, C-CAES, and A-CAES base cases are $84, $59, and $101 per MWh, respectively. The LCOE decreases with an increase in plant capacity because of economies of scale. For Alberta’s electricity market, C-CAES integrated with any storage type and capacity is a sound financial investment. PHS yields profits for plant capacities greater than 294 MW. A-CAES is not feasible for energy arbitrage due to a higher LCOE.

A sensitivity analysis showed that the pump turbine efficiency, inlet temperature to second turbine, and air flow rate are the most sensitive parameters for PHS, C-CAES, and A-CAES, respectively.

To provide more robustness to the developed model and mitigate risk, an uncertainty analysis was performed and yielded mean LCOEs of $96.82 per MWh, $57.87 per MWh, and $104.48 per MWh for PHS, C-CAES, and A-CAES, respectively.

The results of this techno-economic study provide insight on the cost competitiveness of PHS and CAES.

2.7 References

1. Kousksou, T., et al., *Energy storage: Applications and challenges.* Solar Energy Materials and Solar Cells, 2014. **120, Part A**: p. 59-80.
2. *World Energy Outlook Special Report 2016: Energy and Air Pollution*. 2016. p. 266.
3. Poullikkas, A., *Implementation of distributed generation technologies in isolated power systems.* Renewable and Sustainable Energy Reviews, 2007. **11**(1): p. 30-56.
4. Fisher, A.C., *Energy and environment in the long term.* Energy Policy, 1989. **17**(2): p. 84-87.
5. Rogelj, J., et al., *Paris Agreement climate proposals need a boost to keep warming well below 2 C.* Nature, 2016. **534**(7609): p. 631-639.
6. Aneke, M. and M. Wang, *Energy storage technologies and real life applications – A state of the art review.* Applied Energy, 2016. **179**: p. 350-377.

7. Luo, X., et al., *Overview of current development in electrical energy storage technologies and the application potential in power system operation.* Applied Energy, 2015. **137**: p. 511-536.

8. Martinot, E., *Renewables 2015: Global status report.* REN21 Renewable Energy Policy Network/Worldwatch Institute, 2015: p. 251.

9. Hadjipaschalis, I., A. Poullikkas, and V. Efthimiou, *Overview of current and future energy storage technologies for electric power applications.* Renewable and Sustainable Energy Reviews, 2009. **13**(6–7): p. 1513-1522.

10. Decourt, B.D., Romain; , *Electricity Storage*, in *Leading the energy transition*. 2013.

11. Chen, H., et al., *Progress in electrical energy storage system: A critical review.* Progress in Natural Science, 2009. **19**(3): p. 291-312.

12. Beaudin, M., et al., *Energy storage for mitigating the variability of renewable electricity sources: An updated review.* Energy for Sustainable Development, 2010. **14**(4): p. 302-314.

13. Ferreira, H.L., et al., *Characterisation of electrical energy storage technologies.* Energy, 2013. **53**: p. 288-298.

14. Cavallo, A.J., *Energy storage technologies for utility scale intermittent renewable energy systems.* Journal of solar energy engineering, 2001. **123**(4): p. 387-389.

15. Ibrahim, H., A. Ilinca, and J. Perron, *Energy storage systems—Characteristics and comparisons.* Renewable and Sustainable Energy Reviews, 2008. **12**(5): p. 1221-1250.

16. Connolly, D., *A review of energy storage technologies: For the integration of fluctuating renewable energy*. 2010.

17. Palizban, O. and K. Kauhaniemi, *Energy storage systems in modern grids—Matrix of technologies and applications.* Journal of Energy Storage, 2016. **6**: p. 248-259.

18. Mahlia, T.M.I., et al., *A review of available methods and development on energy storage; technology update.* Renewable and Sustainable Energy Reviews, 2014. **33**: p. 532-545.

19. Schoenung, S.M. and W.V. Hassenzahl, *Long-vs. short-term energy storage technologies analysis. a life-cycle cost study. a study for the doe energy storage systems program.* Sandia National Laboratories, 2003.
20. Schoenung, S.M. and J. Eyer, *Benefit/cost framework for evaluating modular energy storage.* SAND2008-0978, 2008.
21. Schoenung, S., *Energy Storage Systems Cost Update* 2011.
22. Akhil, A.A., et al., *DOE/EPRI 2013 electricity storage handbook in collaboration with NRECA*. 2013: Sandia National Laboratories Albuquerque, NM.
23. Viswanathan, V., et al., *National Assessment of Energy Storage for Grid Balancing and Arbitrage, Phase II, Volume 2: Cost and Performance Characterization.* Report PNNL-21388, Pacific Northwest National Laboratory, Richland, WA, 2013.
24. Bozzolani, E., *Techno-economic analysis of compressed air energy storage systems.* 2010.
25. Zakeri, B. and S. Syri, *Electrical energy storage systems: A comparative life cycle cost analysis.* Renewable and Sustainable Energy Reviews, 2015. **42**: p. 569-596.
26. Locatelli, G., E. Palerma, and M. Mancini, *Assessing the economics of large Energy Storage Plants with an optimisation methodology.* Energy, 2015. **83**: p. 15-28.
27. Shinobe, O.A., *Economics of Underground Conversion in an Operating Limestone Mine*. 1997, McGill University Montreal, Canada.
28. *Technology Roadmap Energy storage*. 2014: France.
29. Rastler, D., *Electricity energy storage technology options: a white paper primer on applications, costs and benefits*. 2010: Electric Power Research Institute.
30. American Society of Civil, E., *Compendium of pumped storage plants in the United States*. 1993, New York, NY: The Society. 744 p.

31. Carson, J., et al., *Operation and maintenance experiences of pumped-storage plants*. 1991, Morrison-Knudsen Engineers, Inc., San Francisco, CA (USA); Electric Power Research Inst., Palo Alto, CA (USA).
32. Stelzer, R.S. and R.N. Walters, *Estimating reversible pump-turbine characteristics*. 1977, Bureau of Reclamation, Denver, CO (USA). Engineering and Research Center.
33. Korakianitis, T. and D.G. Wilson, *Models for Predicting the Performance of Brayton-Cycle Engines.* Journal of Engineering for Gas Turbines and Power, 1994. **116**(2): p. 381-388.
34. Cohen, H., et al., *Gas turbine theory.* 1987.
35. Borgnakke, C. and R.E. Sonntag, *Fundamentals of thermodynamics*. 2009: Wiley.
36. Cengel, Y.A. and M.A. Boles, *Thermodynamics: an engineering approach.* Sea, 1994. **1000**: p. 8862.
37. Pollak, R., *History of First US Compressed-Air Energy Storage (CAES) Plant (110 MW 26h) Volume 2: Construction.* Electric Power Research Institute (EPRI), 1994.
38. Kays, W.M., R.K. Jain, and S. Sabherwal, *The effectiveness of a counter-flow heat exchanger with cross-flow headers.* International Journal of Heat and Mass Transfer, 1968. **11**(4): p. 772-774.
39. Kyle, B.G., *Chemical and process thermodynamics.* 1984.
40. Moore, W.J., *Basic physical chemistry*. 1983: Prentice Hall.
41. Walsh, P.P. and P. Fletcher, *Gas turbine performance*. 2004: John Wiley & Sons.
42. *Overall Heat Transfer Coefficient Table Charts and Equation* 2017 [cited 2017 July 1]; Available from: http://www.engineersedge.com/thermodynamics/overall_heat_transfer-table.htm.
43. McDonald, A.G. and H. Magande, *Introduction to thermo-fluids systems design*. 2012: John Wiley & Sons.

44. Crotogino, F., et al., *More than 20 years of successful operation. Spring 2001 Meeting of the Solution Mining Research Institute*. April.

45. Kaya, D., et al., *Energy efficiency in pumps.* Energy Conversion and Management, 2008. **49**(6): p. 1662-1673.

46. *Typical overall heat transfer coefficients (U-Values)*. 2017 [cited 2017 July 2]; Available from: http://www.engineeringpage.com/technology/thermal/transfer.html.

47. Jubeh, N.M. and Y.S. Najjar, *Green solution for power generation by adoption of adiabatic CAES system.* Applied Thermal Engineering, 2012. **44**: p. 85-89.

48. Gabbrielli, R. and R. Singh, *Economic and scenario analyses of new gas turbine combined cycles with no emissions of carbon dioxide.* Journal of engineering for gas turbines and power, 2005. **127**(3): p. 531-538.

49. Turton, R., et al., *Analysis, synthesis and design of chemical processes*. 2008: Pearson Education.

50. Norge, A., *Cost base for hydropower plants* J. Slapgård, Editor. 2012: Norway.

51. Dawes, J.H. and M. Wathne, *Cost of reservoirs in Illinois*. 1968: Illinois State Water Survey.

52. *Land value trends*. 2013: Alberta. p. 6.

53. Goodson, O.J., *History of First U.S. Compressed Air Energy Storage (CAES) Plant (110-MW-26 h): Volume 1: Early CAES Development*. 1993. p. 150.

54. Miller, P.C. *Bakken has lowest average drilling and completion cost*. 2016 April 06, 2016 [cited 2017 July 2]; Available from: http://thebakken.com/articles/1515/bakken-has-lowest-average-drilling-and-completion-cost.

55. *OCCinfo: Occupations and Educational Programs* 2015 [cited 2017 July 2]; Available from: http://occinfo.alis.alberta.ca/occinfopreview/info/browse-wages.html.

56. Peters, M.S., et al., *Plant design and economics for chemical engineers*. Vol. 4. 1968: McGraw-Hill New York.

57. Zamalloa, C., et al., *The techno-economic potential of renewable energy through the anaerobic digestion of microalgae.* Bioresource Technology, 2011. **102**(2): p. 1149-1158.

58. Veatch, B., *Cost and Performance Data for Power Generation Technologies.* Cost Report, ed. BVH Company, 2012.

59. Taylor, M., *Renewable Energy Technologies: Cost Analysis Series*, in *Hydropower*. 2012. p. 144.

60. *2014 Annual Market Statistics*. 2015.

61. *Inflation*. [cited 2017 july 2]; Available from: http://www.bankofcanada.ca/core-functions/monetary-policy/inflation/.

62. Towler, G. and R. Sinnott, *Chapter 7 - Capital Cost Estimating*, in *Chemical Engineering Design (Second Edition)*. 2013, Butterworth-Heinemann: Boston. p. 307-354.

Chapter 3

3 Development of Net Energy Ratio over Life Cycle of Large-Scale Energy Storage SystemsIntroduction

The consumption of fossil fuels leads to increased greenhouse gas (GHG) emissions in the earth's atmosphere and results in climate change [1]. The drive to protect the environment and achieve energy sustainability goals has led governments, industries, and scientists to make efforts to tackle climate change as evidenced in the Paris Convention [2].

GHG emissions from industrial activities are one of the main contributors of global warming. In 2010, electricity and heat production accounted for 25% of global GHG emissions [3, 4]. Most of the emissions come from the use of fossil fuels, as coal and natural gas still dominate the power sector [5]. Thus, there is rapidly growing interest in renewable energy production technologies as they have high potential to reduce GHG emissions. To achieve the International Energy Agency's (IEA) two-degree scenario target, renewable energy production will need to meet 74% of global electricity demand by 2060 [6].

ESSs will play a vital part globally in achieving the IEA's two-degree target. An energy storage systems (ESS) stores excess electricity from the grid when there is less demand and releases electricity to the grid when demand exceeds supply [11, 12]. ESSs are an intermediate system that integrates renewable sources into existing electricity grids and thus helps lower overall GHG emissions. That said, the life cycle stages (construction, operation, and decommissioning) of an ESS require material and energy inputs, and there are associated GHG emissions. Therefore, to evaluate the environmental impacts and benefits associated with different ESSs, it is imperative to perform a life cycle assessment (LCA) of these systems. Besides the life cycle GHG emissions, the energy consumption of ESSs is relevant. Electricity cannot be stored in all the ESS as electricity and thus needs to be converted to another form of energy. Therefore, it is important to evaluate the net energy ratio (NER) of ESSs to determine how much electrical energy output can be achieved per unit of electricity input to ESSs. This study considers both the energy losses associated with the conversion of electricity from one energy form to another and the energy consumed during the construction and operational phases of the ESSs.

Many published papers can be found on ESSs. Denholm and Kulcinski [13] did a pioneering study on LCAs of ESSs. They developed life cycle energy requirements, GHG emissions, and NERs of utility-scale applications ESSs such as pumped hydroelectric storage (PHS), compressed air energy storage (CAES), and battery energy storage systems. Hiremath et al. [14] and Rydh et al. [15] conducted comparative assessments of battery energy storage systems for stationary applications. Their results show that using batteries as a storage medium has significant greater impacts on overall GHG emissions. Jing et al. [16] focused on thermal energy storage systems for combined cooling, heating, and power system applications. The system operated following the thermal load operational strategy wherein excess electricity produced is stored for future use and this strategy has a lower pollutant impact and more energy-saving potential. Eduard et al. [17] did a comparative assessment of thermal energy storage systems for solar power plants. A system using solid media (i.e., concrete) has fewer environmental impacts than a system using liquid media (i.e., molten salt). A few other studies considered a bundle of storage technologies together [18-20]. The results indicate that compared to other storage systems batteries have higher impacts during their construction and end-of-life phases and lower impacts during operation. Akhil et al. [21] comprehensively reviewed and compared life cycle GHG emissions from different hydro facilities including pumped hydroelectric plants. Bouman et al. [22] conducted a LCA of a CAES plant integrated with offshore wind plants through a cradle-to-grave approach. The results show that integrating conventional compressed air energy storage (C-CAES) with a wind plant significantly increases the environmental impacts whereas adiabatic compressed air energy storage (A-CAES) only moderately increases these impacts. Oliveira et al. [18] carried out a comparative LCA on a range of storage technologies.

Most of the above studies are recent and consolidate the increasing interest in renewables and storage technologies. However, a holistic evaluation of the life cycle GHG emissions and NER is required to understand the overall environmental performance of the storage systems. For example, most of the studies did not consider storage system size, one of the key parameters of an ESS, but used generic data and software to perform the analysis and provide point estimates of emissions. These results may not reflect the actual situation as they are based on various assumptions and do not include the product specifications. Some studies do not provide detailed information on the method used and how the results are obtained, and others do not consider the same life cycle stages; for example, they usually omit the decommissioning emissions. This study aims to fill these gaps.

The overall aim of this study is to use a comprehensive bottom-up approach to compile a life cycle inventory and estimate the GHG emissions and the NER for selected ESSs considering their specific system sizes for providing information to policymakers and governments to help them make informed energy decisions. The specific objectives are:

1 Develop the net-energy-ratio for three large mechanical storage systems including A-CAES, C-CAES, and PHS, the leading candidates for large-scale storage applications such as load shifting and spinning reserves for integration of large capacities of renewable technologies with the utility grid;

2 Estimate the life cycle GHG emissions of these energy storage systems;

3 Perform an uncertainty analysis is to provide ranges of estimates for life cycle GHG emissions and NER.

4 A case study for various provinces in Canada with respect to integration of the storage systems and associated GHG emissions

3.2 Method

3.2.1 Goal and Scope Definition

The aim of the study is to evaluate the life cycle GHG emissions and NER of large-scale storage systems and to conduct a comparative LCA of three energy storage systems, A-CAES, C-CAES, and PHS. Each storage technology is described in detail below.

3.2.1.1 Pumped Hydroelectric Storage (PHS)

The schematic diagram of PHS is shown in Figure 22. It comprises a pump turbine, motor, generator, penstock, inlet valve, penstock valve, upper reservoir, and lower reservoir. When the electricity demand is less than the supply, the excess electricity from the grid is used to pump the water from the lower reservoir to the upper reservoir. When the electricity demand is more than the supply, the PHS uses the gravitational potential energy of water in the upper reservoir to operate the turbine, generating electricity and adding it back to the grid.

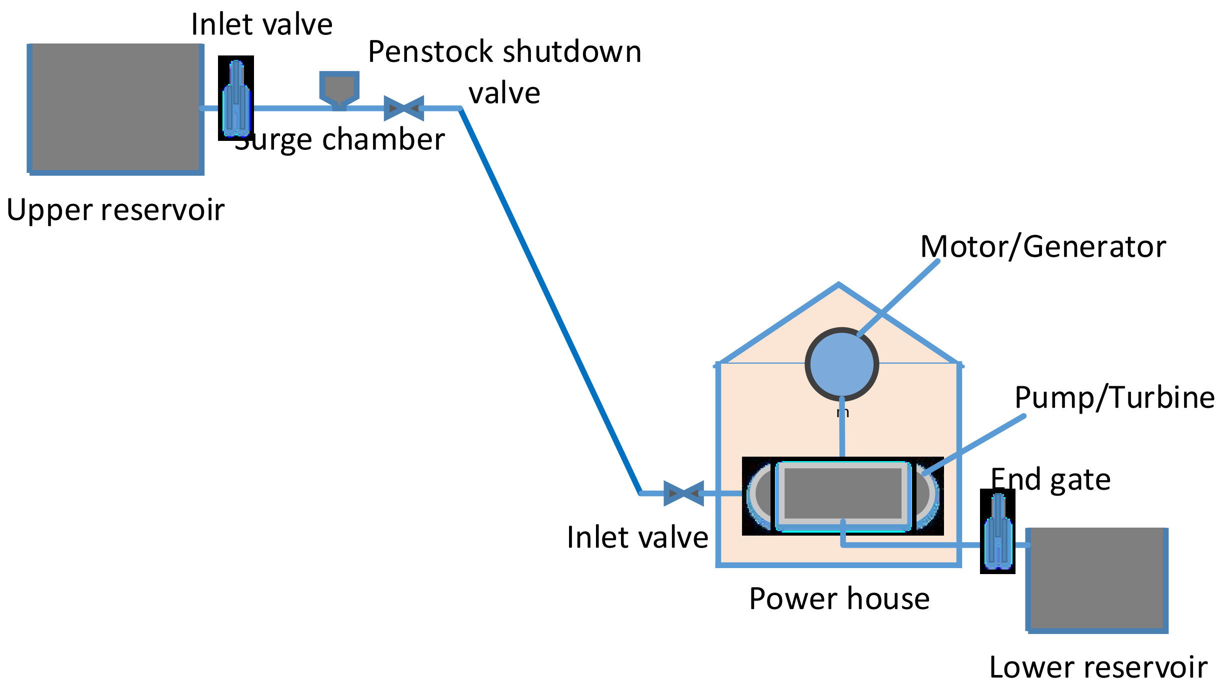

Figure 22: Pumped hydro storage system diagram

3.2.1.2 Conventional Compressed Air Energy Storage (C-CAES)

C-CAES is a hybrid storage system that works similar to conventional gas turbine technology. It requires the combustion of natural gas in its operational phase to produce electricity. The main components of a C-CAES plant are shown in Figure 23. When electricity demand is less than supply, the excess electricity from the grid is used to compress air for storage in an underground cavern and later used to combust natural gas and supply electricity when there is a shortage. The compressed air is preheated with exhaust gases in the recuperator before entering the combustor.

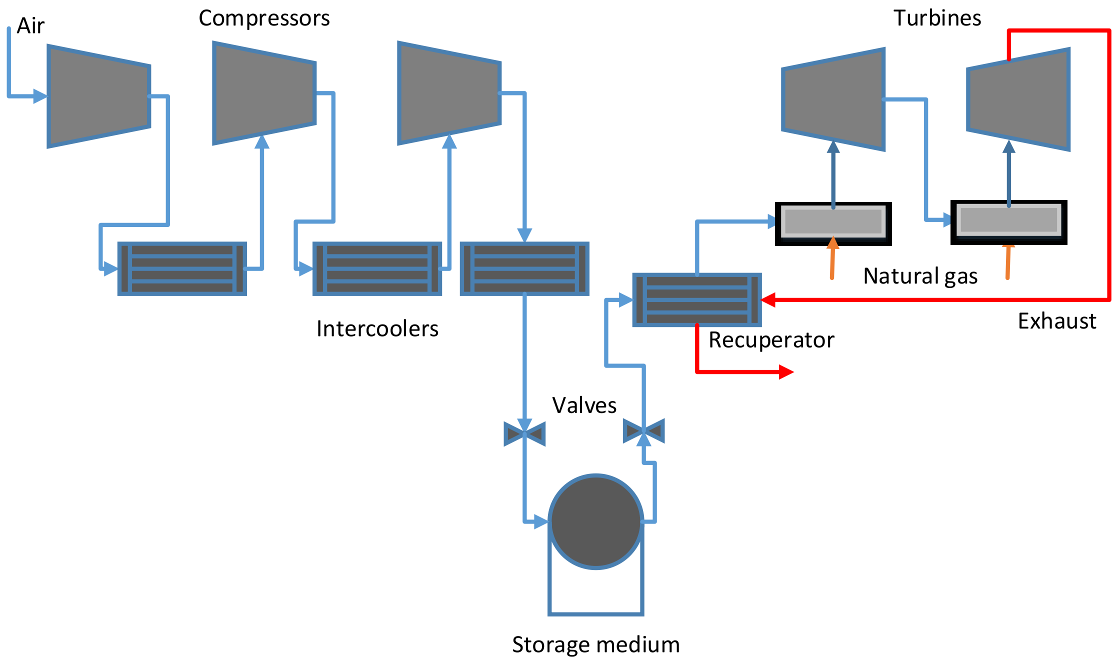

Figure 23: Conventional compressed air energy storage system diagram

3.2.1.3 Adiabatic Compressed Air Energy Storage (A-CEAS)

The main components of an A-CEAS system are the compressor, heat exchanger, underground storage medium, heat transfer fluid (stream), and turbine, as presented in Figure 24. An A-CAES system does not combust natural gas for its operation; instead it uses a thermal energy storage system to store the heat generated when the air is compressed. The thermal energy storage consists of two series of heat exchangers and Dowtherm T as a heat transfer fluid. When there is less demand, the excess electricity is used to compress air that can be heated later with the stored heat in the compressor. The compressed air expands through turbines to generate electricity to meet excess demand.

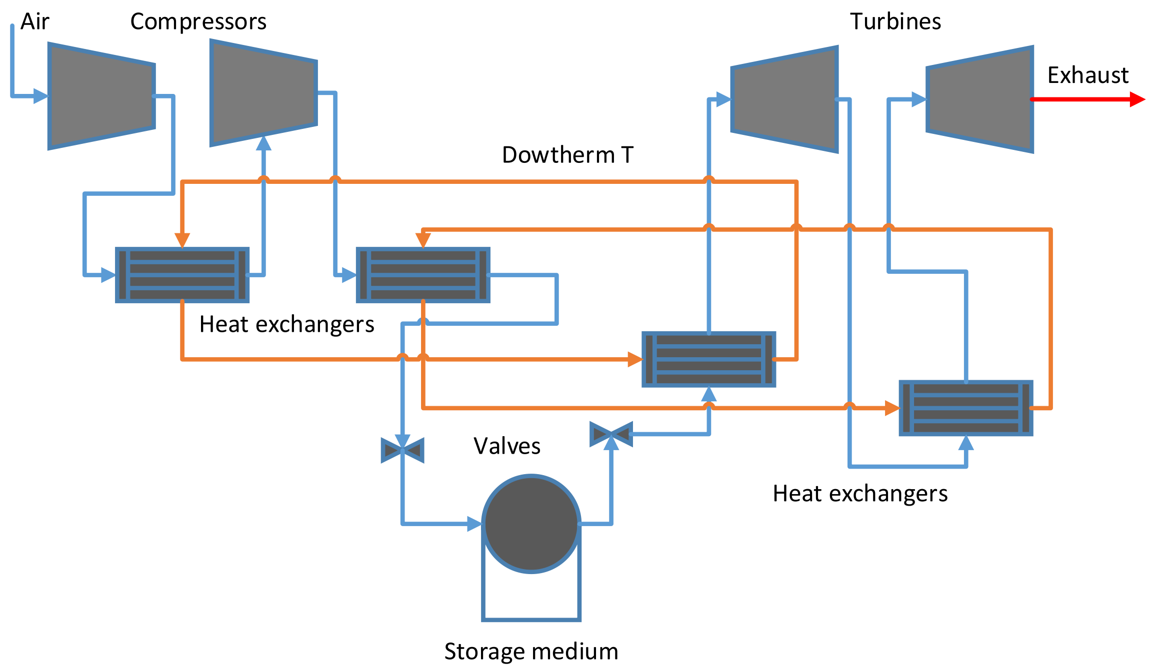

Figure 24: Adiabatic compressed air energy storage system diagram

The system boundary for all three ESSs considered in this study is presented in Figure 25. Three life cycle phases of storage systems were considered: construction, operation, and decommissioning. The construction phase includes the required equipment and energy to build the storage plant, the site preparation, and the transportation of the equipment to the site. The operational phase comprises the input and output of energy from the storage systems, and the decommissioning phase involves dismantling the equipment and restoring the site to its original condition [23]. The removed equipment disposal/recycling is out of the scope of this study. The functional unit is one kWh of electricity output from the storage system.

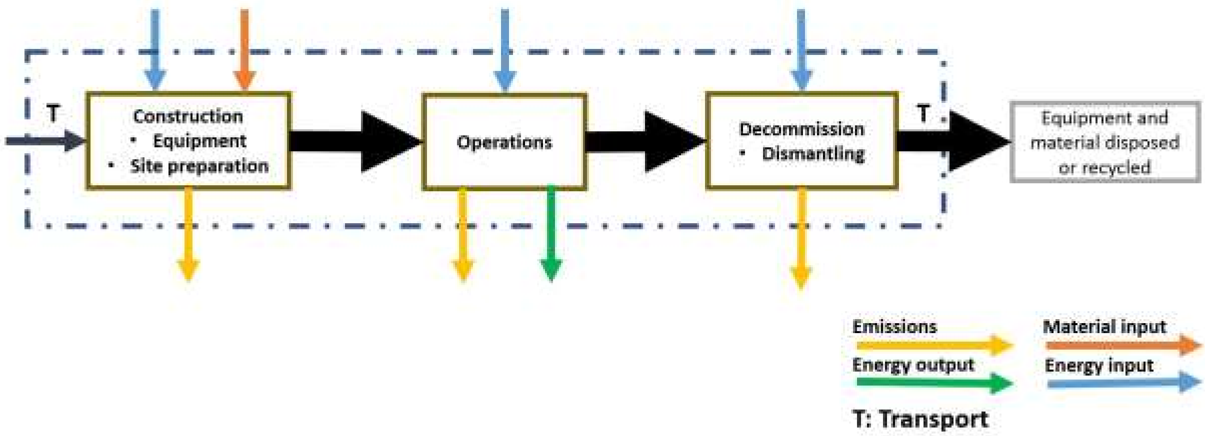

Figure 25: ESS system boundary

3.2.2 Life Cycle Inventory Assessment

The considered technologies were simulated through development of process models to obtain the base case plant size. The ESS defining characteristics were input in the simulation model to obtain the individual equipment sizes. The material and energy required to build equipment of specific sizes were obtained by linearly scaling the data from the literature. The transportation of the equipment to the plant site was also considered in the analysis. Then, the total amounts of material and energy required to build a storage facility of a specific size were calculated and material and energy inventories were built.

3.2.3 Development of Simulation Model

Base case scenarios were established by modeling PHS and CAES plants [24]. The power capacities considered for the base case are 118 MW, 81 MW, and 60 MW for PHS, C-CAES, and A-CAES, respectively. These system sizes are determined by input parameters used in simulations. The simulations are described in detail below.

3.2.3.1 Pumped Hydroelectric Storage

The key parameters for the PHS simulation model are presented in Table 12. The database of existing PHS plants in the US was created by compiling data [25, 26]. One of the facilities considered for building database is Bath County PHS facility which is the world's largest storage facility with the capacity of 3003 MW and has 6 units in total. The head and volume flow rates, the most important characteristics in defining the power capacity of a PHS facility, are 300 m and 40 m^3/s, respectively [25, 26]. Both values are the averages from references [18, 19].

Table 12: Input parameters for pumped hydro storage simulation

Stream/Component	**Parameter**	**Value**	**Units**	**Reference**
Water	Head	300	m	[13, 25]
	Flow rate	40	m^3/s	[25, 26]
	Velocity of flow	5	m/s	[25, 26]
Pump turbine	Efficiency (pumping mode)	0.91		[27, 28]
	Efficiency (generation mode)	0.9205		[27, 29]
Other losses	Pipe, frictional, evaporation	0.02		[30]
Motor/generator	Motor efficiency	0.984		[28, 29]
	Generator efficiency	0.984		[28, 29]
Transformer	Efficiency	0.993		[28, 29]
Hours of operation	Pumping mode	12	hours	

3.2.3.2 Compressed Air Energy Storage

The ambient air temperature and pressure are assumed to be 288.15 K and 1 bar, respectively. The key parameters for C-CAES simulation are presented in Table 13. The modeled plant consists of three compressors and two turbines. The compressor ratio is 4:1 and the storage cavern is assumed to operate between 45 and 70 bar [31]. The discharge pressure of the first turbine was optimized based on the maximum power output from the plant and was found to be 10 bars.

Table 13: Input parameters for conventional compressed air energy storage simulation

Stream/Component	Parameter	Value	Units	Reference
Air	Inlet temperature	288.15	K	
	Pressure	1	bar	
	Flow rate	100	kg/s	
	Specific heat ratio	1.4		[32]
	Specific gas constant	287	J/kg K	[33]
Natural gas	Inlet temperature	288.15	K	
	Pressure	1	bar	
	Lower heating value	48120	KJ/kg	[34]
Compressor	Compression ratio	4.3		[31]
Intercooler	Effectiveness	0.8		[35]
	U value (air to water)	200	$W/(m^2K)$	[30, 36]
Storage cavern	Inlet pressure	70	bar	[37]
	Outlet pressure	45	bar	[37]
	Temperature	303.15	K	
Recuperator	Effectiveness	0.8		[35]
	U value (air to air)	150	$W/(m^2K)$	[30, 36]
Turbine 1	Intel temperature	823.15	K	[38]
	Discharge pressure	10	bar	[38]
Turbine 2	Operating temperature	1098.15	K	[38]
	Turbine discharge pressure	1	bar	[38]
Hours of operation	Compression mode	12	hours	

The A-CAES simulation model was developed using the parameters presented in Table 14. The modeled plant consists of two compressors and two turbines. The compressor ratio was taken to be 13:1 and the storage cavern was assumed to operate between 140 and 160 bar [39]. Higher cavern pressures are required for an A-CAES plant than a C-CAES plant as there is no additional fuel input to heat the compressed air. The discharge pressure of the first turbine was optimized based on maximum power output from the plant and found to be 15 bars.

Table 14: Input parameters for the adiabatic compressed air energy storage model

Stream/Component	**Parameter**	**Value**	**Unit**	**Reference**
Air	Inlet temperature	288.15	K	
	Pressure	1	bar	
	Flow rate	100	kg/s	
	Specific heat ratio	1.4		[32]
Dowtherm T	flow rate (kg/s)	40	kg/s	
	Initial temperature	288.15	K	
Compressor	Compression ratio	13.1		[39]
Heat exchanger	Effectiveness	0.9		[35]
	U value	200	$W/(m^2K)$	[36, 40]
Storage cavern	Inlet pressure	160	bar	[39]
	Outlet pressure	140	bar	[39]
	Temperature	298.15	K	
Turbine 1	Discharge pressure	15	bar	[39]
Turbine 2	Discharge pressure	1	bar	[39]
Hours of operation	Compression mode	12	hours	

3.2.4 Life cycle Inventory Results

This section describes all the processes and unit operations used in the PHS and CAES base case scenarios to create material and energy inventories.

3.2.4.1 Pumped Hydroelectric Storage

The PHS inventory includes two reservoirs (lower and upper), a dam on each reservoir, a penstock, anchors, a pump turbine, a motor and generator, and explosives.

Reservoirs: The volume of each reservoir is 518,400 m^3 and is calculated based on the amount of water required for one complete operation cycle of a PHS plant. The height of each reservoir is estimated to be 30 m. It is assumed that the volume of earth material removed to create the reservoir is 10% of the volume of the reservoir. The density of the material removed is considered to be 1440 kg/m^3 [41]. 0.73 g of dynamite is required per kg of rock mined [22]. It is also assumed that material removed is transported 50 km from the site by a truck. The truck energy consumption is assumed to be 3 MJ per ton-km [42].

Dams: Dams are built on both the upper and lower reservoirs. The height and width of the upper dam are assumed to be 35 m and 50 m, respectively [25]. The height and width of the lower dam are 25 m and 40 m, respectively [25]. The dam type is concrete gravity [43]. The amount of concrete required for each dam is calculated based on its dimensions.

Facility: The amount of concrete required for the facility is calculated based on the amount required for the dams. 0.71 kg of concrete is used in dam construction per unit kg concrete used for the overall hydro plant [44].

Pump turbine: The calculated capacity of the pump turbine is 118 MW. It is assumed to be composed of 50% carbon steel, 45% stainless steel, and 5% copper [45]. The 465 MW unit pump turbine used in Bath County facility in the US weighs 87 tons [46]. The pump turbine weight in this study was calculated assuming a linear relation between the weight and capacity of the pump turbine.

Motor/Generator: The material and energy requirement for the motor and generator were obtained from the ecoinvent database [47]. A linear relation between weight and capacity of the motor and generator was assumed to fulfill the size requirement.

Penstock: An on-surface penstock supported by concrete anchors was chosen for the PHS facility [48]. The length and diameter of the penstock, determined through the technical simulation, are 424 m and 3 m^3, respectively. The penstock thickness is calculated using Equation 22 [48]:

$$t = \frac{p * d}{2 * s} \tag{22}$$

Where *t* is the thickness of the penstock, *p* is the maximum pressure, d is the diameter of the penstock, and *s* is the maximum allowable stress. The maximum allowable stress is 20 KSI [48] and the penstock material is assumed to be steel [48].

Anchors: The penstock is supported by concrete anchors spaced 90 m apart. Each has a volume of 80 m^3 [43]. The density of the concrete is considered to be 2,400 kg/m^3 [49].

Vegetation removal impact: PHS plant construction occupies a vast area and requires the removal of existing vegetation or forest. On average, a new forest absorbs 2.5 tons of carbon per acre annually [50]. Thus, PHS construction indirectly results in a release of GHG emissions that would otherwise have been absorbed by the existing forest over the years. The PHS covers an area of 25.62 acre calculated based on dimensions of the reservoirs.

Transportation: All the construction material and equipment are transported to the plant site by truck and train. The transportation data for PHS was extracted from the literature [44]. Energy consumption in the form of electricity for the train and diesel for the truck is 0.5 and 3 MJ per ton, respectively [42]. Average distances of 300 km by train and 50 km by the truck are assumed. The summary of material and energy requirement for a PHS facility is presented in Table 15.

Table 15: Developed PHS life cycle inventory list

Equipment	**Material**	**Amount**	**Units**
Dams	Concrete	77625000	kg
	Carbon steel	457688	kg
	Stainless steel	411919	kg
Pump-turbine	Cooper	45769	kg
Explosives	Dynamite	753	kg
Penstock	Steel	1016425	kg
Anchors	Concrete	906240	kg
	Cast iron	350217	kg
Motor/Generator	Copper	150093	kg
	Diesel	2940504	L
Reservoirs	Energy	111974400	MJ
Vegetation removal Impact		3842979495	gCO_2e
	Electricity	4491951	MJ
Transportation	Diesel	2409329	L
	Electricity	33829011	MJ
Facility construction	Concrete	31705986	kg

3.2.4.2 Compressed Air Energy Storage

The C-CAES and A-CAES inventories are presented in Tables 5 and 6, respectively.

Compressor: The C-CAES has three compressors, each with a compression ratio of 4:1. The compressors have power ratings of 17.25, 17.57, and 17.89 MW. The A-CAES plant has two compressors with a compressor ratio of 13:1 and power ratings of 39.69 MW and 45.36 MW. The material and energy requirements were calculated using the data from an axial compressor in the ecoinvent database, assuming a linear relationship [47].

Turbine: The power capacity of the two turbines is 28 MW and 53 MW for C-CAES and 27 MW and 33 MW for A-CAES. The turbines are linearly scaled from available data for a gas turbine in the ecoinvent database [47].

Cavern: This analysis assumes an underground salt cavern for both C-CAES and A-CAES. The cavern is formed by drilling holes into the ground to the required depth using a drill rig. Then water, extracted by pumps to reach the required volume, is supplied to the cavern to form a brine solution [51]. Carbon steel and stainless steel pipes 16 to 48 inches in diameter are installed in the drilled holes [37]. The space between the pipes is filled with concrete to consolidate the foundation [37].

Heat exchangers: The amount of material and energy required for heat exchangers is calculated from published data [37]. The operating temperature of the heat exchangers is below 200^0C in C-CAES and above 200^0C in A-CAES. The materials required for C-AES heat exchangers are carbon steel for the pipes and outer structure and aluminum for fins [52]. Because of the high operating temperature, the recuperator is made of stainless steel. A-CAES heat exchangers are made entirely of stainless steel [52].

Motor/Generator: The motor/generator capacity for C-CAES and A-CAES plants are 81 MW and 60 MW, respectively. The material and energy data are extracted from the ecoinvent database [47].

Natural gas infrastructure: The natural gas infrastructure includes pipeline for the transportation of natural gas to the plant site and storage tanks to store the natural gas at the site and supply to the turbines. The storage tanks are made of stainless steel and store natural gas for daily operations. The pipeline is assumed to be 1000 km long., Site where there is abundance of wind, could be an ideal site to integrate an ESS with a wind facility [54]. The dimensions of the pipeline are based on a target velocity of 1.4 m/s [55].

Dowtherm T storage tanks: Two stainless steel storage tanks are assumed to store Dowtherm T fluid. The dimensions of the tanks are based on the amount of Dowtherm T fluid required.

Transportation: All the construction materials and equipment are transported to the plant site in the same manner as for the PHS plant.

The summary of material and energy requirements for C-CAES and A-CAES is presented in Table 16 and Table 17, respectively.

Table 16: Developed C-CAES life cycle inventory list

Equipment	**Material**	**Amount**	**Units**
Turbines	Concrete	969185	kg
	Copper	40383	kg
	Steel	383636	kg
	Stainless steel	20191	Kg
	Electricity	378790	MJ
	Diesel	313910	L
Compressors	Aluminum	77306	kg
	Cast Iron	298680	kg
	Copper	105417	kg
	Steel	737916	kg

	Stainless steel	87847	kg
	Rubber	1581	kg
Motor/Generator	Cast Iron	240277	kg
	Copper	102976	kg
	Electricity	74708	MJ
	Diesel	91476	L
Cavern	Carbon steel	266464	kg
	Stainless steel	45030	kg
	Concrete	578964	kg
	Electricity	2846251	MJ
Natural gas infrastructure	Stainless steel	79463	kg
	Diesel	3508772	L
Heat exchangers	Carbon steel	223827	kg
	Aluminum	8481	kg
Transportation	Electricity	196011	MJ
	Diesel	18530	L

Table 17: Developed A-CAES life cycle inventory list

Equipment	**Material**	**Amount**	**Units**
Turbines	Concrete	719494	kg
	Copper	29979	kg
	Steel	284800	kg
	Stainless steel	14989	kg

Equipment	Material	Amount	Units
	Electricity	281202	MJ
	Diesel	233037	L
Compressors	Aluminum	124747	kg
	Cast Iron	481979	kg
	Copper	170110	kg
	Steel	1190770	kg
	Stainless steel	141758	kg
	Rubber	2552	kg
Motor/Generator	Cast iron	253039	kg
	Copper	108445	kg
	Electricity	78676	MJ
	Diesel	96335	L
Cavern	Carbon steel	266464	kg
	Stainless steel	45030	kg
	Concrete	578964	kg
	Electricity	4592975	MJ
Dowtherm T storage tank	Stainless steel	375118	kg
Heat exchangers	Carbon steel	213664	kg
	Aluminum	11308	kg
Transportation	Electricity	230255	MJ
	Diesel	21768	L

3.2.5 System Boundary for Life Cycle Impact Assessment

Figure 26 shows the general framework to calculate life cycle emissions per functional unit. The life cycle emission factor is determined as the ratio of total life cycle emissions to life cycle energy produced by the storage systems over the course of the systems' life cycle [13]. The life cycle GHG emissions estimated are direct and total emissions. While the direct emissions include only for the construction, operation, maintenance, and decommission emissions, the total emissions include the life cycle emissions associated with the generation of electricity. The PHS and CAES are modeled to determine the required equipment size to build the storage facility. Life cycle inventories were developed using an available dataset [47] and data from the literature. The material and energy required to manufacture the equipment were calculated. The energy required to build the plant comes from coal, natural gas, electricity, and diesel. Coal and natural gas are used in various industrial processes to extract and refine the building materials. Electricity is required to build the equipment, and diesel is required to transport material and equipment. The construction emissions were calculated using material and energy emissions factors. Decommissioning emissions were taken from data available in the literature [13, 56]. Decommissioning emissions come from the energy used in dismantling the equipment. What is done with the dismantled equipment is not part of this study.

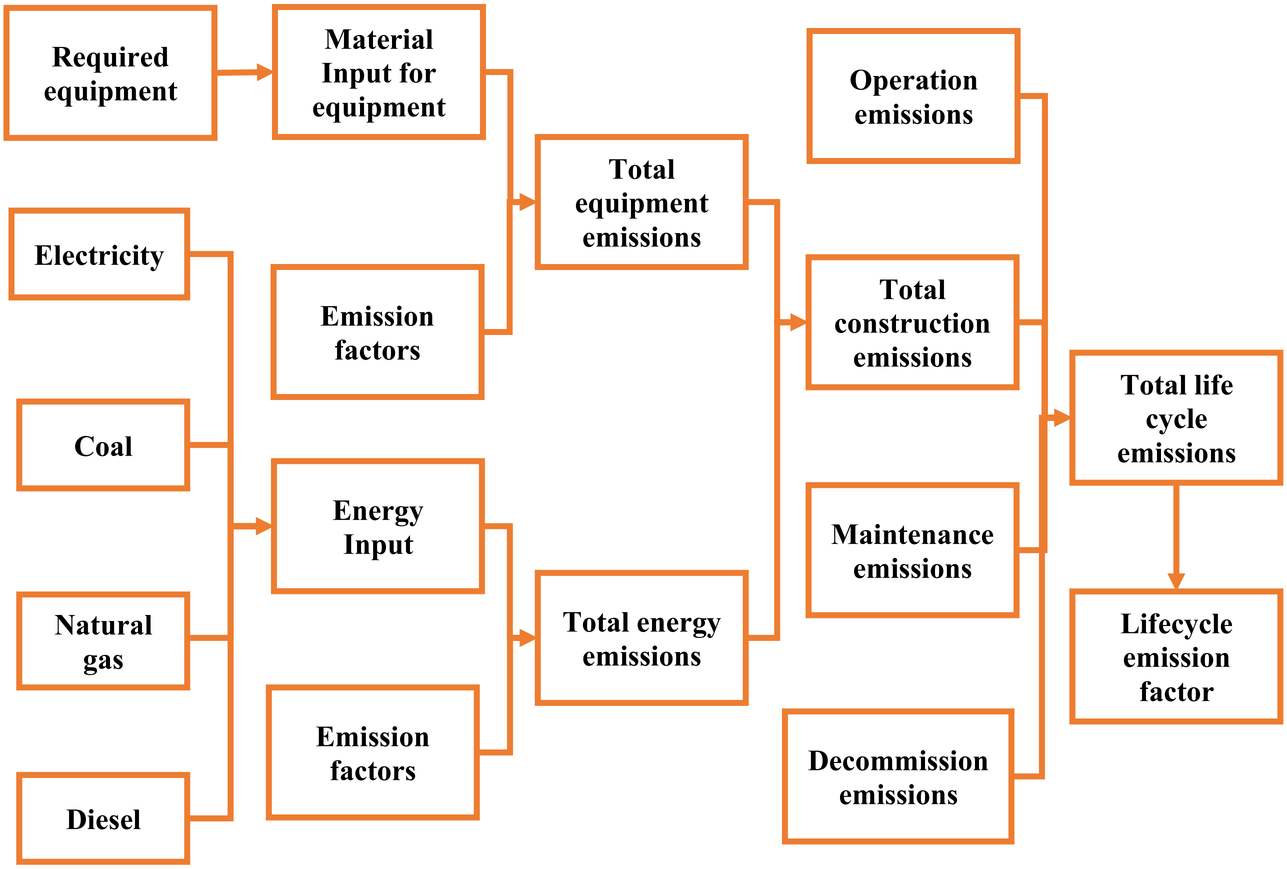

Figure 26: LCA system boundary

The NER is defined as the ratio of total energy output to total energy input to the system over the life of the storage plants and is calculated with Equation 23. The input energy includes construction, operation, and maintenance energy.

$$NER = \frac{Output\ energy}{Contruction\ energy\ + Maintenance\ energy + Operational\ energy} \tag{23}$$

3.3 Results and Discussion

3.3.1 Net Energy Ratio

The construction of a storage plant requires a large amount of energy. This energy comes from sources like electricity, coal, natural gas, and diesel. Sankey diagrams of one operation cycle of PHS, C-CAES, and A-CAES are shown in Figure 27, Figure 28, and Figure 29, respectively. The diagrams also include transmission losses associated with the transmission of electricity from generation site to storage site and then to the end user. A 5% transmission loss is included in the energy flow diagrams [13].

The energy consumed and produced over the life cycle was obtained based on plant life and daily hours of operation. The lifetime of PHS and CAES plants was taken as 60 years and 40 years, respectively [57, 58]. It is assumed that the storage facility is operated 12 hours a day, 300 days a year. The NERs for PHS, C-CAES, and A-CAES are 0.778, 0.542, and 0.702, respectively (Table 18). The energy losses in the turbine contribute to 6.9% of input energy for a PHS. The intercooler cooler losses are major contributors, amounting to 29% of input energy in C-CEAS since the compression heat needs to be dissipated. The heat exchanger losses are highest in A-CAES and account for 9.8% of input energy.

Table 18: Net Energy Ratios

	Construction Energy (GWh)	**Operational energy consumed per cycle (KWh)**	**Energy produced per cycle (KWh)**	**NER**
PHS	153	1413	1105	0.778
C-CAES	36	1782	969	0.542
A-CAES	46	1021	719	0.702

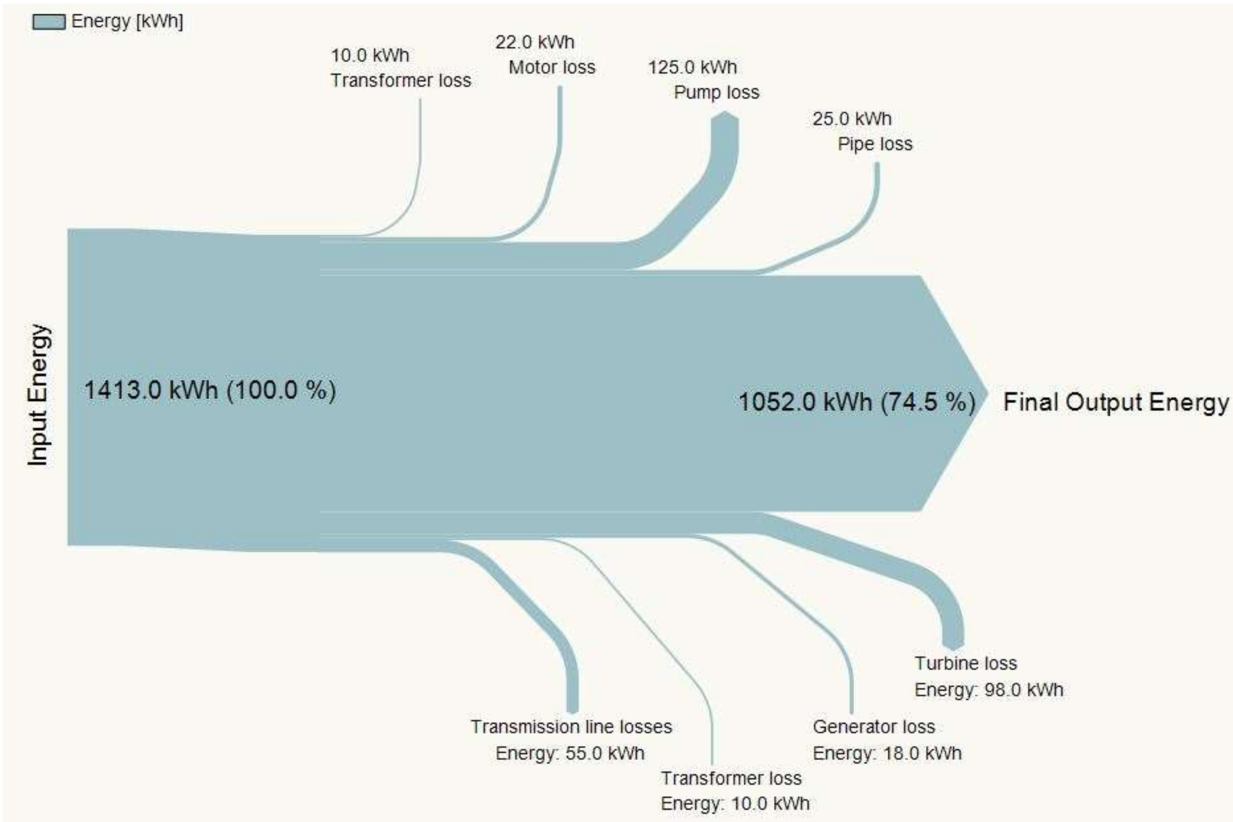

Figure 27: Energy flow diagram for single PHS cycle

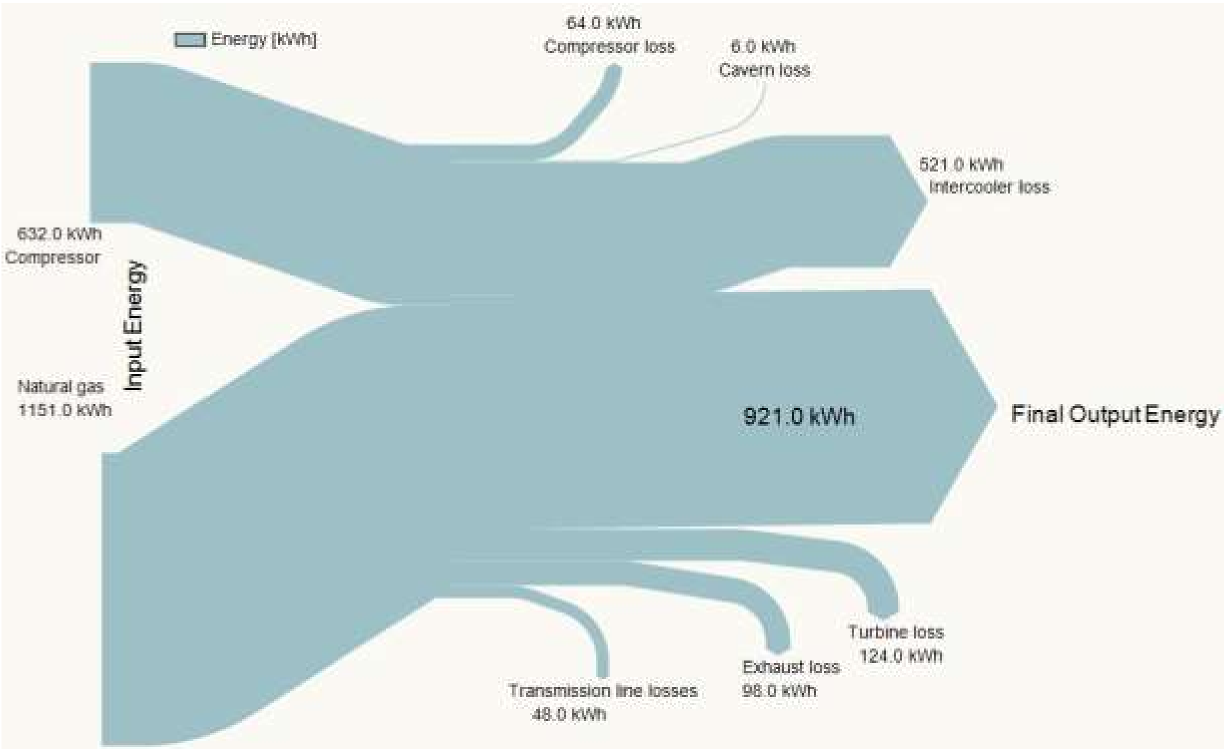

Figure 28: Energy flow diagram for single C-CAES cycle

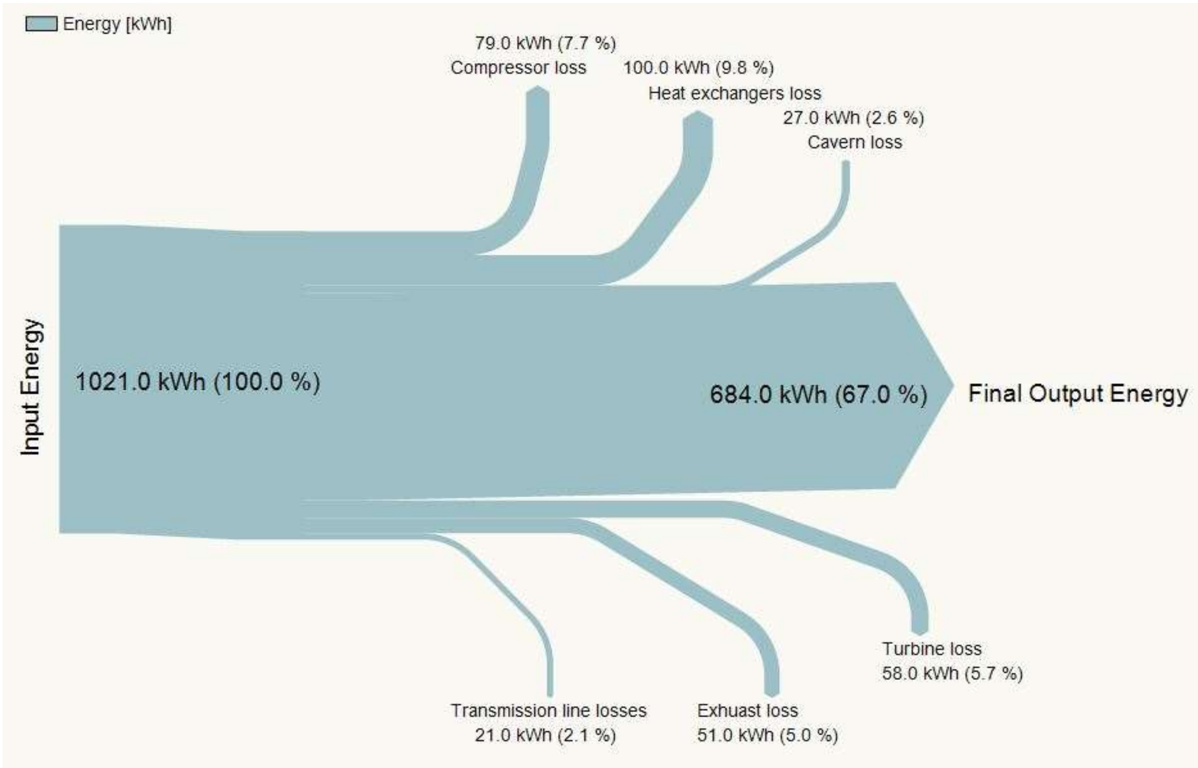

Figure 29: Energy flow diagram for single A-CAES cycle

3.3.2 Direct GHG Emissions

The emissions from equipment construction consist of the manufacturing of the equipment, the transportation of the equipment to the facility, and the erection of the facility. Equipment emissions depend on the material and energy required in manufacturing. The GHG emissions factors associated with construction materials and energy sources are listed in Table 19. The breakdown of construction emissions for PHS, C-CAES, and A-CAES is shown in Figure 30, Figure 31, and Figure 32, respectively. Dam construction (52%) and facility building (26%) are the largest contributors to construction emissions for a PHS facility. The infrastructure required to transport natural gas to the plant site (28%) and the compressors (26%) are the major sources of construction emissions for a C-CAES facility. The compressors (44%) and underground cavern development (26%) are the major contributors to construction emissions for an A-CAES facility.

The calculated direct GHG emissions and the main contributing factors are shown in Table 20. The global direct emissions for PHS, C-CAES, and A-CAES are 7.79, 264.36, and 4.96, respectively. C-CAES exhibits relatively higher emissions than PHS and A-CAES; this is mainly because C-CAES is a hybrid storage technology that requires additional conventional fuel (natural gas) input during the operation phase. PHS and A-CAES are pure storage technologies; they are self-sufficient and generate their own electricity during the operation phase. For C-CAES, the natural gas used to produce electricity alone results in emissions of 260.5 gCO_2e/KWh. If the emissions associated with natural gas are omitted, the impact of C-CAES is comparable to that of PHS and A-CAES.

Table 19: Materials emission factor

Material/Energy	**Emission Factor (gCO_2e/kg)**	**Units**	**Reference**
Concrete	403	gCO_2e/kg	[59]
Stainless steel	2113	gCO_2e/kg	[59]
Carbon Steel	4901	gCO_2e/kg	[59]
Steel	1535	gCO_2e/kg	[59]
Cast iron	711	gCO_2e/kg	[59]
Copper	3261	gCO_2e/kg	[59]
Aluminum	8623	gCO_2e/kg	[59]
Dynamite	7748	gCO_2e/kg	[60]
Diesel	3113	gCO_2e/L	[55]
Natural gas	64385	gCO2e/MMBtu	[61]
Coal	820	gCO_2e/kWh	[62]
Natural gas	490	gCO_2e/kWh	[62]

Diesel	3113	gCO_2e/L	[55]

Table 20: Direct emission factor along with contributing factors

	Emissions (gCO2e/KWh)						
	Construction			**Maintenance**	**Decommission**	**Operations**	**Total direct emissions**
	Material	**Energy**	**Transportation**				
PHS	3.21	4.08	0.26	0.15	0.09	-	7.79
C-CAES	0.74	2.86	0.02	0.04	0.19	260.51	264.36
A-CAES	1.25	3.43	0.03	0.06	0.19	-	4.96

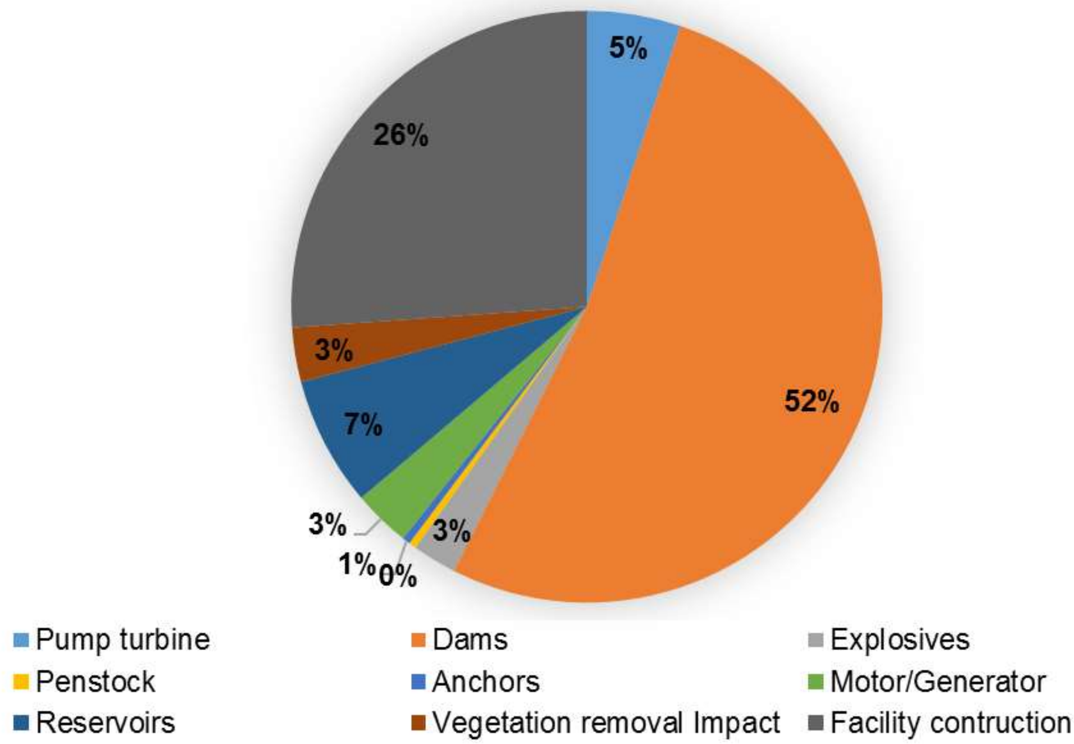

Figure 30: Breakdown of construction emissions for PHS

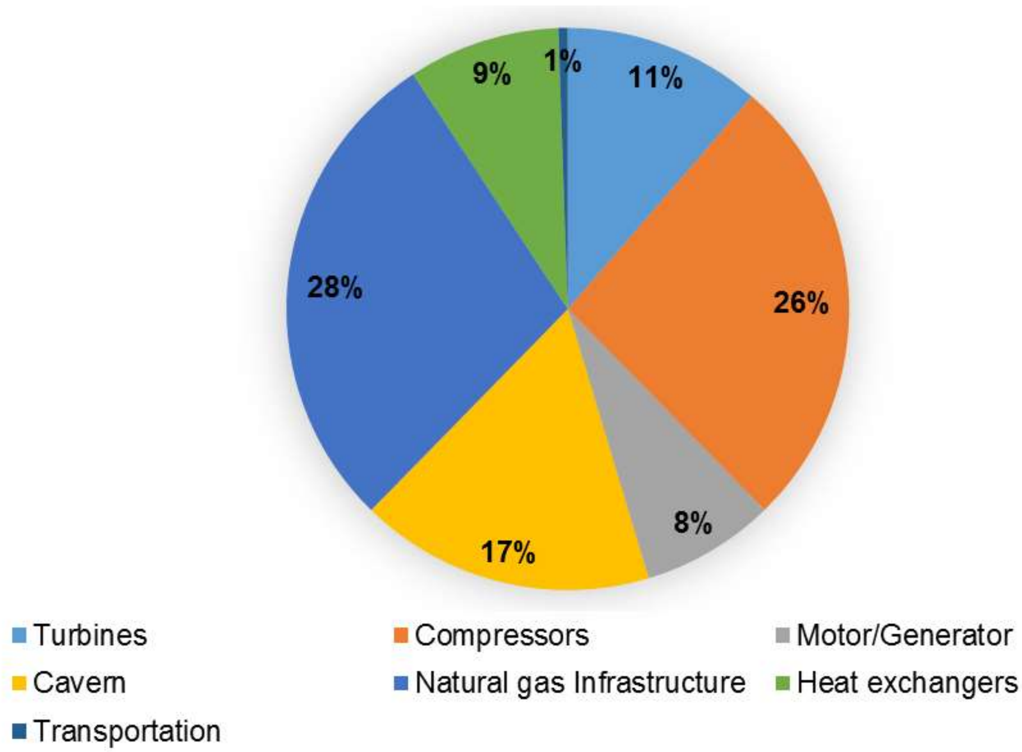

Figure 31: Breakdown of construction emissions for C-CAES

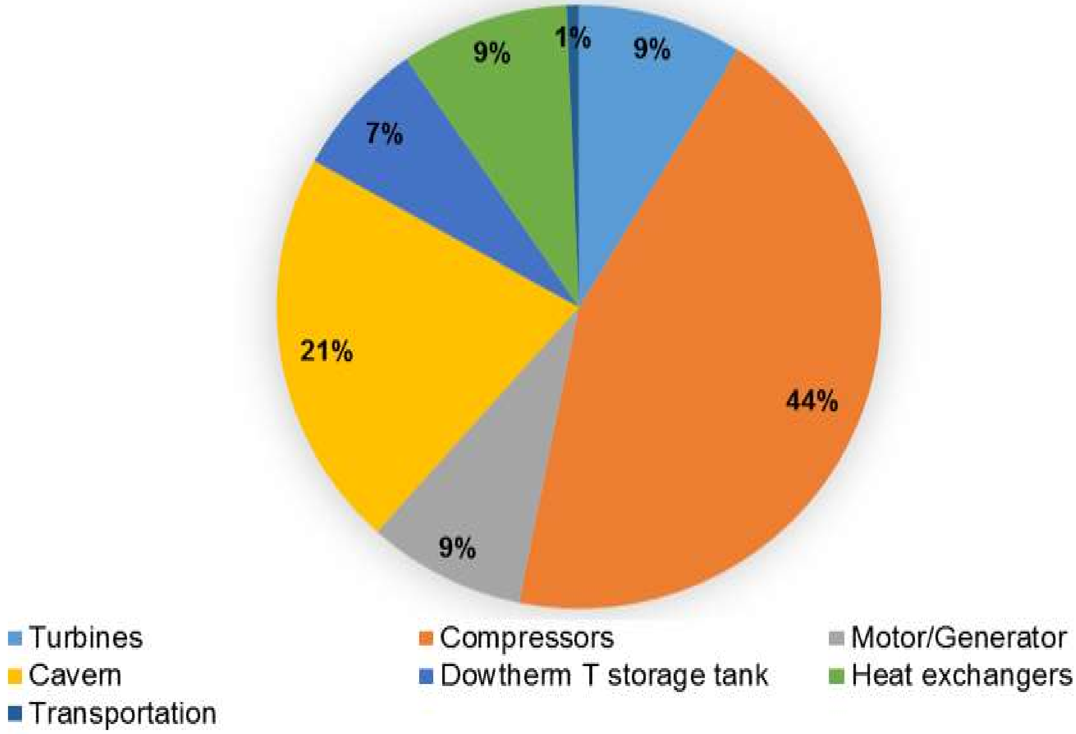

Figure 32: Breakdown of construction emissions for A-CAES

3.3.3 Total GHG Emissions Based on Energy Mix

The total GHG emissions are the upstream emissions from electricity generation added to the direct GHG emissions. The electricity input could be from conventional (coal, natural gas, etc.) or renewable (the wind, solar, geothermal, etc.) sources. The emissions factor of electricity generated by various energy sources is presented in Table 21. Figure 33 shows the total GHG emissions for PHS, C-CAES, and A-CAES integrated with nuclear, solar PV, wind, coal, and natural gas plants. For PHS and A-CAES integrated with nuclear, wind, or solar PV, the emissions factor is significantly smaller than for C-CAES integrated with nuclear, wind, or solar PV; this is attributed to the hybrid nature of C-CAES. However, when PHS and A-CAES are integrated with a coal or natural gas plant, the emissions factor is higher than for C-CAES integrated with a coal or natural gas plant.

In addition to a single source energy mix as presented above, a case study for Canada was conducted. Various provincial energy mixes from 2014 in Canada were considered in the analysis. The emissions for four provincial energy mixes in Canada are listed in Table 22. GHG emissions results for ESS integration with provincial energy mixes are shown in Figure 34. Global emissions are high for PHS and A-CAES compared to C-CAES when integrated with the coal-dominated Alberta energy mix [8]. Total GHG emissions are significantly lower for PHS and A-CAES when integrated with energy mixes from Ontario, British Columbia, and Quebec, which have a high share of renewable energy sources.

Table 21: Emissions from different sources of electricity [62]

Energy Mix	**gCO2e/KWh**
Geothermal	38
Hydropower	24
Nuclear	12
Concentrated solar power	27
Solar PV	45
Wind	11.5
Coal	820
Natural gas	490

Table 22: Emissions from national and provincial energy mixes, 2014 [4]

Energy Mix	**gCO2e/KWh**
Canada	160
Alberta	820

Ontario	50
British Columbia	15
Quebec	2.3

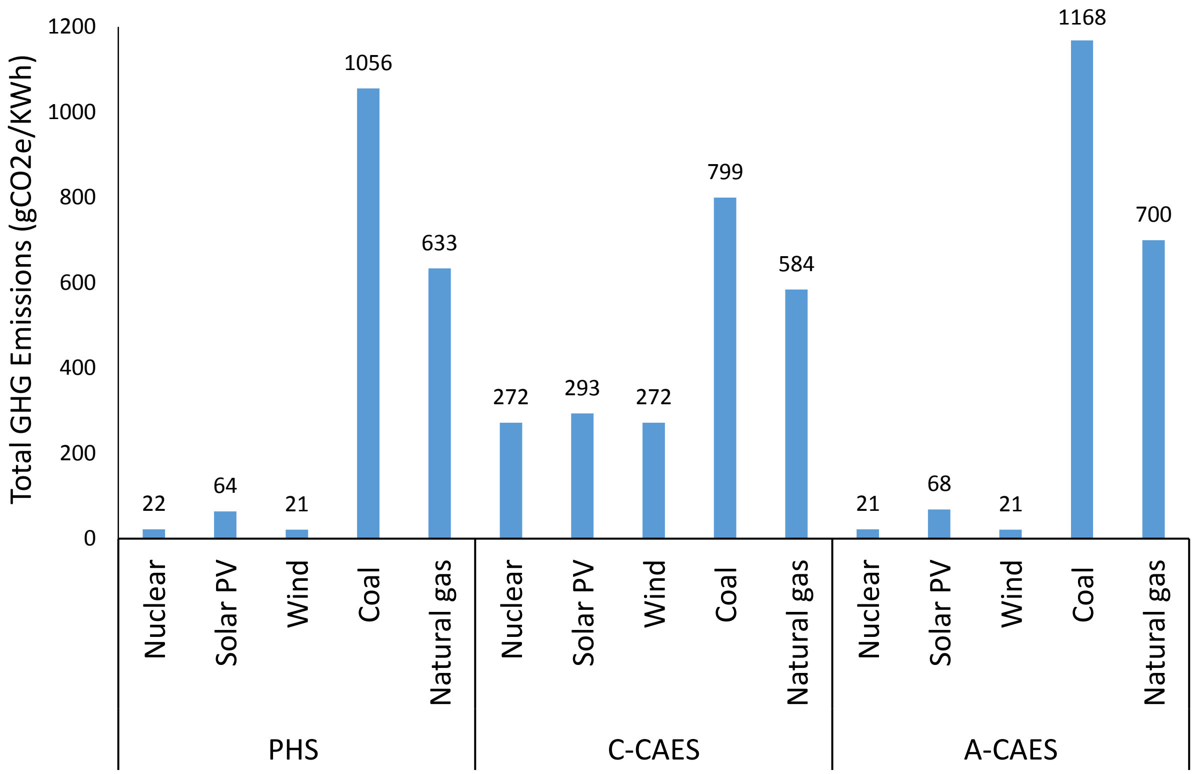

Figure 33: Total GHG emissions by electricity source

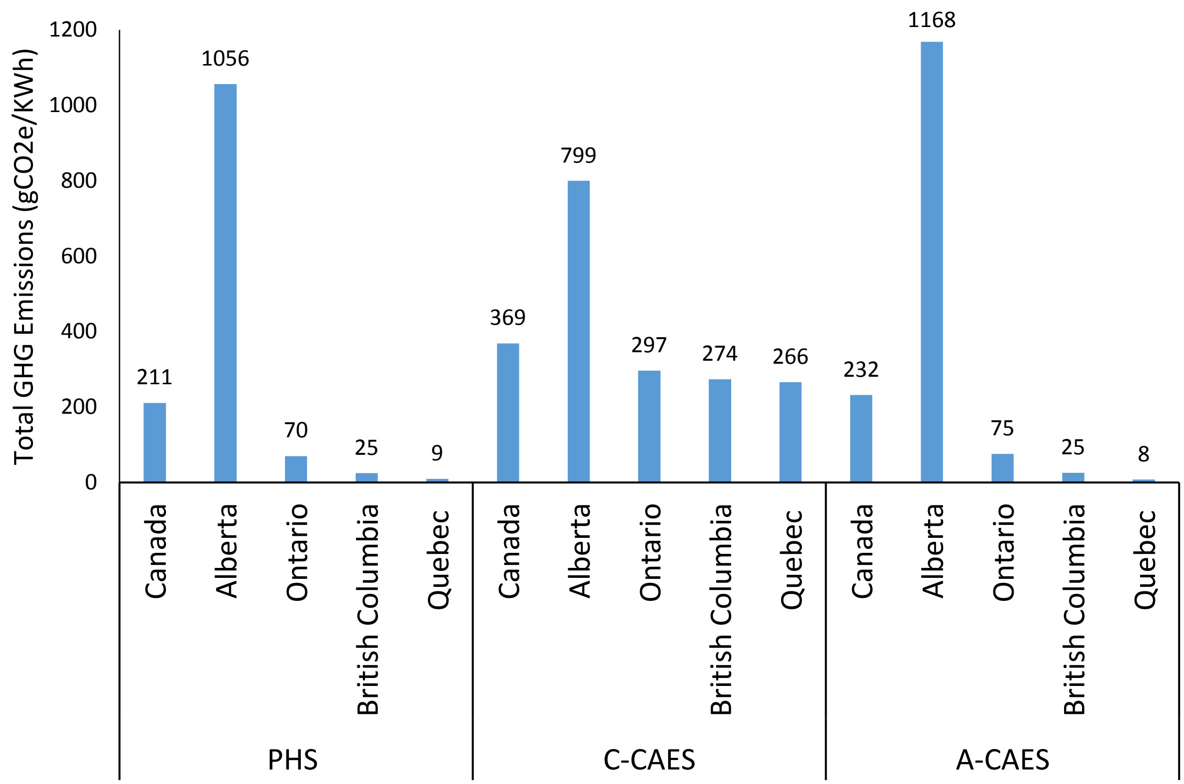

Figure 34: Total emissions factor based on the national and provincial energy mix

3.3.4 Sensitivity Analysis

A sensitivity analysis was conducted to investigate the effects of input process parameters on the NER and direct GHG emissions from the considered storage facilities. The selected parameters for PHS are the head, flow rate, pump efficiency, turbine efficiency, material emissions, plant life, and daily hours of operation. For C-CAES and A-CAES, the following were selected: air inlet temperature, flow rate, compressor efficiency, turbine inlet temperature, material emissions, plant life, daily hours of operation, and natural gas emission factor.

3.3.4.1 NER Sensitivity Analysis

The results of the NER sensitivity analysis for PHS, C-CEAS, and A-CAES are presented in Figure 35, Figure 36 and Figure 37, respectively. The NER for PHS is most sensitive to pump turbine efficiency. The increase in pump turbine efficiency increases the operation cycle electricity output.

A 5% increase in pumping efficiency results in a 5% increase in NER. The NER for C-CAES is highly sensitive to turbine inlet temperatures. Though operating turbines at higher inlet temperatures results in increased natural gas consumption, it also leads to increased turbine energy output. The increased turbine output dominates the increase in natural gas consumption. A 5% increase in turbine two inlet temperature results in 1.4% increase in NER. The NER for A-CAES is sensitive to flow rate and turbine efficiency. The decrease in flow rate reduces both the energy consumed by the compressors and the energy produced by the turbines. The decrease in turbine energy production outweighs the reduced energy consumed by the compressors, thus lowering the NER. A 5% decrease in flow rate results in 3.1% reduction in NER. On the other hand, the lower turbine efficiency decreases the unit cycle energy output and thus reduces the NER.

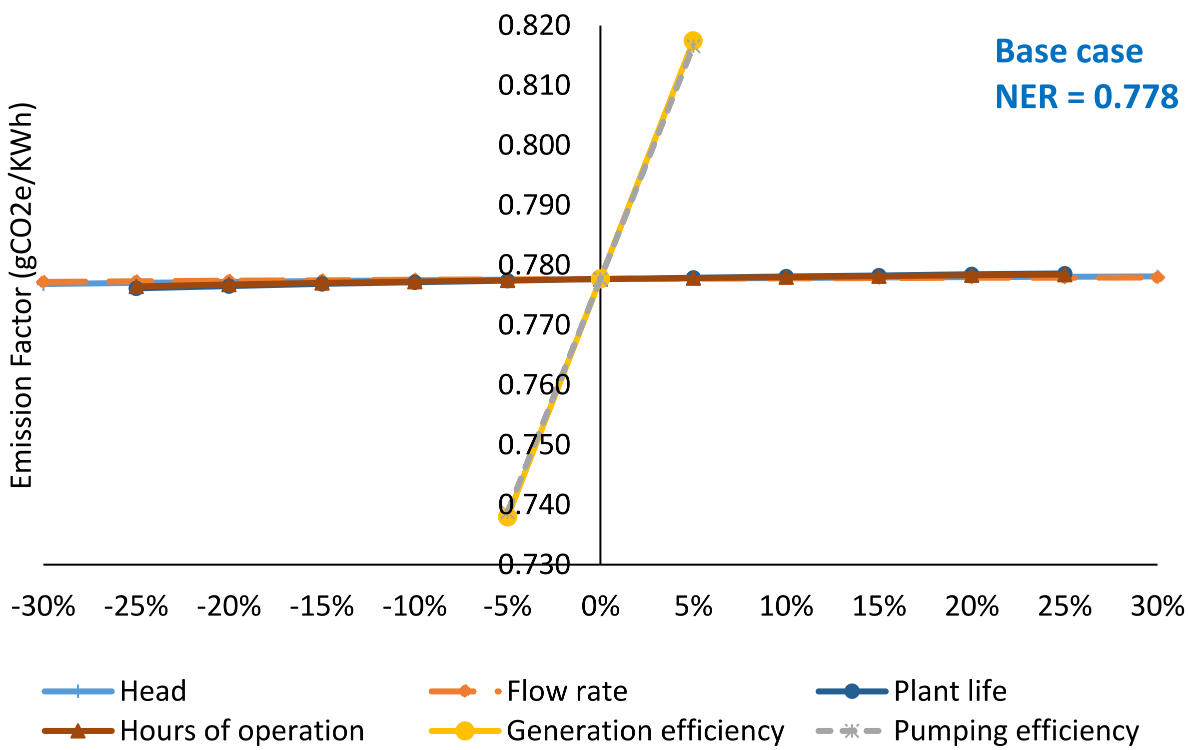

Figure 35: Sensitivity analysis for PHS net energy ratio

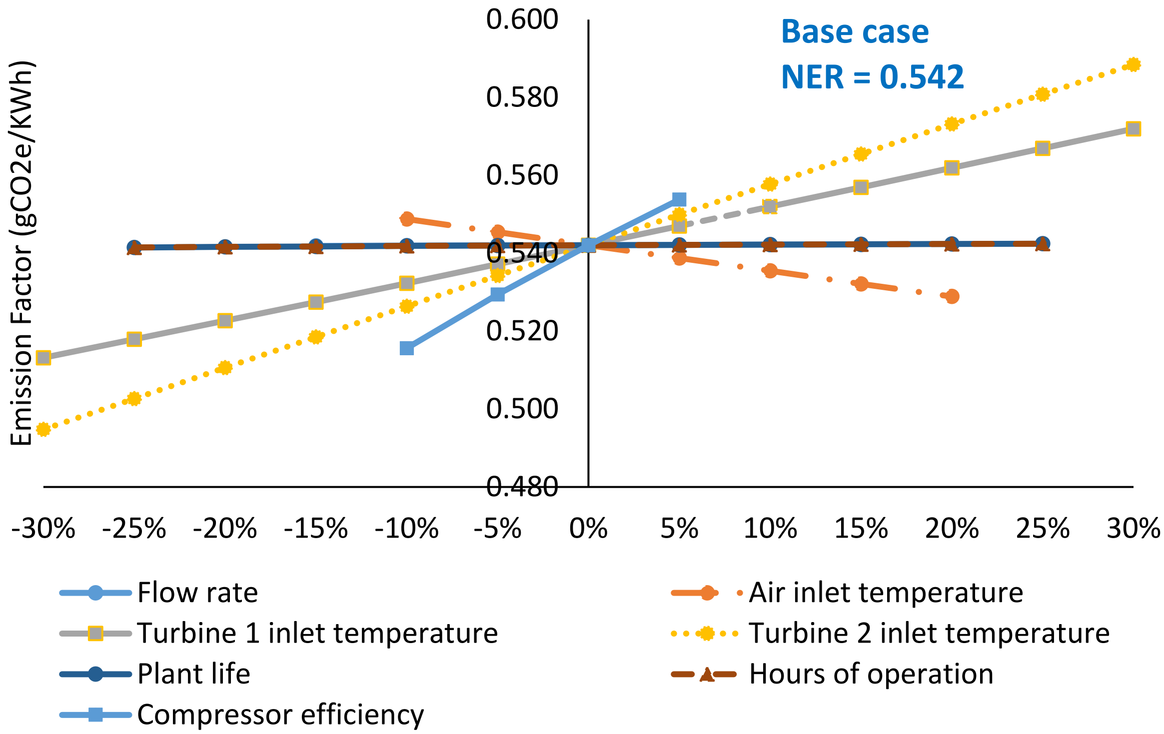

Figure 36: Sensitivity analysis for C-CAES net energy ratio

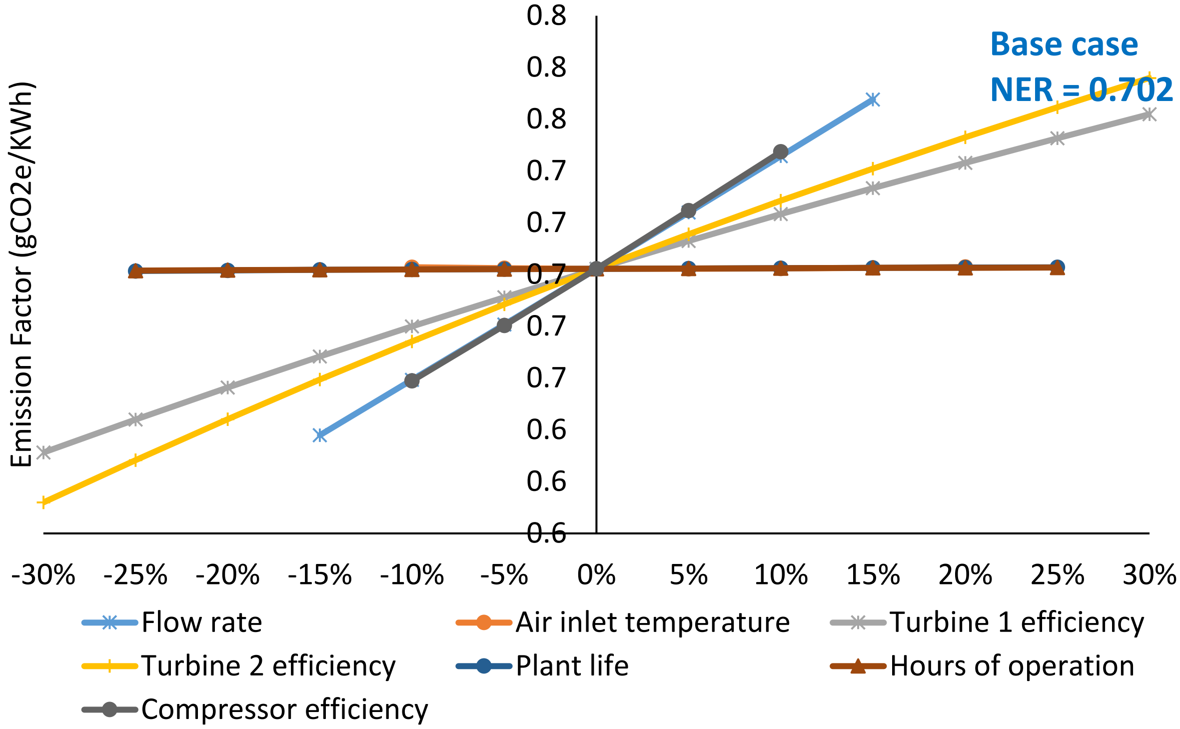

Figure 37: Sensitivity analysis for A-CAES net energy ratio

3.3.4.2 Direct GHG emissions Sensitivity Analysis

The results of the direct GHG emissions sensitivity analysis for PHS, C-CEAS, and A-CAES are presented in Figure 38, Figure 39, and Figure 40, respectively. The direct GHG emissions for PHS are most sensitive to plant life followed by daily hours of operation. An increase in plant life or in daily hours of operation considerably increases the facility's electricity output over the lifetime. As the functional unit is one kWh, the increase in electricity output results in a decrease in direct GHG emissions. A 5% increase in plant life reduces emissions by 4.6%. The emissions result for C-CAES is highly sensitive to the natural gas emissions factor. Another important parameter is the turbine inlet temperature. The upstream emissions from natural gas have a great effect on construction and decommissioning emissions for C-CAES, a hybrid system that consumes natural gas. A 5% increase in the natural gas emissions factor will increase the total direct GHG emissions by 4.9%. The A-CAES DEF is most sensitive to plant life, followed by daily hours of operation. An increase in plant life or daily hours of operation considerably increases the facility's electricity output over the lifetime. A 5% increase in plant life reduces emissions by 4.8%.

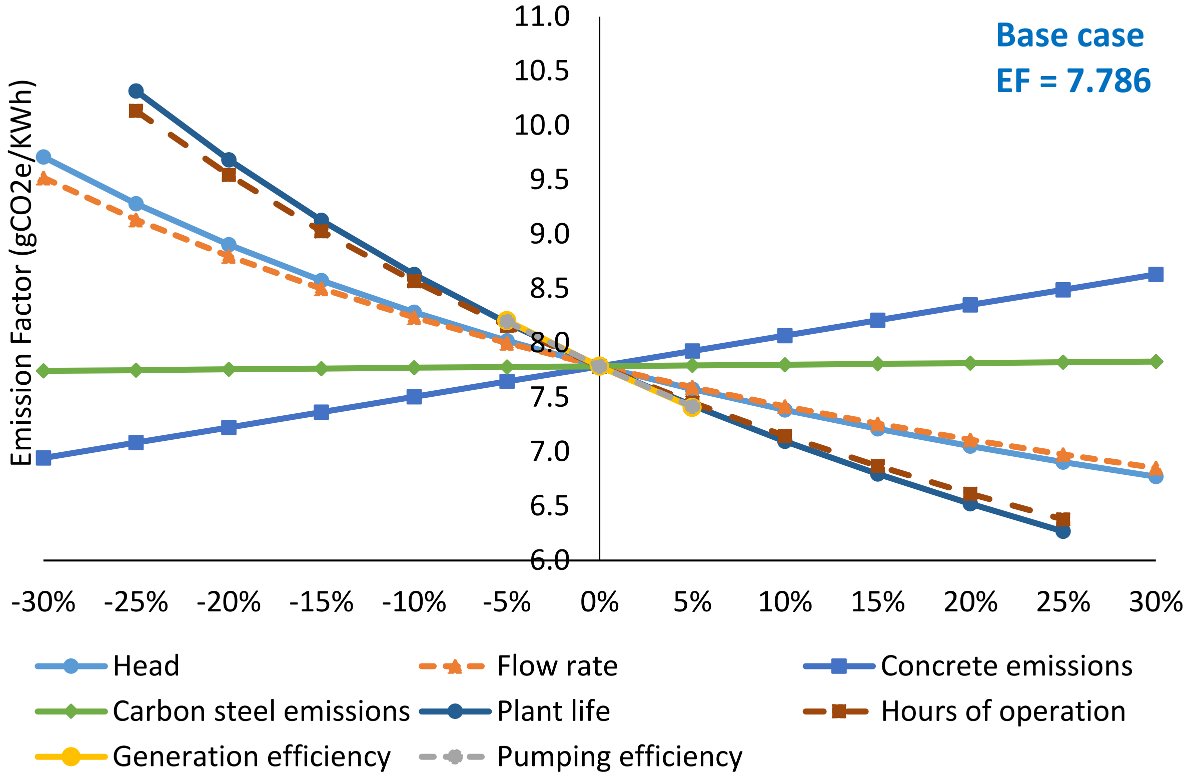

Figure 38: Sensitivity analysis for PHS direct emissions factors

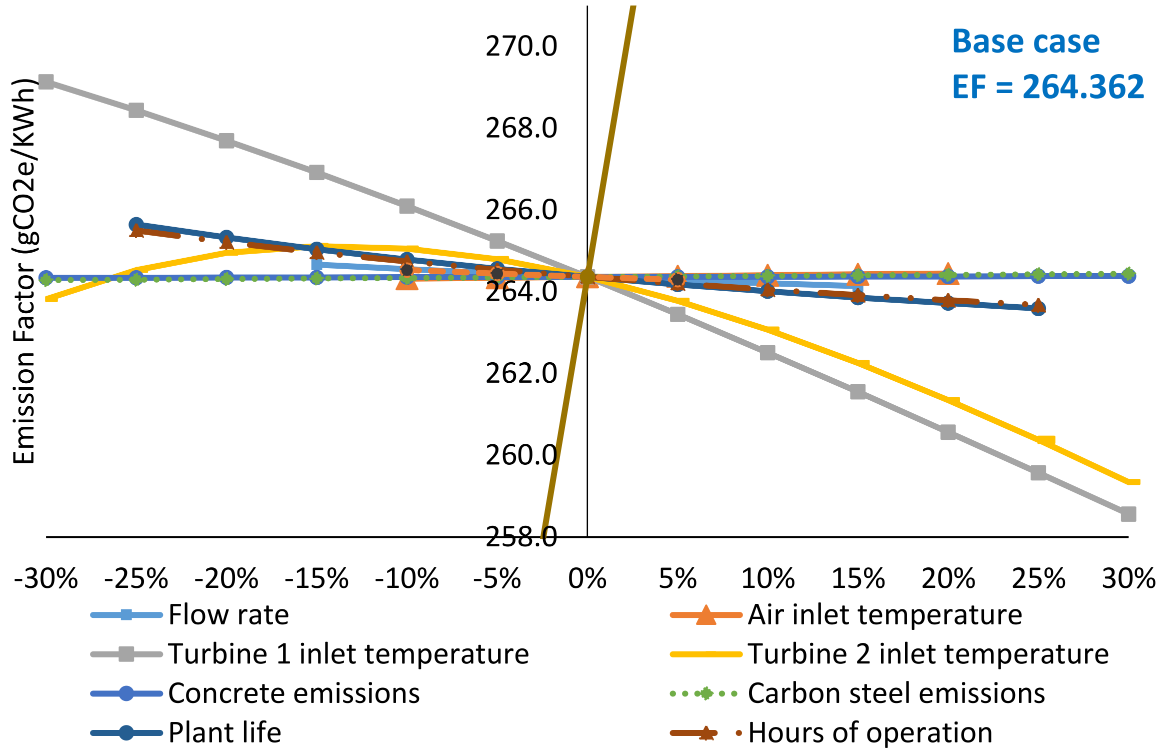

Figure 39: Sensitivity analysis for C-CAES direct emissions factors

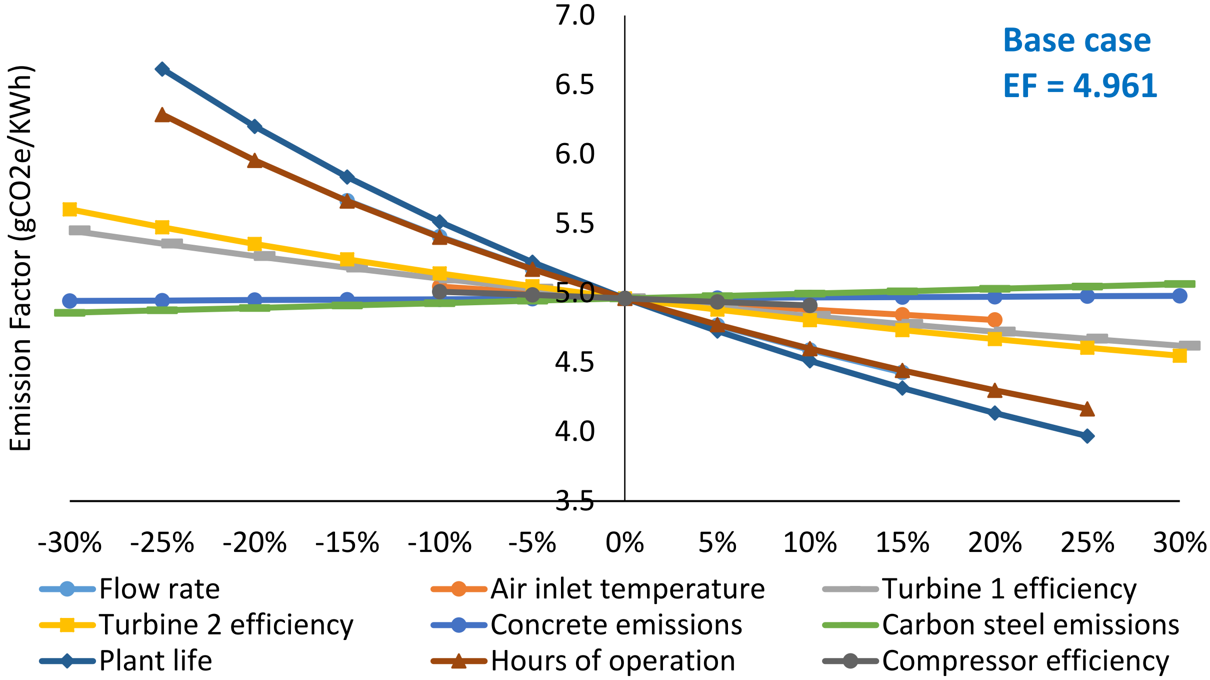

Figure 40: Sensitivity analysis for C-CAES direct emissions factors

3.3.4.3 Uncertainty Analysis

An uncertainty analysis was performed to evaluate the effect of a simultaneous change in multiple input parameters on the NER and direct GHG emissions. A Monte Carlo simulation was conducted through ModelRisk software to evaluate the range of direct emissions associated with storage facilities. All the uncertain process input variables were identified with their highest and lowest ranges. The range of input variables is presented in Table 23. A random sample was selected from the range of input variables to obtain final outputs and the process was iterated 100,000 times to obtain the final output distribution.

The results of uncertainty analyses for the PHS, C-CAES, and A-CAES base cases are shown in Figure 41 and Figure 42. The mean NERs for PHS, C-CAES, and A-CAES are 0.777, 0.542, and 0.704, respectively. The NER ranges obtained for PHS, C-CAES, and A-CAES are 0.774-0.781, 0.541-0.544, and 0.699-0.711, respectively. The emissions from natural gas were omitted from the DEF of C-CAES before performing an uncertainty analysis to make it comparable to PHS and A-CAES DEFs. The mean direct emissions for PHS, C-CAES, and A-CAES are 8.05 gCO_2e/kWh, 3.84 gCO_2e/kWh, and 4.92 gCO_2e/kWh, respectively. The ranges of direct emissions obtained for PHS, C-CAES, and A-CAES are 6.63-8.94 gCO_2e/kWh, 3.59-4.07 gCO_2e/kWh, and 4.6-5.21 gCO_2e/kWh, respectively.

Table 23: Uncertainty analysis input parameters

	Parameters	Min value	Base value	Max value	Units	Reference
PHS						
	Head	100	300	600	m	[25, 26]
	Efficiency (pump)	0.9	0.91	0.92		[27, 28]
	Efficiency (turbine)	0.916	0.9205	0.925		[27, 29]
	Hours of operation (pumping)	10	12	13	hours	
	Flow rate (m^3/s)	20	40	80	m^3/s	[25, 26]
	Velocity of flow	4	5	10	m/s	[25, 26]
	Plant life	50	60	70	years	[11, 63]
	Motor efficiency	0.978	0.984	0.99		[28, 29]
	Generator efficiency	0.978	0.984	0.99		[28, 29]
	Transformer efficiency	0.99	0.993	0.996		[28, 29]
C-CAES						
	Flow rate	95	100	105	m^3/s	
	Air inlet temperature	273.15	288.15	298.15	K	

Parameters	Min value	Base value	Max value	Units	Reference
Turbine 1 temperature	810.15	823.15	823.15	K	[37, 38]
Turbine 2 temperature	1073.15	1098.15	1144.15	K	[37, 38]
Plant life	35.00	40.00	50.00	years	[11, 64]
Hours of operation	10.000	12.00	13.00	hours	
A-CAES					
Flow rate	95	100	105	m^3/s	
Air inlet temperature	273.15	288.15	298.15	K	
Plant life	35	40	50	years	[11, 64]
Hours of operation	10	12	13	hours	

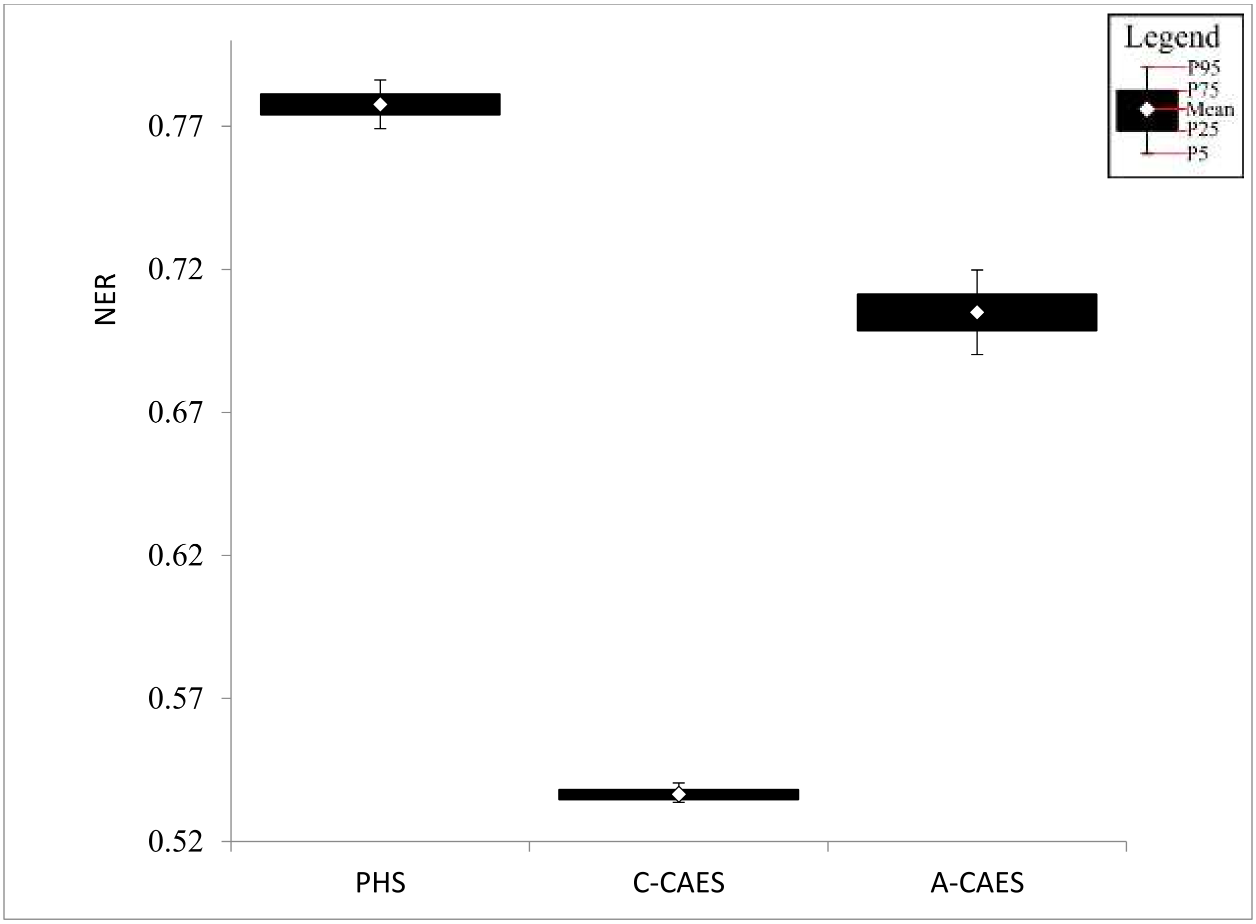

Figure 41: Net energy ratio uncertainty analysis

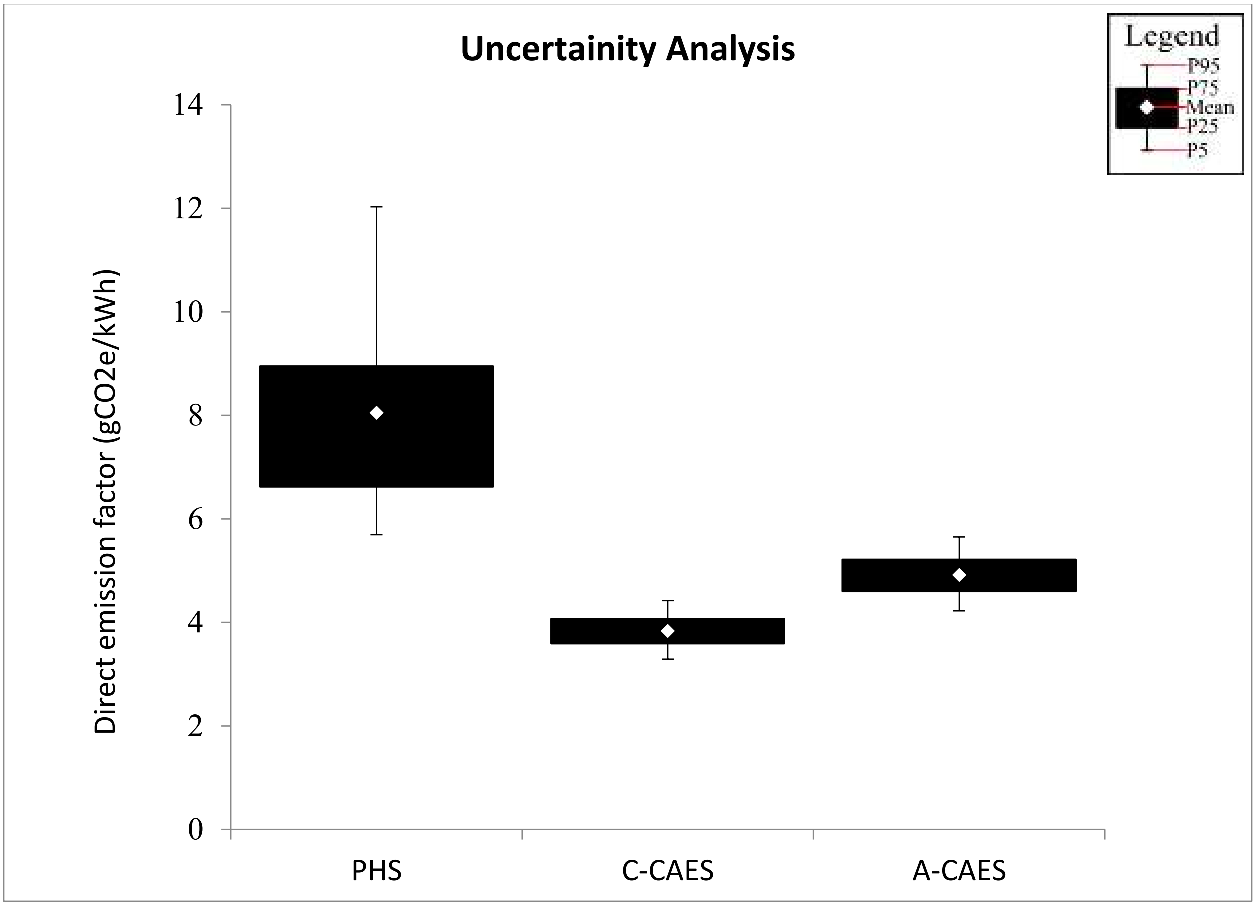

Figure 42: Emissions factor uncertainty analysis

3.4 Conclusion

The objective of this study was to develop NERs and evaluate the life cycle GHG emissions of PHS and CAES. To that end, the direct emission factors (DEFs) and total emission factors (TEFs) of these technologies were investigated and life cycle inventories were established. Simulation models were developed to model PHS and CAES systems and determine the required equipment sizes. The NER was calculated from construction and operational energy. Unit process and operational losses were included in determining the energy output of each cycle. The DEFs were evaluated and found out to be 7.79, 264.36, and 4.96, for PHS, C-CAES, and A-CAES, respectively. The high emissions factor for C-CAES is due to its hybrid nature (i.e., electricity needs to be combusted during the operation stage). The TEF was investigated by integrating the storage facility with several energy mixes. It was observed that the TEF is a function of the origin of the stored electricity. The TEF is lower for PHS and A-CAES if the energy mix is renewable or nuclear and higher for a conventional energy mix.

A sensitivity analysis showed that the DEF for PHS and A-CAES is most sensitive to plant life, whereas the DEF for C-CAES is most sensitive to the natural gas emissions factor. Furthermore, to both consolidate the developed model and mitigate risk, an uncertainty analysis was performed and showed mean DEF values of 8.05 gCO_2e/kWh, 3.84 gCO_2e/kWh, and 4.92 gCO_2e/kWh, for PHS, C-CAES, and A-CAES, respectively. Finally, it can be said that the environmental performance of an ESS is highly dependent on system efficiency and the emissions from the energy mix whose electricity is stored by ESS.

The results of this LCA provide useful insight on the NERs and the life cycle GHG emissions of PHS and CAES. An ESS is crucial to achieve GHG emission targets in various jurisdictions and IEA's two-degree global target. The integrated C-CAES wind power plant shows emissions of 272 gCO_2e/kWh whereas the integrated A-CAES or PHS wind power plant shows emissions of only 21 gCO_2e/kWh, a figure far lower than Alberta's current energy mix emissions of 830 gCO_2e/kWh. Thus, it can be concluded that the GHG emissions can be reduced through the implementation of more renewable power plants along with energy storage without compromising the reliability and flexibility in power systems.

3.5 References

1. *What Is Climate Change?* 2014 [cited 2017 July 11]; Available from: https://www.nasa.gov/audience/forstudents/k-4/stories/nasa-knows/what-is-climate-change-k4.html.

2. Rogelj, J., et al., *Paris Agreement climate proposals need a boost to keep warming well below 2 C.* Nature, 2016. **534**(7609): p. 631-639.
3. *Climate Change 2014: Mitigation of Climate Change* in *Climate Change*. 2014. p. 1246.
4. *National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada*. 2016: Canada [cited 2017 Sep 10]; Available from: https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
5. *World Energy Resources* 2016: England and Wales [cited 2017 Sep 10]; Available from: https://www.worldenergy.org/wp-content/uploads/2016/10/World-Energy-Resources-Full-report-2016.10.03.pdf.
6. Gielen, D., *Energy technology perspectives.* Paris: International Energy Agency, 2017 [cited 2017 Sep 10] ; Available from: https://www.iea.org/publications/freepublications/publication/EnergyTechnologyPerspectives2017ExecutiveSummaryEnglishversion.pdf.
7. Rahimi, E., *Alberta Climate Leadership Plan*. 2016.
8. Leach, A., et al., *Climate leadership: Report to minister*. 2015: Department of Environment Alberta and Climate Change Advisory Panel.
9. Xu, Y. and C. Singh, *Adequacy and economy analysis of distribution systems integrated with electric energy storage and renewable energy resources.* IEEE Transactions on power systems, 2012. **27**(4): p. 2332-2341.
10. Hertwich, E.G., et al., *Integrated life-cycle assessment of electricity-supply scenarios confirms global environmental benefit of low-carbon technologies.* Proceedings of the National Academy of Sciences, 2015. **112**(20): p. 6277-6282.
11. Decourt, B.D., Romain;, *Electricity Storage*, in *Leading the energy transition*. 2013.
12. *How Energy Storage Works*. [cited 8 Aug 2017]; Available from: http://www.ucsusa.org/clean-energy/how-energy-storage-works#.WZ3-U1FGmUk.

13. Denholm, P. and G.L. Kulcinski, *Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems.* Energy Conversion and Management, 2004. **45**(13–14): p. 2153-2172.

14. Hiremath, M., K. Derendorf, and T. Vogt, *Comparative life cycle assessment of battery storage systems for stationary applications.* Environmental science & technology, 2015. **49**(8): p. 4825-4833.

15. Rydh, C.J., *Environmental assessment of vanadium redox and lead-acid batteries for stationary energy storage.* Journal of Power Sources, 1999. **80**(1): p. 21-29.

16. Jing, Y.-Y., et al., *Life cycle assessment of a solar combined cooling heating and power system in different operation strategies.* Applied Energy, 2012. **92**: p. 843-853.

17. Oró, E., et al., *Comparative life cycle assessment of thermal energy storage systems for solar power plants.* Renewable Energy, 2012. **44**: p. 166-173.

18. Oliveira, L., et al., *Environmental performance of electricity storage systems for grid applications, a life cycle approach.* Energy conversion and management, 2015. **101**: p. 326-335.

19. Sternberg, A. and A. Bardow, *Power-to-What?–Environmental assessment of energy storage systems.* Energy & Environmental Science, 2015. **8**(2): p. 389-400.

20. Ma, T., H. Yang, and L. Lu, *Feasibility study and economic analysis of pumped hydro storage and battery storage for a renewable energy powered island.* Energy Conversion and Management, 2014. **79**: p. 387-397.

21. Kadiyala, A., R. Kommalapati, and Z. Huque, *Evaluation of the life cycle greenhouse gas emissions from hydroelectricity generation systems.* Sustainability, 2016. **8**(6): p. 539.

22. Bouman, E.A., M.M. Øberg, and E.G. Hertwich, *Environmental impacts of balancing offshore wind power with compressed air energy storage (CAES).* Energy, 2016. **95**: p. 91-98.

23. Energy Center, *Life-Cycle Energy Costs and Greenhouse Gas Emissions for Gas Turbine Power.* 2000.

24. Kapila, S., A.O. Oni, and A. Kumar, *The development of techno-economic models for large-scale energy storage systems.* Energy, 2017. **140**(Part 1): p. 656-672.

25. American Society of CIvil Engineers, *Compendium of pumped storage plants in the United States*. 1993, New York, NY: American Society of Civil Engineers. 744 p.

26. Carson, J., et al., *Operation and maintenance experiences of pumped-storage plants*. 1991, Morrison-Knudsen Engineers, Inc., San Francisco, CA (USA); Electric Power Research Inst., Palo Alto, CA (USA).

27. Stelzer, R.S. and R.N. Walters, *Estimating reversible pump-turbine characteristics*. 1977, Bureau of Reclamation, Denver, CO (USA). Engineering and Research Center.

28. MWH Americas, I., et al., *Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest*. 2009: MWH.

29. Barnes, F.S. and J.G. Levine, *Large energy storage systems handbook*. 2011: CRC press.

30. McDonald, A.G. and H. Magande, *Introduction to thermo-fluids systems design*. 2012: John Wiley & Sons.

31. Bozzolani, E., *Techno-economic analysis of compressed air energy storage systems, 2010,* Cranfield Collection of E-Research, U.K.

32. Kyle, B.G., *Chemical and process thermodynamics*. 3rd ed. 1984: Prentice-Hall, Inc., Englewood Cliffs, NJ.

33. Moore, W.J., *Basic physical chemistry*. 1983: Prentice Hall.

34. Walsh, P.P. and P. Fletcher, *Gas turbine performance*. 2004: John Wiley & Sons.

35. Kays, W.M., R.K. Jain, and S. Sabherwal, *The effectiveness of a counter-flow heat exchanger with cross-flow headers.* International Journal of Heat and Mass Transfer, 1968. **11**(4): p. 772-774.

36. *Overall Heat Transfer Coefficient Table Charts and Equation* 2017 [cited 2017 July 1]; Available from: http://www.engineersedge.com/thermodynamics/overall_heat_transfer-table.htm.

37. Pollak, R., *History of First US Compressed-Air Energy Storage (CAES) Plant (110 MW 26h) Volume 2: Construction.* Electric Power Research Institute (EPRI), 1994.

38. Crotogino, F., et al. *More than 20 years of successful operation. Spring 2001 Meeting of the Solution Mining Research Institute*. [cited 2017 Sep 10]; Available from: http://www.fze.uni-saarland.de/AKE_Archiv/AKE2003H/AKE2003H_Vortraege/AKE2003H03c_Crotogino_ea_HuntorfCAES_CompressedAirEnergyStorage.pdf.

39. Jubeh, N.M. and Y.S. Najjar, *Green solution for power generation by adoption of adiabatic CAES system.* Applied Thermal Engineering, 2012. **44**: p. 85-89.

40. *Typical overall heat transfer coefficients (U-Values)*. 2017 [cited 2017 July 2]; Available from: http://www.engineeringpage.com/technology/thermal/transfer.html.

41. *Density of Some Common Building Materials*. 2017 [cited 2017 Sep 5]; Available from: http://www.rfcafe.com/references/general/density-building-materials.htm.

42. Adams, M., et al., *European Union emission inventory report 1990–2010 under the UNECE Convention on Long-range Transboundary Air Pollution (LRTAP)*. 2012, EEA technical report.

43. Norge, A., *Cost base for hydropower plants* J. Slapgård, Editor. 2012: Norway.

44. Flury, K. and R. Frischknecht, *Life cycle inventories of hydroelectric power generation.* ESU-Services, Fair Consulting in Sustainability, commissioned by€ Oko-Institute eV, 2012: p. 1-51.

45. *The choice of materials for turbines*. [cited 2017 July 17]; Available from: http://www.ivt.ntnu.no/ept/fag/tep4200/innhold/The%20choice%20of%20materials.pdf.

46. *Bath County, USA*. [cited 2017 July 16]; Available from: http://voith.com/en/markets-industries/industries/hydro-power/pumped-storage-plants/bathcounty_main-11333-11333.html.

47. *Ecoinvent 3.3*. 2017 [cited 2017 12 June]; Available from: http://www.ecoinvent.org/.

48. Iron, A., S. Institute, and S.P.F. Association, *Buried Steel Penstocks*. 1992: American Iron and Steel Institute.

49. *Concrete - Properties*. 2017 [cited 2017 July 17]; Available from: http://www.engineeringtoolbox.com/concrete-properties-d_1223.html.

50. *Trees Improve Our Air Quality*. 2017 [cited 2017 July 19]; Available from: http://urbanforestrynetwork.org/benefits/air%20quality.htm.

51. Succar, S.W., Robert H. , *"Compressed Air Energy Storage: Theory, Resources and Applications for Wind Power*. 2008.

52. Waheed, M.A. and A.O. Oni, *Performance improvement of a crude oil distillation unit.* Applied Thermal Engineering, 2015. **75**: p. 315-324.

53. *Plants and Facilities* 2017 [cited 2017 28 Aug]; Available from: http://www.aer.ca/data-and-publications/statistical-reports/plants-and-facilities.

54. *Wind energy in Canada*. [cited 2017 28 Aug]; Available from: http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/pdf/fichier/81770/windtrm_resource_map.pdf.

55. Nimana, B., et al., *Life Cycle Analysis of Bitumen Transportation to Refineries by Rail and Pipeline.* Environmental Science & Technology, 2017. **51**(1): p. 680-691.

56. Bock, T., *Greenhouse Gas Emissions and the Decommissioning of Hydroelectric Dams.*

57. Kousksou, T., et al., *Energy storage: Applications and challenges.* Solar Energy Materials and Solar Cells, 2014. **120, Part A**: p. 59-80.

58. Akhil, A.A., et al., *DOE/EPRI 2013 electricity storage handbook in collaboration with NRECA*. 2013: Sandia National Laboratories Albuquerque, NM.

59. *GREET Vehicle Cycle (GREET 2)*, A.N. Laboratory, Editor. 2016: Argonne, IL.

60. *AP 42, Fifth Edition, Volume I Chapter 13: Miscellaneous Sources*. U.S.

61. *GREET Fuel Cycle (GREET 1)*, A.N. Laboratory, Editor. 2016: Argonne, IL.

62. Schlömer, S., et al., *Annex III: Technology-specific cost and performance parameters.* Climate change, 2014: p. 1329-1356.

63. Beaudin, M., et al., *Energy storage for mitigating the variability of renewable electricity sources: An updated review.* Energy for Sustainable Development, 2010. **14**(4): p. 302-314.

64. Ferreira, H.L., et al., *Characterisation of electrical energy storage technologies.* Energy, 2013. **53**: p. 288-298.

Chapter 4

4 Conclusions and Recommendations for Future Work

4.1 Conclusion

In this study, we presented techno-economic and life cycle assessments of Pumped hydroelectric storage (PHS) and compressed air energy storage (CAES). The objective was to develop comprehensive economic and environmental performance information that will serve as a decision-making tool for policy makers, industry, and government, and assist them in policy formulation. The first objective of the study was to build data-extensive techno-economic models to investigate economy of scale, capital investment, and life cycle costs of PHS and CAES. To that end, techno-economic simulation models were developed to investigate the power output of the storage systems and their equipment sizes. Five scenarios of different storage capacities for each energy storage system (ESS) considered were modeled ranging from 98 to 491 MW, 81 MW to 404 MW, and 60 to 298 MW for PHS, C-CAES, and A-CAES, respectively. The developed scale factors for PHS, C-CAES, and A-CAES are 0.5, 0.9, and 0.91, respectively. The results show that building large-capacity PHSs is advantageous from a cost point of view due to the favorable scale factor. Also, the total investment cost (TIC) per unit output decreases with increases in plant capacity due to economies of scale. Thus, it is always beneficial to build larger plant capacities for these technologies. The unit output capital cost is lowest for C-CAES, followed by PHS and then A-CAES. For CAES, three storage types were considered. The cost is lowest for a porous formation, slightly higher for a salt cavern, and highest for a hard rock formation. So, if locations permit, it is financially competitive to consider building C-CAES facilities with porous formation storage.

The levelized costs of electricity (LCOE) for the PHS, C-CAES, and A-CAES in base case are $84, $59, and $101 per MWh, respectively. For Alberta's electricity market, it was concluded that C-CAES can be integrated with any storage type and capacity and is economically attractive, whereas PHS is economically attractive only for plant capacities greater than 294 MW. A-CAES is not feasible for energy arbitrage[3] due to its high LCOE. The pump turbine efficiency, inlet temperature to the second turbine, and air flow rate are the most sensitive parameters in an LCOE of PHS, C-CAES, and A-CAES, respectively. Therefore, improving pump turbine efficiency can reduce the LCOE for PHS. Increasing the turbine inlet temperature and air flow rate can reduce the LCOE for CAES.

Another focus of this study was to present the NER and comprehensively evaluate the life cycle GHG emissions for PHS and CAES. To that extent, the NER was calculated and found to be 0.778, 0.542, and 0.702 for PHS, C-CAES, and A-CAES, respectively. The results show that PHS has the highest energy output among the three for the same amount of energy storage. The direct emission factors (DEFs), i.e. emissions associated with storage system per unit of energy produced were evaluated and found to be 7.79, 264.36, and 4.96, for the PHS, C-CAES, and A-CAES base cases, respectively. Though C-CAES has a strong economic case, its environmental performance is poor due to the high GHG emissions associated with it. The high GHG emissions are attributed to its hybrid nature (i.e., the electricity combustion requirement during the operation stage). The DEF for PHS and A-CAES is most sensitive to plant life, whereas the DEF for C-CAES is most sensitive to natural gas GHG emissions. Increasing the plant life will lower GHG emissions for PHS and A-CAES. The technological improvements in natural gas production and delivery will result in lower GHG emissions for C-CAES. The investigation of total emission factor (TEF) (ESS integrated with different energy mixes in Canada), shows that TEF is a function of

[3] *Energy arbitrage is buying the electricity at a particular time for a lower price, then sell it another time for a higher price.*

the origin of the stored electricity. The TEF is lower for PHS and A-CAES if the energy mix is renewable or nuclear and higher in the conventional energy mix. So, it can be concluded that renewables integrated with PHS and A-CAES perform better environmentally and have large potential to replace conventional energy production technologies.

The results of this techno-economic study provide insight into the cost competitiveness and environmental impacts of PHS and CAES. It can be concluded that the economic and environmental performance of ESS highly depends on system efficiency and energy mixes whose electricity is stored. The study looks into the life cycle costs, NERs, and GHG emissions of PHS and CAES. PHS performs best in NER, C-CAES in life cycle costs, and A-CAES in life cycle GHG emissions. The use of ESS is a crucial to achieve Alberta's CLP and the IEA's global two-degree targets. The emissions from Alberta's current energy mix are very high, 820 gCO_2e/kWh, because of the dominance of coal power production. A wind power plant integrated with C-CAES has emissions of 272 gCO_2e/kWh whereas a wind power plant integrated with A-CAES or PHS has emissions of only 21 gCO_2e/kWh. The emissions of a wind power plant integrated with A-CAES or PHS are far lower than the emissions of Alberta's current energy mix. Thus, it can be concluded that the CLP target of phasing out coal can be achieved with the implementation of more renewable power plants along with energy storage without compromising the reliability and flexibility of power systems. The cost framework developed in this work provides additional assurance of the competitiveness of energy storage systems.

4.2 Recommendations for Future Work

To improve the accuracy of the techno-economic and life cycle models for energy storage systems, further research can be conducted in the following areas:

1. A detailed optimization study can be performed to optimize each unit process in the technical simulation of PHS and CAES.

2. The cost of equipment used for PHS and CAES facilities was calculated based on existing costs in the literature. Alternately, real-time cost data can be taken from industry, and existing projects can be used and compared with theoretical results.
3. Other greenhouse gases and volatile compounds can be included in the analysis. Only three major greenhouse gases (CO_2, CH_4, and N_2O) are considered in this study to calculate life cycle GHG emissions. Other greenhouse gases like CO, SO_x, NO_x, etc., and compounds like volatile organic compounds, black carbon, etc., can be included to provide a more accurate representation of the total environmental impact of energy production from storage systems.
4. Additional work on decommissioning cost and emissions can be included. The cost recovery from the decommissioning of storage facilities can be evaluated. The emissions from the decommission stage can be extended to include scraping and recycling the equipment and material.
5. Both PHS and C-CAES are bound by location restraints. Large dams and reservoirs need to be built for PHS. Only a few suitable sites are available for such reservoirs. Also, building reservoirs sometimes displaces human settlements. Currently, C-CAES is cost-effective for underground storage, i.e., salt caverns, hard rock formations, abandoned mines, aquifers, etc. Further study can be performed to identify suitable sites in Canada for building PHS and CAES facilities and their implication on people, wildlife, and the environment.
6. Storing compressed air in above ground pipes or tanks can be investigated. Such storage would remove the geographical constraints on CAES and make it highly mobile.
7. Electricity source: Currently, the Alberta electricity market is the base from which GHG emissions and economic feasibility of storage technologies are evaluted. A study can

be done to compare the life cycle GHG emissions in building storage facilities as well as their economic feasibility in other jurisdictions.

8. Technological advancements: Recent technology advancements have made the implementation of ESS possible. Further advancements will bring new storage technologies and make existing technologies more competitive. A study can be performed to include these technological advancements.
9. The developed methodology can be implemented on other storage technologies such as battery storage systems, supercapacitors, and flywheel energy storage systems.
10. Finally, all the storage technologies can be considered and compared in terms of investment costs, GHG footprints. etc.

References

1. Kousksou, T., et al., *Energy storage: Applications and challenges.* Solar Energy Materials and Solar Cells, 2014. **120, Part A**: p. 59-80.
2. Poullikkas, A., *Implementation of distributed generation technologies in isolated power systems.* Renewable and Sustainable Energy Reviews, 2007. **11**(1): p. 30-56.
3. Rogelj, J., et al., *Paris Agreement climate proposals need a boost to keep warming well below 2 C.* Nature, 2016. **534**(7609): p. 631-639.
4. *Climate Change 2014: Mitigation of Climate Change* in *Climate Change*. 2014. p. 1246.
5. *National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada*. 2016: Canada.
6. *World Energy Resources* 2016: England and Wales.
7. Aneke, M. and M. Wang, *Energy storage technologies and real life applications – A state of the art review.* Applied Energy, 2016. **179**: p. 350-377.
8. Luo, X., et al., *Overview of current development in electrical energy storage technologies and the application potential in power system operation.* Applied Energy, 2015. **137**: p. 511-536.
9. Xu, Y. and C. Singh, *Adequacy and economy analysis of distribution systems integrated with electric energy storage and renewable energy resources.* IEEE Transactions on power systems, 2012. **27**(4): p. 2332-2341.
10. Hertwich, E.G., et al., *Integrated life-cycle assessment of electricity-supply scenarios confirms global environmental benefit of low-carbon technologies.* Proceedings of the National Academy of Sciences, 2015. **112**(20): p. 6277-6282.
11. Gielen, D., *Energy technology perspectives.* Paris: International Energy Agency, 2017.

12. Martinot, E., *Renewables 2015: Global status report.* REN21 Renewable Energy Policy Network/Worldwatch Institute, 2015: p. 251.

13. Hadjipaschalis, I., A. Poullikkas, and V. Efthimiou, *Overview of current and future energy storage technologies for electric power applications.* Renewable and Sustainable Energy Reviews, 2009. **13**(6–7): p. 1513-1522.

14. Decourt, B. and R. Debarre, *Electricity Storage*, in *Leading the energy transition*. 2013. p. 98.

15. Chen, H., et al., *Progress in electrical energy storage system: A critical review.* Progress in Natural Science, 2009. **19**(3): p. 291-312.

16. Cavallo, A.J., *Energy storage technologies for utility scale intermittent renewable energy systems.* Journal of solar energy engineering, 2001. **123**(4): p. 387-389.

17. Rahimi, E., *Alberta Climate Leadership Plan*. 2016.

18. Leach, A., et al., *Climate leadership: Report to minister*. 2015: Department of Environment Alberta and Climate Change Advisory Panel.

19. Beaudin, M., et al., *Energy storage for mitigating the variability of renewable electricity sources: An updated review.* Energy for Sustainable Development, 2010. **14**(4): p. 302-314.

20. Ferreira, H.L., et al., *Characterisation of electrical energy storage technologies.* Energy, 2013. **53**: p. 288-298.

21. *Technology Roadmap Energy storage*. 2014: France.

22. Rastler, D., *Electricity energy storage technology options: a white paper primer on applications, costs and benefits*. 2010: Electric Power Research Institute.

23. Denholm, P. and G.L. Kulcinski, *Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems.* Energy Conversion and Management, 2004. **45**(13–14): p. 2153-2172.

24. Ibrahim, H., A. Ilinca, and J. Perron, *Energy storage systems—Characteristics and comparisons.* Renewable and Sustainable Energy Reviews, 2008. **12**(5): p. 1221-1250.

25. Connolly, D., *A review of energy storage technologies: For the integration of fluctuating renewable energy*. 2010.

26. Palizban, O. and K. Kauhaniemi, *Energy storage systems in modern grids—Matrix of technologies and applications.* Journal of Energy Storage, 2016. **6**: p. 248-259.

27. Mahlia, T.M.I., et al., *A review of available methods and development on energy storage; technology update.* Renewable and Sustainable Energy Reviews, 2014. **33**: p. 532-545.

28. Schoenung, S.M. and W.V. Hassenzahl, *Long-vs. short-term energy storage technologies analysis. a life-cycle cost study. a study for the doe energy storage systems program.* Sandia National Laboratories, 2003.

29. Schoenung, S.M. and J. Eyer, *Benefit/cost framework for evaluating modular energy storage.* SAND2008-0978, 2008.

30. Schoenung, S., *Energy Storage Systems Cost Update* 2011.

31. Akhil, A.A., et al., *DOE/EPRI 2013 electricity storage handbook in collaboration with NRECA*. 2013: Sandia National Laboratories Albuquerque, NM.

32. Viswanathan, V., et al., *National Assessment of Energy Storage for Grid Balancing and Arbitrage, Phase II, Volume 2: Cost and Performance Characterization.* Report PNNL-21388, Pacific Northwest National Laboratory, Richland, WA, 2013.

33. Bozzolani, E., *Techno-economic analysis of compressed air energy storage systems.* 2010.

34. Zakeri, B. and S. Syri, *Electrical energy storage systems: A comparative life cycle cost analysis.* Renewable and Sustainable Energy Reviews, 2015. **42**: p. 569-596.

35. Locatelli, G., E. Palerma, and M. Mancini, *Assessing the economics of large Energy Storage Plants with an optimisation methodology.* Energy, 2015. **83**: p. 15-28.
36. Hiremath, M., K. Derendorf, and T. Vogt, *Comparative life cycle assessment of battery storage systems for stationary applications.* Environmental science & technology, 2015. **49**(8): p. 4825-4833.
37. Rydh, C.J., *Environmental assessment of vanadium redox and lead-acid batteries for stationary energy storage.* Journal of Power Sources, 1999. **80**(1): p. 21-29.
38. Jing, Y.-Y., et al., *Life cycle assessment of a solar combined cooling heating and power system in different operation strategies.* Applied Energy, 2012. **92**: p. 843-853.
39. Oró, E., et al., *Comparative life cycle assessment of thermal energy storage systems for solar power plants.* Renewable Energy, 2012. **44**: p. 166-173.
40. Oliveira, L., et al., *Environmental performance of electricity storage systems for grid applications, a life cycle approach.* Energy conversion and management, 2015. **101**: p. 326-335.
41. Sternberg, A. and A. Bardow, *Power-to-What?–Environmental assessment of energy storage systems.* Energy & Environmental Science, 2015. **8**(2): p. 389-400.
42. Ma, T., H. Yang, and L. Lu, *Feasibility study and economic analysis of pumped hydro storage and battery storage for a renewable energy powered island.* Energy Conversion and Management, 2014. **79**: p. 387-397.
43. Kadiyala, A., R. Kommalapati, and Z. Huque, *Evaluation of the life cycle greenhouse gas emissions from hydroelectricity generation systems.* Sustainability, 2016. **8**(6): p. 539.
44. Bouman, E.A., M.M. Øberg, and E.G. Hertwich, *Environmental impacts of balancing offshore wind power with compressed air energy storage (CAES).* Energy, 2016. **95**: p. 91-98.

45. Kousksou, T., et al., *Energy storage: Applications and challenges.* Solar Energy Materials and Solar Cells, 2014. **120, Part A**: p. 59-80.
46. *World Energy Outlook Special Report 2016: Energy and Air Pollution*. 2016. p. 266.
47. Poullikkas, A., *Implementation of distributed generation technologies in isolated power systems.* Renewable and Sustainable Energy Reviews, 2007. **11**(1): p. 30-56.
48. Fisher, A.C., *Energy and environment in the long term.* Energy Policy, 1989. **17**(2): p. 84-87.
49. Rogelj, J., et al., *Paris Agreement climate proposals need a boost to keep warming well below 2 C.* Nature, 2016. **534**(7609): p. 631-639.
50. Aneke, M. and M. Wang, *Energy storage technologies and real life applications – A state of the art review.* Applied Energy, 2016. **179**: p. 350-377.
51. Luo, X., et al., *Overview of current development in electrical energy storage technologies and the application potential in power system operation.* Applied Energy, 2015. **137**: p. 511-536.
52. Martinot, E., *Renewables 2015: Global status report.* REN21 Renewable Energy Policy Network/Worldwatch Institute, 2015: p. 251.
53. Hadjipaschalis, I., A. Poullikkas, and V. Efthimiou, *Overview of current and future energy storage technologies for electric power applications.* Renewable and Sustainable Energy Reviews, 2009. **13**(6–7): p. 1513-1522.
54. Decourt, B.D., Romain; , *Electricity Storage*, in *Leading the energy transition*. 2013.
55. Chen, H., et al., *Progress in electrical energy storage system: A critical review.* Progress in Natural Science, 2009. **19**(3): p. 291-312.
56. Beaudin, M., et al., *Energy storage for mitigating the variability of renewable electricity sources: An updated review.* Energy for Sustainable Development, 2010. **14**(4): p. 302-314.

57. Ferreira, H.L., et al., *Characterisation of electrical energy storage technologies.* Energy, 2013. **53**: p. 288-298.

58. Cavallo, A.J., *Energy storage technologies for utility scale intermittent renewable energy systems.* Journal of solar energy engineering, 2001. **123**(4): p. 387-389.

59. Ibrahim, H., A. Ilinca, and J. Perron, *Energy storage systems—Characteristics and comparisons.* Renewable and Sustainable Energy Reviews, 2008. **12**(5): p. 1221-1250.

60. Connolly, D., *A review of energy storage technologies: For the integration of fluctuating renewable energy*. 2010.

61. Palizban, O. and K. Kauhaniemi, *Energy storage systems in modern grids—Matrix of technologies and applications.* Journal of Energy Storage, 2016. **6**: p. 248-259.

62. Mahlia, T.M.I., et al., *A review of available methods and development on energy storage; technology update.* Renewable and Sustainable Energy Reviews, 2014. **33**: p. 532-545.

63. Schoenung, S.M. and W.V. Hassenzahl, *Long-vs. short-term energy storage technologies analysis. a life-cycle cost study. a study for the doe energy storage systems program.* Sandia National Laboratories, 2003.

64. Schoenung, S.M. and J. Eyer, *Benefit/cost framework for evaluating modular energy storage.* SAND2008-0978, 2008.

65. Schoenung, S., *Energy Storage Systems Cost Update* 2011.

66. Akhil, A.A., et al., *DOE/EPRI 2013 electricity storage handbook in collaboration with NRECA*. 2013: Sandia National Laboratories Albuquerque, NM.

67. Viswanathan, V., et al., *National Assessment of Energy Storage for Grid Balancing and Arbitrage, Phase II, Volume 2: Cost and Performance Characterization.* Report PNNL-21388, Pacific Northwest National Laboratory, Richland, WA, 2013.

68. Bozzolani, E., *Techno-economic analysis of compressed air energy storage systems.* 2010.
69. Zakeri, B. and S. Syri, *Electrical energy storage systems: A comparative life cycle cost analysis.* Renewable and Sustainable Energy Reviews, 2015. **42**: p. 569-596.
70. Locatelli, G., E. Palerma, and M. Mancini, *Assessing the economics of large Energy Storage Plants with an optimisation methodology.* Energy, 2015. **83**: p. 15-28.
71. Shinobe, O.A., *Economics of Underground Conversion in an Operating Limestone Mine*. 1997, McGill University Montreal, Canada.
72. *Technology Roadmap Energy storage*. 2014: France.
73. Rastler, D., *Electricity energy storage technology options: a white paper primer on applications, costs and benefits*. 2010: Electric Power Research Institute.
74. American Society of Civil, E., *Compendium of pumped storage plants in the United States*. 1993, New York, NY: The Society. 744 p.
75. Carson, J., et al., *Operation and maintenance experiences of pumped-storage plants*. 1991, Morrison-Knudsen Engineers, Inc., San Francisco, CA (USA); Electric Power Research Inst., Palo Alto, CA (USA).
76. Stelzer, R.S. and R.N. Walters, *Estimating reversible pump-turbine characteristics*. 1977, Bureau of Reclamation, Denver, CO (USA). Engineering and Research Center.
77. Korakianitis, T. and D.G. Wilson, *Models for Predicting the Performance of Brayton-Cycle Engines.* Journal of Engineering for Gas Turbines and Power, 1994. **116**(2): p. 381-388.
78. Cohen, H., et al., *Gas turbine theory.* 1987.
79. 35. Borgnakke, C. and R.E. Sonntag, *Fundamentals of thermodynamics*. 2009: Wiley.

80. Cengel, Y.A. and M.A. Boles, *Thermodynamics: an engineering approach.* Sea, 1994. **1000**: p. 8862.

81. Pollak, R., *History of First US Compressed-Air Energy Storage (CAES) Plant (110 MW 26h) Volume 2: Construction.* Electric Power Research Institute (EPRI), 1994.

82. Kays, W.M., R.K. Jain, and S. Sabherwal, *The effectiveness of a counter-flow heat exchanger with cross-flow headers.* International Journal of Heat and Mass Transfer, 1968. **11**(4): p. 772-774.

83. Kyle, B.G., *Chemical and process thermodynamics.* 1984.

84. Moore, W.J., *Basic physical chemistry*. 1983: Prentice Hall.

85. Walsh, P.P. and P. Fletcher, *Gas turbine performance*. 2004: John Wiley & Sons.

86. *Overall Heat Transfer Coefficient Table Charts and Equation* 2017 [cited 2017 July 1]; Available from: http://www.engineersedge.com/thermodynamics/overall_heat_transfer-table.htm.

87. McDonald, A.G. and H. Magande, *Introduction to thermo-fluids systems design*. 2012: John Wiley & Sons.

88. Crotogino, F., et al., *More than 20 years of successful operation. Spring 2001 Meeting of the Solution Mining Research Institute*. April.

89. Kaya, D., et al., *Energy efficiency in pumps.* Energy Conversion and Management, 2008. **49**(6): p. 1662-1673.

90. *Typical overall heat transfer coefficients (U-Values)*. 2017 [cited 2017 July 2]; Available from: http://www.engineeringpage.com/technology/thermal/transfer.html.

91. Jubeh, N.M. and Y.S. Najjar, *Green solution for power generation by adoption of adiabatic CAES system.* Applied Thermal Engineering, 2012. **44**: p. 85-89.

92. Gabbrielli, R. and R. Singh, *Economic and scenario analyses of new gas turbine combined cycles with no emissions of carbon dioxide.* Journal of engineering for gas turbines and power, 2005. **127**(3): p. 531-538.

93. Turton, R., et al., *Analysis, synthesis and design of chemical processes*. 2008: Pearson Education.

94. Norge, A., *Cost base for hydropower plants* J. Slapgård, Editor. 2012: Norway.

95. Dawes, J.H. and M. Wathne, *Cost of reservoirs in Illinois*. 1968: Illinois State Water Survey.

96. *Land value trends*. 2013: Alberta. p. 6.

97. Goodson, O.J., *History of First U.S. Compressed Air Energy Storage (CAES) Plant (110-MW-26 h): Volume 1: Early CAES Development*. 1993. p. 150.

98. Miller, P.C. *Bakken has lowest average drilling and completion cost*. 2016 April 06, 2016 [cited 2017 July 2]; Available from: http://thebakken.com/articles/1515/bakken-has-lowest-average-drilling-and-completion-cost.

99. *OCCinfo: Occupations and Educational Programs* 2015 [cited 2017 July 2]; Available from: http://occinfo.alis.alberta.ca/occinfopreview/info/browse-wages.html.

100. Peters, M.S., et al., *Plant design and economics for chemical engineers*. Vol. 4. 1968: McGraw-Hill New York.

101. Zamalloa, C., et al., *The techno-economic potential of renewable energy through the anaerobic digestion of microalgae.* Bioresource Technology, 2011. **102**(2): p. 1149-1158.

102. Veatch, B., *Cost and Performance Data for Power Generation Technologies.* Cost Report, ed. BVH Company, 2012.

103. Taylor, M., *Renewable Energy Technologies: Cost Analysis Series*, in *Hydropower*. 2012. p. 144.

104. *2014 Annual Market Statistics*. 2015.

105. 61. *Inflation*. [cited 2017 july 2]; Available from: http://www.bankofcanada.ca/core-functions/monetary-policy/inflation/.

106. Towler, G. and R. Sinnott, *Chapter 7 - Capital Cost Estimating*, in *Chemical Engineering Design (Second Edition)*. 2013, Butterworth-Heinemann: Boston. p. 307-354.

107. *What Is Climate Change?* 2014 [cited 2017 July 11]; Available from: https://www.nasa.gov/audience/forstudents/k-4/stories/nasa-knows/what-is-climate-change-k4.html.

108. Rogelj, J., et al., *Paris Agreement climate proposals need a boost to keep warming well below 2 C.* Nature, 2016. **534**(7609): p. 631-639.

109. *Climate Change 2014: Mitigation of Climate Change* in *Climate Change*. 2014. p. 1246.

110. *National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada*. 2016: Canada [cited 2017 Sep 10]; Available from: https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.

111. *World Energy Resources* 2016: England and Wales [cited 2017 Sep 10]; Available from: https://www.worldenergy.org/wp-content/uploads/2016/10/World-Energy-Resources-Full-report-2016.10.03.pdf.

112. Gielen, D., *Energy technology perspectives.* Paris: International Energy Agency, 2017 [cited 2017 Sep 10] ; Available from: https://www.iea.org/publications/freepublications/publication/EnergyTechnologyPerspectives2017ExecutiveSummaryEnglishversion.pdf.

113. Rahimi, E., *Alberta Climate Leadership Plan*. 2016.

114. Leach, A., et al., *Climate leadership: Report to minister*. 2015: Department of Environment Alberta and Climate Change Advisory Panel.

115. Xu, Y. and C. Singh, *Adequacy and economy analysis of distribution systems integrated with electric energy storage and renewable energy resources.* IEEE Transactions on power systems, 2012. **27**(4): p. 2332-2341.

116. Hertwich, E.G., et al., *Integrated life-cycle assessment of electricity-supply scenarios confirms global environmental benefit of low-carbon technologies.* Proceedings of the National Academy of Sciences, 2015. **112**(20): p. 6277-6282.

117. Decourt, B.D., Romain;, *Electricity Storage*, in *Leading the energy transition*. 2013.

118. *How Energy Storage Works*. [cited 8 Aug 2017]; Available from: http://www.ucsusa.org/clean-energy/how-energy-storage-works#.WZ3-U1FGmUk.

119. Denholm, P. and G.L. Kulcinski, *Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems.* Energy Conversion and Management, 2004. **45**(13–14): p. 2153-2172.

120. Hiremath, M., K. Derendorf, and T. Vogt, *Comparative life cycle assessment of battery storage systems for stationary applications.* Environmental science & technology, 2015. **49**(8): p. 4825-4833.

121. Rydh, C.J., *Environmental assessment of vanadium redox and lead-acid batteries for stationary energy storage.* Journal of Power Sources, 1999. **80**(1): p. 21-29.

122. Jing, Y.-Y., et al., *Life cycle assessment of a solar combined cooling heating and power system in different operation strategies.* Applied Energy, 2012. **92**: p. 843-853.

123. Oró, E., et al., *Comparative life cycle assessment of thermal energy storage systems for solar power plants.* Renewable Energy, 2012. **44**: p. 166-173.

124. Oliveira, L., et al., *Environmental performance of electricity storage systems for grid applications, a life cycle approach.* Energy conversion and management, 2015. **101**: p. 326-335.

125. Sternberg, A. and A. Bardow, *Power-to-What?–Environmental assessment of energy storage systems.* Energy & Environmental Science, 2015. **8**(2): p. 389-400.

126. Ma, T., H. Yang, and L. Lu, *Feasibility study and economic analysis of pumped hydro storage and battery storage for a renewable energy powered island.* Energy Conversion and Management, 2014. **79**: p. 387-397.

127. Kadiyala, A., R. Kommalapati, and Z. Huque, *Evaluation of the life cycle greenhouse gas emissions from hydroelectricity generation systems.* Sustainability, 2016. **8**(6): p. 539.

128. Bouman, E.A., M.M. Øberg, and E.G. Hertwich, *Environmental impacts of balancing offshore wind power with compressed air energy storage (CAES).* Energy, 2016. **95**: p. 91-98.

129. Energy Center, *Life-Cycle Energy Costs and Greenhouse Gas Emissions for Gas Turbine Power.* 2000.

130. Kapila, S., A.O. Oni, and A. Kumar, *The development of techno-economic models for large-scale energy storage systems.* Energy, 2017. **140**(Part 1): p. 656-672.

131. American Society of CIvil Engineers, *Compendium of pumped storage plants in the United States*. 1993, New York, NY: American Society of Civil Engineers. 744 p.

132. Carson, J., et al., *Operation and maintenance experiences of pumped-storage plants*. 1991, Morrison-Knudsen Engineers, Inc., San Francisco, CA (USA); Electric Power Research Inst., Palo Alto, CA (USA).

133. Stelzer, R.S. and R.N. Walters, *Estimating reversible pump-turbine characteristics*. 1977, Bureau of Reclamation, Denver, CO (USA). Engineering and Research Center.

134. MWH Americas, I., et al., *Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest*. 2009: MWH.

135. Barnes, F.S. and J.G. Levine, *Large energy storage systems handbook*. 2011: CRC press.

136. McDonald, A.G. and H. Magande, *Introduction to thermo-fluids systems design*. 2012: John Wiley & Sons.

137. Bozzolani, E., *Techno-economic analysis of compressed air energy storage systems, 2010,* Cranfield Collection of E-Research, U.K.

138. Kyle, B.G., *Chemical and process thermodynamics*. 3rd ed. 1984: Prentice-Hall, Inc., Englewood Cliffs, NJ.

139. Moore, W.J., *Basic physical chemistry*. 1983: Prentice Hall.

140. Walsh, P.P. and P. Fletcher, *Gas turbine performance*. 2004: John Wiley & Sons.

141. Kays, W.M., R.K. Jain, and S. Sabherwal, *The effectiveness of a counter-flow heat exchanger with cross-flow headers.* International Journal of Heat and Mass Transfer, 1968. **11**(4): p. 772-774.

142. *Overall Heat Transfer Coefficient Table Charts and Equation* 2017 [cited 2017 July 1]; Available from: http://www.engineersedge.com/thermodynamics/overall_heat_transfer-table.htm.

143. Pollak, R., *History of First US Compressed-Air Energy Storage (CAES) Plant (110 MW 26h) Volume 2: Construction.* Electric Power Research Institute (EPRI), 1994.

144. Crotogino, F., et al. *More than 20 years of successful operation. Spring 2001 Meeting of the Solution Mining Research Institute*. [cited 2017 Sep 10]; Available from: http://www.fze.uni-saarland.de/AKE_Archiv/AKE2003H/AKE2003H_Vortraege/AKE2003H03c_Crotogino_ea_HuntorfCAES_CompressedAirEnergyStorage.pdf.

145. Jubeh, N.M. and Y.S. Najjar, *Green solution for power generation by adoption of adiabatic CAES system.* Applied Thermal Engineering, 2012. **44**: p. 85-89.

146. *Typical overall heat transfer coefficients (U-Values)*. 2017 [cited 2017 July 2]; Available from: http://www.engineeringpage.com/technology/thermal/transfer.html.

147. *Density of Some Common Building Materials*. 2017 [cited 2017 Sep 5]; Available from: http://www.rfcafe.com/references/general/density-building-materials.htm.

148. Adams, M., et al., *European Union emission inventory report 1990–2010 under the UNECE Convention on Long-range Transboundary Air Pollution (LRTAP)*. 2012, EEA technical report.

149. Norge, A., *Cost base for hydropower plants* J. Slapgård, Editor. 2012: Norway.

150. Flury, K. and R. Frischknecht, *Life cycle inventories of hydroelectric power generation.* ESU-Services, Fair Consulting in Sustainability, commissioned by€ Oko-Institute eV, 2012: p. 1-51.

151. *The choice of materials for turbines*. [cited 2017 July 17]; Available from: http://www.ivt.ntnu.no/ept/fag/tep4200/innhold/The%20choice%20of%20materials.pdf.

152. *Bath County, USA*. [cited 2017 July 16]; Available from: http://voith.com/en/markets-industries/industries/hydro-power/pumped-storage-plants/bathcounty_main-11333-11333.html.

153. *Ecoinvent 3.3*. 2017 [cited 2017 12 June]; Available from: http://www.ecoinvent.org/.

154. Iron, A., S. Institute, and S.P.F. Association, *Buried Steel Penstocks*. 1992: American Iron and Steel Institute.

155. *Concrete - Properties*. 2017 [cited 2017 July 17]; Available from: http://www.engineeringtoolbox.com/concrete-properties-d_1223.html.

156. *Trees Improve Our Air Quality*. 2017 [cited 2017 July 19]; Available from: http://urbanforestrynetwork.org/benefits/air%20quality.htm.

157. Succar, S.W., Robert H. , *"Compressed Air Energy Storage: Theory, Resources and Applications for Wind Power*. 2008.

158. Waheed, M.A. and A.O. Oni, *Performance improvement of a crude oil distillation unit.* Applied Thermal Engineering, 2015. **75**: p. 315-324.

159. *Plants and Facilities* 2017 [cited 2017 28 Aug]; Available from: http://www.aer.ca/data-and-publications/statistical-reports/plants-and-facilities.

160. *Wind energy in Canada*. [cited 2017 28 Aug]; Available from: http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/pdf/fichier/81770/windtrm_resource_map.pdf.

161. Nimana, B., et al., *Life Cycle Analysis of Bitumen Transportation to Refineries by Rail and Pipeline.* Environmental Science & Technology, 2017. **51**(1): p. 680-691.

162. Bock, T., *Greenhouse Gas Emissions and the Decommissioning of Hydroelectric Dams.*

163. Kousksou, T., et al., *Energy storage: Applications and challenges.* Solar Energy Materials and Solar Cells, 2014. **120, Part A**: p. 59-80.

164. Akhil, A.A., et al., *DOE/EPRI 2013 electricity storage handbook in collaboration with NRECA*. 2013: Sandia National Laboratories Albuquerque, NM.

165. *GREET Vehicle Cycle (GREET 2)*, A.N. Laboratory, Editor. 2016: Argonne, IL.

166. *AP 42, Fifth Edition, Volume I Chapter 13: Miscellaneous Sources*. U.S.

167. *GREET Fuel Cycle (GREET 1)*, A.N. Laboratory, Editor. 2016: Argonne, IL.

168. Schlömer, S., et al., *Annex III: Technology-specific cost and performance parameters.* Climate change, 2014: p. 1329-1356.

169. Beaudin, M., et al., *Energy storage for mitigating the variability of renewable electricity sources: An updated review.* Energy for Sustainable Development, 2010. **14**(4): p. 302-314.

170. Ferreira, H.L., et al., *Characterisation of electrical energy storage technologies.* Energy, 2013. **53**: p. 288-298.

Appendix A

Cost functions of considered ESS are depicted in Tables A 1 and A 2.

Table A 1: PHS equipment and their cost functions

Equipment or component	Cost equation
Pump turbine	$500.25 * 10^3 * Q^{-0.3139} * P)$
Generator	$0.6067 * 10^6 * P^{0.6306}$
Tunnels & pipes	$0.9 * 0.0027 * D^{1.8267} * L$
Penstock valve	$166 * (0.0003 * D^2 - 0.2699 * D + 301)$
Gates	$0.2209 * 10^6 * X^{0.5796}$
Misc. equipment	$0.166 * ((-38.795 \ * \ln X + 309.89) * (\frac{P}{10^3})$
Surge chamber	$59.8 * 360 * S_x * S_h$
Dam	$694.456 * H^{1.69} * W$

Where,

Q is the water flow rate in (m^3/s)

P is the power input (MW)

D is the diameter of penstock (mm)

L is the length of penstock (m)

X is the cross-section area of penstock (m^2)

S_x is the surge chamber cross section (m^2)

S_h is the height of surge chamber (m)

W is the width of dam (m)

H is the height of dam (m)

Table A 2: CAES equipment and their cost functions

Equipment or component	Cost equation
Compressor	$(\frac{74}{1-n_c}) * m * r_c * \ln r_c$
Turbine	$(\frac{1763}{1-n_e}) * m * ln r_e * (1 + e^{(0.036*TIT-65.66)})$
Generator	$133 * P^{0.95}$
Heat exchanger or intercooler	$4016 * S^{0.69} * {P_r}^{0.28}$
Combustor	$(\frac{862}{1-f_{cc}}) * m * (1 + e^{(0.018*TIT-31.86)}$
Pump	$5569 * {P_{pump}}^{0.71} * (1 + (\frac{(1-0.8)^3}{(1-n)^3})$
Storage tank	$3.42 * 10^{(3.4974+0.4483*log(V)+0.1074*(log(V))^2)}$

Where,

P is the power of generator (kW)

n_c is the isentropic efficiency of the compressor

r_c is the compression ratio

n_c is the isentropic efficiency of the compressor

m is the mass flow rate of air (kg/s)

r_e is the expansion ratio

S is the surface area of heat exchanger or intercooler (m^2)

P_r is the max pressure (bar)

f_{cc} is the pressure drop in the combustor

TIT is the turbine inlet temperature (k)

P_{ump} is the power of pump (KW)

V is the volume of storage tank (m^3)