Assessing the economic feasibility of utility-scale electrical energy storage technologies for South Africa

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> “Energy is the master resource, because energy enables us to convert one material into another. As natural scientists continue to learn more about the transformation of materials from one form to another with the aid of energy, energy will be even more important. Therefore, if the cost of usable energy is low enough, all other important resources can be made plentiful.”
>
> – Julian Simon (1996:162).

ABSTRACT

Increased electrical production from renewable energy technologies, such as solar photovoltaic (PV) and wind plants, is at the forefront of the global energy transition to environmentally sustainable economic growth and development. The variability and intermittency associated with their resources, however, entail growing risks to the stability of electricity systems as their share in total electricity generation capacity rises. Energy storage systems provide an opportunity to overcome the risks associated with renewable energy technologies, although uncertainty regarding their technical capability and cost competitiveness has limited their application at the utility scale.

The purpose of this study is to assess the competitive ability and economic feasibility of utility-scale energy storage systems for South Africa in 2016 and projected for 2020. The research method to achieve this general objective is divided into a literature review and empirical analysis. Background is provided on the role for energy storage in electricity environments characterised by rising shares of variable and intermittent renewable energy electrical production plants. Context is offered by clarifying the utility-scale energy storage concept, need, system components, selection criteria, various technologies, technical characteristics, value applications, costs and related considerations. Literature regarding the economic feasibility of energy storage technologies is reviewed and the relevance of such technologies to economic theory is explained. Existing methods to analyse and forecast the economic feasibility or cost competitiveness of energy storage systems is improved upon and applied in practice.

A novel contribution of this study is the development, description and use of a techno-economic levelised cost of energy storage (LCOS) model and its extension to the weighted average levelised cost of energy storage systems coupled with solar PV plants (LCOS-PV). The LCOS articulates the comparable present value cost per kilowatt hour (kWh) over the lifetime of an energy storage system, while accounting for all lifecycle cost and technical performance parameters. The methods are applied to estimate, project and assess the cost competitiveness of utility-scale energy storage systems with one another and alternative electrical generation options.

The technologies selected for the empirical analysis include lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries. This is due to their modular scalability to provide high energy and/or electrical power capacity and capability to perform the primary utility-scale application investigated, namely renewables integration with solar PV plants. The application requires the select technologies to discharge electrical energy for four hours at a 50 megawatt (MW) power rating for 350 days a year to overcome solar resource variability and intermittency, supply electrical energy during peak demand periods, enable electricity price arbitrage and integrate more renewable generators into the electric grid. These services are important for economic growth and development by supporting electrical energy security, reliability, flexibility, access and relative affordability. The modelling results are evaluated under four scenarios as a function of either one or two charge-discharge cycles per day and 10- or 20-year project contract lifetimes.

The outcome of this study confirms the economic feasibility or cost competitiveness of the select utility-scale energy storage technologies for South Africa. It is demonstrated empirically that the select energy storage systems coupled with solar PV plants offer improved investment alternatives in comparison to concentrating solar power (CSP) plants with thermal energy storage capability. More specifically, under the most cost competitive scenario, which requires two daily cycles over 20 years, the collective average LCOS-PV is approximately 20.8% and 27.2% lower than the levelised cost of electricity (LCOE) for CSP plants with thermal energy storage capability in 2016 and projected for 2020, respectively. The select technologies coupled with solar PV plants could conceivably further be economic alternatives to some fossil fuel-based electrical generation options within the South African context. The cost competitiveness of energy storage and renewable energy technologies will continue to improve and increasingly displace the need for conventional electricity generators. This study involves academic, practical and policy recommendations, as well as suggestions for further research.

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JEL classification: C02, L94, N77, O00, O33, P18, Q01, Q42, Q43, Q47, Q48, Q55

Key terms: Electricity, energy storage, batteries, lithium-ion, vanadium redox flow (VRFB), sodium-sulphur (NaS), technologies, applications, levelised cost of storage (LCOS), utility-scale, solar photovoltaic (PV), cost competitiveness, economic feasibility, energy economics, economic theory, economic development, projections, South Africa

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OPSOMMING

Toenemende elektriese produksie vanaf hernubare energie-tegnologieë, soos fotovoltaïese (PV) son- en windkragaanlegte, is aan die voorpunt van die globale energie-oorskakeling na omgewingsvolhoubare ekonomiese groei en ontwikkeling. Die veranderlike en onderbroke aard van hul bronne behels egter groeiende risiko's vir die stabiliteit van elektrisiteitstelsels soos hul aandeel in totale kragopwekkingskapasiteit styg. Energiestoorstelsels bied ŉ geleentheid om die risiko's verbonde aan hernubare energie-tegnologieë te oorkom, alhoewel onsekerheid aangaande hul tegniese vermoë en koste-mededingendheid hul toepassing op kragvoorsiener-skaal beperk.

Die doel van hierdie studie is om die mededingende vermoë en ekonomiese lewensvatbaarheid van kragvoorsiener-skaal energiestoorstelsels vir Suid-Afrika te assesseer in 2016 en geprojekteer vir 2020. Die navorsingsmetode om hierdie doelstelling te bereik, is verdeel in ŉ literatuuroorsig en empiriese analise. Agtergrond word verskaf oor die rol van energieberging in elektrisiteit-omgewings wat gekenmerk is deur stygende aandele van veranderlike en onderbroke hernubare energie elektriese-aanlegte. Konteks word aangebied deur ŉ verduidelikking van die kragvoorsiener-skaal energiestoor konsep, behoefte, stelselkomponente, seleksiekriteria, verskeie tegnologieë, tegniese eienskappe, waarde-applikasies, kostes en verwante oorwegings. Literatuur aangaande die ekonomiese lewensvatbaarheid van energiestoortegnologieë word hersien en die toepaslikheid van sulke tegnologieë op ekonomiese teorie word verduidelik. Bestaande metodologie om die ekonomiese haalbaarheid of kostemededingendheid van energiestoorstelsels te analiseer en voorspel, word verbeter en prakties toegepas.

ŉ Besondere bydrae van hierdie studie is die ontwikkeling, beskrywing en gebruik van ŉ tegno-ekonomiese lewensikluskoste van energie stoor (LCOS)-model en die uitbreiding daarvan na die geweegde gemiddelde lewensikluskoste van energiestoorstelsels gekoppel aan PV-sonkragaanlegte (LCOS-PV). Die LCOS artikuleer die vergelykbare huidige waarde koste per kilowattuur (kWh) oor die leeftyd van ŉ energiestoorstelsel terwyl alle lewensikluskostes en tegniese uitvoeringsparameters in ag geneem word. Die metodes word toegepas om die kostemededingendheid van kragvoorsiener-skaal energie-stoorstelsels met mekaar en alternatiewe elektriese opwekking opsies te beraam, projekteer en evalueer.

Die tegnologieë wat geselekteer is vir die empiriese analise sluit in litium-ioon, vanadium redoks-vloei (VRFB) en natrium-swael (NaS)-batterye. Dit is ’n gevolg van hul modulêre skaalbaarheid om hoë energie en/of elektriese kragkapasiteit te lewer en vermoë om die primêre kragvoorsiener-skaal-applikasie wat ondersoek word, naamlik hernubare integrasie met PV-sonkragaanlegte, uit te voer. Die applikasie vereis dat die geselekteerde tegnologieë vir vier ure elektriese energie ontlaai teen ’n 50 megawatt (MW) kraggradering vir 350 dae per jaar om die veranderlikheid en onderbroke natuur van sonkragbronne te oorkom, elektriese energie tydens piek aanvraagperiodes te voorsien, elektrisiteitprys-arbitrasie moontlik te maak en meer hernubare kragopwekkers in die elektrisiteitsnetwerk te integreer. Hierdie dienste is belangrik vir ekonomiese groei en ontwikkeling deur die sekuriteit, betroubaarheid, buigsaamheid, toegang en relatiewe bekostigbaarheid van elektrisiteit te ondersteun. Die modelleringsresultate word onder vier scenario’s geëvalueer as ’n funksie van een of twee laai-ontlaai-siklusse per dag en 10 of 20 jaar-projekkontrak leeftye.

Die uitkoms van hierdie studie bevestig die ekonomiese lewensvatbaarheid of koste mededingendheid van die geselekteerde kragvoorsiener-skaal energiestoortegnologieë vir Suid-Afrika. Daar word empiries bewys dat die geselekteerde energiestoorstelsels tesame met PV-sonkragaanlegte beter beleggingsalternatiewe bied in vergelyking met konsentrerende sonkragstasies (CSP) met termiese-energie-bergingsvermoë. Meer spesifiek is die kollektiewe gemiddelde LCOS-PV onder die mees koste-mededingende scenario, wat twee daaglikse siklusse oor 20 jaar benodig, onderskeidelik ongeveer 20.8% en 27.2% laer as die lewensikluskoste van elektrisiteit (LCOE) vir CSP met termiese-energie-bergingsvermoë in 2016 en geprojekteer vir 2020. Die tegnologieë in kombinasie met PV-sonkragaanlegte mag moontlik verder ekonomiese alternatiewe wees vir sommige fossielbrandstof-gebaseerde elektriese kragopwekkingsopsies binne die Suid-Afrikaanse konteks. Die kostemededingendheid van energiebergings- en hernubare energie-tegnologieë sal voortdurend verbeter en die behoefte aan konvensionele elektriese kragopwekkers toenemend verplaas. Hierdie studie behels akademiese, praktiese en beleidsaanbevelings, asook voorstelle vir verdere navorsing.

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JEL-klassifikasie: C02, L94, N77, O00, O33, P18, Q01, Q42, Q43, Q47, Q48, Q55

Sleutelterme: Elektrisiteit, energiestoor, batterye, litium-ioon, vanadium redoks-vloei (VRFB), natrium-swael (NaS), tegnologieë, applikasies, lewensikluskoste van energiestoor (LCOS), kragvoorsiener-skaal, sonkrag fotovoltaïese (PV), ekonomiese lewensvatbaarheid, kostemededingendheid, energie-ekonomie, ekonomiese teorie, ekonomiese ontwikkeling, projeksies, Suid-Afrika

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PREFACE

Electricity is an important driver of economic growth and development. Concurrently, it is our collective responsibility to reduce the reliance on environmentally unsustainable, human health endangering and finite fossil fuel-based electrical generators through the increased adoption of renewable energy-related alternatives. While electricity generation from solar- and wind-based renewable energy electrical production plants will continue to rise in South Africa and elsewhere, the stochastic nature of their resources involve growing risks to the stability of the electric grid and maintaining a continuous balance between electricity supply and prevailing demand.

Fortunately, energy storage technologies have the technical capability to help overcome the electric output variability and intermittency associated with renewable energy-based electrical generators, such as solar photovoltaic (PV) plants. This is particularly important as the share of these, often opinionated as precarious, electrical producers in total installed electricity generation capacity increases. The widespread application of energy storage systems, however, is influenced by their economic cost competitiveness relative to alternative electrical energy solutions. Integrating economically viable and technically advanced energy storage systems with renewable energy electrical production plants would support and accelerate the transition to a more environmentally conscious energy landscape in a manner that promotes sustainable economic growth and development.

Uncertainty about the performance characteristics and cost competitiveness of utility-scale energy storage technologies, however, has limited their appropriate inclusion in national electricity planning, policy and regulatory frameworks. The commercialisation and implementation of energy storage systems as potentially superior electricity system solutions has consequently been restricted. It is therefore important to develop improved analytical techniques to evaluate the economic viability of such systems. This general ambivalence contributed to the initiation of this dissertation in order to study and assess the economic feasibility of energy storage systems, in isolation and coupled with solar PV plants, within the South African context and to disseminate the acquired knowledge to interested readers. The economic value of this study is embedded in the diffusion of contextual and empirical information that supports the structural transformation towards a more efficient, cost effective and environmentally sustainable electricity industry.

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On a more personal note, I would like to sincerely thank my friends and loved ones for their persistent encouragement, understanding and support. You know who you are and the next one is on me! I would also like to extend my heartfelt appreciation to Ms Nellie Mkhwanazi for her care and general assistance.

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Deon Fourie
10 September 2017
Potchefstroom

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LIST OF ABBREVIATIONS

AC	Alternating Current
°C	Degrees Celsius
¢	Currency Cents
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CSIR	Council for Scientific and Industrial Research
CSP	Concentrating Solar Power
DC	Direct Current
DoD	Depth of Discharge
EIA	United States Energy Information Administration
EUR	Euros
FeCr	Iron-Chromium
Hz	Hertz
IEA	International Energy Agency
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan for Electricity
kg	kilogram
kW	kilowatt
kWh	kilowatt Hour
l	Litre
LCOE	Levelised Cost of Electricity Generation
LCOS	Levelised Cost of Energy Storage

LIST OF ABBREVIATIONS (CONTINUED)

LCOS-PV	Weighted Average Levelised Cost of Energy Storage Systems Coupled with Solar Photovoltaic (PV) Plants
MW	Megawatt
MWh	Megawatt Hour
NaS	Sodium-Sulphur
NERSA	National Energy Regulator of South Africa
NiCd	Nickel-Cadmium
NiMH	Nickel-Metal Hydride
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
PCS	Power Conversion System
PHS	Pumped Hydroelectric Energy Storage
PPA	Power Purchase Agreement
PSB	Polysulfide Bromine
PV	Photovoltaic
REIPPPP	Renewable Energy Independent Power Producers Procurement Programme
SMES	Superconducting Magnetic Energy Storage
USD	United States Dollars
VRFB	Vanadium Redox Flow Batteries
W	Watt
Wh	Watt Hour
ZEBRA	Zero Emission Battery Research Activity or Zeolite Applied to Battery Research Africa
$NaNiCl_2$	Sodium-Nickel-Chloride
ZnBr	Zinc-Bromine

CHAPTER 1:

INTRODUCTION, BACKGROUND AND RESEARCH DESCRIPTION

1.1 INTRODUCTION

Stable, reliable and affordable electricity availability is essential for economic growth and development (Khan & Arsalan, 2016:415; Mandelli, Molinas, Park, Leonardi, Colombo & Merlo, 2016:287-288; Nhamo & Mukonza, 2016:69; Kyriakopoulos & Arabatzis, 2016:1045; Amirante, Cassone, Distaso & Tamburrano, 2017:373). At the same time, countries must strive to minimise the impact of economic activity on the environment and climate change (Tapia Granados & Carpintero, 2013:693-705; Price & Elu, 2015:54-55; Kyriakopoulos *et al.*, 2016:1045-1065).

Renewable energy-based electrical production techniques, especially from solar photovoltaic (PV) and wind plants, are driving the global transition to more environmentally sustainable, low-carbon, electricity systems (Khan *et al.*, 2016:414; Aneke & Wang, 2016:351; Nhamo *et al.*, 2016:69-73; Amirante *et al.*, 2017:373). The stochastic nature of their resources, due to a dependence on prevailing weather conditions, however, entails a growing risk to maintaining grid stability and therefore limits their integration into the electric grid (Akinyele & Rayudu, 2014:74-88; Zakeri & Syri, 2015:570-571; Delarue & Morris, 2015:4-10; Lazkano, Nøstbakken & Pelli, 2017:3).

Energy storage systems fortunately offer enhanced flexibility that can be used to overcome the electric output variability and intermittency associated with many renewable energy technologies so that available electricity supply can equal prevailing demand at any given time. This ensures the stability of the electric grid, improves the efficiency of the electricity industry and supports transitioning to a more environmentally sustainable, reliable and secure electricity system (Akinyele *et al.*, 2014:74-75; Lund, Lindgren, Mikkola & Salpakari, 2015:793-799; Aneke *et al.*, 2016:350-352; Kyriakopoulos *et al.*, 2016:1045-1065; Amirante *et al.*, 2017:373; Lazkano *et al.*, 2017:1-16).

Uncertainty about the economic feasibility of energy storage systems, however, have restricted their incorporation into the South African electrical energy landscape (Kempener & Borden, 2015:5-24; Ferroukhi, Sawin, Sverisson, Wuester, Kieffer, Nagpal, Hawila, Khalid, Saygin & Vinci, 2017:80; Rycroft, 2017:22). It is therefore important to determine the cost competitiveness of energy storage systems relative to alternative electrical energy solutions at the utility scale in order to establish their economic viability for widespread implementation (Pawel, 2014:68-69; Kondziella & Bruckner, 2016:20; Amirante *et al.*, 2017:373-385).

The intention of this study is consequently to assess the economic feasibility of utility-scale electrical energy storage technologies for South Africa. Accordingly, it offers a novel contribution to literature through the development, description and use of a levelised cost of energy storage (LCOS) model and its extension to appropriately estimate, project and assess the cost competitiveness of utility-scale energy storage systems with one another and, in combination with solar photovoltaic (PV) plants, with alternative electrical generation options. The utility-scale application investigated refers to energy storage systems that are sized to the equivalent nominal output capacity of an electrical power station. In that regard, the mathematical modelling involves energy storage systems that are required to discharge electrical energy for four hours per day during the morning and/or evening peak demand periods at a 50 megawatt (MW) electrical power rating.

Chapter 1 provides an introduction to the research conducted for this dissertation as necessary to address the research problem and attain the set objectives. In that regard, the goal of this chapter is to outline the primary thesis; clarify key terms; provide background information on the research topic; describe the research problem, questions and objectives; explain the method through which the research objectives will be realised; convey the scope of research and express the research contributions. This provides the relevant context for the literature review and empirical analysis throughout the remainder of this study.

This chapter is structured according to ten sections. The next section (1.2) describes the key terms in the title to this study. Section 1.3 provides background information on the growing importance of renewable energy-based electrical generation options, the need to maintain a continuous balance between electricity demand and supply as the share of renewables rise and the potential for energy storage technologies to support the stability of electricity systems.

Section 1.4 describes the research problem that is addressed by this study. Section 1.5 stipulates the research questions to be resolved. Section 1.6 establishes the research objectives to be attained. Section 1.7 explains the research method to attain the specific objectives set for the study through a literature review, novel methodological description and empirical analysis. Section 1.8 outlines the scope of research through a division of chapters. Section 1.9 indicates the academic, practical and policy contributions of this dissertation. Section 1.10 summarises and concludes Chapter 1.

1.2 KEY TERMS

A description of the key terms as reflected in the title of this dissertation will provide clarity regarding the focus of research conducted for this study. An economic feasibility assessment involves determining the degree to which the advantages or value derived from a proposed investment outweigh the associated costs or the costs of prevailing alternatives (Whipple, 1962:219-220; Young, 1970:376-377; Sullivan, Wicks & Koelling, 2015:187-467). It entails an investigation into overall technology costs and determining the extent to which technologies can compete with alternatives (Kondziella *et al.*, 2016:12-17). The term ‘technology’ refers to the technical processes, knowledge or methods through which a task is accomplished (Comin & Mestieri, 2014:565).

An electric utility is commonly known to represent a physical structure involved in the generation, transmission, distribution and/or procurement of electricity (Sim, 2012:11). Utility-scale electrical energy refers to the generation of electricity for bulk supply by way of an electric transmission grid (Walston, Rollins, LaGory, Smith & Meyers, 2016:405). While there is no clearly specified definition for the minimum size that characterises utility-scale electrical energy, such generation plants are generally regarded to have a power rating of more than one megawatt (MW) capacity (Hernandez, Easter, Murphy-Mariscal, Maestre, Tavassoli, Allen, Barrows, Belnap, Ochoa-Hueso, Ravi & Allen, 2013:767-768; Johnstone & Haščič, 2013:143; Giglmayr, Brent, Gauché & Fechner, 2015:779; Dehdashti, 2016:1; Walston *et al.*, 2016:405).

Energy storage involves a process of converting electrical power into an energy form and storing it in a tangible installation for later use by converting it back to electrical energy upon demand (Baxter, 2006:3; Chen, Cong, Yang, Tan, Li & Ding, 2009:291; Evans, Strezov & Evans, 2012:4142; Akinyele *et al.*, 2014:76; Kousksou, Bruel, Jamil, El Rhafiki & Zeraouli, 2014:60; Luo, Wang, Dooner & Clarke, 2015:511; Ibrahim, Belmokhtar & Ghandour, 2015:306; Mandelli *et al.*, 2015:113). Similarly, electrical energy storage refers to the charging or absorption of electric power into a device and storing it as energy for later discharge and use as electricity when required (Suberu, Mustafa & Bashir, 2014:500-501; Gallo, Simões-Moreira, Costa, Santos & dos Santos, 2016:802). The ability to store electrical energy provides flexibility that can support the supply or generation of electricity to equal prevailing demand or load at any given time (Baxter, 2006:4; Sørensen, 2011:540; Chaanaoui, Vaudreuil & Bounahmidi, 2016:783; World Energy Council, 2016a:6-8; Berrada, Loudiyi & Zorkani, 2017:94).

Energy storage technologies denote different mechanical, thermal, electrical, chemical and electrochemical apparatus that share the common capability to transform electricity as an input, store it as energy and provide electricity as an output when needed (Suberu *et al.*, 2014:501; Luo *et al.*, 2015:511; Mandelli, Brivio, Leonardi, Colombo, Molinas, Park & Merlo, 2016:291; Amrouche, Rekioua, Rekioua & Bacha, 2016:20915-20922). There are numerous energy storage technologies at various stages of development or maturity and that are appropriate under different circumstances (Hall, 2008:4365; Zahedi, 2011:867; Akinyele *et al.*, 2014:76; Castillo & Gayme, 2014:886-887; Mandelli *et al.*, 2016:291). Examples include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), flywheels, molten salts, supercapacitors, superconducting magnetic energy storage (SMES), hydrogen fuel cells and various battery compositions (Chen *et al.*, 2009:294; Beaudin, Zareipour, Schellenberglabe & Rosehart, 2010:304-310; Castillo *et al.*, 2014:886-887; Mahlia, Saktisahdan, Jannifar, Hasan & Matseelar, 2014:534-543; Suberu *et al.*, 2014:501-508; Amirante *et al.*, 2017:373-385).

Utility-scale electrical energy storage can therefore be considered as an encompassing term referring to the various grid-service applications that can be performed by different technologies with a wide range of characteristics and the capability to store more than one megawatt hour (MWh) of energy (Johnstone *et al.*, 2013:143; Castillo *et al.*, 2014:885-888; Hameer & Van Niekerk, 2015:1179; Kyriakopoulos *et al.*, 2016:1056). It represents projects connected to the electricity generation facility and/or transmission grid to perform large-scale applications, such as bulk energy storage and ancillary services required for grid stability, through the charging, storing and discharging of electrical energy (Suberu *et al.*, 2014:500; Akinyele *et al.*, 2014:76; Kempener *et al.*, 2015:25; Dehdashti, 2016:1-5).

1.3 BACKGROUND

1.3.1 Renewables on the rise

Electrical energy is a significant driver of economic growth, especially in the presence of cost reductions. Increasing electricity prices and disruptions to electrical generation and supply have a large negative impact on social and economic development aspirations (Simon, 1996:162-163; Stern, 2011:26-46; Kohler, 2014:526; Pollet, Staffell & Adamson, 2015:16685; Khan *et al.*, 2016:415; Mandelli *et al.*, 2016:287-288; Eskom 2016a:82; Aneke *et al.*, 2016:351; Nhamo *et al.*, 2016:69; Amirante *et al.*, 2017:373). It has been estimated that economic growth rates in Sub-Saharan African countries could be restricted by 2 to 4% annually as a result of inferior electrical energy infrastructure and the resulting disruptions to the supply of electricity (Andersen & Dalgaard, 2013:22; African Development Bank, 2016:3). In South Africa, inadequate electricity supply could potentially reduce real gross domestic product (GDP) by 3.15% between 2012 and 2019 (Bohlmann, Bohlmann, Inglezi-Lotz & Van Heerden, 2016:451-456).

The global energy market is rapidly changing. Factors such as renewable energy technologies and electric vehicles are amongst the main divers of the energy transition away from traditional sources of energy, such as oil, gas and coal. Renewable energy, in particular, is experiencing the most rapid growth of all primary energy sources. The share of renewable energy in total global primary energy is projected to increase from 3% in 2015 to 10% by 2035 (BP, 2017:5-37). Electrical energy generation from renewable energy sources is further at the forefront of the shift to more environmentally sustainable, less carbon-intensive, electricity systems (Beaudin *et al.*, 2010:302; Zahedi, 2011:866-867; Darling, You, Veselka & Velosa, 2011:3133-3134; Ibrahim & Ilinca, 2013:1; Pawel, 2014:69; Akinyele *et al.*, 2014:74; Zakeri *et al.*, 2015:570; Delarue *et al.*, 2015:1-2; De la Rubia, Klein, Shaffer, Kim & Lovric, 2015:20; Lund *et al.*, 2015:786; Jülch, 2016:1594; Gallo *et al.*, 2016:817; BP, 2017:40-43; Zou, Chen, Yu, Xia & Kang, 2017:57; Amirante *et al.*, 2017:372-373; Obi, Jensen, Ferris & Bass, 2017:909).

Renewable energy refers to energy derived from natural resource flows that are constantly replenished in a sustainable manner or are regarded as inexhaustible (Heiman & Solomon, 2004:94; Sørensen, 2011:18; Kaltschmitt, Themelis, Bronicki, Söder & Vega, 2013:290-847; Akinyele *et al.*, 2014:74). The primary renewable energy sources include solar, wind, water, biomass and geothermal (Tahvonen & Salo, 2001:1381; Heiman *et al*., 2004:94; Sørensen, 2011:3; Kaltschmitt *et al.*, 2013:847; Akinyele *et al.*, 2014:74).

Of these renewable sources, electrical energy generation from solar and wind is receiving the most attention, mainly due to rapid cost declines, the need to reduce greenhouse gas emissions and technical improvements experienced with solar photovoltaic (PV) and wind turbine electrical energy production technologies (Kaltschmitt *et al.*, 2013:1663; Battke, Schmidt, Grosspietsch & Hoffmann, 2013:241; Bortolini, Gamberi & Graziani, 2014:81-82; Wiebe & Lutz, 2016:740-741; Khan *et al.*, 2016:414; Nhamo *et al.*, 2016:72-73; Mundada, Shah & Pearce, 2016:693). Solar PV is an environmentally sustainable renewable energy technology that converts irradiation from the sun directly into electricity, while wind turbines utilise wind energy to turn a rotor in order to generate electricity (Branker, Pathak & Pearce, 2011:4471; Hemami, 2012:118; Nhamo *et al.*, 2016:71; Khan *et al.*, 2016:419). Solar PV and wind electrical energy production technology prices are declining at faster rates than previously anticipated, including in South Africa, and are now cost competitive with conventional power plants (Branker *et al.*, 2011:4470-4471; Bortolini *et al.*, 2014:81-82; Nhamo *et al.*, 2016:70; Mundada *et al.*, 2016:693; Dehdashti, 2016:3; Council for Scientific and Industrial Research, 2017b:38-43).

South Africa’s own electrical energy generation and supply environment is changing (South Africa, 2011:17; Department of Energy, 2016a:26; Eberhard, Gratwick, Morella & Antmann, 2016:186-189). This change is mainly being driven by interrelated factors such as public finance revenue and expenditure limitations; electricity generation, transmission and distribution capacity constraints; ageing electrical energy infrastructure; the substitution of coal for other energy sources; progressively rising electricity prices; inferior electricity access for low income households; the need for distributed generation; climate change mitigation objectives and the accelerated penetration of renewable energy technologies (Hall, 2008:4363; Pollet *et al.*, 2015:16685-16687; Pretorius, Piketh, Burger & Neomagus, 2015:27-29; De Vos, 2015:6-22; Eskom, 2016a:53-93; Nhamo *et al.*, 2016:69; Trimble, Kojima, Arroyo & Mohammadzadeh, 2016:20-34; Dehdashti, 2016:3; Eberhard *et al.*, 2016:159-189; Minnaar, 2016:1140).

The rapid uptake of renewable energy-based electrical generation technologies is anticipated to continue in South Africa and elsewhere (South Africa, 2011:17; Minnaar, 2016:1140; Department of Energy, 2016a:26; World Energy Council, 2016b:8-48). This trend has been, and is being, encouraged by technological progress, declining costs, climate change, environmental consciousness, volatile fossil fuel prices, finite fossil fuel depletion, increasing demand for energy and growing private sector participation in the electric utility industry (Neuhoff, 2005:88; Chen *et al.*, 2009:293; Sørensen, 2011:3-32; Evans *et al.*, 2012:4142; Ibrahim *et al*., 2013:1; Suberu *et al.*, 2014:509; Akinyele *et al.*, 2014:74; Hammond & Hazeldine, 2015:559-560; Pfenninger & Keirstead, 2015:303-304; Venkataramani, Parankusam, Ramalingam & Wang, 2016:895-896; Khan *et al.*, 2016:414; Aneke *et al.*, 2016:350-352; Gallo *et al*., 2016:800-801; Minnaar, 2016:1140; Malhotra, Battke, Beuse, Stephan & Schmidt, 2016:706; Amirante *et al.*, 2017:372-373).

South Africa, however, has faced a situation of excess electricity supply since the second half of 2016. This has been brought about by weak economic growth, rising electricity prices, additions of new large and inflexible electrical power stations, lower electricity intensity and the consequent lower demand for electricity. As the domestic growth outlook improves, older electrical power stations are decommissioned and fossil-fuel based and nuclear power stations continue to become less competitive, the potential for renewable energy and complementary flexible technologies, such as energy storage systems, increases to meet the growing demand for electricity. This is particularly relevant in the presence of rapid renewable energy and energy storage technology cost reductions as the country transitions to a more environmentally sustainable growth path (Steyn, Burton & Steenkamp, 2017:3-37; Council for Scientific and Industrial Research, 2017b:34; Council for Scientific and Industrial Research, 2017c:11-50; Gupta, Inglesi-Lotz & Muteba Mwamba, 2017:228-235; Mense, 2017; Eskom, 2017:12-13).

The South African electricity policy and planning framework establishes and supports the diversification of the country's electricity generation mix to accommodate for a larger and increasing share of electrical energy to be produced from renewable energy technologies. The Integrated Resource Plan for Electricity (IRP) 2010 to 2030 is the official and primary policy document that provides South Africa's long-term plan for electricity generation. According to the IRP 2010 to 2030, an additional, newly built capacity of 8 400 megawatt (MW) from solar PV, 8 400 MW from wind and 1 000 MW from concentrating solar power (CSP) technologies should be connected to the national electricity grid by 2030 (South Africa, 2011:7-14; Kusakana & Vermaak, 2013:467; Minnaar, 2016:1140).

The draft IRP 2016 to 2050 went through public consultation in 2017 and, once it is finalised and has been policy adjusted, will replace the IRP 2010 to 2030. While its capacity allocations will change during the review process, the initial base case nonetheless assigns significantly more capacity to solar PV and wind-based electrical generators. Preliminarily, solar PV plants have been allocated 17 600 MW and wind plants 37 400 MW (Department of Energy, 2016a:24-26).

1.3.2 Balancing electricity supply and demand

It is critical to maintain the stability and reliability of the electricity system through a continuous balance between the production and total consumption of electricity, while accounting for losses during transmission (Stoft, 2002:40; Kaltschmitt *et al.*, 2013:1664; Rejc & Čepin, 2014:654-655, Kyriakopoulos *et al.*, 2016:1045; Lazkano *et al.*, 2017:3). This implies that electricity market equilibrium, a situation in which the supply of electrical energy equals prevailing demand, has to be retained at any given time to prevent a shortfall of electricity and consequent load curtailment, with dire economic implications (Stoft, 2002:40-48; Carnegie, Gotham, Nderitu & Preckel, 2013:4; Infield & Hill, 2014:18-20; Kempener *et al.*, 2015:3; Delarue *et al.*, 2015:5-8; Lund *et al.*, 2015:786). The power system therefore has to be flexible enough to ensure that electricity production changes as consumption varies to maintain an uninterrupted balance between electrical energy demand and supply (Kaltschmitt *et al.*, 2013:1664; Kondziella *et al.*, 2016:11; Dehdashti, 2016:4; Kyriakopoulos *et al.*, 2016:1045).

The required system flexibility is secured by operating reserves, which include spinning and non-spinning reserves, having a short response time for ramping up and down as needed to manage uncertainty in electricity supply and demand (Kaltschmitt *et al.*, 2013:1664-1823; De Vos & Driesen, 2014:566-567; Rejc *et al.*, 2014:654; Lund *et al.*, 2015:792; Akhil, Huff, Currier, Kaun, Rastler, Chen, Cotter, Bradshaw & Gauntlett, 2015:161). Spinning reserves refer to spare capacity in operational or online electrical generation plants synchronised or connected to the electricity grid that can respond rapidly to supply electrical energy in the event of an emergency. Non-spinning reserves refer to stand-alone electrical generation plants that are not connected to the electricity grid, but can quickly be brought online, within 10 to 15 minutes, to supply electrical energy in the event of an emergency (Newberry & Sioshansi, 2009:37; Rejc *et al.*, 2014:655; Lund *et al.*, 2015:792; Akhil *et al.*, 2015:160-161).

Both spinning and non-spinning reserves are retained to supply electricity when there is a sudden shortfall in available electrical generation capacity, an unexpected surge in demand for electricity and/or a need to manage variations in electric load (Carnegie *et* *al.*, 2013:4; Kaltschmitt *et al.*, 2013:1664-1667; Rejc *et al.*, 2014:654; Delarue *et al.*, 2015:5-8; Pretorius *et al.*, 2015:33). Examples of operating reserves that have the capability to rapidly change their electrical output levels so that generation matches the national demand profile on a minute-by-minute basis include open and combined cycle gas turbines, hydroelectric power plants, various energy storage options, regional electricity trading, excess capacity in existing electrical generation plants and load curtailment (Willis *et al.*, 2013:6; Kaltschmitt *et al.*, 2013:1668; De Vos *et al.*, 2014:567; Rejc *et al.*, 2014:654; Lund *et al.*, 2015:797; Aneke *et al*., 2016:354; Kondziella, 2016:11-20; Jülch, 2016:1594; Kyriakopoulos *et al.*, 2016:1045).

The extent to which renewable energy generation options can be integrated into the electricity grid is limited by the stochastic nature of their resources (Beaudin *et al.*, 2010:303-304; Ibrahim *et al*., 2013:1; Akinyele *et al.*, 2014:74; Rejc *et al.*, 2014:655; Zou *et al.*, 2017:57; Amirante *et al.*, 2017:373). This is a direct result of the variability and intermittency associated with renewables due to their dependence on prevailing weather conditions (Akinyele *et al.*, 2014:74; Delarue *et al.*, 2015:4-5; Gallo *et al.*, 2016:801; Kondziella *et al.*, 2016:11; Zou *et al.*, 2017:57). For example, electrical energy from solar is only available when the sun shines due to its reliance on solar irradiation. Similarly, electricity production from wind is only possible when the wind blows. Even as electricity generation from renewable energy sources occurs, the electrical output realised is not perfectly stable and varies as the resource availability fluctuates at any given time (Neuhoff, 2005:92; Beaudin *et al.*, 2010:303-304; Zahedi, 2011:866-868; Kaltschmitt *et al.*, 2013:1677-1781; De Vos *et al.*, 2014:567; Bortolini, Gamberi, Graziani & Pilati, 2015:1031; Gielen, Kempener, Taylor, Boshell & Seleem, 2016:14; Huang & Davy, 2016:633; Lai & McCulloch, 2017:194-197; Rycroft, 2017:24; Pan & Dinter, 2017:386-387).

The variability and intermittency of renewable energy sources, especially solar and wind, imply that electricity generated from it cannot be dispatched upon request and has to be utilised as soon as it is produced, even when the prevailing demand for electricity is below the total available national supply, or alternatively be wasted (Evans *et al.*, 2012:4142; Kaltschmitt *et al.*, 2013:1664; Akinyele *et al.*, 2014:74; Delarue *et al.*, 2015:5; Amirante *et al.*, 2017:373; Lai *et al.*, 2017:194). The dispatchability of a generator refers to its ability to change its electrical output upon request to meet varying electricity supply requirements in line with prevailing load demand conditions (Akhil *et al.*, 2015:153).

The variability, intermittency, relative uncertainty and non-dispatchability of renewable energy electrical generation plants could further create a sudden shortfall in electrical generation capacity, which could compromise the stability of the national electricity grid by creating a mismatch between electricity supply and demand. This risk is becoming more pronounced as a larger share of intermittent renewable energy-based electrical generation options begin to feed electricity into the grid, since it raises potential grid instability (Heiman *et al.*, 2004:98; Chen *et al.*, 2009:292-293; Beaudin *et al.*, 2010:302-304; Zahedi, 2011:867-868; Battke *et al*., 2013:241; Poullikkas, 2013:778; Infield *et al.*, 2014:19-20; Rejc *et al.*, 2014:654-655; Akinyele *et al.*, 2014:74; Pfenninger *et al.*, 2015:303; Zakeri *et al.*, 2015:570-571; Delarue *et al.*, 2015:4-10; Kempener *et al*., 2015:3; Mandelli *et al.*, 2016:298; Zou *et al*., 2017:57; Rycroft, 2017:23; Berrada *et al.*, 2017:94; Obi *et al.*, 2017:909). It has further been argued that the intermittency of renewable energy sources has restricted the transition from fossil fuel-based to sustainable electrical energy systems (Battke & Schmidt, 2015:334).

In South Africa, the greatest threat to maintaining an efficient balance between electricity supply and demand, in a high economic growth environment, is to meet peak or maximum load demand for three hours in the mornings between 07:00 and 10:00, and for four hours in the evenings between 18:00 and 22:00 in summer and between 17:00 and 21:00 in winter (Silinga & Gauché, 2014:1544; Eskom, 2016a:52-112; Lai *et al.*, 2017:197; Pan *et al.*, 2017:387). The national electric utility, Eskom, has further stated that the intermittency associated with solar PV and wind generation plants is harming the overall electricity system due to the relative resource unavailability during peak demand hours and surplus availability during periods of low demand (Eskom, 2015:20; Kenny, 2015:15-18; Pollet *et al.*, 2015:16697; Nhamo *et al.*, 2016:72; Dehdashti, 2016:3). Grid capacity constraints in some parts of the country, especially in the Northern Cape Province, are also restricting new connections of renewable energy-based generation plants until planned grid infrastructure expansion projects have been completed, which is further limiting electricity availability (Eskom, 2015:13-14; Eskom, 2016a:52; Minnaar, 2016:1140).

Emergency spinning and non-spinning reserves are relied upon to supply electrical energy during periods of high demand for electricity, resource intermittency and unexpected capacity losses, for example, due to breakdowns. These include expensive diesel-fired open cycle gas turbines, inefficient and ageing coal fired power stations and geographically limited pumped hydroelectric energy storage (Stoft, 2002:42; Beaudin *et* *al.*, 2010:304; Infield *et al.*, 2014:6-19; Delarue *et al.*, 2015:7; Bohlmann, Bohlmann & Inglezi-Lotz, 2015:6; Pretorius *et al.*, 2015:33-34; Eberhard *et al.*, 2016:164-170; Kondziella *et al.*, 2016:11; Eskom, 2016a:112; Covert, Greenstone & Knittel, 2016:129).

As more renewable energy projects begin to feed electrical energy into the grid, increased flexibility from existing generation options and energy storage technologies will be required to accommodate the variability and intermittency associated with wind and solar energy (Zahedi, 2011:866-867; Delarue *et al.*, 2015:5-28; Lund *et al.*, 2015:786-801; Mandelli *et al.*, 2016:289; Gallo *et al.*, 2016:817; Jülch, 2016:1594; Kondziella *et al.*, 2016:10-20; Astarloa, Kaakeh, Lombardi & Scalise, 2017:10; Lai *et al.*, 2017:191). Some studies have found that electricity grids can typically integrate variable and intermittent renewable energy electrical generation plants of approximately 10 to 20% of total installed system capacity before technical issues are experienced and additional electricity system flexibility is required (Beaudin *et al.*, 2010:304; Whittingham, 2012:1519; Akinyele *et al.*, 2014:88; Giglmayr *et al.*, 2015:784; Gallo *et al.*, 2016:801; Ferroukhi *et al.*, 2017:75).

The increased penetration of renewables comes at an added cost to the electricity system as conventional generation plants, such as base load coal and nuclear power stations, have to be operated below their rated output (Infield *et al.*, 2014:19-20; Delarue *et al.*, 2015:5-28). The reason for this is that coal fired and nuclear energy generation plants are not designed to operate efficiently and/or effectively over the full operating capacity range to match time-variable electricity demand (Chen *et al.*, 2009:292; Bhattacharyya, 2011:231; Evans *et al.*, 2012:4142; Carnegie *et al.*, 2013:6; Pfenninger *et al.*, 2015:311-312; Lund *et al.*, 2015:797). The situation is further intensified if conventional base load generation options are relied upon to supply peak demand periods, as it results in inefficient, oversized, environmentally damaging and uneconomical electrical energy solutions prone to more frequent breakdowns, increased maintenance expenses and reduced lifetimes (Carnegie *et al.*, 2013:6; Zakeri *et al.*, 2015:571).

To ensure adequate flexibility within the electrical power system as the share of renewables increases in the national electricity mix, additional utility-scale operating reserves or other electrical infrastructure investments have to be made to complement variable renewable energy electrical generation options. This is required to ensure the stability of the electricity grid so that electricity supply matches prevailing demand at any given time in support of economic development (Kaltschmitt *et al.*, 2013:1664-1823; Delarue *et al.*, 2015:6-8; Gallo *et al.*, 2016:800-801; Zou *et al.*, 2017:57).

Over the longer term, as conventional fossil fuel-based power generation sources are progressively phased out in favour of larger shares of cleaner and lower cost energy sources, it will increasingly be necessary for diverse technologies to function optimally and in unison. Such technologies should collectively provide the required dispatch, response, cost, efficiency and environmental profiles to meet prevailing national demand for electricity, while ensuring overall system stability and economic viability (Hall, 2008:4363-4366; De la Rubia *et al.*, 2015:5; Lund *et al.*, 2015:793; Bortolini *et al.*, 2015:1025-1027; Nhamo *et al*., 2016:69-70; Dehdashti, 2016:3-8).

1.3.3 Potential for energy storage technologies

Innovative technological solutions are arising that could displace or reduce the need for costly conventional emergency, peak, mid-merit and base load supply options, as well as improve the utilisation of the national electricity grid to successfully integrate intermittent electrical energy generation sources, such as solar and wind (Chen *et al*., 2009:292; Infield *et al*., 2014:6-23; Lund *et al.*, 2015:786; Kempener *et al.*, 2015:3-4; Flaherty, Peladeau & Carey, 2016:8-33; Covert *et al.*, 2016:130; Astarloa *et al.*, 2017:10-11). Utility-scale energy storage technologies, especially various modern battery technologies, are at the forefront of these electricity system innovations (Dufo-López, Bernal-Agustín & Domíngues-Navarro, 2009:126; Chen *et al*., 2009:291-292; Beaudin *et al.*, 2010:302-313; Zahedi, 2011:866-870; Battke *et al*., 2013:240-242; Akinyele *et al.*, 2014:74-75; Zakeri *et al.*, 2015:570-571; Kempener & De Vivero, 2015:31; Battke *et al.*, 2015:334-335; Mandelli *et al.*, 2016:289; Dehdashti, 2016:1-3; Venkataramani *et al.*, 2016:896; Aneke *et al*., 2016:350-352; Gallo *et al*., 2016:800; Lazkano *et al.*, 2017:3; Amirante *et al.*, 2017:373).

The global utility-scale energy storage market has been growing rapidly in recent years and will continue to do so into the future. It has been projected that the global demand for energy storage technologies not representative of pumped hydroelectric energy storage (PHS) could increase to around 50 000 megawatt hours (MWh) by 2025, from approximately 400 MWh in 2015 (Astarloa *et al.*, 2017:10).

This could potentially entail significant benefits for the South African electrical energy environment. As in other countries, competitive, dispatchable and reliable renewable energy is important to South Africa’s future energy mix and capacity expansion choices (Pollet *et al.*, 2015:16696-16697; Dehdashti, 2016:8; Günter & Marinopoulos, 2016:229-230). Complementing the deployment of renewable energy-based electrical generation options with energy storage systems offers an efficient and effective way to overcome resource variability and intermittency, as well as the need for sub-optimal operating reserves (Sørensen, 2011:892; Ibrahim *et al*., 2013:1; Akinyele *et al.*, 2014:74; Hammond *et al.*, 2015:560; Pfenninger *et al.*, 2015:303; Kyriakopoulos *et al.*, 2016:1062; Gielen *et al.*, 2016:14; World Energy Council, 2016a:6; Chaanaoui *et al.*, 2016:783; Aneke *et al.*, 2016:350-352; Amrouche *et al.*, 2016:20914-20922; Amirante *et al.*, 2017:372-373). The increased uptake of innovative energy storage systems also stimulates additional productivity-enhancing innovation spillovers to both renewable and conventional electrical energy generation technologies, which contribute to the improved efficiency of the entire electricity industry (Lund *et al.*, 2015:793; Lazkano *et al.*, 2017:2-16).

Energy storage technologies are highly flexible and have the capability to absorb electrical energy from the electricity grid and/or renewable energy generation plants, which makes it possible for electricity from them to be dispatched upon demand in a stable and reliable manner. Such technologies can also provide further system benefits, such as ancillary services and improved utilisation of the electricity grid (Chen *et al.*, 2009:293-294; Zahedi, 2011:866-870; Whittingham, 2012:1518-1519; Evans *et al.*, 2012:4142; Battke *et al.*, 2013:240; Willis *et al.*, 2013:5-8; Ibrahim *et al*., 2013:1; Akinyele *et al.*, 2014:74-75; Infield *et al.*, 2014:1-5; Suberu *et al.*, 2014:501; Delarue *et al.*, 2015:9; Ibrahim *et al.*, 2015:306; Bortolini *et al.*, 2015:1024; Zakeri *et al.*, 2015:571-572; Gallo *et al*., 2016:801; Dehdashti, 2016:3-8; Amirante *et al.*, 2017:373; Obi *et al.*, 2017:909).

Energy storage can essentially make renewable energy-based electricity systems as dependable as fossil fuel-based systems (Sørensen, 2011:540; Evans *et al.*, 2012:4142; Suberu *et al.*, 2014:501; Lund *et al.*, 2015:793; Kyriakopoulos *et al.*, 2016:1062-1065; Amrouche *et al.*, 2016:20921-20922; Lazkano *et al.*, 2017:2; Amirante *et al.*, 2017:373). The likely future result is that economically viable utility-scale energy storage technologies combined with renewable energy electrical producers will increasingly replace the need for conventional fossil fuel-based electricity generators (Lund *et al.*, 2015:799; Dehdashti, 2016:3; Zou *et al.*, 2017:66; Lazkano *et al.*, 2017:2-16; Lai *et al.*, 2017:193-194).

Some projections are that electrical energy storage combined with solar PV plants could be cost competitive with conventional generation options by 2020 (DNV GL, 2016:18). Pollet *et al.* (2015:16696) expect the South African energy sector to change substantially until at least 2020, by which time the country would begin to adopt energy storage systems, among other measures, as it experiences a rapid uptake of renewable energy electrical production plants and strives to attain its environmental objectives.

Energy storage systems offer various beneficial uses that can improve the operation of electricity generation and supply infrastructure, which may ultimately entail consumer, producer, environment and economic growth benefits (Dufo-López *et al*., 2009:126-137; Sioshansi, 2009:1-11; Sioshansi, Denholm, Jenkin & Weiss, 2009:269-277; He, Delarue, D'haeseleer & Glachant, 2011:1575; Akinyele *et al.*, 2014:74; Infield *et al*., 2014:1-5; Bortolini *et al.*, 2015:1024; Pollet *et al.*, 2015:16685; Zakeri *et al.*, 2015:571; Jülch, Telsnig, Shulz, Hartmann, Thomsen, Eltrop & Schlegl, 2015:22-26; Aneke *et al*., 2016:350-352; Amrouche *et al.*, 2016:20922). Such benefits include increased energy security and reliability, improved electricity system flexibility and affordability, greater electricity access, innovation, technological progress, reducing greenhouse gas emissions and decarbonisation of the electricity system, investment, productive activity in the goods and services sectors and job creation (Makansi & Abboud, 2002:3; Sioshansi, 2009:1-11; Dunn, Kamath & Tarascon, 2011:928; Kaun & Chen, 2013:29-30; Infield *et al.*, 2014:1-6; Pollet *et al.*, 2015:16685; Bortolini *et al.*, 2015:1024; Jülch *et al*., 2015:22-26; De la Rubia *et al*., 2015:8; Mandelli *et al.*, 2015:113; Mandelli *et al.*, 2016:288-298; Aneke *et al.*, 2016:350; Amrouche *et al.*, 2016:20914-20922; Astarloa *et al.*, 2017:6).

The capability to store energy entails a number of value applications as an integrated set of beneficial services that a technology can offer to the grid (Kaun *et al*., 2013:26). Broadly, the main applications offered by utility-scale energy storage technologies include curtailing the intermittency associated with renewable energy sources, such as solar and wind, smoothing out the variability of electrical energy output from renewable generation options, discharging electrical energy during periods of high demand for electricity and/or insufficient electrical generation output, creating opportunities for electricity price arbitrage, providing relief for areas characterised by electricity transmission and/or distribution grid constraints and deferring investments in new electric grid and generation capacity (Sioshansi *et al.*, 2009:269-270; Chen *et al.*, 2009:293-294; Beaudin *et al.*, 2010:305; Battke *et al*., 2013:242; Akinyele *et al.*, 2014:74-75; Infield *et al.*, 2014:1-23; Zakeri *et al.*, 2015:571-572; Bortolini *et al.*, 2015:1027; Delarue *et al.*, 2015:16-17; Mandelli *et al.*, 2016:289; Dehdashti, 2016:4-5; Amrouche *et al.*, 2016:20922; Gallo *et al.*, 2016:801; Venkataramani *et al.*, 2016:896; Obi *et al.*, 2017:910). Moreover, many applications could be offered sequentially and/or simultaneously, which significantly enhances the value of energy storage relative to cost (Sioshansi *et al.*, 2009:277; He *et al.*, 2011:1575; Zhang, 2013:39; Kaun *et al.*, 2013:25-85; Pawel, 2014:69; Castillo *et al.*, 2014:888; Battke *et al.*, 2015:339; Lambruschi, 2015:24-26; De la Rubia *et al.*, 2015:7-8; Kondziella *et al.*, 2016:15-20; Ferroukhi *et al.*, 2017:80-81).

As global markets for energy storage technology development and public interest to participate in the energy transformation grows, it becomes increasingly important to conduct fair and independent assessments of the competitiveness and economic performance of various energy storage technologies (Pawel, 2014:68-69; Amirante *et al.*, 2017:373). Such assessments are required to prevent undue influence on uninformed market participants, which could potentially lead to inferior national electricity solutions (Kondziella *et al.*, 2016:20).

1.4 PROBLEM DESCRIPTION

The share of solar- and wind-based electrical energy producers in total installed electricity generation capacity is growing rapidly throughout the world (Battke *et al*., 2013:241; Kaltschmitt *et al.*, 2013:1663; Khan *et al*., 2016:414; Mundada *et al.*, 2016:693; Obi *et al.*, 2017:909; Amirante *et al.*, 2017:373). The stochastic nature of their resources, however, could compromise the stability of the national electricity grid (Beaudin *et al.*, 2010:302-304; Akinyele *et al.*, 2014:74-88; Zakeri *et al.*, 2015:570-571; Delarue *et al.*, 2015:4-10; Gallo *et al.*, 2016:801). Energy storage technologies offer enhanced flexibility that could be used to overcome the variability and intermittency of renewable energy resources in support of transitioning to more environmentally sustainable, reliable and secure national electricity systems (Dufo-López *et al*., 2009:126-137; Sørensen, 2011:892; Akinyele *et al.*, 2014:74-75; Lund *et al.*, 2015:799; Bortolini *et al.*, 2015:1024; Dehdashti, 2016:3-8; Aneke *et al.*, 2016:350-352; World Energy Council, 2016a:6-7; Chaanaoui *et al.*, 2016:783; Amrouche *et al.*, 2016:20914-20922; Lai *et al.*, 2017:193-194).

The widespread demonstration, commercialisation and uptake of appropriate utility-scale energy storage technologies have started to feature and grow in many parts of the world, but have not received serious consideration for incorporation into the South African electrical energy landscape. A highly limited number of projects have thus far been implemented in South Africa (Mandelli *et al.*, 2016:289; Günter *et al.*, 2016:228-230; Malhotra *et al.*, 2016:710-712; Rycroft, 2017:22). This could be attributed to insufficient knowledge of the technical ability and economic feasibility or cost competitiveness of such technologies, as well as how they could be successfully integrated into the domestic electricity system (Battke *et al*., 2013:241; Kondziella *et al.*, 2016:21-22; Gallo *et al*., 2016:800).

The economic implications of utility-scale energy storage technologies are often unclear to parties interested in the electrical energy environment, including policymakers, regulatory agencies, procurement institutions, grid operators, electrical power producers, industry and consumers (Kaun *et al.*, 2013:9; Zakeri *et al.*, 2015:569; Mandelli *et al.*, 2016:292-298; Astarloa *et al.*, 2017:6). Unfamiliarity about the technical capability, value applications, reflective costs, financial competitiveness and economic feasibility of energy storage technologies remain, which could prevent the implementation of appropriate utility-scale system solutions (He *et al.*, 2011:1575; Battke *et al*., 2013:241; Zakeri *et al.*, 2015:570; Kempener *et al.*, 2015:5-24; De la Rubia *et al.*, 2015:7-12; Covert *et al.*, 2016:129; Kondziella *et al.*, 2016:20; Gallo *et al.*, 2016:800-819; Ferroukhi *et al.*, 2017:80; Amirante *et al.*, 2017:385). This problem could also be inhibiting the widespread adoption of utility-scale electrical energy storage technologies in South Africa.

The issue is compounded by the limited body of encompassing academic literature available on the economic feasibility of energy storage technologies and more specifically utility-scale electrochemical or battery-based technologies (Covert *et al.*, 2016:129; Amirante *et al.*, 2017:385). Research into the economic feasibility of energy storage systems coupled with intermittent renewable energy electrical production options, such as solar photovoltaic (PV) technologies, has also been deficient and obscure (Lai *et al.*, 2017:192). Much of the existing literature is further limited in scope, by being narrowly focused on individual technologies and/or selected features of such technologies, rather than providing a comprehensive overview and economic feasibility assessment for improved knowledge dissemination, understanding and decision-making (Beaudin *et al.*, 2010:303; He *et al.*, 2011:1575; Zhang, 2013:12; Infield *et al.*, 2014:6-24; Castillo *et al.*, 2014:888-891; Gallo *et al.*, 2016:802; Kondziella *et al.*, 2016:20-21).

The affordability and economic feasibility of energy storage technologies depend on the ability of such technologies to compete with one another and with prevailing alternative generation options in terms of cost effectiveness (Pawel, 2014:73; Jülch *et al*., 2015:19-26; Bortolini *et al.*, 2015:1026-1029; Zakeri *et al.*, 2015:588; De la Rubia *et al*., 2015:7; Kondziella *et al.*, 2016:12; Lai *et al.*, 2017:191-202; Obi *et al.*, 2017:910). It is, however, difficult to compare the costs of different energy storage technologies with one another as they not only depend on price, but also on the performance characteristics per technology, how they optimise into different use applications and their respective advantages and disadvantages (Battke *et al*., 2013:241-247; Pawel, 2014:72; Zakeri *et al.*, 2015:573; Lazard, 2015:12; Jülch *et al*., 2015:19-26; Mandelli *et al.*, 2016:291; Hoff & Lin, 2016:1; Kondziella *et al.*, 2016:11). Energy storage technologies in isolation can also not be appropriately compared with generation options, since they have different technical functionalities, modes of operation and, as a consequence, dissimilar cost determinants (Pawel, 2014:69-70; Akhil *et al.*, 2015:113).

To overcome this cross-comparative issue, it is necessary to estimate the reflective levelised costs of energy storage systems (LCOS) in isolation and when such systems are coupled with intermittent renewable energy-based electrical production plants. This is needed to determine the extent to which energy storage technologies can compete with one another and, when linked to intermittent renewable energy electrical producers, with alternative electricity generators with similar electrical output dispatch characteristics (Pawel, 2014:72-73; Bortolini *et al.*, 2015:1029; Jülch *et al*., 2015:19-26; Lai *et al.*, 2017:200; Obi *et al.*, 2017:908-918).

The LCOS is a metric that articulates the comparable present value cost per kilowatt hour (kWh) over the applicable lifetime of an energy storage system, while accounting for all lifecycle cost and technical performance parameters associated with an installation through to the termination of service. It enables a fair and meaningful comparison of different technologies according to the applications they are required to perform, regardless of technological specifications or chemical composition (Poonpun & Jewell, 2008:532; Battke *et al.*, 2013:242-247; Pawel, 2014:68-77; Zakeri *et al.*, 2015:573-588; Battke *et al.*, 2015:334; Jülch *et al.*, 2015:19; Lazard, 2015:20-29; Hoff *et al.*, 2016:2; World Energy Council, 2016a:4; Lai *et al.*, 2017:194; Obi *et al.*, 2017:910).

Existing academic literature and commercial information on the current and future LCOS, the economic value of different energy storage technologies and their competitive ability with one another and with prevailing alternative generation options is, however, also insufficient and/or obscure (Battke *et al*., 2013:242-243; Infield *et al.*, 2014:6-24; Zakeri *et al.*, 2015:573; Lai *et al.*, 2017:191-192; Obi *et al.*, 2017:918). A thorough literature review and appropriate levelised cost methodological description, analysis and assessment would contribute to research efforts on the economic feasibility of energy storage technologies, especially within the South African context. In this regard, it is important to specify the research questions to be addressed in this dissertation.

1.5 RESEARCH QUESTIONS

Sections 1.1 to 1.4 explained that energy storage technologies have the technical capability to support the transition to a more environmentally sustainable electricity system by helping to overcome the variability and intermittency associated with renewable energy technologies, such as solar and wind-based electrical production plants. Uncertainties regarding their cost competitiveness or economic viability, however, have limited their application at the utility scale in the South African electrical energy landscape. To address this uncertainty, this study seeks to contribute to the resolution of the following general research question, which, in turn, requires answering further specific questions.

1.5.1 General research question

The general question that is addressed through this study can be stated as follows:

- What is the competitive ability and economic feasibility of utility-scale electrical energy storage technologies for South Africa?

1.5.2 Specific research questions

To respond to the general research question, the following specific questions can be formulated based on the description of the research problem:

- Would an overview of the concept, characteristics, technical capability, value applications, cost considerations and existing literature associated with energy storage technologies, as well as how such technologies relate to economic theory, contribute to an improved understanding of the competitive ability and economic feasibility of energy storage technologies?

- How could energy storage technologies reasonably be compared with one another and with prevailing generation options if they have different functionalities? Based on this, the following sub-questions need to be addressed:

    - Could a standard methodology be developed to test the competitive ability of different energy storage technologies?
    - Based on this methodology, what is the competitive ability of select utility-scale energy storage technologies with one another?
    - What is the competitive ability of select utility-scale energy storage technologies with prevailing alternative generation options?
- When could it potentially be economically feasible to incorporate energy storage technologies at the utility scale into the South African electrical energy landscape?

In order to answer the research questions, the following objectives have been established to guide the resolution of the queries specified.

1.6 RESEARCH OBJECTIVES

Based on the research questions, the general objective for the dissertation has been formulated, which comprises further specific objectives.

1.6.1 General research objective

The general objective of the research for this study can be stated as follows:

- Assess the competitive ability and economic feasibility of utility-scale electrical energy storage technologies for South Africa.

1.6.2 Specific research objectives

The general research objective can be attained by addressing the following specific objectives:

- Provide an overview of the concept, characteristics, technical capability, value applications and reflective cost considerations associated with energy storage technologies.
- Conduct a literature review of previous investigations into the economic feasibility of energy storage technologies and describe how such technologies relate to economic theory.

- Examine the method through which energy storage technologies could reasonably be compared with one another and with prevailing alternative electrical energy generation options. Based on this, the following assessments can be performed:
    - Develop a proposed methodology to determine the reflective levelised cost of energy storage (LCOS) technologies,
    - Estimate the competitive ability of select utility-scale energy storage technologies with one another, and
    - Establish the means through which energy storage technologies can be compared with alternative electrical generation options and perform such a comparative assessment as a case study.
- Use the above assessments to further estimate and project when it could be economically feasible to incorporate such technologies into the South African electrical energy environment at the utility scale.

It is anticipated that the attainment of the research objectives for this dissertation would contribute contextual and empirical information for the benefit of academia, practitioners and policymakers. To realise the objectives established for this study, it is necessary to outline the research method that will be followed.

1.7 RESEARCH METHOD OUTLINE

The research for this study builds on, and contributes to, the existing body of literature on energy storage technologies through the attainment of the specific objectives set for the study. This is primarily completed through two overarching phases, namely a literature review and an empirical study.

1.7.1 Literature review

The first phase includes a comprehensive overview of the utility-scale energy storage context, need, concept, system components, selection criteria, leading technologies, characteristics, technical capabilities, value applications and encompassing cost considerations. A literature review on the economic feasibility of utility-scale energy storage technologies and how such technologies relate to economic theory is also undertaken. In doing this, the following sources of information were consulted:

- Primary (academic) sources: Accredited journal articles, studies and books;
- Secondary (technical) sources: Commissioned and/or independent studies, articles and books from well-known, credible and respected organisations, including, but not limited to, the Council for Scientific and Industrial Research (CSIR), South African Reserve Bank (SARB), National Energy Regulator of South Africa (NERSA), International Renewable Energy Agency (IRENA), International Energy Agency (IEA), United States Energy Information Administration (EIA), Eskom, Independent Power Producers Office and other reliable energy storage research organisations. Secondary sources were utilised when primary sources proved inadequate; and
- Tertiary sources: Professional experience obtained by working in the economics and energy fields and the expertise of other electrical energy practitioners.

1.7.2 Empirical study

The second phase includes a novel methodological description and empirical assessment of the competitive ability and economic feasibility of select utility-scale energy storage technologies for South Africa. This involves a detailed mathematical model specification and assessment of the cost competitiveness between different energy storage systems, as well as the extent to which such systems, in combination with solar photovoltaic (PV) plants, can compete with alternative electrical generation options in 2016 and projected for 2020.

The novelty of the empirical study is realised by improving and developing the methods to calculate, forecast and assess the cost competitiveness of utility-scale energy storage systems for South Africa. This is achieved through a comprehensive techno-economic levelised cost of energy storage (LCOS) model formulation, extension and analysis, which is summarised below. The LCOS model and its extension allows for improved economic estimates, projections, analyses and feasibility assessments of energy storage technologies is isolation and coupled with solar PV plants by addressing a number of shortcomings identified during the literature review. The novelty, shortcomings addressed, formulation, parameters, explanatory variables, formulae, technical and financial data inputs, calculations, assumptions and interpretation of the LCOS model and its extension is described in more detail in Chapter 6.

The LCOS is a metric that articulates the present value cost per kilowatt hour (kWh) over the applicable lifetime of an energy storage system. It includes all cost and performance parameters associated with an installation through to the termination of service and enables comparison between different energy storage technologies, as well as with electrical generators, according to the applications they are required to perform (Poonpun *et al.*, 2008:532; Battke *et al.*, 2013:242-247; Pawel, 2014:68-77; Zakeri *et al.*, 2015:573-588; Battke *et al.*, 2015:334; Jülch *et al.*, 2015:19; Hoff *et al.*, 2016:2; World Energy Council, 2016a:4; Lai *et al.*, 2017:194; Obi *et al.*, 2017:910).

The research method is quantitative in nature and primarily entails mathematical modelling and analyses. This method was chosen over a qualitative research approach in order to address the stated research questions, especially since the specific questions related to the empirical study for this dissertation require quantitative techniques, measurable results and a cost-benefit analysis.

A cost-benefit analysis entails the quantification of costs, as required monetary disbursements, and anticipated benefits, as net favourable consequences, expected from a proposed investment (Drèze & Stern, 1987:911; Sullivan *et al.*, 2015:444-467). Cost-benefit analyses for infrastructure investments are commonly performed by expressing anticipated costs in future years in net present value (NPV) terms, to account for the time value of money, and weighing those costs against the benefits expected from proposed investments. The most attractive investment would be characterised by benefits that exceed its own associated costs, as well as the costs and benefits of alternative investment options (Layard & Glaister, 1994:1-4; Boardman, Greenberg, Vinning & Weimer, 2006:7-17; Cellini & Kee, 2010:494-495; Bhattacharyya, 2011:163-177; Weyman-Jones, 2011:24-25; Schoenung, 2011:12; Berrada *et al.*, 2017:101).

A cost-benefit analysis corresponding to Watson’s dictum is used to perform the empirical assessment. According to the principles of this dictum, benefits emanating from electrical output are equal regardless of the energy source utilised to enable such output and cost comparisons alone are therefore appropriate for cost-benefit analyses of electrical energy infrastructure (Donald & Watson, 1971; Bhattacharyya, 2011:177; Lombaard & Kleynhans, 2016:3). This maxim could also be applied to energy storage systems, since it involves the storing of electrical energy generated for later discharge and use (Baxter, 2006:3; Chen *et al.*, 2009:291; Evans *et al.*, 2012:4142; Suberu *et al.*, 2014:500; Kousksou *et al.*, 2014:60; Akinyele *et al.*, 2014:76; Luo *et al.*, 2015:511; Gallo *et al.*, 2016:802).

In that regard, the cost-benefit analyses performed in this study focus on costs in assessing the economic feasibility of utility-scale electrical energy storage systems. The cost comparisons, however, do not account for externalities such as resource availability and environmental or human health considerations, which could result in overvalued results for technologies that have improved environmental repercussions and resource utilisation relative to alternatives. It could be reasonably anticipated that energy storage and renewable energy electrical production technologies are likely to have improved environmental and human health implications in comparison to fossil fuel-based electricity generators (Donald *et al.*, 1971; Roth & Ambs, 2004:2138-2142; Lombaard *et al.*, 2016:7; Sklar-Chik, Brent & De Kock, 2016:130).

The need for empirical research and analyses into the performance characteristics, costs, competitive ability and economic feasibility of energy storage technologies has been recognised (He *et al*., 2011:1575; Zhang, 2013:12-109; Battke *et al*., 2013:241; Infield *et al*., 2014:6; Pawel, 2014:68; Tapia-Ahumada, Octaviano, Rausch & Pérez-Arriaga, 2015:243; Zakeri *et al*., 2015:573-590; Covert *et al*., 2016:129-130; Dehdashti, 2016:4; Amirante *et al.*, 2017:385). To contribute to the fulfilment of this need, the empirical analyses would follow a bottom-up modelling approach.

The structures of bottom-up models vary considerably, but usually require a partial equilibrium perspective in which a particular sector or industry is represented in detail, rather than the interactions between sectors and the rest of the economy. Bottom-up models have been receiving increased attention for electrical energy analyses and involve the detailed specification of technological features and costs that seek to identify the most economic or least-cost option to supply electricity in order to meet prevailing demand (Delarue *et al.*, 2015:4; García-Gusano, Espegren, Lind & Kirkengen, 2016:57).

Through the bottom-up modelling approach, the reflective lifecycle cost or LCOS of utility-scale energy storage systems in isolation and coupled with solar PV plants is estimated in 2016 terms and projected to 2020 in order to determine the extent to which they could compete with one another and alternative electrical generators with similar dispatch characteristics. In this regard, a detailed LCOS model has been developed and the results analysed to test the competitive ability of select energy storage technologies.

While this dissertation covers energy storage technologies in general, the empirical analysis mainly focuses on assessing the economic feasibility of select electrochemical or battery-based technologies. The technologies selected for the modelling include lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries. These electrochemical technologies are modularly scalable to provide high energy and/or electrical power capacity (Dunn *et al.*, 2011:928-934). They further have the technical readiness, capability and high potential for deployment at the utility-scale, including overcoming the stochastic nature of variable and intermittent renewable energy-based electrical production plants (Dunn *et al.*, 2011:928-934; Akinyele *et al.*, 2014:74-76; Lund *et al.*, 2015:793-799; Chaanaoui *et al.*, 2016:783; Amirante *et al.*, 2017:372-373; Lai *et al.*, 2017:191-194).

The proposed methodology used to develop the LCOS model is clarified and applied to estimate, project and assess the economic feasibility or cost competitiveness of the select energy storage technologies for South Africa at the utility scale through a detailed levelised cost analysis. The levelised cost analysis is performed for energy storage technologies in isolation to enable comparison between the different technologies under consideration, as well as for such technologies coupled with solar PV plants to enable comparison with alternative generation options with similar dispatch or electrical output characteristics.

The LCOS model is used to estimate the lifecycle costs of the select energy storage systems, in isolation and coupled with solar PV plants, in 2016 and project these costs to 2020 under four scenarios. The four scenarios investigated are a function of either one or two daily charge-discharge cycling requirements and 10- or 20-year project contract lifetime specifications. In each scenario, the primary application involves renewables integration with solar PV plants, which requires the select energy storage technologies to provide four hours of energy discharge capability at a 50 megawatt (MW) electrical power rating for 350 days a year. The purpose of the primary application is for the select technologies to overcome issues of solar resource variability and intermittency, supply electrical energy during peak demand periods, enable electricity price arbitrage opportunities and integrate more renewable generators into the electric grid. These services are important for economic growth and development by supporting increased electrical energy security, reliability, flexibility, access and relative affordability.

The LCOS modelling scenario results enables an evaluation of the economic feasibility or cost competitiveness of the energy storage technologies under consideration for South Africa by comparing the results to the levelised costs of alternative generation options with similar electrical output dispatch characteristics. In this regard, to demonstrate the economic feasibility of the select energy storage systems, the total weighted average levelised cost of the energy storage systems combined with solar PV plants (LCOS-PV) at the utility-scale is estimated, projected and compared to the 2016 and anticipated 2020 levelised cost of electricity (LCOE) for concentrating solar power (CSP) plants with thermal energy storage capability as a case study.

This case study provides a fair basis for comparison, since both energy storage systems coupled with solar PV plants and CSP plants with thermal energy storage capability produce and store solar-based electrical energy. CSP, particularly parabolic trough and solar tower plants, is further regarded as mature technology (Grobbelaar, Gauché & Brent, 2014:479; Khan *et al.*, 2016:419; Van Ravenswaay, Roos, Surridge-Talbot, Xosa & Sattler, 2015:1839; Chaanaoui *et al.*, 2016:782-789). The case study therefore makes it possible to test whether the select technologies, coupled with solar PV plants, offer improved investment alternatives in comparison to CSP plants with thermal energy storage capability as appropriate electrical energy system solutions in terms of economic feasibility. The cost competitiveness of the select energy storage systems integrated with solar PV plants relative to other electrical generation options is also considered within the South African context.

The modelling scenario results offer insight into the affordability, economic feasibility and appropriate timing of incorporating electrical energy storage technologies at the utility scale into the South African electrical energy landscape. The empirical study makes a contribution to addressing the need for more detailed research and analyses on the performance characteristics, competitive ability and economic feasibility of energy storage systems in isolation and when such systems are coupled with solar PV plants. The research, however, does not examine the pragmatic electricity system operational need, or urgency, for energy storage technologies within the South African electrical energy generation, supply and demand environment.

1.7.3 Data

The data used throughout this study and to develop, perform and assess the lifecycle or levelised cost modelling was obtained from various sources of published academic literature and well-known, credible and respected organisations recognised for data integrity. Such organisations included, but were not limited to, the Council for Scientific and Industrial Research (CSIR), Eskom, National Energy Regulator of South Africa (NERSA), International Renewable Energy Agency (IRENA), United States Energy Information Administration (EIA), International Energy Agency (IEA), IHS Global Insight, Statistics South Africa (StatsSA) and other reliable energy storage research institutions.

The data mainly pertains to economic and electrical energy variables. It was relatively easily accessible, mostly readily available and could be obtained through internet-based research. In instances in which data could not be obtained, informed assumptions were made and the sources used to derive them were documented.

The data was used to perform background, time-series, cross-sectional and cost-benefit analyses, formulate figures and tables and undertake mathematical modelling to estimate and forecast the levelised cost of energy storage systems (LCOS) and total weighted average levelised cost of such systems coupled with solar photovoltaic (PV) technologies (LCOS-PV). The data was further utilised to project future costs related to solar PV plants and concentrating solar power (CSP) plants with thermal energy storage capability as necessary to perform the economic feasibility assessment for 2016 and anticipated 2020.

The quantitative modelling was also informed by, and will inform, time-series and cross-sectional data. Time-series data was mainly used to inform the LCOS modelling inputs, estimates and projections. Cross-sectional data was used to inform the specific characteristics, model parameters and input variables used to determine the levelised costs of selected competing energy storage technologies.

1.8 SCOPE

This dissertation is structured according to eight chapters. Chapter 1 introduced the research topic; provided background information on the potential for utility-scale energy storage systems in South Africa; outlined the research problem, questions and objectives; clarified the research method followed during the course of this study and expressed the research contributions.

The literature review is divided between Chapters 2 to 5. Of these, Chapters 2 to 4 have a narrower, more specific focus. Chapter 2 describes the concept of utility-scale energy storage, the main elements of energy storage systems and criteria influencing energy storage technology selection. Chapter 3 classifies and provides an overview of various distinct energy storage technologies that are appropriate for use at the utility scale. Chapter 4 elaborates on utility-scale energy storage value applications and encompassing cost considerations. Chapter 5 has a broader concentration and includes a review of literature that has considered the economic feasibility of energy storage technologies and uniquely contextualises the relevance of energy storage systems in light of economic theory.

The empirical study is divided between Chapters 6 and 7. Chapter 6 explains the methodological procedure developed and used to formulate the levelised cost of energy storage (LCOS) model and its extension to the weighted average levelised cost of energy storage systems coupled with solar photovoltaic (PV) plants (LCOS-PV). It discusses the rationale, parameters, cost variables, formulae, calculations, data inputs and relevant assumptions used to mathematically estimate and forecast the LCOS and LCOS-PV. This is necessary to perform the economic feasibility assessment, in terms of cost competitiveness, for energy storage systems in isolation and when such systems are coupled with solar PV plants in comparison to alternative electrical generation options.

Chapter 7 examines the LCOS modelling scenario results and assesses the competitive ability of select utility-scale energy storage systems with one another and with alternative generation options involving similar electrical output dispatch characteristics. In that regard, the LCOS results in isolation and coupled with solar PV plants are estimated for 2016, projected to 2020 and compared to the levelised cost of electricity (LCOE) for concentrating solar power (CSP) plants with thermal energy storage capability as a case study. The cost competitiveness of the select technologies integrated with solar PV plants relative to other electrical generators is also considered within the South African context for conceptual purposes. The outcome of the empirical study is to provide an indication of the affordability, cost competitiveness and economic feasibility of utility-scale electrical energy storage technologies for South Africa in comparison to prevailing alternatives.

Chapter 8 summarises the key findings, makes recommendations, highlights limitations encountered, outlines opportunities for further research and concludes the study. Chapter 8 is followed by Annexures A and B to Chapter 7, which detail the LCOS modelling scenario results and composition. This dissertation ends with a bibliography of sources referenced throughout the study.

1.9 RESEARCH CONTRIBUTIONS

It is envisioned that this study would have academic, practical and policy implications. The related recommendations from the research completed for this study are provided in section 8.3 of the concluding Chapter 8.

1.9.1 Academic contributions

A need has been identified for further research into the performance characteristics, levelised costs and economic feasibility of modern energy storage systems in isolation and coupled with intermittent electrical generation options (He *et al.*, 2011:1575; Zhang, 2013:12-109; Pawel, 2014:68; Akinyele *et al.*, 2014:88; Infield *et al.*, 2014:6-24; Tapia-Ahumada *et al.*, 2015:243; Zakeri *et al.*, 2015:573-590; Kondziella *et al.*, 2016:20; Covert *et al.*, 2016:129; Dehdashti, 2016:4; Amirante *et al.*, 2017:385; Lai *et al.*, 2017:192). This study therefore contributes to the existing body of academic literature on utility-scale energy storage technologies by providing an overview of the concept, characteristics, value applications, complexities and cost considerations of such technologies. The research further enriches contemporary information through a review of previous literature related to the economic feasibility of utility-scale energy storage technologies and by describing how they relate to economic theory.

More specifically, the research advances knowledge about the reflective levelised costs of energy storage systems (LCOS) and how such systems could be compared with one another, as well as with alternative electrical energy generation options within the South African context. This is primarily completed empirically through a methodological development and an economic feasibility assessment of the cost competitiveness of energy storage systems in isolation and coupled with solar photovoltaic (PV) plants. Additional value is added to existing research by extrapolating the estimated levelised costs and associated input variables for 2016 forward to 2020 in order to deduce the appropriate timing for the introduction of energy storage systems as competitive utility-scale solutions into the domestic electrical energy environment.

1.9.2 Practical contributions

A comprehensive overview and economic feasibility assessment of energy storage systems in isolation and coupled with solar photovoltaic (PV) plants will contribute to the existing knowledge base through background, explanations, mathematical estimations, modelling exercises and related evaluations. This could, in turn, be used in practice to inform the affordability, competitive ability, decision-making capabilities and future procurement of utility-scale energy storage technologies to complement variable and intermittent renewable energy electrical production plants as viable electricity system solutions, including within the South African context.

1.9.3 Policy contributions

The research, analyses and findings conveyed in this dissertation could potentially be utilised to inform policy and regulatory formulations and determinations related to the incorporation of energy storage technologies into the South African electrical energy planning, procurement, generation and supply environment. The research contributions could be especially relevant to improve the electrical output stability and dispatchability of variable and intermittent renewable energy-based production plants in a future increasingly characterised by sustainable energy solutions (Battke *et al*., 2013:240-243; Infield *et al.*, 2014:1-13; Zakeri *et al.*, 2015:570; Tapia-Ahumada *et al.*, 2015:243).

1.10 SUMMARY AND CONCLUSION

This chapter initiated the research for this dissertation by providing background information; describing the research problem, questions and objectives; explaining the research method; outlining the scope of research; and indicating the research contributions. It articulated the relevant context for the literature review and empirical analysis throughout the remainder of this dissertation as necessary to address the research problem and attain the objectives set for the study.

Section 1.1 introduced the content to Chapter 1. Section 1.2 clarified the key terms in the title of this dissertation. Section 1.3 provided background information on the potential for energy storage technologies to support the stability of electricity systems in environments increasingly characterised by variable and intermittent renewable energy-based electrical generators. Section 1.4 described the research problem of insufficient knowledge about the technical capability, value applications, reflective costs, financial competitiveness and economic feasibility of energy storage systems in isolation and when such systems are coupled with variable and intermittent electrical production plants, which is addressed in the remainder of this study.

Section 1.5 stipulated the general and specific research questions pertaining to the economic feasibility of utility-scale electrical energy storage technologies for South Africa. Section 1.6 established the general and specific research objectives to guide the resolution of the queries specified. Section 1.7 explained the research method followed in this study during the completion of the background information, literature review, data requirements, methodology and empirical analysis. Section 1.8 outlined the scope of the research. Section 1.9 indicated the academic, practical and policy implications of the research conducted for this dissertation.

The focus of Chapter 2 is to supply contextualising background information on the fundamentals of energy storage. This is completed through a literature review on the energy storage concept, main elements of energy storage systems and criteria influencing the selection of energy storage technologies. The content disclosed in Chapter 2 provides the framework for Chapter 3, which considers various technologies that are appropriate for utility-scale energy storage.

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CHAPTER 2:

LITERATURE REVIEW ON THE ENERGY STORAGE CONCEPT, SYSTEM COMPONENTS AND SELECTION CRITERIA

2.1 INTRODUCTION

Chapter 2 provides background information on the notion of utility-scale energy storage and related considerations. The chapter builds on the preceding introductory Chapter 1 and contributes to the attainment of the specific objectives set for the study by clarifying fundamental aspects of energy storage.

In that regard, the goal of this chapter is to describe the concept of utility-scale energy storage, primary energy storage system components and common criteria influencing the selection of energy storage technologies for particular applications. This provides the relevant context for the overview of various energy storage technologies supplied in Chapter 3 and the techno-economic detail throughout the remainder of this study.

This chapter is structured according to five sections. The next section (2.2) sets the context by explaining the fundamental concept of utility-scale energy storage. Section 2.3 describes the main elements of an energy storage system, namely the energy storage medium; power conversion system (PCS); management, monitoring and control systems; and balance of plant features. Section 2.4 defines key characteristics influencing energy storage technology selection, which can be grouped under performance life, location, economic, supplier risk and policy and regulatory criteria. Section 2.5 summarises and concludes Chapter 2.

2.2 ENERGY STORAGE CONCEPT

Energy storage has, and continues to, become increasingly important for sustainable economic development (Amrouche *et al.*, 2016:20915-20922). It involves a process by which energy is converted from one form, usually electrical energy, into a storable form and retaining it in an appropriate medium or technology for later use by converting it back to electrical energy when needed (Baxter, 2006:3; Chen *et al.*, 2009:291; He *et al.*, 2011:1575; Evans *et al.*, 2012:4142; Ibrahim *et al.*, 2013:3; Kousksou *et al.*, 2014:60;

Akinyele *et al.*, 2014:76; Luo *et al.*, 2015:511; Mandelli *et al.*, 2015:113; Ibrahim *et al.*, 2015:306; World Energy Council, 2016a:8).

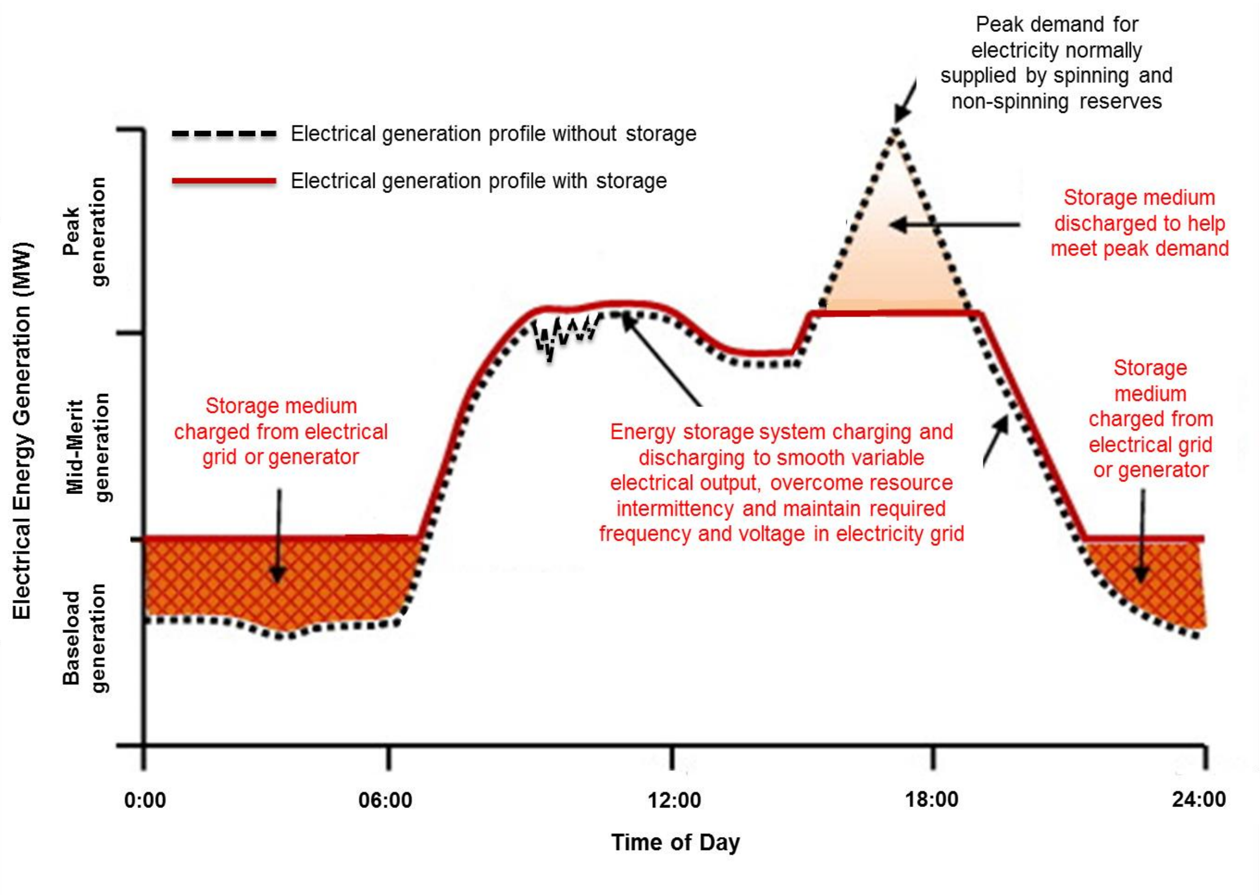
Energy storage technologies are undergoing rapid technical and economic advancements (Luo *et al.*, 2015:524-531; Kempener *et al.*, 2015:8; Dehdashti, 2016:1; Obi *et al.*, 2017:909-913; Astarloa *et al.*, 2017:10-11; Ferroukhi *et al.*, 2017:80; Saboori, Hemmati, Ghiasi & Dehghan, 2017:1108). Several distinct technologies exist that are at varying stages of maturity, development or commercialisation. The suitability of each technology for diverse uses or applications varies under different circumstances due to their respective inherent and wide-ranging technical characteristics (Hall, 2008:4365; Zahedi, 2011:867; Hittinger, Whitacre & Apt, 2012:436; Carnegie *et al.*, 2013:14; Akinyele *et al.*, 2014:76; Castillo *et al.*, 2014:886-887; Lund *et al.*, 2015:793; Luo *et al.*, 2015:524-531; Mandelli *et al.*, 2016:291; Dehdashti, 2016:6). A detailed overview of various utility-scale energy storage technologies is provided in Chapter 3.

Utility-scale energy storage entails different technologies with the capability to typically store more than one megawatt hour (MWh) of energy to perform a number of value applications (Johnstone *et al.*, 2013:143; Castillo *et al.*, 2014:885-888; Hameer *et al.*, 2015:1179; Kyriakopoulos *et al.*, 2016:1056). It refers to projects connected to the electric grid and/or a generation plant to perform large-scale applications, such as bulk energy storage and ancillary services, through the capability to transform electrical energy as an input, store it in energy form and provide electrical energy as an output when required (Suberu *et al.*, 2014:500-501; Akinyele *et al.*, 2014:76; Kempener *et al.*, 2015:25; Luo *et al.*, 2015:511; Mandelli *et al.*, 2016:291; Dehdashti, 2016:1-5). Bulk energy storage refers to large-scale energy applications, while ancillary services are support services required to manage the stable, reliable and continuous delivery of electricity from electrical generators to consumers (Kaltschmitt *et al.*, 2013:1822; Carnegie *et al.*, 2013:8; Lund *et al.*, 2015:791-792; Akhil *et al.*, 2015:149; Dehdashti, 2016:5).

Storing electrical energy at the utility scale dates back to the early 1900s. In the beginning of the 20th century, lead-acid accumulators were used to supply residual loads while electrical power stations were receiving maintenance. Similarly, during that time period, pumped hydroelectric energy storage (PHS) plants were also being installed to provide electric utilities with increased flexibility and reserves (Chen *et al.*, 2009:291; Whittingham, 2012:1519-1521; Ibrahim *et al.*, 2013:2; Suberu *et al.*, 2014:501; Amirante *et al.*, 2017:375).

The ability to store electrical energy at the utility scale enables the required flexibility to balance the production and consumption of electricity in order to support the stability and reliability of the electrical power system at any given time (Baxter, 2006:4; Sørensen, 2011:540; Dunn *et al.*, 2011:929; Poullikkas, 2013:778; World Energy Council, 2016a:6-8; Aneke *et al*., 2016:351; Chaanaoui *et al.*, 2016:783; Berrada *et al.*, 2017:94). Energy storage also entails further benefits, such as assisting to conserve exhaustible fossil fuels, increase the penetration of variable and intermittent renewable energy resource-based electrical production technologies, lower greenhouse gas emissions and allow conventional base load and mid-merit generation options to operate at high efficiency during low electricity demand periods, while reducing the need for expensive peaking power plants during high demand periods (Mahlia *et al.*, 2014:533-534; Lund *et al.*, 2015:793; Ibrahim *et al.*, 2015:306; Aneke *et al*., 2016:354; Obi *et al.*, 2017:909). Figure 2.1 provides a descriptive example of the fundamental idea of utility-scale energy storage (adapted from Makansi *et al.*, 2002:7; Ibrahim *et al.*, 2013:3; Akinyele *et al.*, 2014:76-77).

Figure 2.1: Concept of utility-scale energy storage



Source: Adapted from Makansi *et al.* (2002:7); Ibrahim *et al.* (2013:3); Akinyele *et al.* (2014:76-77)

In Figure 2.1, an electrical energy generation and load profile in the absence of energy storage is shown by the dotted lines, while the generation profile with the use of energy storage is shown by the solid line. The vertical axis indicates the type of electrical energy generation, namely base load, mid-merit and peak generation, and the horizontal axis indicates the daily time of that generation to meet the prevailing demand for electricity.

Base load generators are operated continuously at constant output throughout the year, except during scheduled and unscheduled maintenance, to supply the minimum load in the electricity system at least cost. Mid-merit plants represent more costly intermediate or load following plants that are usually started and operated to supply electrical energy on a daily basis from the early morning peak to evening peak demand periods. Peak generators are highly flexible, but very costly to operate, and usually provide electrical energy for short periods of highest demand in the mornings between 07:00 and 10:00, in the evenings between 18:00 and 22:00 and during emergency hours when unforeseen circumstances necessitate additional electricity supply (Stoft, 2002:42; Masters, 2004:137; Worthington, 2009:114; Kaltschmitt *et al.*, 2013:844-1299; Eskom, 2014:1; Kenny, 2015:22; Akhil *et al.*, 2015:150; Lund *et al.*, 2015:797; Eskom, 2016a:52-112; Eskom 2016b:4; Martinot, 2016:23). In South Africa, base load electrical energy generation plants mainly include coal and nuclear, while mid-merit and peaking plants include some inefficient and ageing coal power stations, hydroelectric generators, PHS and gas- and diesel-fired electrical generation turbines (Eskom, 2014:1; Eskom, 2015:19-81; Kenny, 2015:21).

As shown in Figure 2.1, the use of utility-scale energy storage to charge and discharge as needed, is likely to alter a conventional generation or system load profile. For example, an energy storage system has the capability to charge when excess electrical energy generation is occurring or electricity is cheap and discharge when there is a shortfall of electricity or when electricity is more expensive (Makansi *et al.*, 2002:7; Dufo-López *et al.*, 2009:126-129; Chen *et al.*, 2009:291; Ibrahim *et al.*, 2013:3; Castillo *et al.*, 2014:887-888; Kempener *et al.*, 2015:31; Ibrahim *et al.*, 2015:306; Berrada *et al.*, 2017:94).

As the energy storage medium charges from the grid or electrical generator, the conventional generation profile will increase as additional energy is being absorbed. Conversely, the conventional generation profile will decrease as electrical energy is discharged from the energy storage system due to the prior absorption of excess electricity into the storage medium. This not only helps to ensure that electricity production equals consumption at any given time, but also circumvents or reduces the need to use costly spinning and non-spinning reserves or other ancillary grid support services (Makansi *et al.*, 2002:7; Dufo-López *et al.*, 2009:126-129; Chen *et al.*, 2009:292-293; Akinyele *et al.*, 2014:76-77; Castillo *et al.*, 2014:886-888; Amrouche *et al.*, 2016:20922).

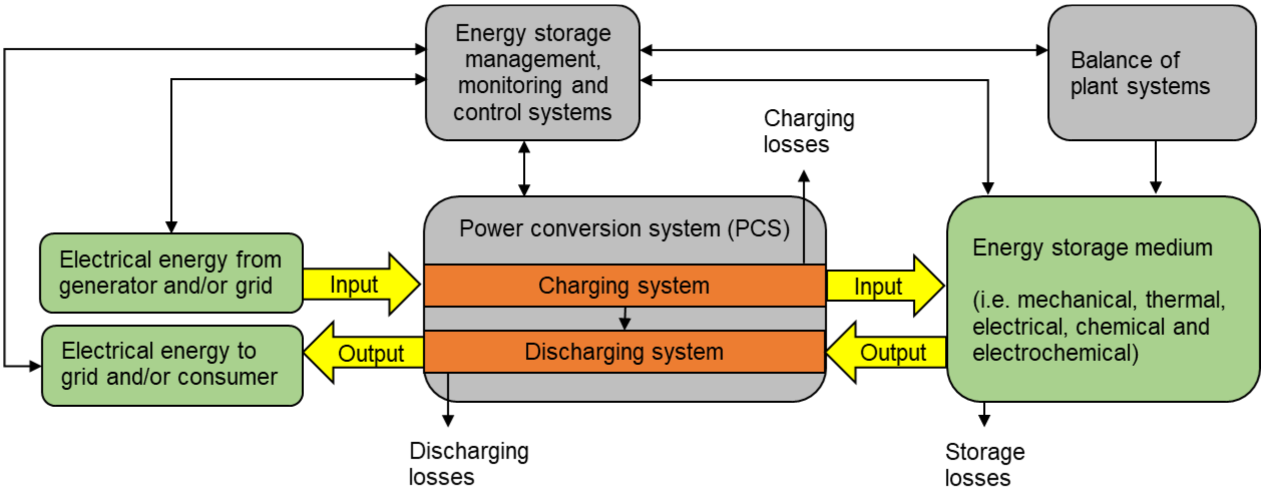
Further value is derived from an energy storage system when it also provides additional support services, such as smoothing the variable electrical output from renewable energy-based production technologies, overcoming solar and wind resource intermittency and providing electricity frequency and voltage regulation (Dufo-López *et al.*, 2009:126-129; Chen *et al.*, 2009:292-293; Sioshansi *et al.*, 2009:269-277; Ibrahim *et al.*, 2013:3-4; Castillo *et al.*, 2014:887-888; Kempener *et al.*, 2015:31; Amrouche *et al.*, 2016:20922). More information on the value applications offered by energy storage technologies is supplied in section 4.2.

2.3 MAIN ELEMENTS OF ENERGY STORAGE SYSTEMS

Various energy storage technologies exist, each with their own characteristics, advantages and disadvantages. The chapter provides an overview of different utility-scale energy storage technologies. Irrespective of the technological composition, any energy storage facility can broadly be classified into four primary system components. These involve the energy storage medium; power conversion system (PCS); energy storage management, monitoring and control systems; and balance of plant systems. The basic elements of energy storage systems are explained in sub-sections 2.3.1 to 2.3.4. Energy storage systems can be directly tied to an electrical generation facility or along the electricity grid to fulfil required use applications (Evans *et al.*, 2012:4142; Ibrahim *et al.*, 2013:4-5; Willis, Aguero, Brown, Edris, Sheble & Wilkins, 2013:2-5; Akinyele *et al.*, 2014:76; Zakeri *et al.*, 2015:572; Lambruschi, 2015:25-28; Kempener *et al*., 2015:7-8; Amrouche *et al.*, 2016:20914-20915; Berrada *et al.*, 2017:97).

Figure 2.2 illustrates the main components and electrical power flows associated with a generic utility-scale energy storage system (adapted from Dufo-López *et al*., 2009:128; Willis *et al.*, 2013:2-3; Suberu *et al.*, 2014:503; Akinyele *et al.*, 2014:76; Zakeri *et al.*, 2015:572; Lambruschi, 2015:25; Kempener *et al*., 2015:7-8, Bussar, Stöcker, Cai, Moraes, Alvarez, Chen, Breuer, Moser, Leuthold & Sauer, 2015:148-149; Günter *et al.*, 2016:229-230; Leslie, Oliver, Prendergast, 2016; Saboori *et al.*, 2017:1111).

Figure 2.2: Main components and electrical power flows of a generic energy storage system



Source: Adapted from Dufo-López *et al*. (2009:128); Willis *et al.* (2013:2-3); Suberu *et al.* (2014:503); Akinyele *et al.* (2014:76); Zakeri *et al.* (2015:572); Lambruschi (2015:25); Kempener *et al*. (2015:7-8); Bussar *et al.* (2015:148-149); Günter *et al.* (2016:229-230); Leslie *et al.* (2016); Saboori *et al.* (2017:1111)

2.3.1 Energy storage medium

The energy storage medium entails the technological means through which potential energy is stored and retained for later use. Various energy storage technologies exist that can generally be grouped into mechanical, thermal, electrical, chemical and electrochemical mediums (Chen *et al.*, 2009:294; Ibrahim *et al*., 2013:4-5; Suberu *et al.*, 2014:501; Akinyele *et al.*, 2014:76; Zakeri *et al.*, 2015:572; Luo *et al.*, 2015:511; Hameer *et al.*, 2015:1180-1189; Mandelli *et al.*, 2016:291; World Energy Council, 2016a:10; Amirante *et al.*, 2017:373-374). An overview of the main utility-scale technologies under each of these mediums is provided in Chapter 3. Energy storage mediums have inherent inefficiencies that result in some standby losses of stored energy, which implies that it is a net energy consumer (Ibrahim *et al.*, 2013:17; Willis *et al.*, 2013:5; Carnegie *et al.*, 2013:13; Jülch *et al*., 2015:20; Zakeri *et al.*, 2015:572; Lund *et al.*, 2015:793).

2.3.2 Power conversion system (PCS)

The power conversion system incorporates the charging and discharging systems, as well as the transformer. It is the electrical interface between the generator, grid and/or customer and the energy storage medium required to convert electrical energy between alternating current (AC) and direct current (DC) during charging and discharging, while ensuring the safety of the energy storage medium (Baxter, 2006:57; Ibrahim *et al.*, 2013:5; Akinyele *et al.*, 2014:76; Lambruschi, 2015:26; Zakeri *et al.*, 2015:572; Mandelli *et al.*, 2015:113-114; Gallo *et al.*, 2016:814; Leslie *et al*., 2016).

The charging system enables the flow of electrical energy from the grid or generator as an input to the energy storage medium. This is done by a rectifier that converts electrical energy from AC in the grid to DC required to charge the storage device in a controlled manner. The discharging system enables the flow of electrical energy as an output from the energy storage medium to the grid or customer when demanded. This is done by an inverter that converts electrical energy from DC back to AC (Willis *et al.*, 2013:3; Ibrahim *et al.*, 2013:5; Akinyele *et al.*, 2014:76; Kempener *et al*., 2015:8; Gallo *et al.*, 2016:814). Bi-directional inverters also exist that can convert electrical energy to both AC and DC (Suberu *et al.*, 2014:510; Lambruschi, 2015:25-26; Kempener *et al.*, 2015:8). Similar to energy storage mediums, power conversion systems have inherent inefficiencies that result in some electrical energy losses during charging and discharging cycles (Willis *et al.*, 2013:5; Carnegie *et al.*, 2013:13; Zakeri *et al.*, 2015:572; Jülch *et al*., 2015:20).

2.3.3 Energy storage management, monitoring and control systems

These systems govern, monitor and control the overall energy storage system to charge, store and discharge electrical energy when needed, in the volume required and in a manner that does not harm the storage medium (Willis *et al.*, 2013:3-4; Akinyele *et al.*, 2014:76). They also interact with the balance of plant systems and inform maintenance requirements to enhance safety, maximise performance and ensure the quality operation of the overall energy storage system (Kempener *et al.*, 2015:7; Leslie *et al.*, 2016; Amirante *et al.*, 2017:381).

2.3.4 Balance of plant systems

The balance of plant systems comprises the elements responsible for safeguarding the equipment, conditioning and environmental control of the storage facility and connecting the power conversion system with the electrical generator, grid and energy storage medium (Ibrahim *et al.*, 2013:5; Leslie *et al.*, 2016). Balance of plant features typically include components such as the protective enclosure of the facility, foundation and ground grid, land, buildings and other structures, electrical interconnections, surge protection devices, environmental control systems, auxiliary power, air conditioning, metering equipment, electrical protection equipment, safety equipment, communications and control equipment, lighting, security, training, labour, permits, engineering, procurement, project management, construction, installations and system integration. The power conversion system and energy storage management, monitoring and control systems are also often regarded as balance of plant features (Ibrahim *et al.*, 2013:5; Zakeri *et al.*, 2015:572; Lazard, 2016:5; Kyriakopoulos *et al.*, 2016:1061).

2.4 CRITERIA INFLUENCING ENERGY STORAGE TECHNOLOGY SELECTION

Several diverse energy storage mediums exist and the selection and procurement of each technology is ultimately informed by its cost and the extent to which it will optimise into the particular use application(s) it is required to perform given its specific technical characteristics (Kempener *et al.*, 2015:12; Aneke *et al.*, 2016:367; Gallo *et al*., 2016:800). Section 3.2 of Chapter 3 provides a detailed overview of various distinct utility-scale energy storage technologies, while sections 4.2 and 4.3 of Chapter 4 respectively review energy storage value applications and cost considerations.

In order to avoid oversimplification and inferior investment decisions, however, it is also important to consider additional factors in the identification and selection of energy storage systems that would be appropriate for the successful execution of required applications (Raza, Janajreh & Ghenai, 2014:912; Kempener *et al.*, 2015:8-10). In that regard, energy storage technologies share a number of essential features that will influence their applicability for different value applications (Kousksou *et al.*, 2014:73; Castillo *et al.*, 2014:886-888; Suberu *et al.*, 2014:508-509).

The common characteristics influencing energy storage technology selection can be grouped by theme into performance life, location, economic, supplier risk and policy and regulatory criteria. These mutual characteristics by criteria are highlighted in Table 2.1 (compiled from Ibrahim *et al.*, 2013:17; Suberu *et al.*, 2014:501; Castillo *et al.*, 2014:886-887; Kempener *et al.*, 2015:6-10; Gallo *et al.*, 2016:802). The energy storage system selection criteria shown in Table 2.1 are clarified in sub-sections 2.4.1 to 2.4.5, which also serves to contextualise some terminology used throughout the remainder of this dissertation. The criteria further assist in the selection of technologies for the economic feasibility assessment performed in empirical Chapters 6 and 7.

Table 2.1: Criteria influencing energy storage technology selection

Performance life	Location	Economic	Supplier risk	Policy and regulatory
• Energy storage capacity • Electrical power output • Energy density • Power density • Charge, storage and discharge duration • Self-discharge • Capacity degradation • Internal temperature • Depth of discharge (DoD) • Response time • Calendar life • Cycle life • Roundtrip efficiency • Technological maturity	• Space limitations • Safety and environmental considerations • Installation infrastructure • Siting • Ambient conditions • Transportability • Modularity	• Battery cell and module costs • Power component costs • Operations, maintenance, replacement and disposal requirements and costs • Charging costs • Levelised cost of energy storage (LCOS) • Power capital cost • Energy capital cost • Energy capital cost per cycle	• Technology and company track record • Warranty or performance guarantee	• National framework • Value applications • Incentives and remuneration • Interconnection standards or utility grid requirements • Economic development potential

Source: Author’s compilation

2.4.1 Performance life criteria

The performance life criteria for energy storage technology selection can be summarised as follows (Poonpun *et al.*, 2008:530; Dufo-López *et al.*, 2009:130-131; Ibrahim *et al.*, 2013:11-17; Carnegie *et al.*, 2013:11-13; Zhang, 2013:109; Battke *et al.*, 2013:244-246; Pawel, 2014:69-72; Kousksou *et al.*, 2014:73; Infield *et al.*, 2014:21-22; Castillo *et al.*, 2014:886; Kempener *et al.*, 2015:6-7; Jülch *et al.*, 2015:19-20; Hameer *et al.*, 2015:1187; Akhil *et al.*, 2015:152-164; Zakeri *et al.*, 2015:573; Bortolini *et al.*, 2015:1028-1029; Mandelli *et al.*, 2016:293; Mayr & Beushausen, 2016; Lazard, 2016:1; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:367-369; Gallo *et al.*, 2016:806; World Energy Council, 2016a:46-47; Amirante *et al.*, 2017:382-384; Obi *et al.*, 2017:913):

- Energy storage capacity (MWh): Total or maximum amount of energy that can be stored in a storage medium.
- Electrical power output (MW): Nominal, also known as nameplate, electrical power rating capacity or maximum electrical energy output that can be discharged from an energy storage system under normal operating conditions.

- Energy density (Wh/l or Wh/kg): Nominal energy stored per unit volume or the amount of energy that can be stored in a technology with a given volume or mass.
- Power density (W/l or W/kg): Maximum electric power per unit volume or the amount of electrical power that can be discharged from a technology with a given volume or mass.
- Charge, storage and discharge duration: Time needed for an energy storage medium to fully charge, retain and/or discharge its electrical power output rating.
- Self-discharge: Dissipation of stored energy during times that a storage system is not in use due to internal losses.
- Capacity degradation: Usable energy over the lifetime of an asset as a result of ageing or the complete charge-discharge cycles an energy storage medium can perform before its nominal energy capacity falls below a certain percentage, say 80%, of its initial rated capacity, irrespective of whether it is used or not.
- Internal temperature: Requirements to maintain suitable operational temperature for the optimal performance, safety and lifetime of an energy storage system.
- Depth of discharge (DoD): Share of total stored energy that can be discharged relative to full capacity before being recharged to maintain the optimum performance lifetime of an energy storage medium. For example, if it is ideal to retain 20% energy capacity in a storage medium, then the DoD is equal to 80%.
- Response time or rate: Time required for an energy storage system to begin fully discharging the correct amount of electrical energy needed by an application.
- Calendar life: Number of years that an energy storage system can remain useful before reaching the end of its lifetime as a result of continuous degradation or contractual arrangements.
- Cycle life: Number of full charge-discharge cycles that can be performed before an energy storage technology reaches the end of its useful life for performing required applications due to overly deep discharges, excessive operating temperature, continuous degradation and/or contractual arrangements.
- Roundtrip or cycle efficiency: Ratio of electrical energy that can be discharged relative to the electrical energy needed to charge an energy storage system as a result of losses during charging, storing and discharging.
- Maturity: Extent to which a technology has been commercialised or deployed.

The performance life criteria are important considerations in the evaluation and selection of energy storage systems, since they pertain to the technical capabilities and limitations of such systems that influence their respective applicability for the performance of required use applications over specified durations (Dunn *et al.*, 2011:928; Carnegie *et al.*, 2013:65; Castillo *et al.*, 2014:889; Kousksou *et al.*, 2014:73; Suberu *et al*., 2014:509; Gallo *et al.*, 2016:802). Section 4.2 of Chapter 4 describes the value applications that can be performed at the utility scale by various energy storage systems.

2.4.2 Location criteria

The location criteria for energy storage technology selection can be summarised as follows (Ibrahim *et al.*, 2013:12-20; Suberu *et al*., 2014:509; Hameer *et al.*, 2015:1181-1182; Kempener *et al.*, 2015:6; Kyriakopoulos *et al.*, 2016:1063; Gallo *et al.*, 2016:806; Berrada *et al.*, 2017:97):

- Space limitations: When available space is limited or has weight restrictions, energy and power density criteria become increasingly important.
- Safety and environmental considerations: Preference should be given to technologies that are not hazardous to human health or the environment over the lifetime of an energy storage system.
- Installation infrastructure: Availability of suitable infrastructure to enable the construction and operation of an energy storage system.
- Siting: Whether an energy storage system will be connected to an electrical generation plant and/or the electricity grid to perform required value applications.
- Ambient conditions: Temperature of the air in the surrounding environment that can affect the performance and safety of an energy storage system.
- Transportability: Ability to relocate an energy storage system if required.
- Modularity: Ability and ease to increase or decrease energy storage capacity if needed.

The location criteria are important considerations in the evaluation and selection of energy storage systems, since they pertain to the environment in which, and structuring through which, such systems would be required to perform particular use applications over specified durations (Suberu *et al*., 2014:509; Raza *et al.*, 2014:915-916). Section 4.2 of Chapter 4 describes the value applications that can be performed at the utility scale by various energy storage systems.

2.4.3 Economic criteria

The economic criteria for energy storage technology selection can be summarised as follows (Battke *et al.*, 2013:242-247; Ibrahim *et al.*, 2013:13-30; Kousksou *et al.*, 2014:73; Castillo *et al.*, 2014:886; Suberu *et al.*, 2014:508-509; Pawel, 2014:68-77; Akinyele *et al.*, 2014:85; Zakeri *et al.*, 2015:573-588; Lazard, 2015:20-29; Mayr *et al.*, 2016; Jülch, 2016:1603; World Energy Council, 2016a:47; Aneke *et al.*, 2016:367; Kyriakopoulos *et al.*, 2016:1063; Amirante *et al.*, 2017:384; Berrada *et al.*, 2017:100):

- Battery cell and module costs: Total cost of an energy storage medium.
- Power component costs: Total cost of balance of plant infrastructure and systems.
- Operations, maintenance, replacement and disposal requirements and costs: Total variable and fixed costs and the associated intervals thereof anticipated for operating, maintaining, replacing and disposing of an energy storage system over its lifetime.
- Charging costs: Expenses related to the electrical input and charging of an energy storage medium due to efficiency losses, which implies that less energy can be discharged and sold than what is required to charge most technologies.
- Levelised cost of energy storage (LCOS): Present value cost per kilowatt hour (kWh) over the lifetime of an energy storage system.
- Power capital cost (value per kW): Initial upfront capital investment cost of an energy storage system per unit of electrical power rating.
- Energy capital cost (value per kWh): Initial upfront capital investment cost of an energy storage system per unit of energy storage capacity.
- Energy capital cost per cycle (value per kWh per cycle): Capital cost per unit of energy storage capacity per cycle over the total cycle lifetime of an energy storage system.

The economic criteria are important considerations in the evaluation and selection of energy storage systems, since they pertain to the costs associated with such systems to perform particular use applications over specified durations given their respective technical capabilities (Castillo *et al.*, 2014:889; Suberu *et al.*, 2014:508-509; Kousksou *et al.*, 2014:73; Mandelli *et al.*, 2016:291). Section 4.2 of Chapter 4 describes the value applications that can be performed at the utility scale by various energy storage systems, while section 4.3 elaborates on the cost considerations associated with such systems.

2.4.4 Supplier risk criteria

The supplier risk criteria for energy storage technology selection can be summarised as follows (Ibrahim *et al.*, 2013:15-16; Akhil *et al.*, 2015:145; Jülch, 2016:1600; Berrada *et al.*, 2017:104-106):

- Technology and company track record: Past performance of and/or experience with relevant technologies and project companies are important factors to ensure the reliability, durability and safety of an energy storage system.
- Warrantee or performance guarantee: Required to hedge against any potential risk of energy storage system failure.

The supplier risk criteria are important considerations in the evaluation and selection of energy storage systems, since they pertain to the quality, risks and longevity of such systems that influence their respective applicability for the performance of required use applications over specified durations (Raza *et al.*, 2014:915; Kempener *et al.*, 2015:10). Section 4.2 of Chapter 4 describes the value applications that can be performed at the utility scale by various energy storage systems.

2.4.5 Policy and regulatory criteria

The policy and regulatory criteria for energy storage technology selection can be summarised as follows (Dunn *et al.*, 2011:928; Ibrahim *et al.*, 2013:19; Carnegie *et al.*, 2013:6-11; Castillo *et al.*, 2014:891-892):

- National framework: The extent to which energy storage systems and related application services are accommodated for in national socio-economic and electricity policy, planning and regulatory frameworks.
- Value applications: Various beneficial uses or services that an energy storage system is required to perform in support of electric utilities and the balancing of electricity supply and demand.
- Incentives and remuneration: Measures to support the adoption, implementation and/or responsible operation of energy storage systems.
- Interconnection standards: Electric utility grid interconnection rules, procedures and requirements that need to be adhered to.
- Economic development potential: Extent to which energy storage systems can contribute to broader national economic development objectives.

The policy and regulatory criteria are important considerations in the evaluation and selection of energy storage systems, since they pertain to the strategic national objectives and regulations that should be followed during the procurement, implementation and operation of such systems in performing required value applications (Castillo *et al.*, 2014:891-892). Section 4.2 of Chapter 4 describes the value applications that can be performed at the utility scale by various energy storage systems.

2.5 SUMMARY AND CONCLUSION

This chapter provided background information on the concept of utility-scale energy storage, the main elements of energy storage systems and criteria influencing the selection of energy storage technologies. It articulated the fundamental aspects of energy storage that offer context to the remainder of this dissertation as necessary to address the research problem and attain the objectives set for the study in Chapter 1.

Section 2.1 introduced the content to Chapter 2. Section 2.2 explained the concept of utility-scale energy storage and referred to some of its benefits to the electricity system, which is explored in more detail throughout this study. Section 2.3 presented the energy storage system components as involving the energy storage medium and balance of plant systems, including the electrical power conversion system (PCS) and energy storage management, monitoring and control systems. Section 2.4 outlined key characteristics that influence the evaluation and selection of energy storage technologies as grouped under performance life, location, economic, supplier risk and policy and regulatory criteria.

The focus of Chapter 3 is to expand on the information described in this chapter by providing an overview of various energy storage technologies that are appropriate for operation at the utility-scale. This is completed through a literature review of the characteristics, technical capability, advantages and disadvantages of different technologies that can be categorised into mechanical, thermal, electrical, chemical and electrochemical energy storage mediums.

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CHAPTER 3:

LITERATURE REVIEW ON ENERGY STORAGE TECHNOLOGIES

3.1 INTRODUCTION

Chapter 3 classifies and provides an overview of energy storage technologies that are appropriate for utility-scale applications. The fundamental features of energy storage systems described in the preceding chapter produced the relevant context for a summary of different technologies that are suitable for utility-scale operations.

In that regard, the goal of this chapter is to contribute to the specific objectives set for the study in Chapter 1, by supplying an overview of the characteristics, technical capability, functioning, advantages, disadvantages, developments and application suitability of diverse energy storage technologies. This supports the necessary framework for the energy storage technologies referred to throughout the remainder of this dissertation. Together with the energy storage system selection criteria outlined in section 2.4 of Chapter 2, the technology overview further assists in the choice of technologies for the empirical analysis conducted in Chapters 6 and 7.

This chapter is structured according to three sections. The next section (3.2) provides an overview of various utility-scale technologies, categorised into mechanical, thermal, electrical, chemical and electrochemical energy storage mediums. Section 3.3 summarises and concludes Chapter 3.

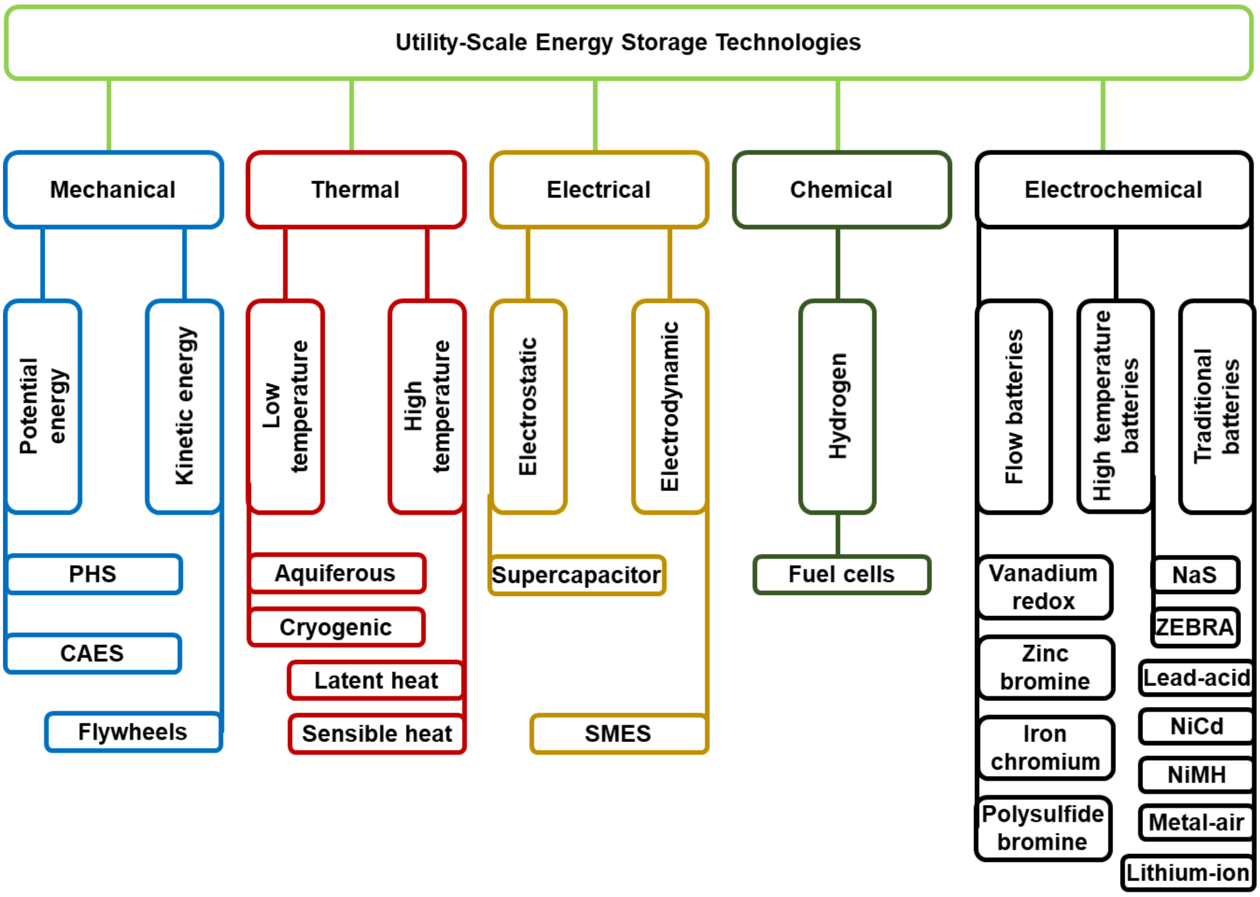
3.2 OVERVIEW OF UTILITY-SCALE ENERGY STORAGE TECHNOLOGIES

Small-scale energy storage technologies typically have an electrical power rating size of kilowatts (kW) to under one megawatt (MW). Utility- or grid-scale energy storage technologies, on the other hand, are generally sized to a power rating of more than one MW (Olaofe & Folly, 2012:2-3; Johnstone *et al.*, 2013:143; Hameer *et al.*, 2015:1179; Kyriakopoulos *et al.*, 2016:1056; Nguyen, Martin, Malmquist & Silva, 2017:1).

Energy storage technologies can generally be categorised into mechanical, thermal, electrical, chemical and electrochemical mediums. Within each of these mediums, a wide variety of technologies exist that are at different stages of maturity and have the proven capability or potential to store energy at the utility scale. In this section, a summary of existing or the most promising technologies that are appropriate for utility-scale energy storage over the short- to medium-term is provided (Evans *et al.*, 2012:4142; Poullikkas, 2013:779-783; Kousksou *et al.*, 2014:60-73; Luo *et al.*, 2015:513-531; Hameer *et al.*, 2015:1180-1189; World Energy Council, 2016a:10; Aneke *et al.*, 2016:354-367; Amirante *et al.*, 2017:373-385).

Figure 3.1 illustrates the taxonomy of utility-scale energy storage technologies (adapted from Evans *et al.*, 2012:4143; Carnegie *et al.*, 2013:21-22; Hameer *et al.*, 2015:1180; Luo *et al.*, 2015:513-514; World Energy Council, 2016a:10; Aneke *et al.*, 2016:356; Ferroukhi *et al.*, 2017:75).

Figure 3.1: Classification of utility-scale energy storage technologies



Source: Adapted from Evans *et al.* (2012:4143); Carnegie *et al.* (2013:21-22); Hameer *et al.* (2015:1180); Luo *et al.* (2015:513-514); World Energy Council (2016a:10); Aneke *et al*. (2016:356)

Mechanical energy storage technologies include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES) and flywheels. Thermal energy storage technologies include low temperature and high temperature storage mediums, of which molten salts is one effective and efficient way of making electrical energy from concentrating solar power (CSP) plants dispatchable. Electrical energy storage technologies include supercapacitors and superconducting magnetic energy storage (SMES). Chemical energy storage technologies include hydrogen fuel cells. Electrochemical energy storage technologies include various battery compositions, such as lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Chen *et al.*, 2009:294; Suberu *et al.*, 2014:501; Luo *et al.*, 2015:511; Hameer *et al.*, 2015:1180-1189; Mandelli *et al.*, 2016:291; Kyriakopoulos *et al.*, 2016:1045-1064; Aneke *et al*., 2016:354-367; Gallo *et al.*, 2016:802-814; Amrouche *et al.*, 2016:20915-20922; Amirante *et al.*, 2017:373-385).

The multifaceted nature of the technologies depicted in Figure 3.1 could be highlighted through an overview of each technology type that is appropriate for operation at the utility scale. In that regard, a review of the technical characteristics, capability, functioning, advantages, disadvantages, developments and practical uses of different energy storage technologies is provided in sub-sections 3.2.1 to 3.2.5.

Table 3.1 summarises the primary technical characteristics of 21 utility-scale technologies grouped under their respective energy storage mediums (compiled from Kaldellis, Zafirakis & Kavadias, 2009:383; Chen *et al.*, 2009:307-308; Beaudin *et al.*, 2010:309-310; Sørensen, 2011:590; Evans *et al.*, 2012:4146; Poullikkas, 2013:786; Kousksou *et al.*, 2014:60-73; Castillo *et al.*, 2014:887; Mahlia *et al.*, 2014:542; Akinyele *et al.*, 2014:85-86; Luo *et al.*, 2015:513-527; Hameer *et al.*, 2015:1181-1192; Zakeri *et al.*, 2015:592; Lund *et al.*, 2015:794-798; Parrado, Marzo, Fuentealba & Fernández, 2016:511; Jülch, 2016:1598; Venkataramani *et al.*, 2016:897; Sessa, Crugnola, Todeschini, Zin & Benato, 2016:110; Kyriakopoulos *et al.*, 2016:1055-1062; Aneke *et al*., 2016:354-367; Amrouche *et al.*, 2016:20915-20922; Gallo *et al.*, 2016:801-817; Lai *et al.*, 2017:202; Amirante *et al.*, 2017:375-385).

Each of the characteristics represented in Table 3.1 is defined in sub-section 2.4.1 of Chapter 2. Given the rapid techno-economic improvements taking place with energy storage technologies, the data represented in Table 3.1 might not be perfectly representative of the developmental state of all technologies in 2017. Table 3.1 is complemented by Table 4.2 in section 4.3 of Chapter 4, which highlights the ranges of major cost indicators of various utility-scale energy storage technologies.

Table 3.1: Technical characteristics of energy storage technologies

Energy storage technology	Energy density (Wh/l)	Power density (W/l)	Roundtrip efficiency (%)	Response time	Storage duration	Discharge duration (hours)	Self-discharge rate (%/day)	Maximum depth of discharge (%)	Cycle life (number of cycles)	Calendar life (years)	Power rating (MW)	Rated energy capacity (MWh)
Mechanical energy storage												
PHS	0.5 – 1.5	0.5 – 1.5	70 – 87	< 1 – 3 minutes	Hours – months	1 – > 24	0.005 – 0.02	80 – 95	10 000 – > 30 000	40 – 60	10 – 5 000	100 – > 5 000
Diabatic CAES	3 – 6	0.5 – 2	50 – 79	9 – 12 minutes	Hours – months	1 – > 24	0.003 – 0.03	80 – 100	10 000 – 30 000	20 – 50	5 – > 400	< 10 – 3 000
Adiabatic CAES	3 – 6	0.5 – 2	70 – 89	1 – 15 minutes	Hours – months	1 – > 24	0.05 – 1	80 – 100	10 000 – 30 000	20 – 40	> 100	> 100
Flywheels	20 – 80	1 000 – 2 000	90 – 95	milliseconds – seconds	Seconds – minutes	milliseconds – 15 minutes	100	100	20 000 – 100 000	15 – 20	0.25 – 20	0.75 – 5
Thermal energy storage												
Molten salt	120 – 500	–	55 – 85	Minutes	Hours – months	1 – > 24	0.05 – 1	100	13 000 – > 15 000	10 – > 20	0.1 – 400	–
Electrical energy storage												
Capacitors	2 – 10	> 100 000	60 – 70	milliseconds	Seconds – hours	milliseconds – 1	40 – 50	75	50 000	5 – 8	0.05	–
Supercapacitors	10 – 30	> 100 000	90 – 95	milliseconds	Seconds – hours	milliseconds – 1	20 – 40	75	> 100 000	10 – 20	0.3 – 10	< 0.01
SMES	0.2 – 2.5	1 000 – 4 000	95 – 98	milliseconds	Minutes – hours	milliseconds – 8 seconds	10 – 15	100	> 100 000	15 – 20	0.1 – 10	< 0.01
Chemical energy storage												
Hydrogen fuel cells	500 – 3 000	> 500	30 – 50	milliseconds – minutes	Hours – months	Seconds – > 24	0.003	100	1 000 – > 20 000	5 – 20	0.3 – 50	0.3 – > 100
Electrochemical energy storage												
Lead-acid	50 – 90	10 – 700	70 – 90	milliseconds	Minutes – days	Seconds – 10	0.1 – 0.3	60	400 – 1 500	5 – 15	0.001 – 40	0.001 – 100
Advanced lead-acid	50 – 90	90 – 700	75 – 90	milliseconds	Minutes – days	Seconds – 10	0.1 – 0.3	80	2 200 – 4 500	5 – 15	0.001 – 40	0.001 – 100
NiCd	60 – 150	80 – 650	60 – 70	milliseconds	Minutes – days	Seconds – 8	0.2 – 0.6	80	800 – 2 500	10 – 20	0.01 – 40	0.001 – 6.75
NiMH	140 – 300	500 – 3 000	65 – 75	milliseconds	Minutes – days	Seconds – 5	0.4 – 1.2	100	800 – 1 500	5 – 10	0.01 – 1	0.001 – 0.5
Metal-air	500 – 10 000	100	55 – 60	milliseconds	Hours – months	Seconds – > 24	Almost zero	100	> 1 000	> 1	> 0.01	> 1
NaS	150 – 300	140 – 200	78 – 90	milliseconds	Seconds – hours	Seconds – 8	0.05 – 20	90	2 500 – 10 000	10 – 15	0.05 – 34	6 – 245
$NaNiCl_2$/ZEBRA	150 – 200	220 – 300	85 – 90	milliseconds	Seconds – hours	Seconds – 5	15	80	2 500 – 4 500	10 – 15	0.001 – > 0.3	0.12 – 5
Lithium-ion	250 – 600	1 500 – 10 000	90 – 97	milliseconds	Minutes – days	Minutes – 4	0.1 – 0.3	80	1 000 – 10 000	5 – 15	> 0.1	> 0.1
ZnBr flow	30 – 65	< 25	67 – 77	milliseconds	Hours – months	Seconds – 10	0.2	100	1 500 – > 10 000	5 – 15	0.05 – > 10	0.05 – > 10
FeCr flow	30 – 65	< 25	70 – 78	milliseconds	Hours – months	Seconds – 8	0.2	100	10 000 – > 13 000	5 – 15	1 – > 2	0.005 – > 2
VRFB flow	25 – 35	< 2	75 – 85	milliseconds	Hours – months	Seconds – 12	0.2	100	10 000 – > 13 000	10 – 20	0.03 – > 10	0.005 – > 10
PSB flow	20 – 30	< 2	60 – 78	milliseconds	Hours – months	Seconds – 10	0.2	100	2 000 – 2 500	5 – 15	1 – 15	0.01 – > 10

Source: Author’s compilation

3.2.1 Mechanical storage

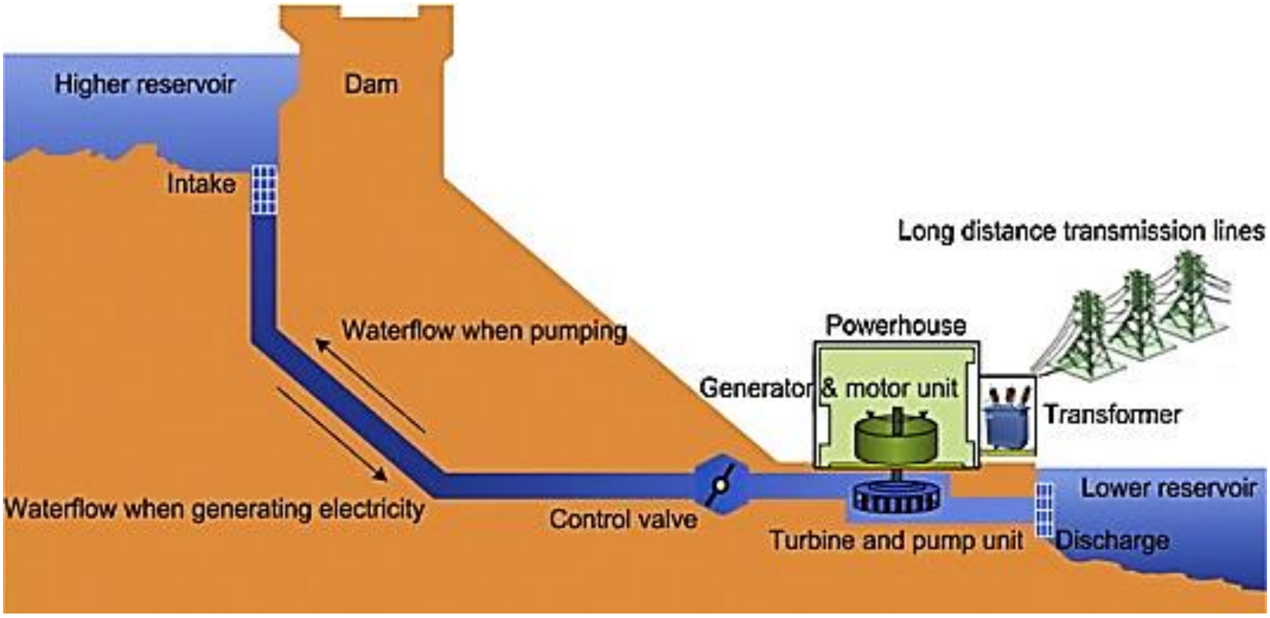
Mechanical energy storage involves a process through which electricity is used as an input and stored as kinetic or potential energy by means such as pumping, compression, expansion, acceleration and deceleration (Chen *et al.*, 2009:294; Evans *et al.*, 2012:4142; Carnegie *et al.*, 2013:22; Gallo *et al.*, 2016:802).

3.2.1.1 Pumped hydroelectric energy storage (PHS)

A pumped hydroelectric energy storage (PHS) scheme makes use of two water reservoirs that are located at different elevations and connected by huge pipes. Water is pumped from the lower to the upper reservoir during low electricity demand and price periods, usually on weekends and/or off-peak hours, where it is kept as hydraulic potential energy for later discharge. When the energy is required, the upper reservoir functions similar to a conventional hydroelectric power plant by allowing water to cascade down and through a turbine back to the lower reservoir to generate electrical energy during high electricity demand and price periods (Chen *et al.*, 2009:295; Beaudin *et al.*, 2010:304; Kousksou *et al.*, 2014:68; Mahlia *et al.*, 2014:536; Luo *et al.*, 2015:513; Akhil *et al.*, 2015:160; Hameer *et al.*, 2015:1181; Lund *et al.*, 2015:794; Kyriakopoulos *et al.*, 2016:1055; Gallo *et al.*, 2016:802; Berrada *et al.*, 2017:97; Amirante *et al.*, 2017:374-376).

Figure 3.2 provides a schematic representation of a pumped hydroelectric energy storage scheme (Luo *et al*., 2015:514).

Figure 3.2: Pumped hydroelectric energy storage (PHS)



Source: Luo *et al*. (2015:514)

PHS is the most established form of utility-scale energy storage globally based on installed capacity, representing around 98% of total installed energy storage capacity in 2017. It has also been reported to have the lowest levelised cost of energy storage (LCOS) for large-scale operations (Hameer *et al.*, 2015:1179-1194; Lund *et al.*, 2015:794; Aneke *et al.*, 2016:356; Jülch, 2016:1594; World Energy Council, 2016a:10; Gallo *et al.*, 2016:802; Amirante *et al.*, 2017:375; Obi *et al.*, 2017:909; Berrada *et al.*, 2017:96-97).

The key advantages and disadvantages of PHS are summarised in Table 3.2 (Kousksou *et al.*, 2014:68; Castillo *et al.*, 2014:887; Hameer *et al.*, 2015:1181-1192; Luo *et al.*, 2015:526; Kyriakopoulos *et al.*, 2016:1055; Aneke *et al.*, 2016:356; Gallo *et al.*, 2016:802-818; Amirante *et al.*, 2017:375; Berrada *et al.*, 2017:96-97; Lazkano *et al.*, 2017:2).

Table 3.2: Advantages and disadvantages of pumped hydroelectric energy storage (PHS)

Advantages	Disadvantages
• Highly mature and commercialised	• Constrained by limited location and water site availability
• High power capacity	• Low energy density
• High energy capacity	• High initial capital investment cost
• Very long calendar life	• Long construction time, around 10 years
• Very long cycle life	• Environmental issues with reservoir building
• Moderate to high roundtrip efficiency	• High evaporation losses in hot climates
• High response rate at large energy volumes	• Exposure to droughts
• Relatively fast ramp rates	• Limited to large energy and power applications
• Very long storage duration and can also provide seasonal storage	
• Very long discharge duration	
• Very low self-discharge rate	

Source: Author's compilation

In some instances, the ocean can be used as a lower reservoir, which might lower construction costs, but requires increased corrosion prevention efforts (Lund *et al.*, 2015:794; Amirante *et al.*, 2017:375). Another innovative solution entails the use of an underground vertical gravity shaft and large internal piston, which could reduce negative environmental impacts by significantly reducing the size of the surface reservoir, improving discharge time and enhancing roundtrip efficiency (Mahlia *et al.*, 2014:536; Lund *et al.*, 2015:794; Aneke *et al.*, 2016:356-357; Gallo *et al.*, 2016:802-803).

PHS could be appropriate for applications such as seasonal energy storage, energy time shifting, load levelling and peak shaving, load following, intermittent renewables integration, transmission and distribution congestion relief and/or investment upgrade deferral and the provision of ancillary services, including frequency regulation, operating reserves and black start capability (Poullikkas, 2013:786; Kousksou *et al.*, 2014:68; Castillo *et al.*, 2014:887; Luo *et al.*, 2015:513-530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-794; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365; Amrouche *et al.*, 2016:20918; Gallo *et al.*, 2016:818; Amirante *et al.*, 2017:375; Berrada *et al.*, 2017:96). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by PHS systems.

3.2.1.2 Compressed air energy storage (CAES)

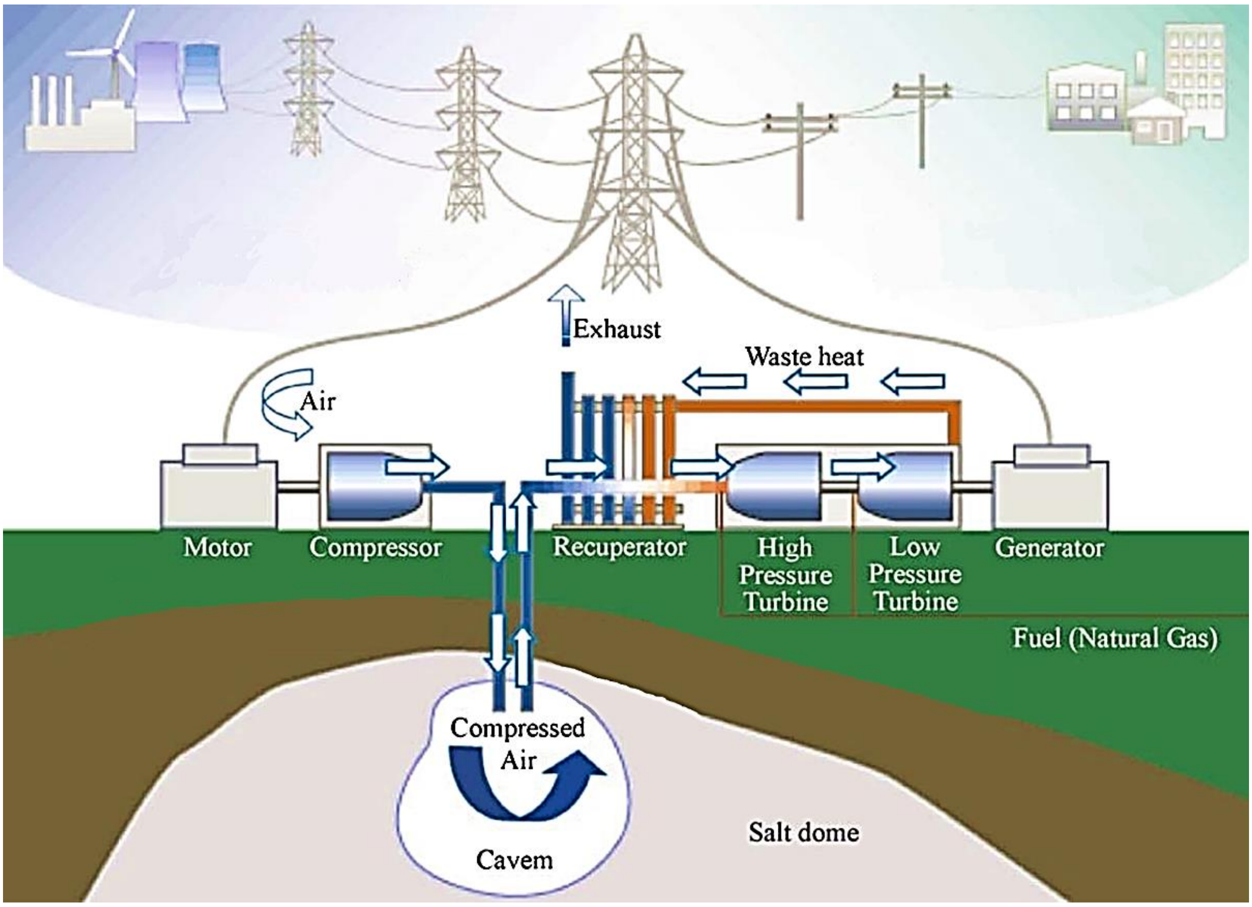
Compressed air energy storage (CAES) uses electricity in low demand and price periods to drive a compressor to compress ambient air and pump it into a confined underground space, such as a salt mine or rock cavern, or aboveground vessel, such as a tank, where the pressurised air can be stored as elastic potential energy for later use. When the energy is required, the pressurised air is released, heated by burning natural gas and/or recovering heat and expanded into a gas fired expansion turbine, which drives a generator that produces electrical energy and delivers it to the grid as electricity during high electricity demand and price periods (Chen *et al.*, 2009:295; Kousksou *et al.*, 2014:68; Mahlia *et al.*, 2014:534; Akinyele *et al.*, 2014:76; Luo *et al.*, 2015:514; Hameer *et al.*, 2015:1182-1183; Lund *et al.*, 2015:794; Ibrahim *et al.*, 2015:306-308; Kyriakopoulos *et al.*, 2016:1055; Aneke *et al.*, 2016:358; Gallo *et al.*, 2016:803; Venkataramani *et al.*, 2016:897; Amirante *et al.*, 2017:377; Berrada *et al.*, 2017:97).

Two main types of CAES technologies are appropriate for utility-scale applications, namely diabatic and adiabatic (Gallo *et al.*, 2016:803-804). The main difference between the two alternatives is that heat generated during air compression in diabatic CAES is wasted, which reduces roundtrip efficiency and necessitates an external heat source for air expansion, while adiabatic CAES includes both compressed air and thermal energy storage so that heat generated during compression can be preserved for later use in expansion through a reversible thermodynamic process (Mahlia *et al.*, 2014:534; Akhil *et al.*, 2015:149; Gallo *et al.*, 2016:803; Jülch, 2016:1597; Venkataramani *et al.*, 2016:897).

Diabatic CAES is a mature technology and has been deployed commercially in a few cases, while adiabatic CAES is still under development and not commercialised as yet (Gallo *et al.*, 2016:803). Adiabatic CAES, however, is a promising innovative technology that would entail improved thermal efficiency and consequent lower gas fuel needs, larger storage capacity, higher roundtrip efficiency and quicker response time (Luo *et al.*, 2015:515; Aneke *et al.*, 2016:358; Gallo *et al.*, 2016:803). Isothermal CAES is also under development, through which air at near ambient temperature can be compressed, stored and expanded without additional fuel heating or thermal energy storage requirements (Akinyele *et al.*, 2014:81; Gallo *et al.*, 2016:803; Venkataramani *et al.*, 2016:897).

Figure 3.3 provides a schematic representation of a CAES system (Chen *et al*., 2009:296; Mahlia *et al*., 2014:534; Hameer *et al*., 2015:1183; Aneke *et al*., 2016:358).

Figure 3.3: Compressed air energy storage (CAES)



Source: Chen *et al*. (2009:296); Mahlia *et al*. (2014:534); Hameer *et al*. (2015:1183); Aneke *et al*. (2016:358)

The key advantages and disadvantages of CAES are summarised in Table 3.3 (Poullikkas, 2013:786; Kousksou *et al*., 2014:68; Luo *et al*., 2015:515; Hameer *et al*., 2015:1182-1193; Kyriakopoulos *et al*., 2016:1055; Amrouche *et al*., 2016:20918; Gallo *et al*., 2016:803-818; Amirante *et al*., 2017:377; Berrada *et al*., 2017:96-97).

Table 3.3: Advantages and disadvantages of compressed air energy storage (CAES)

Advantages	Disadvantages
• Mature, but development is ongoing to improve roundtrip efficiency • High energy capacity • High power capacity • Very long calendar life • Very long cycle life • Leverages existing gas turbine technologies • Very long storage duration and can also provide seasonal storage • Very long discharge duration • Very low self-discharge rate	• Limited geological site availability • Low energy density • High initial capital cost, albeit lower than for pumped hydroelectric storage (PHS) • Long construction time • Requires gas turbine and natural gas as a fuel input, which raises operating costs • Exposure to natural gas prices • Greenhouse gas emissions, but this is limited if heat is recovered • Moderate response time • Difficult to tailor for smaller installations • Moderate round trip efficiency

Source: Author's compilation

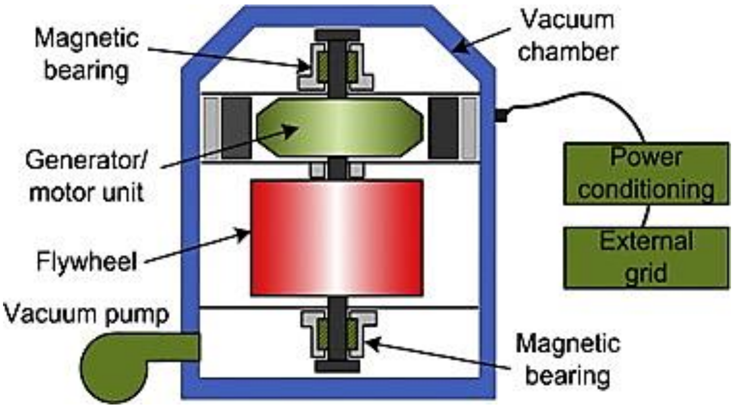
CAES could be appropriate for applications such as seasonal energy storage, energy time shifting, load levelling and peak shaving, variable and intermittent renewables integration, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Poullikkas, 2013:786; Luo *et al.*, 2015:515-530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-794; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366; Gallo *et al.*, 2016:818; Amirante *et al.*, 2017:377). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by CAES systems.

3.2.1.3 Flywheels

Flywheels are rotating cylindrical mechanical devices used to store rotational kinetic energy that can be called upon instantaneously. During charging, it uses electricity to drive an electrical motor generator, which accelerates the flywheel rotor providing the charge, and stores kinetic energy in its centre through the angular momentum of a spinning mass. During discharging, when energy is needed, the flywheel rotor is decelerated to release rapid surges of electrical energy from the motor generator through electromagnetic induction (Hameer *et al.*, 2015:1183; Lund *et al.*, 2015:795-796; Kyriakopoulos *et al.*, 2016:1056; Amrouche *et al.*, 2016:20917; Aneke *et al.*, 2016:355-356; Gallo *et al.*, 2016:804; Amirante *et al.*, 2017:377-378).

Figure 3.4 provides a schematic representation of a flywheel (Luo *et al*., 2015:516).

Figure 3.4: Flywheel energy storage



Source: Luo *et al*. (2015:516)

The key advantages and disadvantages of flywheel energy storage are summarised in Table 3.4 (Carnegie *et al.*, 2013:31-33; Castillo *et al.*, 2014:887; Mahlia *et al.*, 2014:535; Akinyele *et al.*, 2014:89; Luo *et al.*, 2015:516; Hameer *et al.*, 2015:1183; Lund *et al.*, 2015:796; Kyriakopoulos *et al.*, 2016:1056; Aneke *et al.*, 2016:356; Gallo *et al.*, 2016:804; Amirante *et al.*, 2017:378).

Table 3.4: Advantages and disadvantages of flywheels

Advantages	**Disadvantages**
• Mature and commercialised, especially for lower speed applications • High power density • High power capacity • Power and energy capacity easily and independently scalable • Very long cycle life • Very long calendar life • High roundtrip efficiency • Rapid response time • Flat voltage profile • Not limited by depth of discharge (DoD) • Minimal maintenance requirements • No or very limited environmental impact • Rapid ramp rates • Short recharge time • Tolerant to large temperature variations and harsh conditions	• High speed flywheels in demonstration phase • Low energy density and capacity • Very short storage and discharge durations • Very high self-discharge rate • High initial capital cost • Roundtrip efficiency declines with operational period due to frictional effects while flywheel is active • Frequent cycling causes mechanical parts to deteriorate • Noise pollution, which could constrain siting

Source: Author’s compilation

Two types of flywheels exist, namely low speed and high speed flywheels. High speed flywheels provide a longer period of energy storage, but lesser power capacities than low speed flywheels. High speed flywheels can reach 100 000 revolutions per minute, which is equivalent to speeds ten times faster than low speed flywheels, but they can also be up to five times more expensive due to more costly materials and motor-generator equipment (Kousksou *et al.*, 2014:69; Mahlia *et al.*, 2014:535; Luo *et al.*, 2015:515-516; Aneke *et al*., 2016:356; Gallo *et al.*, 2016:804).

Flywheels could be appropriate for applications such as variable renewables integration and ancillary services, including frequency and voltage regulation in particular and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-796; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365; Gallo *et al.*, 2016:818; Amirante *et al.*, 2017:378). The ability of flywheels to provide black start services, which refer to the capability to start electrical generators without using the electric grid, however, might be limited by their short discharge duration (Lund *et al.*, 2015:792; Aneke *et al.*, 2016:366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by flywheel energy storage systems.

3.2.2 Thermal energy storage

Thermal energy storage involves the capturing of energy produced in the form of heat and/or cold in insulated containments for use at a later time (Chen *et al.*, 2009:305; Kousksou *et al.*, 2014:61; Mahlia *et al.*, 2014:540; Amrouche *et al.*, 2016:20915-20919; Gallo *et al.*, 2016:802). Various thermal energy storage mediums exist, which can be classified into low and high temperature thermal energy storage (Chen *et al.*, 2009:292-294; Kousksou *et al.*, 2014:61; Luo *et al.*, 2015:523; Aneke *et al.*, 2016:366).

Low temperature thermal energy storage mediums generally operate below 200°C and mainly include aquifer and cryogenic energy storage (Chen *et al.*, 2009:294; Kousksou *et al.*, 2014:61; Luo *et al.*, 2015:523; Aneke *et al.*, 2016:366). Aquifers cool or freeze water through refrigeration at low demand periods and store it to provide cooling during high demand periods (Chen *et al.*, 2009:305; Akinyele *et al.*, 2014:82-83; Hameer *et al.*, 2015:1180-1189). Cryogenic energy storage boils cryogen, as liquid nitrogen or liquid air, from heat in the surrounding environment and uses it to generate electrical energy through a cryogenic heat engine (Chen *et al.*, 2009:305; Akinyele *et al.*, 2014:83).

High temperature thermal energy storage mediums mainly include latent heat and sensible heat (Luo *et al.*, 2015:523; Amrouche *et al.*, 2016:20920-20921; Gallo *et al.*, 2016:813). Latent heat energy storage involves a phase change process at a constant temperature through which phase change materials, such as liquid crystals, paraffin wax and fatty acids, are usually transformed from a solid to liquid form (Chen *et al.*, 2009:294-306; Kousksou *et al.*, 2014:62-63; Hameer *et al.*, 2015:1184-1187; Aneke *et al.*, 2016:366; Gallo *et al.*, 2016:813). Sensible heat energy storage involves a temperature change of a liquid or solid storage medium, which could encompass steam, hot water accumulators, gravel, hot rocks, fire bricks, graphite, concrete, waste material and molten salts (Chen *et al.*, 2009:294; Kousksou *et al.*, 2014:61; Mahlia *et al.*, 2014:539-540; Aneke *et al.*, 2016:366; Amrouche *et al.*, 2016:20920-20921; Gallo *et al.*, 2016:813).

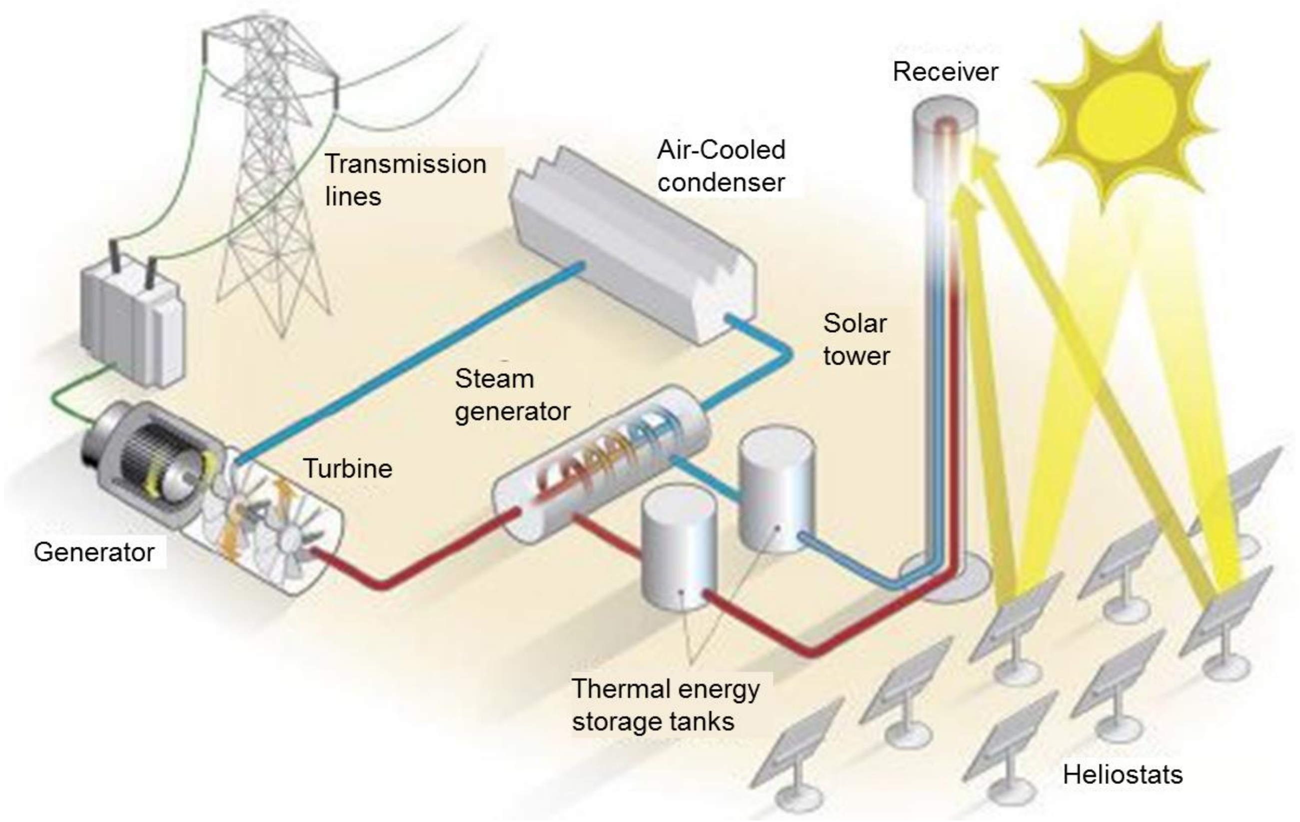
Thermochemical heat storage is also being researched and developed. It involves an operation in which thermal energy is used to separate the chemical compounds in reactive material through an endothermic process, after which the dissociated chemical compounds are stored and recombined when needed to release the thermal energy through an exothermic reaction. While it is technically complex, chemical thermal energy storage has the potential to improve the energy density and storage duration of latent and sensible heat storage (Kousksou *et al.*, 2014:65-67; Mahlia *et al.*, 2014:541; Hameer *et al.*, 2015:1184; Kyriakopoulos *et al.*, 2016:1056; Aneke *et al.*, 2016:366-367).

While many thermal energy storage mediums exist, only molten salt energy storage as high temperature sensible heat is described here. This is mainly due to its dominance as a thermal energy storage medium and demonstrated capability to make electrical energy output from intermittent solar energy-based generation options dispatchable or available upon request. In particular, molten salt thermal energy storage can enable concentrating solar power (CSP) technologies to operate similar to conventional power plants by helping to overcome the inherent resource uncertainty associated with solar energy (Kousksou *et al.*, 2014:61; Aneke *et al.*, 2016:369-375; Parrado *et al.*, 2016:506-507; Liu, Tay, Bell, Belusko, Jacob, Will, Saman & Bruno, 2016:1411-1416; Chaanaoui *et al.*, 2016:782-783; Amrouche *et al.*, 2016:20921-20922). The majority of the remaining thermal energy storage technologies are also usually located on the customer’s side of the meter (Chen *et al.*, 2009:305-306; Carnegie *et al.*, 2013:62).

CSP technologies can be classified into solar power tower, parabolic trough collector, linear Fresnel reflector and parabolic dish collector. All CSP plants, regardless of the technology used, comprise a solar field, energy storage medium and electrical power generation system. A CSP plant with molten salt thermal energy storage capability typically involves storing excess solar energy produced during the day as heat in tanks by using mirrors to concentrate sunlight onto a small area or receiver containing molten salt. The concentrated sunlight heats the molten salt to very high temperatures, approximately 290 to 570°C or higher, and transforms it into liquid form as the heat transfer fluid. When energy is required, the liquid molten salt is dispatched from a hot storage tank through a heat exchanger to produce steam, which is, in turn, used to drive a turbine and generate electricity. Thereafter, the molten salt is cooled and stored in a tank for reuse (Carnegie *et al.*, 2013:62; Busse & Dinter, 2016:51-55; Amrouche *et al.*, 2016:20919-20922; Chaanaoui *et al.*, 2016:782-783; Liu *et al.*, 2016:1411-1416).

Figure 3.5 provides a schematic representation of a CSP tower plant with two-tank molten salt thermal energy storage (United States Department of Energy, 2014:6).

Figure 3.5: Concentrating solar power (CSP) plant with thermal energy storage



Source: United States Department of Energy (2014:6)

The key advantages and disadvantages of molten salt thermal energy storage are summarised in Table 3.5 (Kousksou *et al.*, 2014:61-67; Hameer *et al.*, 2015:1184; Kyriakopoulos *et al.*, 2016:1056; Aneke *et al.*, 2016:366; Amrouche *et al.*, 2016:20921; Parrado *et al.*, 2016:506-513; Liu *et al.*, 2016:1411-1416).

Table 3.5: Advantages and disadvantages of molten salt thermal energy storage

Advantages	Disadvantages
• Mature and commercially available • Uses thermal energy, rather than electrical energy, as fuel input • Excellent thermal heat transfer fluid • Widely used in CSP plants • Very long cycle life • Very long calendar life • Low self-discharge • Very long storage and discharge duration • Reliable • Scalable • Little or no health or environmental danger • Configuration with available materials • Very high operating temperature	• Significant thermal heat loss over time, depending on insulation • Moderate energy density • Large storage volume needed • Moderate roundtrip efficiency • Moderate response time • High freezing point around 100°C to 220°C, which can lead to energy losses and requires expensive anti-freeze systems • Stored heat is not recovered during discharge process

Source: Author's compilation

Molten salt-based energy storage could be appropriate for applications such as seasonal energy storage (i.e. potentially), energy time shifting, load levelling and peak shaving, variable and intermittent renewables integration, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including operating reserves and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:367; Amrouche *et al.*, 2016:20919). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by thermal energy storage systems.

3.2.3 Electrical energy storage

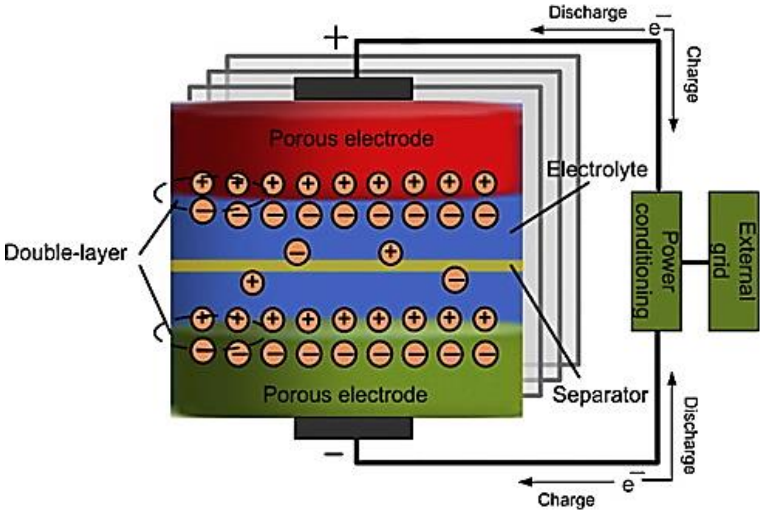
Electrical energy storage involves a process through which electricity is used as an input and stored as electrostatic or electrodynamic potential energy before being converted back to electricity (Chen *et al.*, 2009:294; Carnegie *et al.*, 2013:56; Gallo *et al.*, 2016:802).

3.2.3.1 Supercapacitors

Supercapacitors, also known as ultra-capacitors or electric double-layer capacitors, store electrical charges directly and mainly comprise both a positive and negative porous electrode as active material conductors, which are separated by a permeable membrane and liquid electrolyte solution (Petricca, Ohlckers & Chen, 2013:119; Luo *et al.*, 2015:520; Aneke *et al.*, 2016:359; Amrouche *et al.*, 2016:20915). During charging, ions in the electrolyte move to opposite sides where energy is stored in the electric double-layer capacitors, between the electrolyte solution and respective electrodes, through the creation of an electrostatic field by accumulating positive and negative electrical charges. The opposite occurs during discharging to release an electrical current (Lund *et al.*, 2015:796; Gallo *et al.*, 2016:810; Aneke *et al.*, 2016:359).

Figure 3.6 provides a schematic representation of a supercapacitor (Luo *et al.*, 2015:520).

Figure 3.6: Supercapacitor energy storage



Source: Luo *et al*. (2015:520)

The key advantages and disadvantages of supercapacitors are summarised in Table 3.6 (Evans *et al.*, 2012:4144; Petricca *et al.*, 2013:119; Castillo *et al.*, 2014:887; Mahlia *et al.*, 2014:540-542; Akinyele *et al.*, 2014:89; Luo *et al.*, 2015:520-521; Hameer *et al.*, 2015:1184-1193; Lund *et al.*, 2015:796; Aneke *et al.*, 2016:359-360; Amrouche *et al.*, 2016:20919; Gallo *et al.*, 2016:810; Amirante *et al.*, 2017:378-384).

Table 3.6: Advantages and disadvantages of supercapacitors

Advantages	Disadvantages
• Very high power density	• Developed, but not yet fully commercialised
• High power capacity	• Low to moderate energy density
• Very long cycle life	• High self-discharge rate
• Long calendar life	• Very short discharge duration
• Rapid response time	• Could suffer incomplete discharge
• Rapid charge and discharge rate	• Low cell voltage, which also varies as stored energy varies and requires additional power electronics
• Very high roundtrip efficiency	
• Ongoing operation without degradation	
• Tolerance to low temperatures	
• Low maintenance requirements	
• Durable	
• Limited safety and environmental impact	

Source: Author's compilation

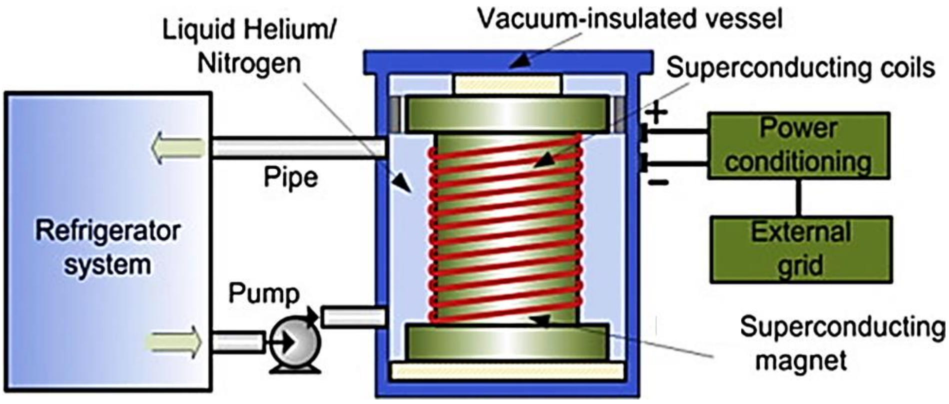
Supercapacitors could be appropriate for applications such as variable renewables integration, load following and ancillary services, including frequency and voltage regulation and black start capability (Castillo *et al.*, 2014:887; Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-796; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366; Amrouche *et al.*, 2016:20915-20919; Gallo *et al.*, 2016:818). The ability of supercapacitors to provide black start services, which refers to the capability to start electrical generators without using the electric grid, however, might be limited by their short discharge duration (Lund *et al.*, 2015:792; Aneke *et al.*, 2016:366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by supercapacitor energy storage systems.

3.2.3.2 Superconducting magnetic energy storage (SMES)

Superconducting magnetic energy storage (SMES) mainly comprises a superconducting coil or magnet as an inductor, cryogenic refrigerator, power conversion system (PCS) and controls. It charges by converting electricity from AC to DC and allowing the current circulation to pass through a cryogenically cooled superconducting wire coil to store energy in a magnetic field. When electrical energy is required, the SMES system discharges by collapsing the magnetic field so that energy can be extracted, allowing the electric current to pass from the coil to the electricity grid after converting it back from DC to AC (Carnegie *et al.*, 2013:59; Mahlia *et al.*, 2014:539-540; Akinyele *et al.*, 2014:78; Luo *et al.*, 2015:521; Lund *et al.*, 2015:796; Aneke *et al.*, 2016:364; Gallo *et al.*, 2016:810; Amrouche *et al.*, 2016:20915; Amirante *et al.*, 2017:379).

Figure 3.7 provides a schematic representation of a SMES system (Luo *et al*., 2015:521; Amirante *et al*., 2017:378).

Figure 3.7: Superconducting magnetic energy storage (SMES)



Source: Luo *et al*. (2015:521); Amirante *et al*. (2017:378)

The key advantages and disadvantages of SMES are summarised in Table 3.7 (Evans *et al.*, 2012:4144; Carnegie *et al.*, 2013:59-61; Kousksou *et al.*, 2014:73; Akinyele *et al.*, 2014:78-89; Hameer *et al.*, 2015:1193; Luo *et al.*, 2015:521; Lund *et al.*, 2015:796; Aneke *et al.*, 2016:367; Gallo *et al.*, 2016:810; Amirante *et al.*, 2017:379).

Table 3.7: Advantages and disadvantages of superconducting magnetic energy storage (SMES)

Advantages	**Disadvantages**
• High power density • High power capacity • High roundtrip efficiency • Rapid response time • Rapid charge and discharge rate • Very long cycle life • Long calendar life • Full discharge without significant deterioration in cycle or calendar life • Power output is independent of energy discharge rating • High reliability • Low maintenance requirements • Durable and reliable technology • Low energy losses	• Developed, but not yet fully commercialised • Low energy density • High self-discharge rate • Very short discharge duration • Concentrated large magnetic field entails negative environmental issues • Superconducting coil is highly sensitive to temperature variations • Low temperature has to be preserved through refrigeration to maintain superconductivity of coil, which uses additional energy and raises operating costs

Source: Author's compilation

SMES could be appropriate for applications such as variable renewables integration, load following and ancillary services, including frequency and voltage regulation and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:366; Gallo *et al.*, 2016:810). The ability of SMES to provide black start services, which refers to the capability to start electrical generators without using the electric grid, however, might be limited by their short discharge duration (Lund *et al.*, 2015:792; Aneke *et al.*, 2016:366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by SMES.

3.2.4 Chemical energy storage

Chemical energy storage involves a process through which electricity or thermal energy is used as an input to produce chemical compounds as liquid or gaseous fuels to be stored for later use as electrical energy (Aneke *et al.*, 2016:359; Gallo *et al.*, 2016:802). Various chemical energy storage compounds are undergoing development, including methane, methanol, hydrocarbons and hydrogen. Of these, hydrogen is considered to be the most efficient way to be converted from electricity directly into a chemical compound, and conversely, as it does not require further reactions (Suberu *et al.*, 2014:507; Mahlia *et al.*, 2014:540; Aneke *et al.*, 2016:359; Amirante *et al.*, 2017:382).

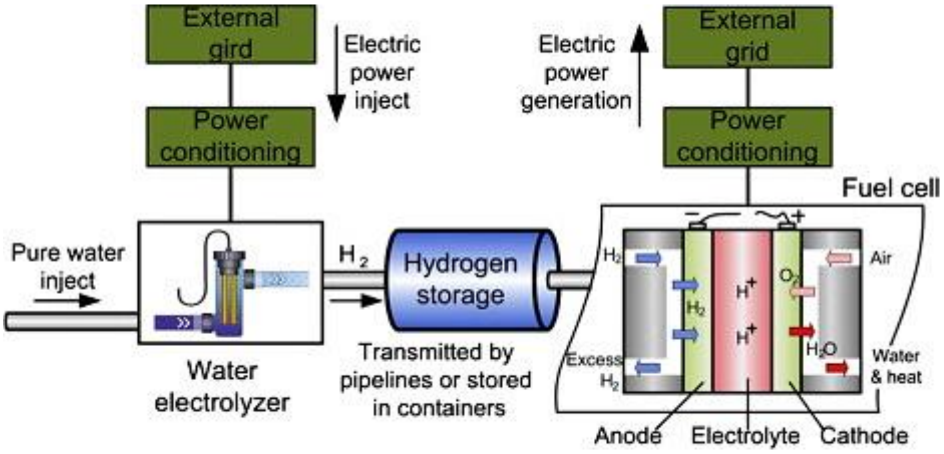
3.2.4.1 Hydrogen energy storage

A hydrogen energy storage system typically includes a pressurised hydrogen storage tank, an electrolyser solution and a regenerative fuel cell. In such a system, electrical energy is transformed through water electrolysis to produce and store hydrogen as chemical energy during low electricity demand and/or price periods. Hydrogen can be produced from various sources, including natural gas, coal, oil, fusion and renewable energy resources such as solar, wind, water and biomass. Hydrogen can be stored in the form of compressed or liquefied gas, carbon materials or metal hydrides. When required, the externally stored hydrogen is sent to a fuel cell and converted back to electrical energy in order to supply electricity during high demand and/or price periods (Dunn *et al.*, 2011:929; Kousksou *et al.*, 2014:71; Luo *et al.*, 2015:522; Lund *et al.*, 2015:794; Kyriakopoulos *et al.*, 2016:1062; Aneke *et al.*, 2016:359; Amrouche *et al.*, 2016:20915-20917; Eriksson & Gray, 2017:351-352).

A fuel cell typically comprises of a hydrogen anode and oxidant cathode that is separated by an electrolyte solution. Hydrogen and oxygen react in a fuel cell to form water and heat, which enable the production of electrical energy. Regenerative fuel cells can also reverse the process to produce hydrogen and oxygen by using water and electrical energy (Chen *et al.*, 2009:299; Evans *et al.*, 2012:4145; Kousksou *et al.*, 2014:71; Suberu *et al.*, 2014:504-507; Luo *et al.*, 2015:522-523; Amrouche *et al.*, 2016:20917; Amirante *et al.*, 2017:382; Eriksson *et al.*, 2017:351). Stored hydrogen can also be converted to electricity by burning it directly in a gas engine (Beaudin *et al.*, 2010:308; Aneke *et al.*, 2016:359-368).

Figure 3.8 provides a schematic representation of a hydrogen fuel cell energy storage system (Luo *et al.*, 2015:523).

Figure 3.8: Hydrogen fuel cell energy storage



Source: Luo *et al*. (2015:523)

The key advantages and disadvantages of hydrogen fuel cells are summarised in Table 3.8 (Chen *et al.*, 2009:299; Evans *et al.*, 2012:4145; Kousksou *et al.*, 2014:71; Mahlia *et al.*, 2014:542; Luo *et al.*, 2015:523; Kyriakopoulos *et al.*, 2016:1058-1062; Aneke *et al.*, 2016:359; Amrouche *et al.*, 2016:20915-20917; Gallo *et al.*, 2016:811-818; Amirante *et al.*, 2017:382).

Table 3.8: Advantages and disadvantages of hydrogen fuel cells

Advantages	Disadvantages
• Very high energy density • Very long cycle life • Long calendar life • Long energy storage duration • Very limited greenhouse gas emissions • Modular scalability of capacity and use • Very low self-discharge rate • Surplus hydrogen production can be diverted to alternative uses and reduce the utilisation of fossil fuels • Fast response time	• Under development and not commercialised • High initial capital investment costs • Very low roundtrip efficiency • High energy losses • Requires recycling of fuel cell materials

Source: Author’s compilation

Hydrogen fuel cells could be appropriate for applications such as seasonal energy storage, energy time shifting, load levelling and peak shaving, load following, variable and intermittent renewables integration, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including operating reserves and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:792-794; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366). Section 4.2

of Chapter 4 provides a description of utility-scale value applications that can be performed by hydrogen fuel cell systems.

3.2.5 Electrochemical energy storage

Electrochemical energy storage involves a process through which electricity is used as an input and stored as chemical energy in active material cells, by means of reversible electrochemical reactions, before being converted back to electrical energy. It refers to rechargeable or secondary battery technologies, which mainly comprise several electrochemical cells connected in parallel and/or in series, a negative electrode or anode that supplies electrons to a load, positive electrode or cathode that accepts electrons and an electrolyte solution that enables the movement of electrons between the electrodes (Hadjipaschalis *et al.*, 2009:1515; Dunn *et al.*, 2011:929-930; Krivik & Baca, 2013:79; Carnegie *et al.*, 2013:34; Kousksou *et al.*, 2014:69; Suberu *et al.*, 2014:502; Mahlia *et al.*, 2014:537; Lund *et al.*, 2015:795; Kyriakopoulos *et al.*, 2016:1056; Aneke *et al.*, 2016:360; Gallo *et al.*, 2016:802-806).

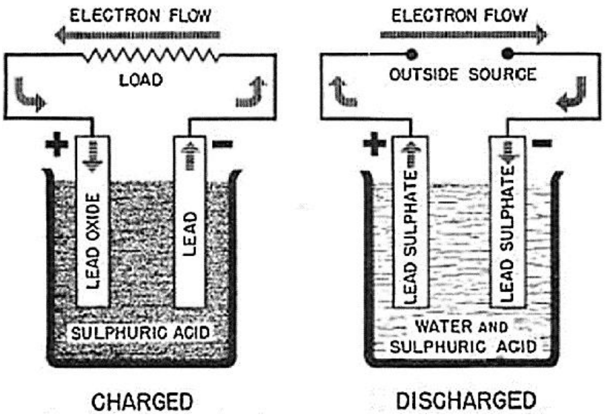
3.2.5.1 Lead-acid batteries

Lead-acid batteries are solid state, comprising a lead dioxide cathode and sponge metallic lead anode, which are immersed in a sulphuric acid electrolyte solution (Krivik *et al.*, 2013:79-84; Mahlia *et al.*, 2014:537; Hameer *et al.*, 2015:1180; Aneke *et al.*, 2016:364; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:806; Berrada *et al.*, 2017:96). During charging, electrons migrate from the cathode to the anode and energy is stored through a reaction that places lead metal on the anode and lead oxide on the cathode, which increases the sulphuric acid concentration of the electrolyte. During discharging, the lead metal and lead oxide transform into lead sulphate, which, in turn, reduces the sulphuric acid concentration of the electrolyte and produces water (Chen *et al.*, 2009:297; Suberu *et al.*, 2014:504; Gallo *et al.*, 2016:806; Berrada *et al.*, 2017:96).

Lead-acid batteries were invented in 1859 and are the oldest, most common and most mature rechargeable battery technology (Poullikkas, 2013:779; Krivik *et al.*, 2013:79; Mahlia *et al.*, 2014:537; Hameer *et al.*, 2015:1180; Aneke *et al.*, 2016:363; Berrada *et al.*, 2017:96). Lead-acid batteries are widely applied in the telecommunication, automotive and residential, commercial and utility energy industries (Krivik *et al.*, 2013:81; Lund *et al.*, 2015:795; Gallo *et al.*, 2016:806).

Figure 3.9 provides a schematic representation of the charge and discharge process of a lead-acid battery (Aneke *et al*., 2016:364).

Figure 3.9: Lead-acid battery energy storage



Source: Aneke *et al*. (2016:364)

The key advantages and disadvantages of lead-acid batteries are summarised in Table 3.9 (Poullikkas, 2013:779; Krivik *et al.*, 2013:79; Kousksou *et al.*, 2014:69; Castillo *et al.*, 2014:887; Mahlia *et al.*, 2014:537; Suberu *et al.*, 2014:504; Luo *et al.*, 2015:516; Hameer *et al.*, 2015:1181; Lund *et al.*, 2015:795; Kyriakopoulos *et al.*, 2016:1059; Aneke *et al.*, 2016:364; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:806; Berrada *et al.*, 2017:96).

Table 3.9: Advantages and disadvantages of lead-acid batteries

Advantages

- Highly mature and commercialised
- Relatively low capital cost
- Moderate to high calendar life
- Moderate to high roundtrip efficiency
- Good reliability
- Readily available
- Very low self-discharge rate
- Established recycling infrastructure
- Robust
- Transportability for relocation relatively easy
- Rapid response time
- Adaptable to numerous uses
- Low manufacturing costs
- Short construction lead time
- Modular scalability
- Tolerant to overcharging

Disadvantages

- Low energy density
- Low depth of discharge (DoD)
- Relatively short cycle life, reducing notably with deeper discharges and frequent cycling
- Short to moderate discharge duration
- Intolerant to large temperature variations and necessitates a thermal management system, which raises costs
- Heavy and large technology
- Relatively slow charge duration
- Regular maintenance requirements
- Degradation in efficiency with frequent charge-discharge cycles raises maintenance requirements
- Most types require regular water addition
- Poor functioning in partially charged state
- Improper disposal has environmental risk due to lead and sulphuric acid toxicity

Source: Author’s compilation

Advanced lead-acid batteries, also known as lead-carbon batteries, are also being developed and include a carbon anode and granular silica electrolyte solution (Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:806). They entail a longer calendar and cycle life, deeper discharge capability, improved roundtrip efficiency, lower maintenance requirements and better overall performance than traditional lead-acid batteries do (Carnegie *et al.*, 2013:36; Poullikkas, 2013:779; Luo *et al.*, 2015:517; Kyriakopoulos *et al.*, 2016:1059; Aneke *et al.*, 2016:364; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:806; Berrada *et al.*, 2017:96).

Lead-acid batteries could be appropriate for applications such as energy time shifting, load levelling and peak shaving, load following, variable and intermittent renewables integration, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Poullikkas, 2013:786; Castillo *et al.*, 2014:887; Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:792; Kyriakopoulos *et al.*, 2016:1061-1063; Aneke *et al.*, 2016:365-366; Gallo *et al.*, 2016:806). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by lead-acid electrochemical energy storage systems.

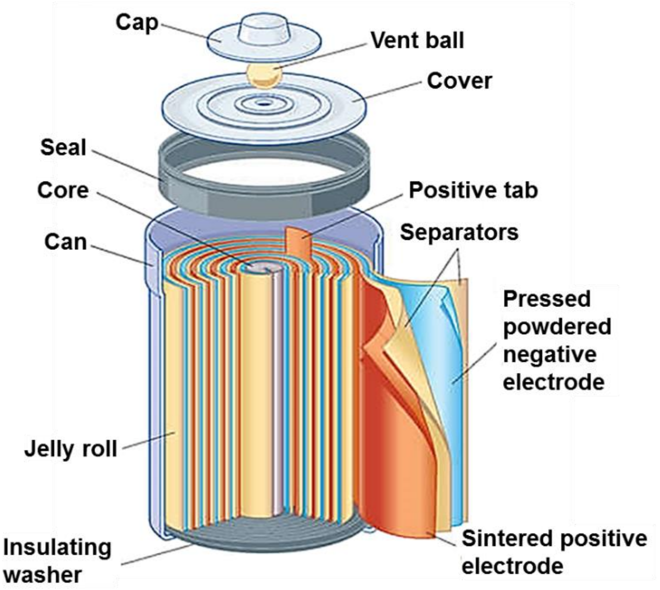
3.2.5.2 Nickel-cadmium (NiCd) batteries

Nickel-cadmium (NiCd) batteries include a nickel hydroxide cathode and metallic cadmium hydroxide anode, which are immersed in a potassium hydroxide electrolyte solution (Evans *et al.*, 2012:4142; Krivik *et al.*, 2013:86; Hammond *et al.*, 2015:561; Luo *et al.*, 2015:518; Hameer *et al.*, 2015:1180; Amrouche *et al.*, 2016:20915; Gallo *et al.*, 2016:806). During charging, energy is stored through a reaction in which the nickel hydroxide is transformed into nickel oxyhydroxide in the cathode, while the cadmium hydroxide is transformed into metallic cadmium in the anode. During discharging, both these reactions are reversed (Akinyele *et al.*, 2014:80; Aneke *et al.*, 2016:364; Gallo *et al.*, 2016:806).

NiCd batteries are widely used in consumer electronics and telecommunications (Chen *et al.*, 2009:297; Poullikkas, 2013:780). The deployment of these batteries for utility-scale applications, however, might be limited in future due to advancements made in alternative electrochemical energy storage technologies (Luo *et al.*, 2015:518).

Figure 3.10 provides a schematic representation of a NiCd battery (Krivik *et al.*, 2013:87).

Figure 3.10: Nickel-cadmium (NiCd) battery energy storage



Source: Krivik *et al*. (2013:87)

The key advantages and disadvantages of NiCd batteries are summarised in Table 3.10 (Chen *et al.*, 2009:297; Krivik *et al.*, 2013:86; Kousksou *et al.*, 2014:70; Suberu *et al.*, 2014:505; Mahlia *et al.*, 2014:537; Luo *et al.*, 2015:518; Lund *et al.*, 2015:795; Aneke *et al.*, 2016:364; Amrouche *et al.*, 2016:20915-20916; Gallo *et al.*, 2016:806).

Table 3.10: Advantages and disadvantages of nickel-cadmium (NiCd) batteries

Advantages	Disadvantages
• Mature and commercialised • High charge and discharge rate • High energy density • High power density • Moderate to high calendar life • Rapid response time • Fairly tolerant to temperature variations • Deep discharge without loss of capacity • Low maintenance requirements • Short construction lead time • Modular scalability • Reliable	• Health and environmental danger due to toxicity of cadmium • Memory effect or rated capacity loss when recharging before fully discharged • Relatively limited cycle life, albeit better than for traditional lead-acid batteries • Higher capital cost than lead-acid batteries, mainly due to the use of expensive nickel and cadmium materials • Low cell voltage • Low to moderate roundtrip efficiency • Moderate self-discharge rate • Low depth of discharge (DoD)

Source: Author’s compilation

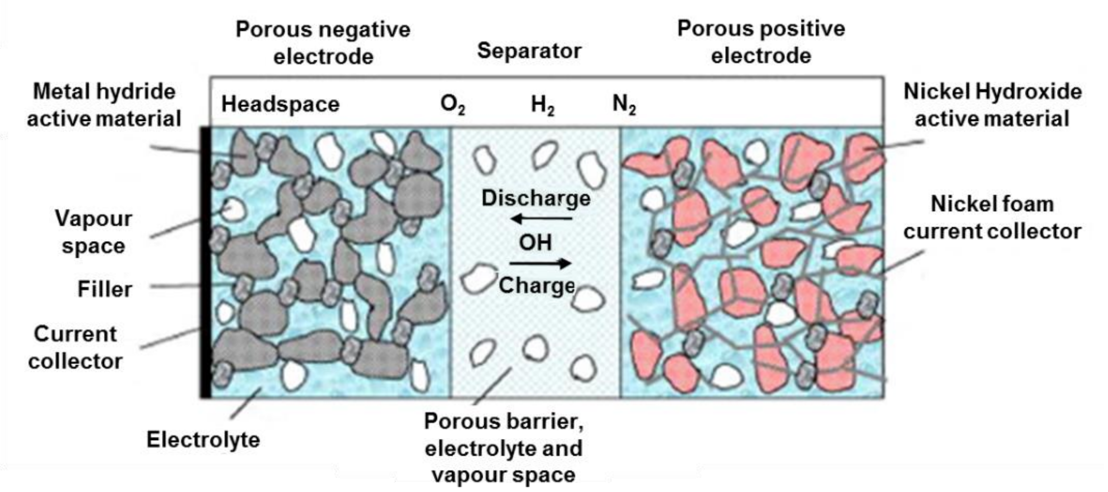
NiCd batteries could be appropriate for applications such as energy time shifting, load levelling and peak shaving, variable and intermittent renewables integration, load following, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Aneke *et al.*, 2016:365-366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by NiCd electrochemical energy storage systems.

3.2.5.3 Nickel-metal hydride (NiMH) batteries

Nickel-metal hydride (NiMH) batteries are similar to nickel-cadmium (NiCd) batteries and include a nickel hydroxide cathode and metal hydride anode, which are immersed in concentrated potassium hydroxide electrolyte (Hadjipaschalis *et al.*, 2009:1516; Krivik *et al.*, 2013:88; Kousksou *et al.*, 2014:70; Gallo *et al.*, 2016:806). During charging, energy is stored through a reaction in which the nickel hydroxide is transformed into nickel oxyhydroxide in the cathode, while water and metal are transformed into metal hydride in the anode. During discharging, both these reactions are reversed (Gallo *et al.*, 2016:806).

Figure 3.11 provides a schematic representation of a NiMH battery (Gallo *et al*., 2016:806).

Figure 3.11: Nickel-metal hydride (NiMH) battery energy storage



Source: Gallo *et al*. (2016:806)

NiMH batteries are being developed to overcome the health and environmental dangers posed by NiCd batteries by removing cadmium from the electrodes (Gallo *et al.*, 2016:806). They are frequently used in the automotive, medical and consumer electronics industries and are being introduced for utility-scale energy storage applications (Luo *et al.*, 2015:518; Lund *et al.*, 2015:795; Amrouche *et al.*, 2016:20916).

The key advantages and disadvantages of NiMH batteries are summarised in Table 3.11 (Hadjipaschalis *et al.*, 2009:1516; Evans *et al.*, 2012:4145; Carnegie *et al.*, 2013:38; Krivik *et al.*, 2013:88-89; Kousksou *et al.*, 2014:70; Mahlia *et al.*, 2014:537; Luo *et al.*, 2015:518; Lund *et al.*, 2015:795; Gallo *et al.*, 2016:806).

Table 3.11: Advantages and disadvantages of nickel-metal hydride (NiMH) batteries

Advantages	Disadvantages
• Mature and commercialised • Lower environmental impact than NiCd batteries • High energy density • High power density • Tolerant to over discharge • Relatively high charge and discharge rates • Fairly tolerant to temperature variations • Rapid response time • Lower maintenance requirements than lead-acid batteries • Short construction lead time • Modular scalability	• Relatively short cycle life • Short to moderate calendar life • High self-discharge rate • Memory effect or rated capacity loss when recharging before fully discharged, albeit less than for NiCd batteries • Low to moderate roundtrip efficiency • Performance deteriorates with frequent charge-discharge cycles over lifetime • Higher capital cost than lead-acid and NiCd batteries • Sensitive to overcharging • Low cell voltage

Source: Author's compilation

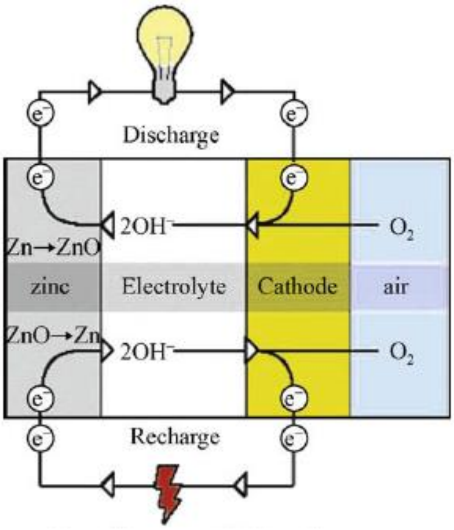
NiMH batteries could be appropriate for applications such as energy time shifting, load levelling and peak shaving, variable and intermittent renewables integration, load following, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Luo *et al.*, 2015:530; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by NiMH electrochemical energy storage systems.

3.2.5.4 Metal-air batteries

Metal-air batteries include an electropositive metal, such as zinc, aluminium, magnesium, sodium or lithium as the anode, atmospheric oxygen air as the cathode and ionic liquid electrolyte (Mahlia *et al.*, 2014:539; Hameer *et al.*, 2015:1180; Aneke *et al.*, 2016:363; Gallo *et al.*, 2016:809). During charging, oxygen enters the air electrode causing an oxidation reaction at the cathode and reduction reaction at the anode, while the opposite takes place during discharging in that oxidation occurs at the anode and reduction reaction at the cathode as hydroxyl ions are produced by air, supported by catalysts, in the liquid electrolyte (Hameer *et al.*, 2015:1180; Aneke *et al.*, 2016:363).

Figure 3.12 provides a schematic representation of a zinc metal-air battery (Chen *et al.*, 2009:300).

Figure 3.12: Zinc metal-air battery energy storage



Source: Chen *et al*. (2009:300)

The key advantages and disadvantages of metal-air batteries are summarised in Table 3.12 (Chen *et al.*, 2009:301; Akinyele *et al.*, 2014:80-84; Mahlia *et al.*, 2014:542; Hameer *et al.*, 2015:1180-1193; Lazard, 2016:10; Aneke *et al.*, 2016:363; Gallo *et al.*, 2016:809).

Table 3.12: Advantages and disadvantages of metal-air batteries

Advantages	**Disadvantages**
• Very light weight • Very high energy density • No or very limited environmental impact • Rapid response time • Low self-discharge rate • Deep discharge capability • Long storage and discharge duration • Short construction lead time • Modular scalability • Highly compact • Highly recyclable	• Under development and not commercialised • Moderate power density • High initial capital costs • Low roundtrip efficiency • Short cycle life • Carbon dioxide from the air could infiltrate the electrolyte solution and cathode • Poor recharge ability

Source: Author's compilation

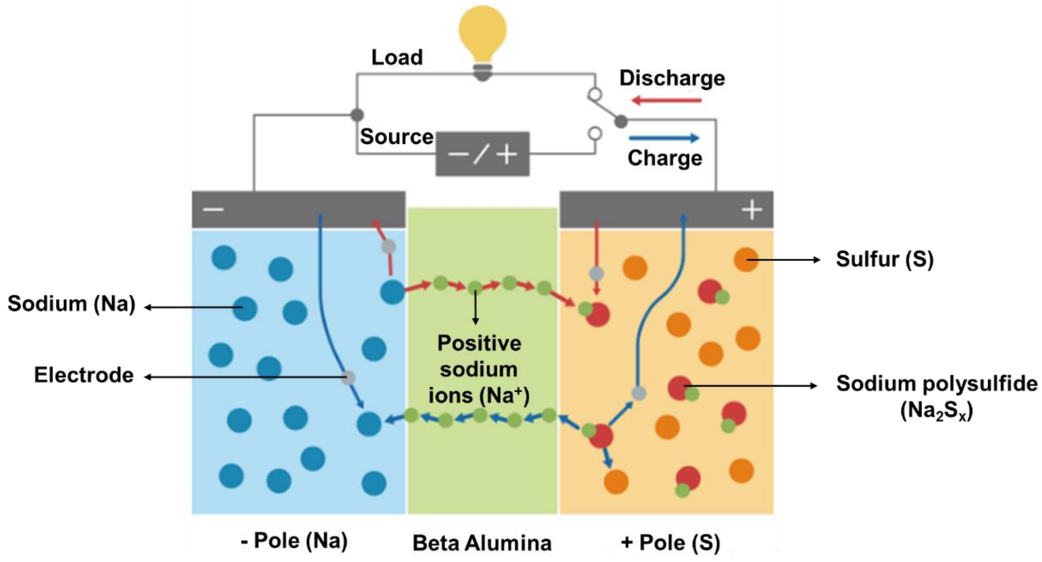
Metal-air batteries could be appropriate for applications such as energy time shifting, load levelling and peak shaving, variable and intermittent renewables integration, load following, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Aneke *et al.*, 2016:365-366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by metal-air electrochemical energy storage systems.

3.2.5.5 Sodium-sulphur (NaS) batteries

Sodium-sulphur (NaS) batteries are non-solid state and mainly comprise a molten sulphur cathode and a molten sodium anode, which are separated by a solid beta alumina ceramic electrolyte. During discharging, the electrolyte only permits positive sodium ions to move between the electrodes, from the sodium anode to combine with sulphur in the cathode, and produce sodium polysulfide. This chemical reaction causes electrons to produce an electric current and flow to outside circuits (Dunn *et al.*, 2011:932; Krivik *et al.*, 2013:97; Mahlia *et al.*, 2014:538; Suberu *et al.*, 2014:504; Hameer *et al.*, 2015:1180; Aneke *et al.*, 2016:360; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:808).

The process is reversed during charging, when electrical energy is stored as chemical energy by allowing sodium ions to flow back to the anode and form sulphur in the cathode. NaS batteries have to be operated at high temperatures, approximately 290 to 360°C, to keep the molten-based electrodes in a liquid state (Dunn *et al.*, 2011:931-932; Akinyele *et al.*, 2014:84; Lund *et al.*, 2015:795; Hameer *et al.*, 2015:1180; Aneke *et al.*, 2016:360; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:808). Figure 3.13 provides a schematic representation of a NaS battery (NGK Insulators, 2016).

Figure 3.13: Sodium-sulphur (NaS) battery energy storage



Source: NGK Insulators (2016)

The key advantages and disadvantages of NaS batteries are summarised in Table 3.13 (Dunn *et al.*, 2011:932; Poullikkas, 2013:781-786; Krivik *et al.*, 2013:96-97; Kousksou *et al.*, 2014:70; Akinyele *et al.*, 2014:84; Castillo *et al.*, 2014:887; Mahlia *et al.*, 2014:538; Suberu *et al.*, 2014:504; Luo *et al.*, 2015:517-518; Hameer *et al.*, 2015:1181; Lund *et al.*, 2015:795; Kyriakopoulos *et al.*, 2016:1060; Aneke *et al.*, 2016:360-361; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:808).

Table 3.13: Advantages and disadvantages of sodium-sulphur (NaS) batteries

Advantages	Disadvantages
• Mature and fairly commercialised • High energy density • Moderate to high power density • High roundtrip efficiency • Long cycle life • Long calendar life • Very long discharge duration • Very low self-discharge rate • Robust to overcharge and discharge • Pulse power delivery or capability to provide electric capacity in excess of power rating • Sodium and sulphur are low cost, non-toxic and commonly available materials • Recyclability of materials for reuse • High depth of discharge (DoD) • Low maintenance requirements and costs • Rapid response time • Can quickly change between charging and discharging • Short construction lead time • Modular scalability	• Lack of manufacturer competition raises costs • Safety concerns due to high temperature operation and molten sodium reaction with water and air risk to flammability • Requires external heat system to maintain molten state temperature, even when battery is not in use, which raises costs • Self-discharge rate accelerates if temperature has to be maintained above 290°C for extended standby periods • Corrosion in insulators can increase self-discharge rate • Molten sulphur cathode requires anti-corrosive current collector

Source: Author's compilation

NaS batteries could be appropriate for applications such as energy time shifting, variable and intermittent renewables integration, load levelling and peak shaving, load following, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Castillo *et al.*, 2014:887; Luo *et al.*, 2015:530; Lund *et al.*, 2015:792; Kyriakopoulos *et al.*, 2016:1060-1063; Aneke *et al.*, 2016:360-366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by NaS electrochemical energy storage systems

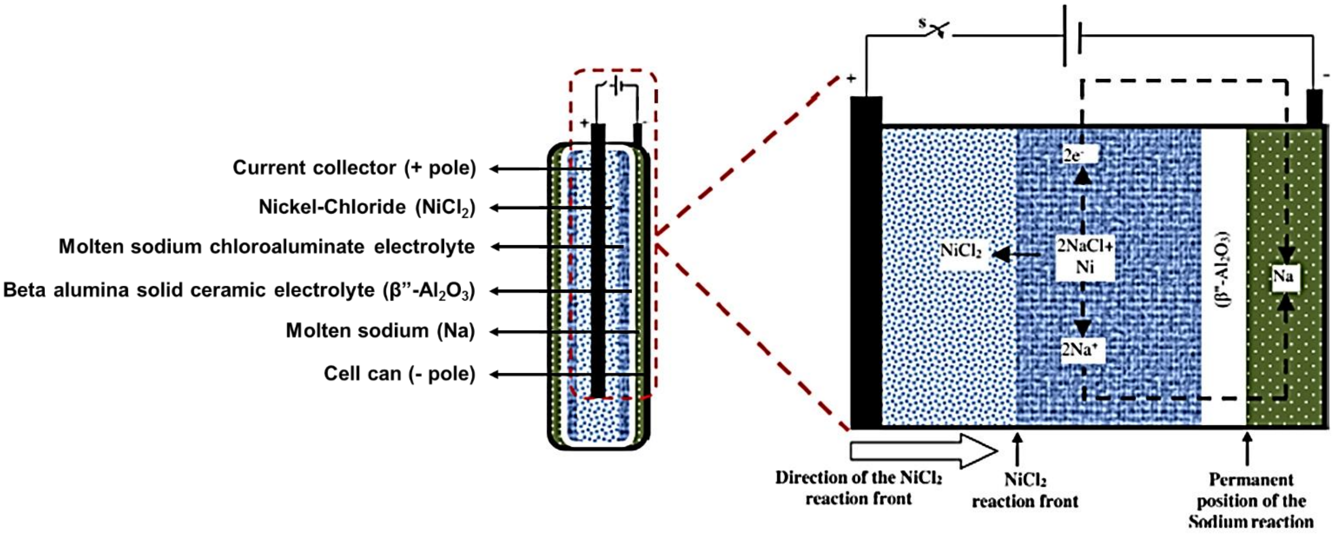
3.2.5.6 Sodium-nickel-chloride ($NaNiCl_2$) batteries

Sodium-nickel-chloride ($NaNiCl_2$) batteries are also known as zero emission battery research activity or zeolite applied to battery research Africa (ZEBRA) batteries. They are similar to sodium-sulphur (NaS) batteries and also operate at high temperature of approximately 260 to 350°C in order to keep the electrodes in a molten state. ZEBRA batteries include a nickel-chloride cathode and a molten sodium anode, which is separated by both a solid beta alumina ceramic electrolyte and molten sodium chloroaluminate electrolyte that only permits positive sodium ions to move between the electrodes (Dunn *et al.*, 2011:932; Krivik *et al.*, 2013:98; Suberu *et al.*, 2014:505; Hammond *et al.*, 2015:560-561; Lund *et al.*, 2015:795; Aneke *et al.*, 2016:361; Amrouche *et al.*, 2016:20916; Sessa *et al.*, 2016:105-106; Gallo *et al.*, 2016:808).

During charging, electrons are released by the cathode and form positive sodium ions that flow from the cathode to the anode and energy is stored by converting sodium-chloride salt and nickel into nickel-chloride and molten sodium. During discharging, these chemical reactions are reversed to release electrons to outside circuits (Hammond *et al.*, 2015:562; Sessa *et al*., 2016:110; Aneke *et al.*, 2016:361; Amrouche *et al.*, 2016:20916).

Figure 3.14 provides a schematic representation of the charge process of a ZEBRA battery (Adapted from Sessa *et al*., 2016:110; Aneke *et al*., 2016:362).

Figure 3.14: Sodium-nickel-chloride ($NaNiCl_2$) battery energy storage



Source: Adapted from Sessa *et al*. (2016:110); Aneke *et al*. (2016:362)

The key advantages and disadvantages of $NaNiCl_2$ or ZEBRA batteries are summarised in Table 3.14 (Chen *et al.*, 2009:298; Beaudin *et al.*, 2010:307; Krivik *et al.*, 2013:99;

Akinyele *et al.*, 2014:84; Luo *et al.*, 2015:518; Lund *et al.*, 2015:795; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:808-809).

Table 3.14: Advantages and disadvantages of sodium-nickel-chloride ($NaNiCl_2$) batteries

Advantages	**Disadvantages**
• Moderate to high energy density • Moderate to high power density • Very long discharge duration • High roundtrip efficiency • Very long cycle life • Long calendar life • Safer than NaS batteries • High cell voltage • Robust to overcharge and discharge • Pulse power delivery or capability to provide electric capacity in excess of power rating • Low maintenance requirements and costs • Rapid response time • Recyclability • Wide temperature operating range • Short construction lead time • Modular scalability • Individual cell failure does not cause stoppage of entire battery	• Developed, but not yet fully commercialised • Starting from a cold or solid material state can take up to 15 hours • Requirement for heat to maintain molten state temperature • Safety concerns due to molten sodium reaction with water and air risk to flammability • Potential could be limited due to lack of supplier competition, which also raises costs • High self-discharge rate, which accelerates if temperature has to be maintained above 290°C for extended standby periods

Source: Author's compilation

ZEBRA batteries could be appropriate for applications such as energy time shifting, load levelling and peak shaving, variable and intermittent renewables integration, load following, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366; Sessa *et al.*, 2016:105). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by ZEBRA electrochemical energy storage systems.

3.2.5.7 Lithium-ion batteries

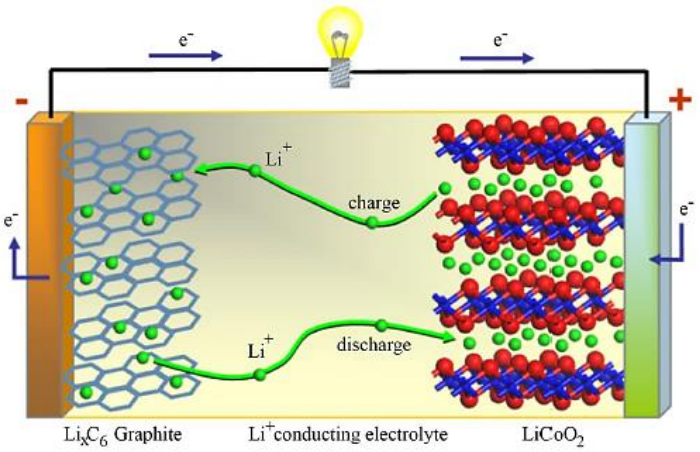
Lithium-ion batteries include a lithiated metal oxide cathode, a graphitic carbon cell anode and a liquid electrolyte solution made of lithium salts that are dissolved in organic carbonates (Krivik *et al.*, 2013:89; Suberu *et al.*, 2014:503; Luo *et al.*, 2015:517; Hameer *et al.*, 2015:1180; Gallo *et al.*, 2016:807-808; Amirante *et al.*, 2017:381; Berrada *et al.*, 2017:96). The electrolyte solution can also take the form of a gel polymer (Hammond *et al.*, 2015:561; Amirante *et al.*, 2017:381).

Lithium-ion batteries can be composed from a wide array of different chemistries, such as lithium nickel cobalt aluminium oxide, lithium iron phosphate, lithium nickel manganese cobalt oxide and lithium manganese oxide. Since there are several variations of lithium-ion batteries, their respective performance and costs can vary widely (Evans *et al.*, 2012:4145; Krivik *et al.*, 2013:89; Hammond *et al.*, 2015:561; Gallo *et al.*, 2016:807).

Irrespective of the chemistry used, the batteries are characterised by the transfer of lithium-ions from the lithium metal oxide cathode to the graphite carbon anode to combine with electrons during charging, while the opposite occurs during discharging (Chen *et al.*, 2009:298; Krivik *et al.*, 2013:89; Suberu *et al.*, 2014:503; Hammond *et al.*, 2015:561; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:807; Amirante *et al.*, 2017:381). The electrolyte solution does not facilitate the energy transformation process, but rather enables the transfer of lithium ions between the electrodes during charging and discharging (Amirante *et al.*, 2017:381).

Figure 3.15 provides a schematic representation of a lithium-ion battery (Gallo *et al.*, 2016:807).

Figure 3.15: Lithium-ion battery energy storage



Source: Gallo *et al*. (2016:807)

The commercialisation of lithium-ion batteries for small uses started in the early 1990s and they are presently used in numerous technologies, including consumer electronics, medical equipment, electric vehicles, aerospace and utility-scale energy storage applications (Chen *et al.*, 2009:298; Dunn *et al.*, 2011:930; Carnegie *et al.*, 2013:41; Hammond *et al.*, 2015:561; Aneke *et al.*, 2016:364; Gallo *et al.*, 2016:807; Amirante *et al.*, 2017:381; Berrada *et al.*, 2017:96). Continued research and development efforts and the widespread deployment of lithium-ion batteries in various industries have rapidly enabled significant technical improvements, operational advances and cost reductions (Gallo *et al.*, 2016:808; Amirante *et al.*, 2017:381-385).

The key advantages and disadvantages of lithium-ion batteries are summarised in Table 3.15 (Dunn *et al.*, 2011:930; Evans *et al.*, 2012:4145; Poullikkas, 2013:786; Krivik *et al.*, 2013:91; Kousksou *et al.*, 2014:71; Castillo *et al.*, 2014:887; Suberu *et al.*, 2014:504; Luo *et al.*, 2015:517; Hameer *et al.*, 2015:1180; Lund *et al.*, 2015:795; Kyriakopoulos *et al.*, 2016:1060-1061; Aneke *et al.*, 2016:364; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:807-808; Amirante *et al.*, 2017:381-385; Berrada *et al.*, 2017:96; Lai *et al.*, 2017:202).

Table 3.15: Advantages and disadvantages of lithium-ion batteries

Advantages	**Disadvantages**
• Mature and commercialised with utility-scale applications starting to be realised • Experiencing rapid cost declines • High energy density • High power density • High roundtrip efficiency • Long cycle life • Moderate to high calendar life • Light weight • High charge and discharge rate • Low self-discharge rate • Rapid response time • High cell voltage • Short construction lead time • Modular scalability	• Safety and environmental issues due to high flammability and toxic materials • Relatively high capital cost for utility-scale applications, but costs are declining rapidly • Limited thermal tolerance • Require complex management, monitoring and control systems, which raise costs, including temperature regulation for safe and efficient operation • Degradation in capacity and efficiency with frequent cycling raises maintenance requirements • Require advanced manufacturing capabilities • Calendar and cycle life reduce significantly when operated at deep depth of discharge (DoD) and/or in high temperatures • High industry demand for lithium could raise costs for utility-scale applications

Source: Author's compilation

Lithium-sulphur and sodium-ion batteries are also under development, which could have the potential to be a credible alternative for lithium-ion and sodium-sulphur batteries due to the possibility for lower costs, higher energy density, improved safety and less environmental impact (Dunn *et al.*, 2011:934; Amirante *et al.*, 2017:382).

Lithium-ion batteries could be appropriate for applications such as energy time shifting, load levelling and peak shaving, load following, variable and intermittent renewables integration, transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Luo *et al.*, 2015:530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:792; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by lithium-ion electrochemical energy storage systems.

3.2.5.8 Flow batteries

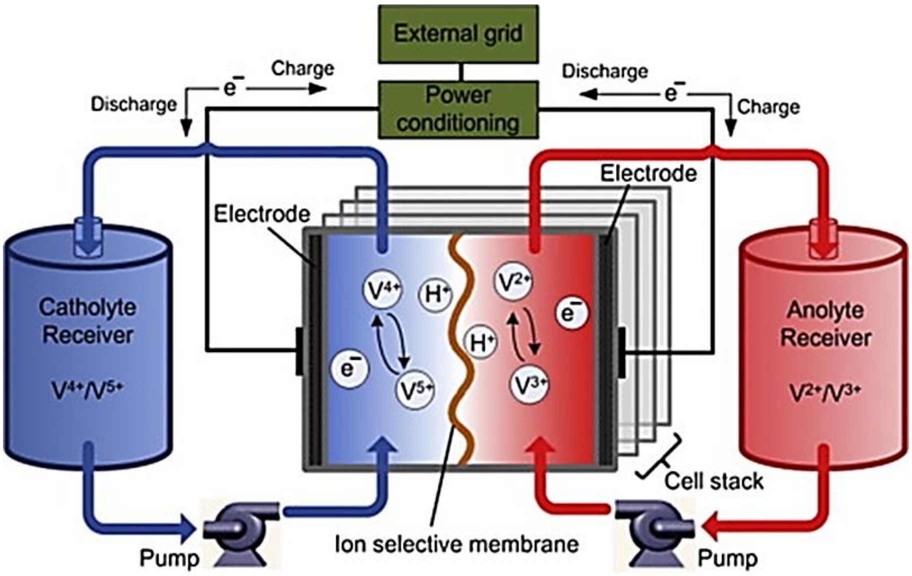
Flow batteries are non-solid state that comprise liquid negative electrolyte, or anolyte, and positive electrolyte, or catholyte, solutions kept in two external tanks, outside of an electrochemical cell stack that is divided by an ion-permeable selective membrane (Luo *et al.*, 2015:518; Pan & Wang, 2015:20499; Lund *et al.*, 2015:795; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:809; Amirante *et al.*, 2017:379). The main difference between conventional solid state batteries and flow batteries is in their respective configurations. In a flow battery, chemical energy is stored in two independent electrolyte solutions containing ions that flow to, and react in, a separate electrochemical battery cell stack. In conventional batteries, energy is stored in two electrodes made of electroactive material immersed in an electrolyte solution as part of a battery cell stack (Dunn *et al.*, 2011:933; Kousksou *et al.*, 2014:71; Amrouche *et al.*, 2016:20917; Gallo *et al.*, 2016:809).

When a flow battery is charged, electrical energy from a load is sent to the battery cell stack, creating a reduction-oxidation reaction by which chemical energy is stored in two external tanks by means of the migration of ions from the negative to positive electrolyte solution through an ion-selective membrane. During discharging, the ions in the electrolyte solutions are pumped into the battery cell stack where electrical energy is produced by means of the exchange of ions between the battery cell stack anode and cathode through a selective membrane (Dunn *et al.*, 2011:933; Poullikkas, 2013:781; Suberu *et al.*, 2014:505; Mahlia *et al.*, 2014:539; Luo *et al.*, 2015:518; Lund *et al.*, 2015:795; Gallo *et al.*, 2016:809; Amirante *et al.*, 2017:379).

There are presently four main categories of flow batteries, which are defined by the chemical composition of the electrolyte solution, namely vanadium redox (VRFB), zinc-bromine (ZnBr), iron-chromium (FeCr) and polysulfide bromine (PSB) flow batteries (Krivik *et al.*, 2013:94-96; Mahlia *et al.*, 2014:539; Luo *et al.*, 2015:519-520; Lund *et al.*, 2015:795; Aneke *et al.*, 2016:361-363; Gallo *et al.*, 2016:809; Amirante *et al.*, 2017:381). Vanadium redox and zinc-bromine flow batteries are starting to be commercialised, while iron-chromium and polysulfide bromine are still undergoing research and development (Dunn *et al.*, 2011:933; Luo *et al.*, 2015:519-520; Aneke *et al.*, 2016:362). VRFBs, however, appear to be a superior flow battery technology due to only requiring vanadium in the electrolyte solution, higher capacity, longer cycle life, better roundtrip efficiency, lower operating costs, improved safety and lower maintenance requirements (Poullikkas, 2013:782; Kousksou *et al.*, 2014:72).

Figure 3.16 provides a schematic representation of a VRFB (Luo *et al*., 2015:519).

Figure 3.16: Vanadium redox flow battery (VRFB) energy storage



Source: Luo *et al*. (2015:519)

The key advantages and disadvantages of flow batteries are summarised in Table 3.16 (Dunn *et al.*, 2011:933; Poullikkas, 2013:781-782; Krivik *et al.*, 2013:94; Kousksou *et al.*, 2014:71-72; Suberu *et al.*, 2014:505; Castillo *et al.*, 2014:887; Mahlia *et al.*, 2014:539; Luo *et al.*, 2015:518; Pan *et al.*, 2015:20499; Hameer *et al.*, 2015:1180; Akhil *et al.*, 2015:55; Cunha, Martins, Rodrigues & Brito, 2015:907; Kyriakopoulos *et al.*, 2016:1061; Aneke *et al.*, 2016:361; Amrouche *et al.*, 2016:20917; Gallo *et al.*, 2016:809; Amirante *et al.*, 2017:380; Lai *et al.*, 2017:202).

Table 3.16: Advantages and disadvantages of flow batteries

Advantages	Disadvantages
• Power and energy capacity easily and independently scalable • Very long cycle life • Long calendar life • Very long discharge duration • Very low self-discharge rate • Stable and durable operational performance • Can withstand 100% depth of discharge (DoD) without shorter cycle and calendar life, efficiency losses or performance degradation • Tolerant to overcharge and discharge • Rapid recharge ability by replacing electrolyte • Rapid response time • Limited safety and environmental issues • Low maintenance requirements • Only battery cell stack needs to be replaced as electrolyte does not degrade, which reduces relative costs • Short construction lead time	• Developed, but not yet fully commercialised • Low to moderate energy density, but partly overcome by scalability • Low to moderate power density, but partly overcome by scalability • More complex system requirements than for traditional batteries • Not suitable for small-scale storage uses • Moderate roundtrip efficiency • Relatively slow ramp and stop rates of around seven minutes due to the need for draining and flooding the cell stack with electrolyte

Source: Author's compilation

The most favourable attribute of flow batteries not shared with conventional batteries is that the power and energy profiles are highly and independently scalable, since they are autonomous from one another, at low incremental cost. The power rating can be enhanced by increasing the active area of the battery cell stack, while the energy storage capacity can be upgraded by raising the volume of the stored electrolyte solutions in the external tanks (Dunn *et al.*, 2011:933; Krivik *et al.*, 2013:94; Mahlia *et al.*, 2014:539; Luo *et al.*, 2015:518; Pan *et al.*, 2015:20499-20500; Lund *et al.*, 2015:795; Aneke *et al.*, 2016:361; Amrouche *et al.*, 2016:20917; Gallo *et al.*, 2016:809; Amirante *et al.*, 2017:380-385; Lai *et al.*, 2017:202).

Flow batteries could be appropriate for applications such as energy time shifting, load levelling and peak shaving, load following, variable and intermittent renewables integration and transmission and distribution congestion relief and/or investment upgrade deferral and ancillary services, including frequency and voltage regulation, operating reserves and black start capability (Poullikkas, 2013:786; Krivik *et al.*, 2013:94-96; Suberu *et al.*, 2014:505; Castillo *et al.*, 2014:887; Luo *et al.*, 2015:519-530; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-795; Kyriakopoulos *et al.*, 2016:1061; Aneke *et al.*, 2016:365-366). Section 4.2 of Chapter 4 provides a description of utility-scale value applications that can be performed by flow batteries, as well as other energy storage systems.

3.3 SUMMARY AND CONCLUSION

This chapter provided a classification and overview of different energy storage technologies with the proven capability or high potential to perform utility-scale applications. It described the technical characteristics, advantages, disadvantages and practical uses of different energy storage technologies for reference throughout the remainder of this study. The detail conveyed in this chapter further informs the selection of energy storage technologies and related technical aspects that will be used for the economic feasibility assessment in Chapters 6 and 7, as necessary to address the research problem and attain the objectives set for the study.

Section 3.1 introduced the content to Chapter 3. Section 3.2 summarised, explained and appraised the respective technical characteristics of various distinct energy storage technologies as grouped under mechanical, thermal, electrical, chemical and electrochemical mediums. Of the technologies reviewed, lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur electrochemical batteries arise as the most suitable to be integrated with renewable energy technologies, which is the primary utility-scale application investigated in Chapters 6 and 7. This is mainly due to superior technical characteristics, such as modular scalability to provide high energy and/or electrical power capacity, long cycle and calendar life, relative maturity and market growth potential, rapid response, low self-discharge, high depth of discharge, high roundtrip efficiency, long storage and discharge duration, reliability and/or high energy and power density.

The multifaceted nature of the utility-scale energy storage technologies covered in section 3.2 implies that each technology optimises differently into specific value applications and has dissimilar cost implications. In that regard, the focus of Chapter 4 is to provide an overview of utility-scale energy storage system applications and costs. This is completed through a literature review of different utility-scale applications that can be performed by energy storage systems and the costs related to such systems, including for the technologies examined in section 3.2.

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CHAPTER 4:

LITERATURE REVIEW ON ENERGY STORAGE VALUE APPLICATIONS AND COSTS

4.1 INTRODUCTION

Chapter 4 provides an overview of different utility-scale energy storage system applications and costs. The technological review supplied in the preceding chapter demonstrated the dissimilarity between the technical characteristics, functioning, performance and capabilities of various energy storage systems. The miscellaneous attributes of such systems suggest that they optimise differently into required use applications, as some technologies could be more appropriate for performing certain tasks than others. It further implies that energy storage systems entail distinct cost determinants, which are also influenced by application requirements.

In that regard, the goal of this chapter is to build on Chapters 1 to 3 and contribute to the specific objectives set for the study. This is completed through a literature review of value applications that can be performed by various energy storage technologies at the utility scale, as well as through an investigation into overall energy storage system costs and related considerations. The overview of applications and costs offers additional context into the role, use, economic value and financial implications of various energy storage systems in the South African electricity landscape and informs the empirical analysis conducted in Chapters 6 and 7.

This chapter is structured according to four sections. The next section (4.2) explains interrelated utility-scale applications that can be fulfilled by energy storage systems. These applications are identified as seasonal energy storage, energy time shifting and arbitrage, load levelling and peak shaving, load following, renewables integration, frequency regulation, voltage regulation, operating reserves, black start capability and electricity grid congestion relief and/or investment upgrade deferral. Section 4.3 describes cost variables that jointly contribute to the total lifetime cost of energy storage systems, including capital, operations and maintenance, replacement and disposal costs. Further cost considerations for improved economic evaluation are also clarified. Section 4.4 summarises and concludes Chapter 4.

4.2 ENERGY STORAGE VALUE APPLICATIONS

Energy storage technologies have the capability to perform a wide range of applications that inform their overall economic value in the electrical energy landscape. Value applications, often referred to as use cases, refer to an integrated set of beneficial services that a given energy storage technology can execute in support of electric utilities and the balancing of electricity supply and demand (Kaun *et al*., 2013:26; Carnegie *et al.*, 2013:6-11; Battke *et al.*, 2015:335-336; Akhil *et al.*, 2015:166; Günter *et al.*, 2016:227; Malhotra *et al.*, 2016:706-709). These services are important for economic growth and development by supporting increased electrical energy security, reliability and flexibility.

Various use applications for energy storage are described in literature, albeit somewhat arbitrary, as the definitions and nomenclature used in studies are highly inconsistent and overlapping between different applications. The number of applications also differ widely across publications and can range anywhere between three and 17 (Battke *et al*., 2013:242-243; Battke *et al.*, 2015:337-338; Günter *et al.*, 2016:227; Malhotra *et al.*, 2016:706-710; Gallo *et al*., 2016:814-815). Despite this, all applications are similar in that they depend on the fundamental ability of energy storage systems to charge, store and discharge electrical energy when needed. The main difference between them is the scale, frequency, time, duration and location at which the adequate volume of stored energy is required, which, in turn, informs the selection of appropriate technologies and the specific site where they will be implemented (Castillo *et al.*, 2014:888; Günter *et al.*, 2016:227).

In this section, the focus is on utility-scale energy storage applications, rather than services offered to electricity consumers, commonly referred to as ‘behind the meter’ applications. A brief description of ten interrelated utility-scale energy storage applications is provided for additional context into the role and economic value that various technologies can have in the electrical energy generation and supply environment. Utility-scale value applications could be regarded as beneficial services that can be performed by different technologies with a wide range of techno-economic characteristics and the capability to store more than one megawatt hour (MWh) of energy (Johnstone *et al.*, 2013:143; Castillo *et al.*, 2014:885-888; Hameer *et al.*, 2015:1179; Battke *et al.*, 2015:338-339; Dehdashti, 2016:1; Kyriakopoulos *et al.*, 2016:1056). The fundamental idea of utility-scale energy storage and applications is illustrated by Figure 2.1 in section 2.2 of Chapter 2, while the specific technical characteristics of different energy storage technologies are outlined in Table 3.1 in section 3.2 of Chapter 3.

Table 4.1 provides a brief summary of each utility-scale application, their respective electrical power and discharge duration requirements and the technologies that are suitable to perform them to some extent (compiled from Neuhoff, 2005:92; Beaudin *et al.*, 2010:305-311; Sørensen, 2011:892; Battke *et al*., 2013:242-246; Carnegie *et al.*, 2013:6-82; Poullikkas, 2013:786; Suberu *et al.*, 2014:505-510; Akinyele *et al.*, 2014:74-77; Castillo *et al.*, 2014:886-888; International Energy Agency, 2014:10; Luo *et al.*, 2015:529-531; Bortolini *et al.*, 2015:1031; Battke *et al.*, 2015:338-345; Zakeri *et al.*, 2015:586; Lund *et al.*, 2015:791-793; Akhil *et al.*, 2015:150-165; Malhotra *et al.*, 2016:718; Amrouche *et al.*, 2016: 20914-20922; Kyriakopoulos *et al.*, 2016:1060-1063; Aneke *et al.*, 2016:350-366; Gallo *et al.*, 2016:801-818; Günter *et al.*, 2016:227; Chaanaoui *et al.*, 2016:783; Zou *et al.*, 2017:57; Sessa *et al*., 2016:105; Kondziella *et al.*, 2016:11; Huang *et al.*, 2016:633; Amirante *et al.*, 2017:372-375; Berrada *et al.*, 2017:95-96; Lai *et al.*, 2017:191-192).

While Table 4.1 is representative of the technological requirements to perform various applications, energy storage technologies, particularly electrochemical batteries, could be scaled-up to meet the associated energy capacity and electrical power requirements of each utility-scale application due to their modularity (Beaudin *et al.*, 2010:312; Hittinger *et al.*, 2012:437; Battke *et al*., 2013:246; Günter *et al.*, 2016:230). The efficiency losses and depth of discharge (DoD) limitations associated with many energy storage systems imply that they could be oversized in electrical power rating, which comes at an added cost, in order to be able to discharge the correct amount of energy required by an application (Battke *et al*., 2013:246; Battke *et al.*, 2015:340; Hoff *et al.*, 2016:2).

The wide ranging technical characteristics of energy storage technologies imply that each technology optimises differently into specific value applications. Different types of energy storage systems should be considered in terms of their diverse characteristics and appropriateness for necessary applications. No technology is superior in meeting all required uses and the suitability of each technology to perform particular applications should be evaluated on a case-by-case basis (Hittinger *et al.*, 2012:436-437; Poullikkas, 2013:779; Battke *et al*., 2013:249; Kousksou *et al.*, 2014:73; Suberu *et al.*, 2014:512; Castillo *et al.*, 2014:888-889; Lund *et al.*, 2015:793-796; World Energy Council, 2016a:6; Aneke *et al.*, 2016:367; Gallo *et al.*, 2016:817-819). Since energy storage performance varies widely by application, it could be rational to anticipate that multiple technologies could penetrate various parts of the market. It is therefore important to conduct a thorough analysis of applicable technologies and required applications before a particular energy storage system is selected (Hadjipaschalis *et al.*, 2009:1513; Kousksou *et al.*, 2014:73).

Table 4.1: Summary of utility-scale energy storage value applications and suitable technologies

Application	Purpose summary	Electrical power needs (MW)	Discharge duration	Response time	Suitable energy storage technologies
Seasonal energy storage	Long-term energy storage and discharge to accommodate for seasonal variations in electricity demand and supply	30 to 500	Up to weeks	Minutes to hours	PHS, CAES, hydrogen and thermal
Energy time shifting and arbitrage	Store energy during off-peak periods when electricity demand and prices are low and discharge during peak periods when electricity demand and prices are higher	Up to 100 or more	Between 1 and 12 hours	Minutes	PHS, CAES, hydrogen, thermal and various batteries
Load levelling and peak shaving	Reduce large fluctuations in demand for electricity and the use of peak generators by storing energy during low demand periods and discharge during high demand periods	Up to 100 or more	Between 1 and 12 hours or more	Minutes	PHS, CAES, hydrogen, thermal and various batteries
Load following	Provide continuous support to maintain the balance of electricity supply and demand due to load variations and insufficient or excess electrical output from generators	Up to 100 or more	Minutes to hours, possibly days	Milliseconds to 1 second	PHS, hydrogen, supercapacitors, SMES and various batteries
Renewables integration	Store and discharge electrical power as needed to overcome issues of renewable resource variability and intermittency, as well as to enable electricity price arbitrage opportunities and integrate more renewable generators into the electricity grid	Up to 20 or more	Seconds to hours, possibly days	Milliseconds to 1 minute	PHS, CAES, hydrogen, thermal, flywheels, supercapacitors, SMES and various batteries
Frequency regulation	Instantaneously and regularly balance or stabilise fluctuations in network frequency outside of permissible limits by rapidly charging and discharging the requisite electrical energy	Up to 10	Seconds to minutes	Milliseconds, occasionally minutes	PHS, CAES, flywheels, supercapacitors, SMES and various batteries
Voltage regulation	Instantaneously and regularly balance or stabilise fluctuations in network voltage within a specified range by rapidly charging and discharging the requisite reactive electric power	Up to 10	Seconds to minutes	Milliseconds	CAES, flywheels, supercapacitors, SMES and various batteries
Operating reserves	Infrequently supply electrical energy in the event of an emergency, such as an unexpected loss of generation or transmission capacity and surge in electricity demand	Up to 100 or more	30 minutes to 5 hours or more	Seconds to 1 hour	PHS, CAES, hydrogen, thermal and various batteries
Black start capability	Start electrical generators without using the electric grid following a major grid failure or blackout	Up to 40	Seconds to hours	Minutes	PHS, CAES, hydrogen, thermal, flywheels, supercapacitors, SMES and various batteries
Electricity grid congestion relief and/or upgrade deferral	Store electrical energy when the electricity grid is constrained and discharge when the grid is less congested to alleviate pressure on available grid capacity and/or defer the need for additional grid infrastructure investments	10 to 100 or more	1 to 6 hours	Milliseconds to minutes	PHS, CAES, hydrogen, thermal and various batteries

Source: Author's compilation

4.2.1 Seasonal energy storage

Seasonal energy storage refers to the use of energy storage systems to charge, store and discharge electrical energy over very long periods of time to accommodate for seasonal variations in electricity production and consumption (International Energy Agency, 2014:10; Lund *et al.*, 2015:793; Luo *et al.*, 2015:530; Aneke *et al.*, 2016:364). This use application can be regarded as long-term energy time shifting (Gallo *et al.*, 2016:815-818).

Seasonal energy storage usually necessitates technologies with a power rating of 30 to 500 megawatt (MW), response time of minutes to hours, large energy storage capacity, storage duration of up to weeks or months, discharge duration of up to weeks and very low self-discharge rate (Beaudin *et al.*, 2010:305-311; Lund *et al.*, 2015:793; Luo *et al.*, 2015:530; Gallo *et al.*, 2016:815). Technologies that are appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), hydrogen fuel cells and possibly thermal energy storage (Lund *et al.*, 2015:791-793; Luo *et al.*, 2015:529-531; Aneke *et al.*, 2016:365-366; Gallo *et al.*, 2016:818).

4.2.2 Energy time shifting and arbitrage

Energy time shifting refers to the use of energy storage systems to store electrical energy produced during a certain time period for discharge and use during another time period when it is needed or has a higher value (Poonpun *et al.*, 2008:529; Günter *et al.*, 2016:227). More specifically, it refers to the charging and storing of electrical energy during off-peak periods, when the demand for electricity is low, and discharging the requisite energy during peak periods, when the prevailing demand for electricity is high (Battke *et al.*, 2013:242; Carnegie *et al.*, 2013:81; Suberu *et al.*, 2014:510; Castillo *et al.*, 2014:886-888; Lund *et al.*, 2015:793; Luo *et al.*, 2015:529; Günter *et al.*, 2016:227).

This value application is often referred to as energy arbitrage as it provides electric utilities with the opportunity to take advantage of electricity price differentials for increased revenues, since they can produce and store electrical energy when electricity prices are less expensive and discharge or sell the stored energy when electricity prices are higher during peak demand periods (Sioshansi *et al.*, 2009:270; Carnegie *et al.*, 2013:6-7; Akinyele *et al.*, 2014:76; Lund *et al.*, 2015:793; Luo *et al.*, 2015:529-530; Battke *et al.*, 2015:338; Akhil *et al.*, 2015:153; Malhotra *et al.*, 2016:718; Amrouche *et al.*, 2016:20918;

Gallo *et al.*, 2016:815; Aneke *et al.*, 2016:365; Obi *et al.*, 2017:916). Energy time shifting can improve the efficiency and lifetime of electrical energy generators and reduce the need for expensive fossil fuel-based peak generation options (Poonpun *et al.*, 2008:530; Carnegie *et al.*, 2013:81; Lund *et al.*, 2015:793; Günter *et al.*, 2016:227).

Energy time shifting usually necessitates technologies with a power rating of up to 100 megawatt (MW) or more, storage duration of hours to days, response time of minutes, low self-discharge rate and discharge duration of between one and 12 hours (Beaudin *et al.*, 2010:305; Carnegie *et al.*, 2013:19; Battke *et al*., 2013:246; Battke *et al.*, 2015:345; Zakeri *et al.*, 2015:586; Luo *et al.*, 2015:530; Gallo *et al.*, 2016:815-818; Aneke *et al.*, 2016:365). Good technological roundtrip efficiency also becomes a key determining factor in the event that price arbitrage will be performed by energy storage systems (Aneke *et al.*, 2016:365). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), thermal energy storage, hydrogen fuel cells and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Castillo *et al.*, 2014:887; Suberu *et al.*, 2014:505; Luo *et al.*, 2015:529; Zakeri *et al.*, 2015:586; Gallo *et al.*, 2016:818; Sessa *et al*., 2016:105; Amirante *et al.*, 2017:375).

4.2.3 Load levelling and peak shaving

Load levelling refers to the use of energy storage systems to charge and store energy during periods of low demand and discharge the requisite electrical energy during periods of high demand to reduce large fluctuations in the demand for electricity. Load levelling is often required to smooth variations in electric load in an area serviced by an energy storage system (Poonpun *et al.*, 2008:529; Chen *et al*., 2009:292; Poullikkas, 2013:786; Suberu *et al.*, 2014:510; Akinyele *et al.*, 2014:76; Castillo *et al.*, 2014:886-888; Lund *et al.*, 2015:792-793; Luo *et al.*, 2015:530; Günter *et al.*, 2016:227).

Load levelling is commonly used interchangeably with peak shaving, which refers to an application in which energy storage systems are specifically used to reduce peak load generation requirements in the electricity system by charging during off-peak periods and discharging during periods of maximum demand for electricity (Chen *et al*., 2009:292; Suberu *et al.*, 2014:510; Castillo *et al.*, 2014:887; Lund *et al.*, 2015:793; Luo *et al.*, 2015:530; Günter *et al.*, 2016:227; Kyriakopoulos *et al.*, 2016:1063). Load levelling and peak shaving help to improve the efficiency of the total electrical energy generation fleet, especially base load generators, and to overcome the need for peaking electricity generation plants (Poonpun *et al.*, 2008:529; Carnegie *et al.*, 2013:7; Suberu *et al.*, 2014:510; Akinyele *et al.*, 2014:76; Lund *et al.*, 2015:792-793; Günter *et al.*, 2016:227).

Load levelling and peak shaving usually necessitate technologies with a power rating of up to 100 megawatt (MW) or more, response time of minutes and discharge duration of between one and 12 hours or more (Beaudin *et al.*, 2010:305; Lund *et al.*, 2015:792; Luo *et al.*, 2015:530). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), thermal energy storage, hydrogen fuel cells and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Poullikkas, 2013:786; Suberu *et al.*, 2014:505; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-792; Luo *et al.*, 2015:529-530; Kyriakopoulos *et al.*, 2016:1060-1063; Sessa *et al*., 2016:105; Berrada *et al.*, 2017:96).

4.2.4 Load following

Load following refers to the use of energy storage systems to provide continuous support in balancing the supply and demand for electricity as electric load requirements change at any given time due to large variations in the prevailing demand for electricity (Poonpun *et al.*, 2008:529; Carnegie *et al.*, 2013:82; Suberu *et al.*, 2014:510; Castillo *et al.*, 2014:886; Lund *et al.*, 2015:792; Luo *et al.*, 2015:529; Battke *et al.*, 2015:338; Günter *et al.*, 2016:227; Malhotra *et al.*, 2016:718). This can be done by charging and storing electrical energy during low demand periods and discharging during periods when demand is higher, electricity supply is insufficient and/or in the event of an emergency, such as an electrical power failure (Suberu *et al.*, 2014:510; Lund *et al.*, 2015:792-793; Luo *et al.*, 2015:529; Günter *et al.*, 2016:227).

Load following allows electric generators to operate at maximum efficiency and could require unit commitment from energy storage systems. This implies that technologies need to be available to discharge adequate electrical energy when electricity output is insufficient to meet prevailing demand at any given time and/or absorb electrical energy when excessive electricity output is available (Beaudin *et al.*, 2010:311; Poullikkas, 2013:786; Suberu *et al.*, 2014:510; Lund *et al.*, 2015:792; Battke *et al.*, 2015:338).

Load following usually necessitates technologies with a power rating of up to 100 megawatt (MW) or more, response time of milliseconds up to one second and discharge duration of minutes to hours and even up to three days (Beaudin *et al.*, 2010:305; Lund *et al.*, 2015:792-793; Luo *et al.*, 2015:530). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), supercapacitors, superconducting magnetic energy storage (SMES), hydrogen fuel cells and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Poullikkas, 2013:786; Castillo *et al.*, 2014:887; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-792; Luo *et al.*, 2015:529-530; Kyriakopoulos *et al.*, 2016:1063; Berrada *et al.*, 2017:96).

4.2.5 Renewables integration

Renewables integration refers to the use of energy storage systems to overcome the inherent variability and intermittency of renewable energy-based electrical production plants. This can be done by absorbing and releasing electrical power as required to smooth variable electricity output and provide back-up power during periods of resource intermittency to enable constant, stable, reliable and dispatchable electrical energy availability from renewable energy sources (Poonpun *et al.*, 2008:529; Hittinger *et al.*, 2012:439; Carnegie *et al.*, 2013:9-10; Suberu *et al.*, 2014:510; Castillo *et al.*, 2014:888; Akinyele *et al.*, 2014:76; Hammond *et al.*, 2015:560; Lund *et al.*, 2015:793; Luo *et al.*, 2015:529; Battke *et al.*, 2015:338; Gielen *et al.*, 2016:14; Chaanaoui *et al.*, 2016:783; Günter *et al.*, 2016:227; Amrouche *et al.*, 2016:20922; Dehdashti, 2016:4; Malhotra *et al.*, 2016:718; Gallo *et al.*, 2016:815; Rycroft, 2017:24; Amirante *et al.*, 2017:372-373; Lai *et al.*, 2017:191).

For example, electrical output from solar photovoltaic (PV) technologies is not only intermittent due to the unavailability of sunshine during periods of cloud cover and after sunset, but also variable due to the inconsistency of solar irradiation required to produce electrical energy from the PV cells. Similarly, electrical energy output from wind turbines is intermittent as the wind emerges and dissipates, as well as variable due to fluctuating wind speeds (Neuhoff, 2005:92; Beaudin *et al.*, 2010:303-304; Zahedi, 2011:866-868; Kaltschmitt *et al.*, 2013:1677-1781; De Vos *et al.*, 2014:567; Akinyele *et al.*, 2014:74; Delarue *et al.*, 2015:4-5; Bortolini *et al.*, 2015:1031; Gallo *et al.*, 2016:801; Kondziella *et* *al.*, 2016:11; Huang *et al.*, 2016:633; Zou *et al.*, 2017:57; Rycroft, 2017:24; Lai *et al.*, 2017:194-197; Pan *et al.*, 2017:380-381).

Energy storage systems can be integrated with such renewable energy-based electrical generators to charge and discharge electric power as needed to overcome issues of natural resource unavailability, variability and intermittency (Sørensen, 2011:892; Ibrahim *et al.*, 2013:1; Carnegie *et al.*, 2013:79; Suberu *et al.*, 2014:510; Akinyele *et al.*, 2014:74-76; Pfenninger *et al.*, 2015:303; Lund *et al.*, 2015:793; Kyriakopoulos *et al.*, 2016:1062; Günter *et al.*, 2016:227; Aneke *et al.*, 2016:350-366; Amrouche *et al.*, 2016:20914-20922; Chaanaoui *et al.*, 2016:783; Malhotra *et al.*, 2016:718; Amirante *et al.*, 2017:372-373; Obi *et al.*, 2017:909-910). Energy storage technologies can further be used by renewable energy electrical power producers to take advantage of price arbitrage, and thereby improved revenues, by charging and storing electrical energy generated from inexpensive renewable sources and retaining it for later discharge and sales when electricity prices are higher during peak demand periods (Poonpun *et al.*, 2008:529; Sioshansi *et al.*, 2009:270; Akinyele *et al.*, 2014:76; Battke *et al.*, 2015:338; Malhotra *et al.*, 2016:718; Günter *et al.*, 2016:227; Dehdashti, 2016:6; Obi *et al.*, 2017:916; Berrada *et al.*, 2017:95).

Renewables integration can also enable the incorporation of more intermittent renewable energy electrical production plants into the electricity grid (Suberu *et al.*, 2014:510; Akinyele *et al.*, 2014:76; Lazard, 2016:6). This can be done by charging a portion of direct electrical output from renewable energy generation plants during periods when the electricity grid is constrained and discharging the stored energy when the grid is less congested. By doing this, more renewable energy generators can be accommodated as excess capacity in transmission and distribution lines is better utilised by levelling the electrical output from intermittent sources that would otherwise peak and fade during certain periods, such as the availability of solar generation during daytime, but not in night time (Suberu *et al.*, 2014:510; Lund *et al.*, 2015:793; Battke *et al.*, 2015:338; Eskom, 2015:20; Günter *et al.*, 2016:227; Berrada *et al.*, 2017:95). Section 6.4 of Chapter 6 elaborates more on the rationale for integrating energy storage systems with solar PV electrical production plants in the South African electricity environment.

Renewables integration usually necessitates technologies with a power rating of up to 20 megawatt (MW) or more, response time of milliseconds up to one minute and discharge duration of seconds to hours and even days for longer periods of resource intermittency (Beaudin *et al.*, 2010:305; Carnegie *et al.*, 2013:19; Luo *et al.*, 2015:530; Gallo *et al.*, 2016:815-818). Good technological roundtrip efficiency also becomes an important determining factor in the event that price arbitrage will be performed by energy storage systems (Aneke *et al.*, 2016:365). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), flywheels, thermal energy storage, supercapacitors, superconducting magnetic energy storage (SMES), hydrogen fuel cells and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Krivik *et al.*, 2013:96; Poullikkas, 2013:786; Suberu *et al.*, 2014:505; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:793-796; Luo *et al.*, 2015:530; Kyriakopoulos *et al.*, 2016:1063; Amrouche *et al.*, 2016:20915-20919; Gallo *et al.*, 2016:818; Aneke *et al.*, 2016:365-366; Sessa *et al*., 2016:105; Amirante *et al.*, 2017:375-377).

4.2.6 Frequency regulation

Frequency regulation is an electric power intensive ancillary service that refers to the use of energy storage systems to instantaneously and regularly balance or stabilise fluctuations in network frequency outside of permissible limits from its nominal value. Frequency imbalances occur as a result of temporary deviations between electrical generation and loads (Battke *et al*., 2013:242; Carnegie *et al.*, 2013:8-16; Akinyele *et al.*, 2014:77; Castillo *et al.*, 2014:887; Lund *et al.*, 2015:791; Günter *et al.*, 2016:227; Malhotra *et al.*, 2016:718). The nominal grid frequency requirement is 50 hertz (Hz) in South Africa (National Energy Regulator of South Africa, 2014:13). This use application can be fulfilled by rapidly charging and discharging the requisite electrical energy to maintain a constant balance between electricity demand and supply and prevent a deviation from nominal frequency and the consequent possibility of damaged equipment, failure of electrical generation plants and a prolonged blackout of the electricity system (Poonpun *et al.*, 2008:530; Carnegie *et al.*, 2013:8; Akinyele *et al.*, 2014:77; Lund *et al.*, 2015:791; Malhotra *et al.*, 2016:715; Gallo *et al.*, 2016:815).

Frequency regulation usually necessitates technologies with a power rating of up to 10 megawatt (MW), response time of milliseconds and occasionally minutes, discharge duration of seconds to minutes and very long cycle life (Beaudin *et al.*, 2010:305; Carnegie *et al.*, 2013:19; Battke *et al*., 2013:246; Battke *et al.*, 2015:345; Zakeri *et al.*, 2015:586; Luo *et al.*, 2015:530; Lund *et al.*, 2015:791; Malhotra *et al.*, 2016:716; Gallo *et al.*, 2016:815-818). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), flywheels, supercapacitors, superconducting magnetic energy storage (SMES) and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Poullikkas, 2013:786; Kousksou *et al.*, 2014:68; Castillo *et al.*, 2014:887; Suberu *et al.*, 2014:505; Zakeri *et al.*, 2015:586; Lund *et al.*, 2015:791-792; Luo *et al.*, 2015:529-530; Amrouche *et al.*, 2016:20915-20919; Gallo *et al.*, 2016:806-818; Amirante *et al.*, 2017:378; Berrada *et al.*, 2017:96).

4.2.7 Voltage regulation

Voltage regulation is an electric power intensive ancillary service that refers to the use of energy storage systems to instantaneously and regularly balance or stabilise fluctuations in network voltage within a specified range when it is unaligned to its nominal value (Carnegie *et al.*, 2013:8-16; Akinyele *et al.*, 2014:77; Castillo *et al.*, 2014:887; Lund *et al.*, 2015:791; Luo *et al.*, 2015:531; Günter *et al.*, 2016:227; Malhotra *et al.*, 2016:718). As with frequency regulation, this use application can be fulfilled by rapidly charging and discharging the requisite reactive power to prevent a deviation from nominal voltage and the consequent possibility of damaged equipment, failure of electrical generation plants and a prolonged blackout of the electricity system (Poonpun *et al.*, 2008:529; Battke *et al.*, 2013:242; Carnegie *et al.*, 2013:82-83; Akinyele *et al.*, 2014:77; Lund *et al.*, 2015:791; Akhil *et al.*, 2015:163; Malhotra *et al.*, 2016:718; Gallo *et al.*, 2016:815).

Voltage regulation usually necessitates technologies with a power rating of up to 10 megawatt (MW), response time of milliseconds, discharge duration of seconds to minutes and very long cycle life (Battke *et al*., 2013:246; Carnegie *et al.*, 2013:19; Luo *et al.*, 2015:530-531; Zakeri *et al.*, 2015:586; Lund *et al.*, 2015:791; Gallo *et al.*, 2016:815-818). Technologies that could be appropriate for this application include compressed air energy storage (CAES), flywheels, supercapacitors, superconducting magnetic energy storage (SMES) and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Castillo *et al.*, 2014:887; Suberu *et al.*, 2014:505; Hameer *et al.*, 2015:1193; Zakeri *et al.*, 2015:586; Lund *et al.*, 2015:791-792; Luo *et al.*, 2015:529-530; Aneke *et al.*, 2016:365-366; Gallo *et al.*, 2016:806-818; Sessa *et al*., 2016:105).

4.2.8 Operating reserves

Operating reserves include spinning and non-spinning reserves and refer to the use of energy storage systems to store and supply electrical energy when there is an unexpected loss of generation and/or transmission capacity, increase in electricity demand and/or large variations in electric load (Carnegie *et al.*, 2013:4-15; Kaltschmitt *et al.*, 2013:1664-1667; Akinyele *et al.*, 2014:76; Castillo *et al.*, 2014:886; Rejc *et al.*, 2014:654; Delarue *et al.*, 2015:5-8; Lund *et al.*, 2015:792; Luo *et al.*, 2015:531; Akhil *et al.*, 2015:161; Pretorius *et al.*, 2015:33; Günter *et al.*, 2016:227). This application is usually not required on a regular basis and could be used to balance longer-term discrepancies in electricity supply and demand, as well as reduce the need for electrical generators earmarked for the provision operating reserves when necessary (Poonpun *et al.*, 2008:529; Carnegie *et al.*, 2013:13-16; Akinyele *et al.*, 2014:76; Lund *et al.*, 2015:792; Malhotra *et al.*, 2016:718).

Operating reserves usually necessitate technologies with a power rating of between one and 100 megawatt (MW) or more, response time of seconds up to one hour and discharge duration of 30 minutes to five hours or more (Beaudin *et al.*, 2010:305; Zakeri *et al.*, 2015:586; Lund *et al.*, 2015:792; Luo *et al.*, 2015:530; Günter *et al.*, 2016:227). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), thermal energy storage, hydrogen fuel cells and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Poullikkas, 2013:786; Castillo *et al.*, 2014:887; Hameer *et al.*, 2015:1193; Zakeri *et al.*, 2015:586; Lund *et al.*, 2015:792; Luo *et al.*, 2015:529-531; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366; Amrouche *et al.*, 2016:20918; Berrada *et al.*, 2017:96).

4.2.9 Black start capability

Black start capability refers to the use of energy storage systems to start or restart isolated electrical energy generators without using the electric grid following a system event such as a major grid failure, loss of generation capacity, electrical power outage or blackout (Poonpun *et al.*, 2008:530; Carnegie *et al.*, 2013:8; International Energy Agency, 2014:10; Lund *et al.*, 2015:792; Luo *et al.*, 2015:531; Akhil *et al.*, 2015:150; Günter *et al.*, 2016:227; Malhotra *et al.*, 2016:718; Aneke *et al.*, 2016:366). The generator requiring black start services usually has the means to ignite further generators along the electric grid (Günter *et al.*, 2016:227).

Black start capability usually necessitates technologies with a power rating of up to 40 megawatt (MW), response time of minutes, discharge duration of seconds to hours and infrequent cycling capability of approximately 10 to 20 times a year (Lund *et al.*, 2015:791-792; Luo *et al.*, 2015:530). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), flywheels, thermal energy storage, supercapacitors, superconducting magnetic energy storage (SMES), hydrogen fuel cells and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Lund *et al.*, 2015:791; Hameer *et al.*, 2015:1193; Luo *et al.*, 2015:529-530; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:365-366; Amrouche *et al.*, 2016:20918). The short discharge duration of flywheels, supercapacitors and SMES might limit their capability to provide black start services (Lund *et al*., 2015:792).

4.2.10 Transmission and distribution grid congestion relief and/or investment upgrade deferral

Transmission and distribution grid congestion relief and/or investment upgrade deferral refers to the use of energy storage systems to improve the utilisation of transmission and distribution lines, increase the efficiency of electricity transmission and distribution, prevent the curtailment of electrical energy production due to network capacity limitations and reduce the need for investments in additional grid infrastructure (Carnegie *et al.*, 2013:9; Akinyele *et al.*, 2014:77; Castillo *et al.*, 2014:888; Lund *et al.*, 2015:792; Luo *et al.*, 2015:531; Gallo *et al.*, 2016:815; Lai *et al.*, 2017:191). This can be done by charging and storing electrical energy when a portion of the electricity grid is constrained or overloaded and discharging the electrical energy when the grid is less congested and spare capacity is available to enable the flow of electricity from the storage medium to areas of demand (Battke *et al*., 2013:242; Carnegie *et al.*, 2013:7-79; Lund *et al.*, 2015:793; Battke *et al.*, 2015:338; Akhil *et al.*, 2015:165; Günter *et al.*, 2016:227; Berrada *et al.*, 2017:95).

Electricity generation capacity and supply could be limited in areas characterised by electricity transmission capacity constraints. For example, excellent solar irradiation levels and abundant land in the Northern Cape Province have attracted the construction of numerous utility-scale solar photovoltaic (PV) electrical energy production plants (Grobbelaar *et al.*, 2014:479; Kenny, 2015:19; Pfenninger *et al.*, 2015:306-307; Walwyn & Brent, 2015:391-393; Van Ravenswaay *et al.*, 2015:1838-1843; Eskom, 2015:66-73; Parrado *et al.*, 2016:510; Busse *et al.*, 2016:52-53; Minnaar, 2016:1140; Nakumuryango & Inglesi-Lotz, 2016:1000; Department of Energy, 2017:23-24). The extent to which these solar-based electrical power producers can be incorporated, however, has been limited by transmission infrastructure electrical capacity constraints during the day when solar irradiation from the sun, and therefore electrical output from solar technologies, is available and abundant (Suberu *et al.*, 2014:510 Eskom, 2015:13-73; Eskom, 2016a:52; Minnaar, 2016:1140; Lai *et al.*, 2017:191).

In the evenings, the transmission lines are much less congested as direct solar energy-based electricity production is unattainable after sunset. This implies that the transmission lines are neither effectively, nor efficiently, utilised and prevent the implementation of additional solar energy-based electrical generation plants until sufficient grid capacity investments have been made (Battke *et al*., 2013:242; Suberu *et al.*, 2014:510; Eskom, 2015:13-67; Lai *et al.*, 2017:191).

Energy storage technologies can help to overcome this issue by being used to store a share of daytime solar-based electrical production, when electricity demand is lower, and discharge the associated energy during the evening and times of cloud cover when the Northern Cape grid is less congested (Poonpun *et al.*, 2008:530; Suberu *et al.*, 2014:510; Lund *et al.*, 2015:792-793; Günter *et al.*, 2016:227; Berrada *et al.*, 2017:97). By using energy storage technologies in this way, transmission congestion relief can be achieved and the operation of transmission and generation infrastructure improved so that planned capital investments can be accommodated or delayed, while increased capacity could be enabled (Poonpun *et al.*, 2008:530; Akinyele *et al.*, 2014:77; Castillo *et al.*, 2014:888; International Energy Agency, 2014:10; Lund *et al.*, 2015:792-793; Akhil *et al.*, 2015:165-166; Malhotra *et al.*, 2016:718; Dehdashti, 2016:4-6; Gallo *et al.*, 2016:815).

Transmission and distribution congestion relief and/or investment upgrade deferral usually necessitate technologies with a power rating of 10 to 100 megawatt (MW) or more, response time of milliseconds to minutes and discharge duration of one to six hours (Beaudin *et al.*, 2010:305; Battke *et al*., 2013:246; Carnegie *et al.*, 2013:77; Lund *et al.*, 2015:792-193; Luo *et al.*, 2015:530-531; Gallo *et al.*, 2016:815-818). Technologies that could be appropriate for this application include pumped hydroelectric energy storage (PHS), compressed air energy storage (CAES), thermal energy storage, hydrogen fuel cells and electrochemical energy storage, including lead-acid, nickel-cadmium (NiCd), nickel-metal hydride (NiMH), metal-air, sodium-sulphur (NaS), sodium-nickel-chloride ($NaNiCl_2$ or ZEBRA), lithium-ion and flow batteries (Castillo *et al.*, 2014:887; Suberu *et al.*, 2014:505; Hameer *et al.*, 2015:1193; Lund *et al.*, 2015:791-793; Luo *et al.*, 2015:529-530; Aneke *et al.*, 2016:365-366; Kyriakopoulos *et al.*, 2016:1063).

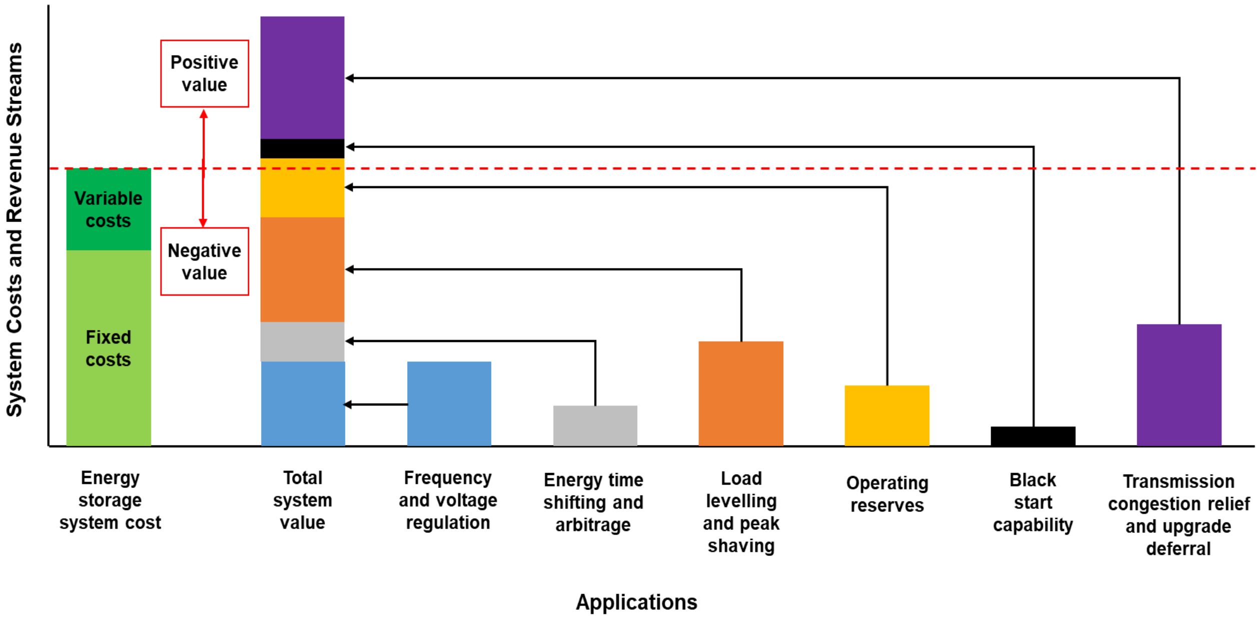
4.2.11 Multiple applications

Many energy storage systems have the technical capability to provide multiple applications, although not all technologies can perform all value applications concurrently (Battke *et al.*, 2015:339; Günter *et al.*, 2016:227; Malhotra *et al.*, 2016:706-708). An energy storage system requires time to charge and discharge electrical energy for a particular application being performed at a certain period and some technologies might not possess the operational compatibility to perform specific applications simultaneously (Carnegie *et al.*, 2013:17; Lazard, 2016:4; Günter *et al.*, 2016:232).

On the other hand, it is often possible for energy storage systems to provide multiple applications sequentially and/or simultaneously, which significantly enhances the value of energy storage relative to cost due to different potential revenue streams (Sioshansi *et al.*, 2009:277; He *et al.*, 2011:1575-1584; Carnegie *et al.*, 2013:14-19; Zhang, 2013:39; Kaun *et al.*, 2013:25-85; Pawel, 2014:69; Castillo *et al.*, 2014:888; Lambruschi, 2015:24-26; De la Rubia *et al.*, 2015:7-8; Battke *et al.*, 2015:334-339; Lazard, 2016:4; Günter *et al.*, 2016:231-234; Kondziella *et al.*, 2016:15-20; Jülch, 2016:1604; Malhotra *et al.*, 2016:706-717; Ferroukhi *et al.*, 2017:80-81). The number of applications that can be performed sequentially and/or simultaneously, as well as the extent to which they can be accomplished, by various distinct energy storage technologies, is situation-specific and needs to be evaluated on a case-by-case basis (He *et al.*, 2011:1576; World Energy Council, 2016a:6). The overall value will be determined by the net economic benefits provided by an energy storage system from delivering particular applications at certain times when those services are required in a way that maximises the productive utilisation of a technology under consideration (Lazard, 2016:4; Günter *et al.*, 2016:232; Berrada *et al.*, 2017:95).

For example, it could be feasible for an energy storage system to perform renewables integration, while also having the capability to provide energy time shifting and arbitrage, load levelling, operating reserves, black start capability and/or transmission infrastructure upgrade deferral (Castillo *et al.*, 2014:888; Günter *et al.*, 2016:231; World Energy Council, 2016a:14; Dehdashti, 2016:6). The multiple services offered by the same energy storage installation could also present an opportunity to displace the need for investing in a single peak generation option, such as a gas turbine (Poonpun *et al.*, 2008:530; Carnegie *et al.*, 2013:7-9; Castillo *et al.*, 2014:888; Malhotra *et al.*, 2016:707-711; Lai *et al.*, 2017:194). Figure 4.1 provides a hypothetical illustration of the value of energy storage relative to system cost (adapted from Kaun *et al*., 2013:26-27; Kempener *et al.*, 2015:15; Lazard, 2016:4). Energy storage costs are described in more detail in section 4.3.

Figure 4.1: Value of energy storage relative to cost



Source: Adapted from Kaun *et al*. (2013:26-27); Kempener *et al.* (2015:15); Lazard (2016:4)

The multi-purpose use capability of energy storage technologies could further entail innovation, growth and spillover effects due to inter-linkages with other electricity production technologies and economic sectors (Battke *et al.*, 2015:335-336; Lazkano *et al.*, 2017:1-16). Failing to account for, and quantify, the various applications that can be met with energy storage technologies could lead to an underestimation of the total intrinsic value of such technologies (Sioshansi *et al.*, 2009:276-277).

4.3 ENERGY STORAGE COSTS

The cost of an energy storage system, together with its technical characteristics, is an essential determining factor of its potential commercialisation, economic feasibility and competitiveness relative to alternative solutions (Akinyele *et al.*, 2014:85; Kyriakopoulos *et al.*, 2016:1063; Aneke *et al.*, 2016:367). As described in section 4.2 and sub-section 4.2.11 in particular, energy storage technologies should be viewed in terms of the number of applications they can perform sequentially and/or simultaneously, since the multi-use capability of such technologies can enhance the overall value of energy storage systems relative to cost by a substantial margin, depending on the net economic benefits provided (Sioshansi *et al.*, 2009:277; He *et al.*, 2011:1575-1584; Carnegie *et al.*, 2013:14-19; Zhang, 2013:39; Kaun *et al.*, 2013:25-85; Pawel, 2014:69; Lambruschi, 2015:24-26; De la Rubia *et al.*, 2015:7-8; Battke *et al.*, 2015:334-339; Lazard, 2016:4; Günter *et al.*, 2016:231-234; Kondziella *et al.*, 2016:15-20; Malhotra *et al.*, 2016:706-717; Ferroukhi *et al.*, 2017:80-81; Berrada *et al.*, 2017:95).

Energy storage costs, however, differ widely by use application as they are influenced by technological capabilities, application needs, siting, electricity prices, discount rates and various cost and performance parameters (Akinyele *et al.*, 2014:85; Akhil *et al.*, 2015:31; Battke *et al.*, 2015:340; Mundada *et al.*, 2016:695; Mayr *et al.*, 2016; Obi *et al.*, 2017:910-911). Energy storage costs also differ widely by publication due to diverse reporting time horizons, data sources, uncertainty, assumptions and estimation procedures (Battke *et al*., 2013:242-243; Zakeri *et al.*, 2015:573-583).

The total cost of an energy storage system can mainly be grouped into capital costs, operations and maintenance costs, replacement costs and disposal costs. Table 4.2 summarises the ranges of important cost indicators for the various utility-scale energy storage technologies described in Chapter 3 (compiled from Poonpun *et al*., 2008:532; Dufo-López *et al*., 2009:130-131; Chen *et al*., 2009:307; Evans *et al*., 2012:4146; Ibrahim *et al*., 2013:5; Battke *et al*., 2013:245-248; Poullikkas, 2013:786; Kousksou *et al*., 2014:68-74; Suberu *et al*., 2014:509; Pawel, 2014:72; Castillo *et al*., 2014:887; Akinyele *et al*., 2014:85-86; Mahlia *et al*, 2014:542; Hammond *et al*., 2015:568; Luo *et al*., 2015:527; Hameer *et al*., 2015:1184-1188; Battke *et al*., 2015:344; Zakeri *et al*., 2015:578-593; World Energy Council, 2016a:22-25; Kyriakopoulos *et al*., 2016:1055-1062; Jülch, 2016:1596-1603; Hill, 2016:1; Gallo *et al*., 2016:814-817; Aneke *et al*., 2016:367-368; Parrado *et al*., 2016:509-512; Amrouch *et al*., 2016:20922-20923; Günter *et al*., 2016:229-230; Lazard, 2016:19-34; Obi *et al*., 2017:911-913; Lai *et al*., 2017:195-202; Berrada *et al*., 2017:99-103; Amirante *et al*., 2017:375-384).

The values in Table 4.2 were derived through the compilation of numerous energy storage technology cost indicators from existing literature. The respective technology cost ranges were obtained by selecting lower- and upper-bound values reported in recent literature that appear realistic and are not considered outliers. Wherever necessary, possible and practical, some individual data entries that were used to derive the values in Table 4.2 were estimated from available application requirements and technology cost characteristics as given in the applicable literature sources. All relevant currency values, for example euros (EUR), were converted to United States dollars (USD) of the year of publication and adjusted for inflation to represent the cost indicators in 2016 terms (IHS Global Insight, 2017).

It could be noted that reported technology costs in literature are subject to wide uncertainty, inconsistency and appear to be outdated. While the cost data was primarily obtained and estimated from recent publications, the rapid techno-economic improvements taking place with energy storage technologies implies that the data summarised in Table 4.2 is representative, but might not pinpoint the exact financial state of all technologies in 2016. Upper- and lower-bound estimates could possibly be less in practice than what is reported here. The intention is nonetheless to show the degree to which energy storage system costs differ between and within technology groupings, rather than place a specific value on each technology.

The indicators are summarised according to, or as a percentage of, the total capital costs of energy storage systems, which include the overall expenses associated with an energy storage medium and balance of plant features as described in section 2.3 of Chapter 2. Table 4.2 complements the technical characteristics of utility-scale energy storage technologies summarised in Table 3.1 in section 3.2 of Chapter 3. It further informs the calculations and costs for the methodology developed in section 6.5 of Chapter 6.

Table 4.2: Energy storage system costs (approximate 2016 values)

Energy storage technology	Total power capital cost (USD/kW)	Total energy capital cost (USD/kWh)	Total capital cost per cycle (USD¢/kWh/Cycle)	Operations and maintenance cost per year as a share of total initial capital cost (%)	Energy storage medium cost as a share of total initial capital cost (%)	Sundry levelised cost estimate (USD/kWh)
Mechanical energy storage						
PHS	500 – > 2 800	10 – > 250	0.1 – 1.4	< 0.69 – 1.14	42.71 – 63.54	0.05 – 0.20
Diabatic CAES	400 – > 1 300	< 25 – 130	2 – 4	< 0.68 – 1.33	14.29 – 75	0.06 – 0.19
Adiabatic CAES	700 – 1 000	< 40 – 80	2 – 6	< 0.68 – 1.33	No information	No information
Flywheels	850 – > 2 000	1 000 – > 5 000	3 – 25	1.57 – > 2	< 78.49 – 83.38	0.30 – > 1.00
Thermal energy storage						
Molten salt	200 – > 1 000	3.75 – 75	No information	1.33 – 2	No information	0.12 – 0.84
Electrical energy storage						
Capacitors	200 – 500	505 – 1 200	No information	< 0.01	No information	No information
Supercapacitors	100 – 360	300 – 2 026	2 – 20	< 0.01	No information	0.23 – > 0.45
SMES	200 – 500	1 000 – 10 000	No information	< 0.01	No information	No information
Chemical energy storage						
Hydrogen fuel cells	1 700 – > 10 000	3 – > 20	6 000 – 20 000	< 4.63 – 6.02	16.94 – 32.08	0.37 – 0.65
Electrochemical energy storage						
Lead-acid	300 – > 600	200 – > 500	20 – 100	2 – > 5	77.57 – 82.56	0.06 – > 0.93
Advanced lead-acid	300 – > 600	450 – 1 000	No information	2 – > 5	> 76.3	0.05 – 0.44
NiCd	500 – > 1 500	800 – > 1 500	20 – 100	< 2 – 2.5	Inconclusive information	0.46 – 0.57
NiMH	600 – 1 800	960 – 1 800	No information	< 2 – 2.5	No information	No information
Metal-air	< 1 160 – 3 300	260 – 746	11.19 – 67.13	2.7 – 3.5	71.38 – 85.44	0.26 – 0.54
NaS	1 000 – > 3 000	300 – > 500	8 – 20	< 1.5 – 3	76.72 – 89.95	0.30 – 0.96
NaNiCl$_2$/ZEBRA	150 – > 1 500	500 – > 750	5 – 10	0.4 – 0.5	42.14 – 59.70	0.47
Lithium-ion	1 200 – 4 000	400 – 2 500	15 – 100	1 – 2.5	< 70 – 85.26	0.27 – > 0.83
ZnBr flow	600 – > 2 500	150 – 1 000	5 – 80	2.9 – 3	74.18 – 90.42	< 0.43 – 0.56
FeCr flow	1 800 – > 2 000	250 – > 1 000	No information	2 – 3	< 79.16 – 85.05	0.34 – > 0.70
VRFB flow	600 – > 2 500	250 – > 1 000	5 – 80	2 – 3	< 59.31 – 85.18	0.27 – > 0.69
PSB flow	600 – > 2 000	120 – > 1 000	5 – 80	2.3 – 3	No information	No information

Source: Author’s compilation

4.3.1 Capital costs

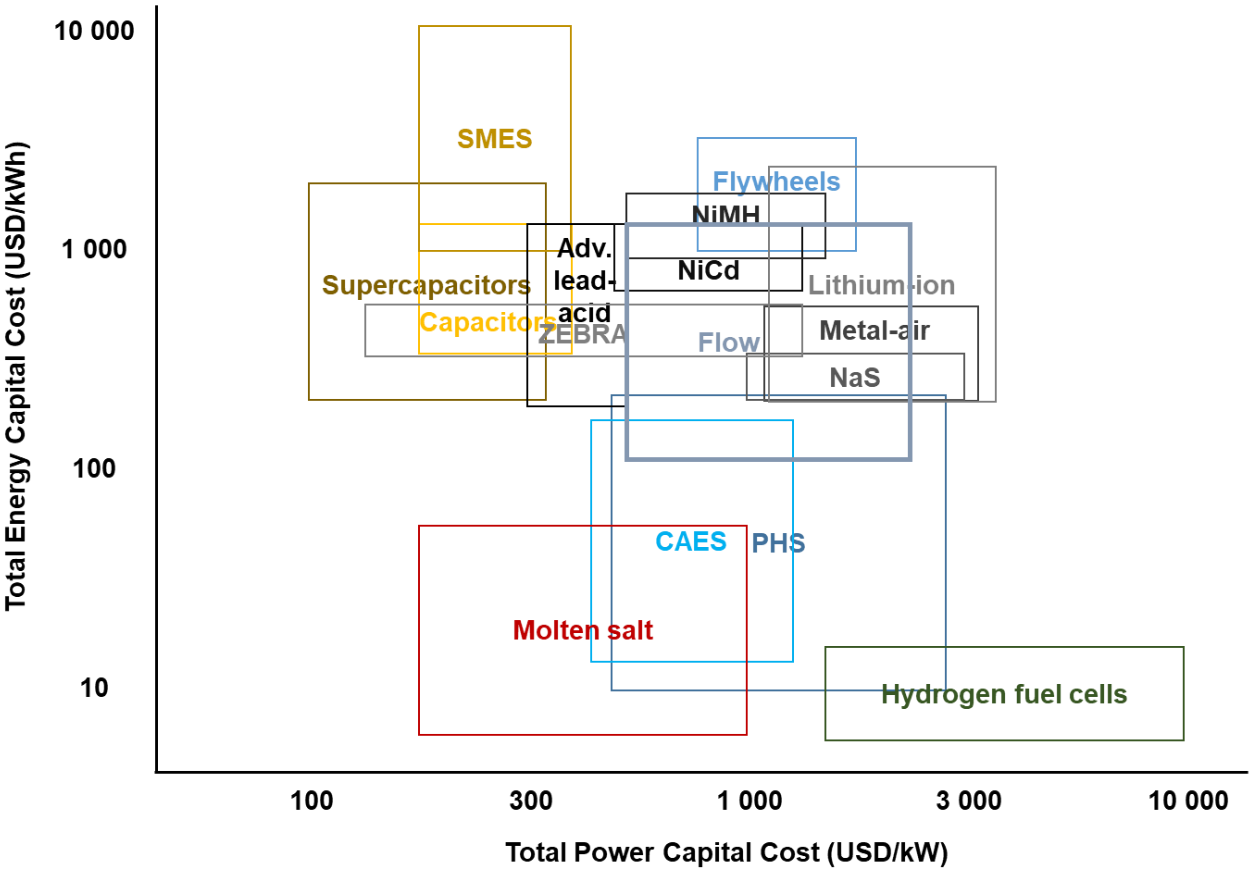
Capital costs refer to the initial investment expenses related to the installation of an entire energy storage system. In other words, capital costs would typically comprise all investment outlays related to the energy storage medium and balance of plant systems, including the power conversion system (PCS), energy storage management, monitoring and control systems and other engineering- and construction-related expenditures (Dufo-López *et al*., 2009:130-131; Dunn *et al.*, 2011:934; Zakeri *et al.*, 2015:572; Hameer *et al.*, 2015:1188; Bortolini *et al.*, 2015:1029; Hoff *et al.*, 2016:3; Aneke *et al.*, 2016:367; Lazard, 2016:5; Günter *et al.*, 2016:229). The main elements of an energy storage system, to which capital costs pertain, are described in section 2.3 of Chapter 2.

The capital costs of an energy storage system are normally expressed in currency, usually in United States dollars (USD), per kilowatt (kW) for electrical power capital cost, per kilowatt hour (kWh) for energy capital cost and per kWh per cycle for capital cost per energy charge-discharge cycle (Poonpun *et al.*, 2008:530; Ibrahim *et al.*, 2013:30; Akinyele *et al.*, 2014:85; Akhil *et al.*, 2015:31; Zakeri *et al.*, 2015:573-585; Aneke *et al.*, 2016:367; Lazard, 2016:21-22; Obi *et al.*, 2017:911; Berrada *et al.*, 2017:100; Amirante *et al.*, 2017:384). Electrical power capital cost (USD per kW) accounts for the initial upfront capital investment cost of an energy storage system per unit of power rating or maximum electrical energy that can be discharged. Energy capital cost (USD per kWh) accounts for the initial upfront capital investment cost of an energy storage system per unit of energy storage capacity or amount of energy that can be retained in the storage medium (Poonpun *et al.*, 2008:530; Castillo *et al.*, 2014:886; Lazard, 2016:1; World Energy Council, 2016a:47; Obi *et al.*, 2017:911).

The specification of capital costs into electrical power and energy capacity is necessary, since applications that energy storage systems are required to fulfil mainly depend on electrical power and/or energy storage capacity capabilities, which differ between diverse technologies, as explained in section 3.2 of Chapter 3 and section 4.2, and inform their overall economic viability. Generally, technologies with relatively low electrical power capital costs are more economical for power intensive applications, such as frequency and voltage regulation, while technologies with relatively low energy capital costs have better prospects for energy intensive applications, such as energy time shifting (Zakeri *et al.*, 2015:585; Aneke *et al.*, 2016:367; Obi *et al.*, 2017:911).

Figure 4.2 illustrates energy storage systems as a function of electrical power and energy capital cost to exhibit the interplay of the capital cost ranges summarised in Table 4.2.

Figure 4.2: Energy storage system capital cost per unit of electrical power rating and energy capacity



Source: Author's compilation

It can be seen from Table 4.2 and Figure 4.2 that capital costs do not only vary substantially between technologies and within their respective technological groupings, but also between the extent to which they can perform electrical power or energy intensive applications (Aneke *et al.*, 2016:372). For example, supercapacitors and superconducting magnetic energy storage (SMES) entail low capital costs per unit of electrical power, but their costs are high per unit of energy capacity. This is mainly due to the suitability of supercapacitors, flywheels and SMES for high-power use applications, rather than energy intensive applications, as a result of technical characteristics such as high power and low energy density, rapid response rates, very short discharge durations, high self-discharge rates and long cycle life as shown in Table 3.1 in section 3.2 of Chapter 3 (Akinyele *et al.*, 2014:85; Luo *et al.*, 2015:526-527; Aneke *et al.*, 2016:372).

Conversely, compressed air energy storage (CAES) and pump hydroelectric energy storage involve high initial investment cost per unit of power, but their costs are lower for applications requiring high energy capacity, long discharge duration and extended calendar life (Luo *et al.*, 2015:526; Aneke *et al.*, 2016:372). Hydrogen fuel cells also have low energy capital costs, but they have by far the highest capital cost per cycle of all technologies (Suberu *et al.*, 2014:511; Akinyele *et al.*, 2014:85). Electrochemical batteries have relatively high nominal power and energy capital costs, but these technologies have the technical capability to perform both power- and energy-intensive applications, as explained in sub-section 3.2.5 of Chapter 3 and section 4.2, and their overall costs should be evaluated and viewed in terms of their complete technical abilities (Zakeri *et al.*, 2015:585). This is explained in more detail in Chapter 6.

Capital cost per energy charge and discharge cycle (USD cents, ¢, per kWh per cycle) accounts for the capital cost per unit of energy storage capacity per cycle over the total cycle lifetime of an energy storage system that will be utilised to perform given applications (Ibrahim *et al.*, 2013:30; Kousksou *et al.*, 2014:73; Zakeri *et al.*, 2015:573; Berrada *et al.*, 2017:100). Capital cost per kWh per cycle shows the lowest investment option based on the number of cycles that an energy storage system can perform over its lifetime and is a useful indicator to assist in the process of identifying economically viable technologies for applications requiring frequent cycling capability (Ibrahim *et al.*, 2013:30; Kousksou *et al.*, 2014:73; Aneke *et al.*, 2016:367; Berrada *et al.*, 2017:100-101).

4.3.2 Operations, maintenance, replacement and disposal costs

Over and above capital costs, operations and maintenance costs also influence the economic feasibility of an energy storage system. These costs refer to all fixed and variable expenses required to continuously maintain the operational functionality and expected lifetime of such a system (Schoenung, 2011:7; Ibrahim *et al*., 2013:13-14; Hoff *et al.*, 2016:4; Günter *et al.*, 2016:229; Obi *et al.*, 2017:913). Fixed operations and maintenance costs do not change as electrical output changes and are a function of electrical power rating, while variable costs change as energy discharge capacity changes and are a function of energy capacity (Obi *et al.*, 2017:913-918).

Operations and maintenance costs include factors such as roundtrip energy efficiency losses and the associated electrical energy charging costs, scheduled and unplanned repairs, monitoring, management and labour costs and electricity for lights, temperature control and other equipment (Ibrahim *et al*., 2013:13-14; Günter *et al.*, 2016:229; Hoff *et al.*, 2016:4; Aneke *et al.*, 2016:373; Obi *et al.*, 2017:913). Roundtrip efficiency can have a large influence on system operating costs, since more electricity has to be purchased during charging than what can be sold during discharging as a result of energy losses, and this influence becomes more significant with lower efficiency rates (Pawel, 2014:70-72; Mayr *et al.*, 2016; Obi *et al.*, 2017:913). Sub-section 6.5.3 of Chapter 6 provides further detail on operations and maintenance costs for select energy storage systems.

A further important factor influencing the economic viability of an energy storage system is replacement costs. These costs refer to all expenses required for the periodic scheduled and unplanned replacement of energy storage system components, including electrochemical cells, modules and balance of plant features to maintain the capacity, operational functionality and expected lifetime of an energy storage system (Ibrahim *et al*., 2013:13-14; Günter *et al.*, 2016:229).

Replacement rates and costs are a function of the calendar and cycle life, cycling frequency and depth of discharge (DoD) of electrical energy storage systems and electrochemical batteries in particular. In other words, the more often and deeper a battery energy storage system is charged and discharged, the faster the maximum cycle or calendar life will be reached, whichever comes first, due to accelerated degradation and would warrant increased replacement of components, such as battery cells (Poonpun *et al.*, 2008:533; Dufo-López *et al*., 2009:130-131; Schoenung, 2011:7; Battke *et al*., 2013:246-248; Bortolini *et al.*, 2015:1029; Lund *et al.*, 2015:795; Mayr *et al.*, 2016; Berrada *et al.*, 2017:101; Obi *et al.*, 2017:913). Replacement costs should also be viewed in conjunction with the time to replacement, since some technologies might have relatively low replacement costs, but higher replacement rates, which might place them at a comparative disadvantage relative to technologies that require less regular, but higher cost, replacements (Zakeri *et al.*, 2015:584). Sub-section 6.5.2 of Chapter 6 provides further information on replacement rates and costs for select energy storage systems.

Disposal costs refer to expenses related to the recycling and discarding of energy storage system components (Zakeri *et al.*, 2015:573; Günter *et al.*, 2016:229). Quantitative estimates of these costs are rare, difficult to obtain and often neglected from energy storage expense considerations and calculations. These costs could further potentially be offset by revenues from selling energy storage system components after the useful life has lapsed (Schoenung, 2011:11; Battke *et al*., 2013:245-248; Zakeri *et al.*, 2015:573).

4.3.3 Further cost considerations for improved economic evaluation

It is challenging to compare the costs of numerous and diverse energy storage technologies with one another. This is mainly because the costs associated with such technologies do not only depend on the relevant technology prices or investment values, but also on the performance characteristics per technology, how they optimise into different use applications and their respective technical advantages and disadvantages (Battke *et al*., 2013:241; Kaun *et al.*, 2013:9; Pawel, 2014:72; Zakeri *et al.*, 2015:573; Lazard, 2015:12; Jülch *et al*., 2015:26; Battke *et al.*, 2015:340; Mandelli *et al.*, 2016:291; Kondziella *et al.*, 2016:11). The specific utility-scale energy storage technology characteristics, advantages and disadvantages are described in section 3.2 of Chapter 3, while the applications into which they can optimise are explained in section 4.2.

These issues make it difficult to evaluate the economics of energy storage and ensure that the best technology alternative is chosen for specific applications (Aneke *et al.*, 2016:372-375; Jülch, 2016:1594-1596). Simply comparing the quoted USD per kilowatt (kW) or kilowatt hour (kWh) across different technologies is also inaccurate and misleading because it does not fully and harmoniously account for differences in crucial parameters such as cycle life, depth of discharge (DoD), accepted degradation in capacity, size of storage, discharge duration and roundtrip energy storage efficiency (Pawel, 2014:69-73; Zakeri *et al.*, 2015:573; Battke *et al.*, 2015:340; Jülch *et al*., 2015:20; Lazard, 2015:8-29; Obi *et al.*, 2017:910-911). To overcome this techno-comparative issue, it is necessary to assess the cost of energy storage systems on an encompassing basis by estimating the levelised cost of energy storage (LCOS) technologies (Battke *et al*., 2013:242; Pawel, 2014:68-76; Battke *et al.*, 2015:340-341; Zakeri *et al.*, 2015:573; Jülch *et al*., 2015:18-26; Hoff *et al.*, 2016:1-22; Jülch, 2016:1594-1595; Lai *et al.*, 2017:192-194; Obi *et al.*, 2017:910-911).

The LCOS is a metric that expresses the single constant, or levelised, price per kWh over the applicable lifetime utilisation of an energy storage system in terms of present value. The LCOS includes all cost and performance parameters associated with energy storage systems and enables a fair and meaningful comparison of different technologies according to the applications they are required to perform, regardless of technological specifications or chemical composition (Battke *et al*., 2013:242-247; Pawel, 2014:68-77; Battke *et al.*, 2015:340-341; Jülch *et al*., 2015:19; Zakeri *et al.*, 2015:573-588; Lazard, 2015:20-29; Hoff *et al.*, 2016:2; World Energy Council, 2016a:4; Lai *et al.*, 2017:194; Obi *et al.*, 2017:910). While it is important to focus on reducing the capital cost of energy storage technologies, the most important cost metric to be minimised for improved economic evaluation is the LCOS (Lai *et al.*, 2017:194). The LCOS is the empirical focus of this dissertation and the methodological detail is described in Chapter 6.

Since levelised cost estimations depend on different assumptions and can have dissimilar input parameters, LCOS values should only be compared in instances where the exact same methodology was applied (Branker *et al.*, 2011:4471; Akhil *et al.*, 2015:32; Mandelli *et al.*, 2016:291; Obi *et al.*, 2017:910-917). The levelised values in Table 4.2, noted as sundry levelised cost estimates, should therefore be regarded as only being indicative, since they were obtained from various publications with wide ranging assumptions, input parameters and formulae. Section 5.2 of Chapter 5 has more information on differing levelised cost estimates in the literature for energy storage technologies.

While cost predictions differ widely and some utility-scale energy storage systems are still in their developmental or early commercialisation phases, rapid advancements are being made and substantial further progress in technological capability and cost reductions can be expected within the next five to eight years, especially for electrochemical energy storage technologies (Jülch *et al*., 2015:26; Kyriakopoulos *et al.*, 2016:1063; Günter *et al.*, 2016:234; Dehdashti, 2016:1-3; Lazard, 2016:19-21; Malhotra *et al.*, 2016:706; Jülch, 2016:1594; Obi *et al.*, 2017:909). This has mainly been, and is being, driven by concurrent factors such as rising demand for electricity, increased deployment for renewable energy system integration, economies of scale effects, growing government and donor support measures, greater research and development funding and efforts, increased development and uptake of electric vehicles, breakthroughs in material sciences, manufacturing advancements and capacity expansion, supply chain integration, supplier competition and technological innovation and progress (Hammond *et al.*, 2015:568; Lazard, 2016:19-21; Hill, 2016:1; Dehdashti, 2016:3; Mundada *et al.*, 2016:693; World Energy Council, 2016a:6-13; Jülch, 2016:1602; Ferroukhi *et al.*, 2017:80; Lai *et al.*, 2017:194; Obi *et al.*, 2017:909-914; Lazkano *et al.*, 2017:2). Energy storage costs are further likely to decline at faster rates than anticipated, which has also been the experience with solar photovoltaic (PV) and wind technologies, including in South Africa (Nykvist & Nilsson, 2015:329; World Energy Council, 2016a:26; Council for Scientific and Industrial Research, 2017b:40-43; Astarloa *et al.*, 2017:6-9).

The decreasing costs of energy storage technologies together with the increased uptake and declining costs of renewable energy technologies suggest that it is inevitable for a point in time to be reached in the near future when utility-scale energy storage systems coupled with intermittent renewable energy electrical production plants will be viable economic alternatives to traditional electricity generators (Lund *et al.*, 2015:799; Gielen *et al.*, 2016:29-45; Dehdashti, 2016:3; Zou *et al.*, 2017:66; Lai *et al.*, 2017:193-194; Obi *et al.*, 2017:908-909). Section 6.3 and sub-sections 6.5.1 and 6.5.2 of Chapter 6 provide further information on the future cost trajectories for select energy storage technologies.

4.4 SUMMARY AND CONCLUSION

This chapter provided an overview of different utility-scale applications that can be performed by energy storage systems, clarified the lifetime cost contributors of such systems and considered further cost factors that have to be taken into account for improved economic evaluation. It further contextualised the information conveyed in the preceding chapters and, combined with the technical characteristics described in Chapter 3, informs the technology selection, cost variables, inputs, assumptions and related estimates used for the economic feasibility assessment conducted in Chapters 6 and 7.

Section 4.1 introduced the content to Chapter 4. Section 4.2 explained ten interrelated value applications that can be executed by various utility-scale energy storage system technological configurations. The utility-scale applications were identified as seasonal energy storage, energy time shifting and arbitrage, load levelling and peak shaving, load following, renewables integration, frequency regulation, voltage regulation, operating reserves, black start capability and transmission and distribution grid congestion relief and/or investment upgrade deferral. No particular technology is superior in fulfilling all applications specified and each energy storage system should be evaluated on a case-by-case basis. The ability of energy storage systems to perform more than one application sequentially and/or simultaneously further significantly enhances the value of energy storage relative to cost.

Section 4.3 summarised the ranges of important cost indicators and described the variables that jointly constitute the total nominal lifetime cost of energy storage systems. These cost variables include capital, operations and maintenance, replacement and disposal costs. Energy storage system costs are likely to continue declining sharply, especially for electrochemical battery technologies. It is challenging to compare the costs of different energy storage systems with one another as such systems are characterised by different technical performance characteristics and application suitability. To appropriately compare and evaluate the economic feasibility of energy storage systems, the levelised cost of energy storage (LCOS) can be estimated. The LCOS is the empirical focus of this study and will be examined throughout the remainder of this dissertation, especially in the methodological Chapter 6.

The information supplied in Chapters 1 to 4 enabled the attainment of the specific objective set for this study that requires an overview of the concept, characteristics, technical capability, value applications and reflective cost considerations associated with energy storage technologies. This is necessary to contribute to addressing the research problem specified in section 1.4 of Chapter 1 and perform the economic feasibility assessment in the empirical analysis of Chapters 6 and 7. It further conveyed the necessary background information for a literature review of previous investigations into the economic feasibility of utility-scale energy storage technologies and how such technologies relate to economic theory, which is the focus of Chapter 5.

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CHAPTER 5:

LITERATURE REVIEW ON THE ECONOMIC FEASIBILITY AND THEORETICAL RELEVANCE OF ENERGY STORAGE TECHNOLOGIES

5.1 INTRODUCTION

Chapter 5 provides a literature review of studies that have considered the economic feasibility of utility-scale energy storage technologies and contextualises the relevance of such technologies in light of economic theory. The content conveyed throughout the preceding Chapters 1 to 4 contributed sufficient background information to review and interpret the main findings and contributions from literature on the economic feasibility of energy storage systems. The information outlined thus far, together with the literature review supplied in the next section, further makes it possible to present energy storage systems within the framework of some related economic theories.

In that regard, the goal of this chapter is to contribute to the specific objectives set for the study in Chapter 1 by conducting a literature review of existing research into the economic feasibility of energy storage technologies and describing how such technologies relate to economic theory within the context of this dissertation. The literature review on the economic feasibility of energy storage systems verifies the degree to which the competitive viability of such systems has been explored and informs the research and analysis requirements for the empirical assessment in Chapters 6 and 7. The description of energy storage technologies within broader economic theory contributes a unique perspective by identifying, clarifying and adapting some economic hypotheses that can accommodate for energy storage systems in a manner that is also aligned to the general research objective and empirical analysis for this study.

This chapter is structured according to four sections. The next section (5.2) reviews literature that has considered the economic feasibility of utility-scale energy storage systems and outlines levelised cost estimates by relevant application for the technologies described in Chapter 3. Section 5.3 explains the applicability of energy storage technologies to a theoretical economic foundation by providing a hypothetical association and representation of such technologies in relation to the empirical analysis in the forthcoming Chapters 6 and 7. Section 5.4 summarises and concludes Chapter 5.

5.2 ECONOMIC FEASIBILITY OF ENERGY STORAGE TECHNOLOGIES

A general review of existing literature that has considered the economic feasibility of utility-scale energy storage technologies is provided in this section. This review mainly draws on academic sources, but also includes findings from selected commissioned and independent sources. While various studies have focused on the technical features of energy storage technologies, literature on the economic feasibility of such technologies is more limited (He *et al.*, 2011:1575; Battke *et al*., 2013:242; Zhang, 2013:109; Pawel, 2014:68; Akinyele *et al.*, 2014:88; Infield *et al.*, 2014:6-27; Zakeri *et al.*, 2015:570-573; Tapia-Ahumada *et al.*, 2015:243).

Pollet *et al.* (2015:16696-16697) note that the increased uptake of renewable energy and energy storage technologies in South Africa is likely to contribute to more robust domestic energy security, electricity reliability and economic growth. While such initiatives would necessitate short-run costs, it will entail important long-run benefits, such as improved electricity availability, lower fuel expenditure, reduced greenhouse gas emissions, improved manufacturing productivity and business confidence in the domestic economy. For energy storage technologies to contribute to environmentally sustainable economic development, it first has to be proven to be an economically feasible solution for the improved supply of electricity in order to encourage more widespread implementation (Battke *et al*., 2013:241; Kondziella *et al.*, 2016:20).

An economic feasibility assessment involves determining the degree to which the advantages or value derived from a proposed investment outweigh its own associated costs or the costs of prevailing alternatives (Whipple, 1962:219-220; Young, 1970:376-377; Sullivan *et al.*, 2015:187-467). This is supported by a narrower view taken by Kondziella *et al.* (2016:12-17), who suggest that economic feasibility assessments entail an investigation into overall technology costs, including fuel costs, and determining the extent to which technologies can compete with alternatives.

According to Sørensen (2011:540), the economic feasibility of energy storage is determined by all fixed and variable costs associated with different technologies and converter types, including the availability and cost of fuel. Berrada *et al.* (2017:94-104) point out that the economic feasibility of energy storage systems depends on the willingness of economic participants to invest in such systems. This, in turn, is affected by factors such as project maturity, technology and external risks, costs and prospective returns. Berrada *et al.* (2017:103) further show that the economic viability of energy storage systems depends on how different technologies compare with one another in terms of their associated strengths, weaknesses, opportunities and threats.

The importance of assessing the economic implications of electrical energy storage technologies is increasingly being recognised and attempts have been made to investigate the competitive viability of such technologies. These attempts have not been sufficient in capturing the full economic value, in terms of cost reflectivity, of energy storage technologies in isolation and when such technologies are combined with intermittent renewable energy electrical generation options. This is especially the case in estimating the extent to which energy storage systems can compete with one another and with alternative electrical generation options (Infield *et al.*, 2014:7; Akinyele *et al.*, 2014:88; Hameer *et al.*, 2015:1187-1191; Lai *et al.*, 2017:191-200; Obi *et al*., 2017:918).

The lack of sufficient and reliable analyses on the performance and economic feasibility of electrical energy storage technologies is hampering the implementation and commercialisation of such technologies at the utility scale. The inadequate body of research is also restraining the establishment of adequate strategies, business models, regulations and ownership structures (Battke *et al*., 2013:241; Zakeri *et al.*, 2015:570; Gallo *et al*., 2016:800-819; Kondziella *et al.*, 2016:20). Amirante *et al.* (2017:385) are further of the view that insufficient research on energy storage technologies is restraining the development of innovative future electrical energy systems, especially by means of renewable energy sources. In that regard, this dissertation further intends to broaden the knowledge base to inform the implementation of utility-scale energy storage systems.

Economic feasibility assessments of energy storage systems, which focus on the competitiveness of different technologies, should be addressed through lifecycle or levelised cost per kilowatt hour (kWh) analyses (Dufo-López *et al*., 2009:129-130; Battke *et al*., 2013:240-249; Zakeri *et al.*, 2015:570-573; Jülch, 2016:1595-1605; Obi *et al.*, 2017:908-918; Lai *et al*., 2017:191-202). Lifecycle cost analyses are important for the evaluation and comparison of different energy storage technologies as it accommodates for all fixed and variable expenses over the lifetime of an energy storage system and expresses them in present value terms (Battke *et al*., 2013:241-242; Pawel, 2014:68-77; Zakeri *et al.*, 2015:573; Hoff *et al.*, 2016:2; Obi *et al.*, 2017:910). Lifecycle cost comparisons should further be based on a common use application and suitable techno-economic specifications of the relevant technologies under consideration (Battke *et al*., 2013:242; Jülch *et al*., 2015:26). Zakeri *et al.* (2015:577) also state that cost estimations of electrical energy storage systems involve both analysis and judgement.

Existing literature on energy storage costs is dispersed and inconsistent among sources with wide uncertainties in cost estimates, especially for batteries. The majority of literature on the costs of energy storage technologies also tends to focus on the cost of capital, whereas research into the levelised cost of energy storage (LCOS) has been insufficient (Battke *et al*., 2013:241-249; Zakeri *et al.*, 2015:573-590 and Obi *et al.*, 2017:918). A significant shortcoming of previous research into levelised cost analyses is the failure to adequately document the uncertainties and assumptions assigned to input parameters, data and cost estimates (Battke *et al*., 2013:240-243; Zakeri *et al.*, 2015:585). Lai *et al.* (2017:192) recognise previous attempts that have estimated the levelised cost of renewable energy generation options and energy storage technologies in isolation, but state that levelised cost analyses for solar PV plants coupled with energy storage systems have been deficient. Chapter 6 clarifies the methodological detail for the LCOS for energy storage systems in isolation and when such systems are combined with solar PV plants.

Table 5.1 summarises sundry nominal levelised cost estimates by relevant application for the utility-scale energy storage systems outlined in Chapter 3 as obtained during the literature review (compiled from Poonpun *et al*., 2008:532-533; Battke *et al*., 2013:246-248; Pawel, 2014:72; Zakeri *et al*., 2015:588-590; Lazard, 2015:20-24; Lazard, 2016:19-34; Jülch, 2016:1594; Parrado *et al*., 2016:509-512; Obi *et al*., 2017:917). All applicable currency values, for example euros (EUR), have been converted to United States dollars (USD) in the year of publication (IHS Global Insight, 2017).

The sundry levelised cost estimates in Table 5.1 should be viewed and compared with caution as each author used different assumptions, input parameters and formulae. Levelised cost values should only be compared when the same methodology is used to derive results for each technology under the associated use applications (Branker *et al.*, 2011:4471; Akhil *et al.*, 2015:32; Mandelli *et al.*, 2016:291; Obi *et al.*, 2017:910-917). The levelised costs summarised in Table 5.1 are elaborated on in the paragraphs that follow and could nonetheless be informative when viewed against one another, as well as against the LCOS estimates derived in the empirical Chapter 7 of this dissertation.

Table 5.1: Literature review of nominal sundry levelised cost estimates for energy storage technologies

Energy storage technology	Literature reference	Levelised cost estimate (USD/kWh)	Energy storage use application
Mechanical energy storage			
PHS	Obi *et al*. (2017:917)	0.05	Energy time shifting and arbitrage over 20 years
	Jülch (2016:1596-1603)	1.55	Seasonal energy storage: 100 MW, 700 hours discharge duration, 1 cycle per year
		0.12	Short-Term energy storage: 100 MW, 4 hours discharge duration, 1 daily cycle for 365 days per year
	World Energy Council (2016a:22-25)	0.08 – 0.16	Stand-Alone system with technical life fully utilised
		0.07 – 0.12	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		0.08 – 0.17	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Lazard (2016:31)	0.15 – 0.20	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
	Lazard (2015:20)	0.19 – 0.27	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Zakeri *et al*. (2015:588-590)	0.16	Bulk energy time shifting: > 10 MW, 8 hours discharge duration, 250 cycles per year over 20 years
	Poonpun *et al*. (2008:532-533)	0.05	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 250 days a year
		0.12	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 100 days a year
Diabatic CAES	Obi *et al*. (2017:917)	0.06	Energy time shifting and arbitrage over 20 years
	Jülch (2016:1596-1603)	2.66	Seasonal energy storage: 100 MW, 700 hours discharge duration, 1 cycle per year
		0.14	Short-Term energy storage: 100 MW, 4 hours discharge duration, 1 daily cycle for 365 days per year
	World Energy Council (2016a:22-25)	0.11 – 0.19	Stand-Alone system with technical life fully utilised
		0.09 – 0.19	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		0.20 – 0.37	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Lazard (2016:21)	0.12 – 0.14	Transmission: 100 MW, 8 hours discharge duration,1 daily cycle for 350 days a year over 20 years
	Lazard (2015:20)	0.19	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Zakeri *et al.* (2015:588-590)	0.18	Bulk energy time shifting: > 10 MW, 8 hours discharge duration, 250 cycles per year over 20 years
Adiabatic CAES	–		
Flywheels	World Energy Council (2016a:22-25)	0.08 – 0.12	Stand-Alone system with technical life fully utilised
		1.46 – 2.37	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		2.92 – 4.65	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Lazard (2016:19-32)	0.34 – 0.56	Peaker Replacement: 100 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.60 – 1.25	Frequency regulation: 10 MW, 0.5 hours discharge duration, 4.8 daily cycles for 350 days a year over 20 years
		0.40 – 0.65	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Lazard (2015:22)	0.28 – 0.99	Frequency regulation: 10 MW, 0.5 hours discharge duration, 4.8 daily cycles for 350 days a year over 20 years
	Zakeri *et al*. (2015:588-590)	0.28	Frequency regulation
	Poonpun *et al*. (2008:532-533)	0.21	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 250 days a year
		0.49	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 100 days a year
Thermal energy storage			
Molten salt	Parrado *et al*. (2016:509-512)	0.12 – 0.14	–
	World Energy Council (2016a:22-25)	0.45 – 0.92	Stand-Alone system with technical life fully utilised
		0.41 – 0.84	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		0.20 – 0.41	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year

Electrical energy storage			
Capacitors	–		
Supercapacitors	World Energy Council (2016a:22-25)	0.23 – 0.45	Stand-Alone system with technical life fully utilised
		4.52 – 9.04	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		9.04 – 18.21	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
SMES	–		
Chemical energy storage			
Hydrogen fuel cells	World Energy Council (2016a:22-25)	0.41 – 0.54	Stand-Alone system with technical life fully utilised
		0.37 – 0.50	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		0.19 – 0.25	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Zakeri *et al*. (2015:588-590)	0.64	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
Electrochemical energy storage			
Lead-acid	Obi *et al*. (2017:917)	0.06	Energy time shifting and arbitrage over 20 years
	Jülch (2016:1596-1603)	0.23	Short-Term energy storage: 100 MW, 4 hours discharge duration, 1 daily cycle for 365 days per year
	World Energy Council (2016a:22-25)	0.15 – 0.53	Stand-Alone system with technical life fully utilised
		0.39 – 0.53	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		0.78 – 1.06	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Lazard (2016:21)	0.43 – 0.93	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Lazard (2015:20-24)	0.46 – 1.43	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.42 – 1.25	Peaker replacement: 25 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.52 – 1.69	Distribution services: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.40 – 1.07	PV integration: 2 MW, 2 hours discharge duration, 1.25 daily cycle for 350 days a year over 20 years
	Pawel (2014:72)	4.08	1 MW, 1 daily cycle for 365 days a year over 25 years
	Battke *et al*. (2013:246-248)	0.32	Energy time shifting: 100 MW, 8 hours discharge duration, 1 daily cycle
		0.37	Transmission and distribution investment deferral: 10 MW, 5 hours discharge duration, 0.68 daily cycle
		2.79	Frequency regulation
		1.55	Voltage regulation
	Poonpun *et al*. (2008:532-533)	0.28	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 250 days a year
		0.52	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 100 days a year
		0.20	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 250 days a year
		0.30	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 100 days a year
Advanced lead-acid	Zakeri *et al*. (2015:588-590)	0.43	Bulk energy time shifting: > 10 MW, 8 hours discharge duration, 250 cycles per year over 20 years
		0.39	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
		0.34	Frequency regulation
NiCd	Zakeri *et al*. (2015:588-590)	0.56	Bulk energy time shifting: > 10 MW, 8 hours discharge duration, 250 cycles per year over 20 years
		0.45	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
NiMH	–		
Metal-air	Lazard (2016:20-34)	0.26 – 0.44	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.28 – 0.46	Peaker Replacement: 100 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.40 – 0.54	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Lazard (2015:20-24)	0.23 – 0.38	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.22 – 0.35	Peaker replacement: 25 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.29 – 0.43	Distribution services: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years

		0.25 – 0.35	PV integration: 2 MW, 2 hours discharge duration, 1.25 daily cycle for 350 days a year over 20 years
NaS	World Energy Council (2016a:22-25)	0.31 – 0.41	Stand-Alone system with technical life fully utilised
		0.32 – 0.43	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		0.62 – 0.82	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Lazard (2016:20-34)	0.30 – 0.78	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.32 – 0.80	Peaker Replacement: 100 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.39 – 0.96	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Lazard (2015:20-24)	0.40 – 1.08	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.37 – 0.95	Peaker replacement: 25 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.43 – 1.13	Distribution services: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.38 – 0.96	PV integration: 2 MW, 2 hours discharge duration, 1.25 daily cycle for 350 days a year over 20 years
	Zakeri *et al*. (2015:588-590)	0.33	Bulk energy time shifting: > 10 MW, 8 hours discharge duration, 250 cycles per year over 20 years
		0.33	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
	Battke *et al*. (2013:246-248)	0.24	Energy time shifting: 100 MW, 8 hours discharge duration, 1 daily cycle
		0.36	Transmission and distribution investment deferral: 10 MW, 5 hours discharge duration, 0.68 daily cycle
		1.08	Frequency regulation
		1.70	Voltage regulation
	Poonpun *et al.* (2008:532-533)	0.18	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 250 days a year
		0.43	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 100 days a year
		0.29	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 250 days a year
		0.56	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 100 days a year
$NaNiCl_2$/ZEBRA	Zakeri *et al*. (2015:588-590)	0.47	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
Lithium-ion	Jülch (2016:1596-1603)	0.33	Short-Term energy storage: 100 MW, 4 hours discharge duration, 1 daily cycle for 365 days per year
	World Energy Council (2016a:22-25)	0.20 – 0.93	Stand-Alone system with technical life fully utilised
		0.61 – 0.93	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		1.22 – 1.85	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Lazard (2016:20-34)	0.27 – 0.56	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.29 – 0.58	Peaker Replacement: 100 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.19 – 0.28	Frequency regulation: 10 MW, 0.5 hours discharge duration, 4.8 daily cycles for 350 days a year over 20 years
		0.35 – 0.66	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Lazard (2015:20-24)	0.35 – 0.74	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.32 – 0.66	Peaker replacement: 25 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.21 – 0.28	Frequency regulation: 10 MW, 0.5 hours discharge duration, 4.8 daily cycles for 350 days a year over 20 years
		0.40 – 0.79	Distribution services: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.36 – 0.69	PV integration: 2 MW, 2 hours discharge duration, 1.25 daily cycle for 350 days a year over 20 years
	Zakeri *et al*. (2015:588-590)	0.83	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
		0.58	Frequency regulation
	Pawel (2014:72)	2.23	1 MW, 1 daily cycle for 365 days a year over 25 years
	Battke *et al*. (2013:246-248)	0.61	Energy time shifting: 100 MW, 8 hours discharge duration, 1 daily cycle
		0.89	Transmission and distribution investment deferral: 10 MW, 5 hours discharge duration, 0.68 daily cycle
		1.06	Frequency regulation
		1.30	Voltage regulation
ZnBr flow	Lazard (2016:19-34)	0.43 – 0.55	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 350 days a year over 20 years

		0.45 – 0.56	Peaker Replacement: 100 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.52 – 0.56	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Lazard (2015:20-24)	0.29 – 0.89	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.25 – 0.93	Peaker replacement: 25 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.29 – 0.92	Distribution services: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.37 – 0.95	PV integration: 2 MW, 2 hours discharge duration, 1.25 daily cycle for 350 days a year over 20 years
	Zakeri *et al*. (2015:588-590)	0.29	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
	Poonpun *et al.* (2008:532-533)	0.07	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 250 days a year
		0.21	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 100 days a year
FeCr flow	Lazard (2016:19-34)	0.34 – 0.63	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.45 – 0.70	Peaker Replacement: 100 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.52 – 0.83	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Zakeri *et al*. (2015:588-590)	0.28	Bulk energy time shifting: > 10 MW, 8 hours discharge duration, 250 cycles per year over 20 years
		0.34	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
VRFB flow	Jülch (2016:1596-1603)	0.42	Short-Term energy storage: 100 MW, 4 hours discharge duration, 1 daily cycle for 365 days per year
	World Energy Council (2016a:22-25)	0.16 – 0.54	Stand-Alone system with technical life fully utilised
		0.37 – 0.52	PV integration: 6 hours discharge duration, 1 daily cycle, 365 days a year
		0.74 – 1.02	Wind integration: 24 hours discharge duration, 1 daily cycle, 183 days a year
	Lazard (2016:19-34)	0.31 – 0.69	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.44 – 0.66	Peaker Replacement: 100 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.52 – 0.77	Distribution substation: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
	Lazard (2015:20-24)	0.29 – 0.89	Transmission: 100 MW, 8 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.25 – 0.93	Peaker replacement: 25 MW, 4 hours discharge duration, 1 daily cycle for 350 days a year over 20 years
		0.29 – 0.92	Distribution services: 4 MW, 4 hours discharge duration, 1 daily cycle for 300 days a year over 20 years
		0.37 – 0.95	PV integration: 2 MW, 2 hours discharge duration, 1.25 daily cycle for 350 days a year over 20 years
	Zakeri *et al*. (2015:588-590)	0.47	Bulk energy time shifting: > 10 MW, 8 hours discharge duration, 250 cycles per year over 20 years
		0.46	Transmission and distribution: 1-10 MW, 2 hours discharge duration, 400 cycles a year over 15 years
	Pawel (2014:72)	0.45	1 MW, 1 daily cycle for 365 days a year over 25 years
	Battke *et al*. (2013:246-248)	0.35	Energy time shifting: 100 MW, 8 hours discharge duration, 1 daily cycle
		0.52	Transmission and distribution investment deferral: 10 MW, 5 hours discharge duration, 0.68 daily cycle
		1.47	Frequency regulation
		2.02	Voltage regulation
	Poonpun *et al*. (2008:532-533)	0.27	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 250 days a year
		0.67	Generation: 10 MW, 8 hours discharge duration, 1 daily cycle for 100 days a year
		0.21	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 250 days a year
		0.55	Transmission and distribution: 2.5 MW, 4 hours discharge duration, 2 daily cycles for 100 days a year
PSB flow	–		

Source: Author's compilation

While more technical in nature, Bortolini *et al.* (2015:1024-1034) investigated the environmental and economic feasibility of a hybrid system that includes the integration of a solar photovoltaic (PV) plant, lead-acid battery energy storage and diesel generator. They recognise that adding battery storage to a solar PV plant could enable cost comparisons with alternative electrical generation options, which is a point also made by Pawel (2014:72-73) and Mundada *et al.* (2016:692-693).

Similarly, Mundada *et al.* (2016:692-697) estimated the levelised cost of electricity (LCOE) for a hybrid solar PV, lead-acid battery and combined heat and power system in an attempt to quantify the economic viability of such a system. Lai *et al*. (2017:195) note that the LCOE for the hybrid system used by Mundada *et al.* (2016:692-701) does not account for the total energy dissipated due to efficiency losses in the battery. Notwithstanding, Mundada *et al.* (2016:697) concluded that a hybrid solar PV, battery and combined heat and power plant could provide an economic incentive for customers to move off-grid and improve their electrical self-sustainability.

Bortolini *et al.* (2015:1024-1034) further found that such hybrid systems offer superior economic, technical and environmental benefits in comparison to traditional diesel generators, even at low fuel cost and moderate irradiation levels. This has also been noted by Jülch *et al*. (2015:22-26). Bortolini *et al.* (2015:1024-1034) show that a solar PV, lead-acid battery and diesel generator hybrid system could not only improve the reliability and autonomy of an electricity system, but it also has the potential to reduce the LCOE by 8% and carbon footprint of energy by more than 20% in comparison to the use of a traditional diesel fuelled generator.

It can also be inferred from Bortolini *et al.* (2015:1024-1025) that the overall costs for solar PV plants with energy storage capability are reduced the most in circumstances with higher irradiation levels as a result of improved electrical energy output from solar-based technologies, which is directly fed into the grid and used to charge the energy storage system. This is a favourable feature for South Africa, where irradiation levels are among the highest in the world, especially in the Northern Cape Province, where low-productivity land is also abundant (Grobbelaar *et al.*, 2014:479; Walwyn *et al.*, 2015:391-393; Van Ravenswaay *et al.*, 2015:1838-1843; Kenny, 2015:19; Pfenninger *et al.*, 2015:306; Busse *et al.*, 2016:52-53; Parrado *et al.*, 2016:510; Minnaar, 2016:1140; Nakumuryango *et al.*, 2016:1000; Pan *et al.*, 2017:379). The positive impact of high irradiation locations on improved electrical energy output from solar-based generation options and lower LCOE values is also emphasised by Busse *et al.* (2016:52-53), Gielen *et al.* (2016:14) and Lai *et al.* (2017:193-194). Battke *et al*. (2013:247-249) further noted that technologies and applications with high energy output levels are likely to have lower LCOS estimates compared to lesser energy output applications and technologies. Additional information in this regard is provided in Chapter 6.

Poonpun *et al.* (2008:530-531), Pawel (2014:68-77), Zakeri *et al.* (2015:569-596), Lai *et al.* (2017:195-197) and Obi *et al.* (2017:908-918) provided rather distinct mathematical frameworks to estimate the LCOS in order to compare the cost competitiveness of different storage technologies with one another. Pawel (2014:68-77) and Lai *et al.* (2017:191-200) also estimated the LCOE for a solar PV and energy storage combined power plant, which could be used to allow for comparisons with other forms of electrical energy generation and determine the potential economic feasibility of energy storage.

Pawel (2014:68-77) and Lai *et al.* (2017:191-200) did not, however, conduct an economic viability assessment based on how energy storage technologies, coupled with solar PV plants, could potentially compete with alternative generation options with similar electrical output dispatch characteristics. It has, nonetheless, been noted that such assessments would be valuable for further research and contribute to discussions on substituting conventional generation options with innovative technological solutions (Pawel, 2014:76; Zakeri *et al.*, 2015:588). Pawel (2014:73) also emphasises that net present value (NPV) calculations are superior in the assessment of the economic feasibility and cost competitiveness of different technologies, which is also recognised by Dufo-López *et al*. (2009:129-130), Dekker, Nthontho, Chowdhury and Chowdhury (2012:2360), Zakeri *et al.* (2015:573), Mandelli *et al.* (2016:293) and Berrada *et al.* (2017:97).

Pawel (2014:68-72) stresses the necessity to include additional parameters beyond those used for conventional LCOE calculations or previously used in attempts to estimate the lifetime cost of energy storage technologies. It is found that roundtrip efficiency may play a less dominant role than might be believed, while the charge-discharge rate is an important factor in energy storage cost calculations. Roundtrip efficiency will have a larger impact on the cost of energy storage when electricity prices are high due to raising charging costs, technology efficiency is below 50% and/or large volumes of storage capacity is required (Zhang, 2013:42; Pawel, 2014:68-75; Zakeri *et al.*, 2015:590).

The methodology followed by Pawel (2014:72) provides levelised cost estimates for energy storage alone of EUR 0.34 per kWh for vanadium redox flow batteries (VRFBs), EUR 1.68 per kWh for lithium-ion batteries and EUR 3.07 per kWh for lead-acid batteries. The estimates for lithium-ion and lead-acid batteries appear to be excessive in comparison to those found in other literature sources, discussed below.

Pawel (2014:78) finds that the combined levelised cost is likely to be somewhere between the LCOE of a solar PV plant and that of an energy storage system. Pawel (2014:75) also established that the LCOS and combined levelised cost of a solar PV plant and energy storage system is likely to increase if the usable storage capacity is underutilised. For example, it was estimated that the LCOS for a system performing one charge-discharge cycle a day is approximately EUR 0.34 per kWh when 100% storage capacity is used, but increases by 82.9% to EUR 0.62 per kWh when only 50% storage capacity is utilised. Similarly, albeit less drastically, the levelised cost of solar PV in combination with energy storage could increase from EUR 0.25 per kWh for 100% storage capacity use to EUR 0.36 per kWh for 50% storage capacity utilisation. It was further indicated that the discount rate is a major driver of costs (Pawel, 2014:76; Lai *et al.*, 2017:200).

The impact of battery utilisation rates on lifecycle costs is also noted by Poonpun *et al.* (2008:532-533), Battke *et al*. (2013:247-249), Fitzgerald, Mandel, Morris and Touati (2015:6-22), Kondziella *et al.* (2016:16), Jülch (2016:1600-1601) and Lai *et al.* (2017:199). Lai *et al.* (2017:199) are of the opinion that an energy storage system integrated with a solar PV plant will not always be utilised to full capacity, as it depends on the surplus electrical power availability from the solar PV plant that can be stored in the energy storage medium, which will place upward pressure on the LCOS. Fitzgerald *et al.* (2015:6-22), however, indicate that applying energy storage technologies to multiple uses sequentially and/or simultaneously would ensure high storage utilisation rates, which would significantly lower costs while enhancing overall system value.

Zakeri *et al.* (2015:569-596) provided a comprehensive review of literature on the costs associated with different energy storage technologies as a means to summarise and draw conclusions of their likely total capital and lifecycle or levelised costs. The study adds value by disseminating the lifecycle cost items of different energy storage systems in a uniform way, such as power conversion system (PCS), balance of plant, storage medium, operations and maintenance and replacement costs (Zakeri *et al.*, 2015:573-592).

Poonpun *et al.* (2008:530-533) formulated an LCOS methodology, but excluded the price of electricity used to charge an energy storage system in order to determine the added cost per kWh as a result of using energy storage technologies to retain electricity for later use. The authors further did not consider the impact of inflation and electricity charging price escalation rates. Similar to Pawel (2014:75-78), Poonpun *et al.* (2008:531) assumed a single daily charge-discharge cycle, albeit for generation applications requiring eight hours of energy discharge capability. The authors, however, used two cycles for transmission and distribution applications requiring four hours of discharge capability to supply electrical energy during the morning and afternoon peak demand periods, while charging at other times.

Poonpun *et al.* (2008:531-533) estimated that the cost added by energy storage systems, operating 250 days a year, to each kWh unit of electricity stored for generation applications requiring an electrical power rating of 10 MW in 2008 was approximately USD 0.28 for lead-acid batteries, USD 0.27 for VRFBs, USD 0.18 for sodium-sulphur (NaS) batteries and USD 0.05 for pumped hydroelectric energy storage (PHS). For transmission and distribution applications requiring a 2.5 MW electrical power rating, the levelised costs were estimated to be approximately USD 0.29 per kWh for NaS batteries, USD 0.21 per kWh for VRFBs and flywheels, USD 0.20 per kWh for lead-acid batteries and USD 0.07 per kWh for zinc-bromine (ZnBr) flow batteries.

While Poonpun *et al.* (2008:530-533) excluded charging costs, Zakeri *et al.* (2015:573-589) deducted electricity charging costs from an LCOE metric for energy storage systems in deriving an LCOS formula to present the net levelised cost of technologies without the influence of charging electricity prices. Zakeri *et al.* (2015:590) also do not account for the number of required charge and discharge cycles or depth of discharge (DoD) in the LCOS formula. The use of an LCOE metric for energy storage technologies, the failure to add, rather than deduct, charging costs to the overall LCOS and the exclusion of cycles and DoD limitations from the formula do not accommodate for the full expenses and technical parameters associated with the installation and operation of such technologies and could therefore lead to an understatement of the results.

Jülch *et al*. (2015:24) and Jülch (2016:1600-1604) confirm the impact that charging electricity prices has on the LCOS and also consider the prospect for significant LCOS declines in the short to medium term. The improper LCOS formulation by Poonpun *et al.* (2008:530-531) and Zakeri *et al.* (2015:573-589) is also noted by Lai *et al.* (2017:194), stating that the levelised cost of energy storage should be higher than that of electrical generation due to efficiency losses and the cost of electricity produced and stored in an energy storage system should be accounted for.

Despite the methodological weakness of excluding the price of charging electricity, Zakeri *et al.* (2015:588-590) analysed the LCOS of different energy storage systems required to perform bulk storage for energy time shifting, transmission and distribution grid support and frequency regulation services. The energy time shifting application requires eight hours discharge duration over 250 cycles a year, while transmission and distribution support requires two hours discharge duration over 400 cycles a year.

Zakeri *et al.* (2015:588-589) observed that the average LCOS per kWh for bulk energy time shifting is approximately EUR 0.42 for nickel-cadmium (NiCd) batteries, EUR 0.21 for iron-chromium (FeCr) flow batteries, EUR 0.35 for VRFBs, EUR 0.24 for NaS batteries, EUR 0.32 for advanced lead-acid batteries, EUR 0.13 for compressed air energy storage (CAES) and EUR 0.12 for PHS. The average LCOS per kWh for transmission and distribution grid support was found to be approximately EUR 0.62 for lithium-ion batteries, EUR 0.48 for hydrogen fuel cells, EUR 0.35 for sodium-nickel chloride ($NaNiCl_2$ or ZEBRA) batteries, EUR 0.34 for VRFBs, EUR 0.34 for NiCd batteries, EUR 0.29 for advanced lead-acid batteries, EUR 0.25 for FeCr flow batteries, EUR 0.25 for NaS batteries and EUR 0.21 for ZnBr flow batteries.

Without disclosing the precise LCOS formula used and subject to wide input parameter uncertainties, Battke *et al*. (2013:246-249) found that the levelised cost of electricity per kWh for storage applications requiring utility-scale energy time shifting for eight hours could be EUR 0.46 for lithium-ion, EUR 0.26 for VRFBs, EUR 0.24 for lead-acid and EUR 0.18 for NaS batteries. The estimates per kWh for transmission and distribution grid investment deferral with four hours discharge duration were higher at EUR 0.67 for lithium-ion, EUR 0.39 for VRFBs, EUR 0.28 for lead-acid and EUR 0.27 for NaS batteries.

In 2015, Lazard (2015:1-29) undertook an independent levelised cost of storage analysis to estimate the lifetime cost of different leading energy storage technologies according to ten value applications they could be required to fulfil. Of these, the primary utility-scale applications in the study were classified as transmission stability and renewable integration support (i.e. transmission), electrical peaker power plant (e.g. gas- or diesel-fired turbines) replacement (i.e. peaker replacement), frequency regulation, distribution substation stability and peaking capacity provision (i.e. distribution services) and solar PV integration and electrical output improvement (i.e. PV integration).

Lazard’s (2015:1-29) findings are also summarised in Table 5.1, but broadly range per kWh between USD 0.19 and USD 0.27 for PHS (i.e. transmission), USD 0.19 for CAES (i.e. transmission), USD 0.28 and USD 0.99 for flywheels (i.e. frequency regulation), USD 0.40 and USD 1.69 for lead-acid batteries (i.e. PV integration, peaker replacement, transmission and distribution services), USD 0.22 and USD 0.43 for zinc-air batteries (i.e. peaker replacement, PV integration, transmission and distribution services), USD 0.37 and USD 1.13 for NaS batteries (i.e. peaker replacement, PV integration, transmission and distribution services), USD 0.21 and USD 0.79 for lithium-ion batteries (i.e. frequency regulation, peaker replacement, PV integration, transmission and distribution services) and USD 0.25 and USD 0.95 for flow batteries (i.e. peaker replacement, transmission, distribution services and PV integration). According to Lazard (2015:18), lithium-ion and flow batteries could be competitive with gas-fired electrical generation turbines by 2020.

Lazard (2016:1-34) provided an updated version of their LCOS study in 2016. In the updated study, the primary utility-scale applications are classified as transmission stability, investment deferral, energy time shifting and renewable integration support (i.e. transmission system); peaking power plant replacement, energy time shifting and operating reserves (i.e. peaker replacement); distribution substation stability and peaking capacity provision (i.e. distribution substation) and frequency regulation.

Apart from flywheels and zinc-air batteries, Lazard’s (2016:31-34) updated study involves lower LCOS estimates of 15 to 44.9% compared to their 2015 analysis, which provides additional evidence of the rapid decline in technology lifetime costs and thereby improved price competition. It is found that the LCOS per kWh is USD 0.15 to USD 0.20 for PHS (i.e. transmission), USD 0.12 to USD 0.14 for CAES (i.e. transmission), USD 0.34 to USD 1.25 for flywheels (i.e. peaker replacement, distribution substation and frequency regulation), USD 0.43 to USD 0.93 for lead-acid batteries (i.e. distribution substation), USD 0.26 to USD 0.54 for zinc-air batteries (i.e. transmission, peaker replacement and distribution substation), USD 0.30 to USD 0.96 for NaS batteries (i.e. transmission, peaker replacement and distribution substation), USD 0.19 to USD 0.66 for lithium-ion batteries (i.e. frequency regulation, transmission, peaker replacement and distribution substation), USD 0.43 to USD 0.56 for ZnBr flow batteries (i.e. transmission, peaker replacement and distribution substation), USD 0.34 to USD 0.83 for FeCr flow batteries (i.e. transmission, peaker replacement and distribution substation) and USD 0.31 to USD 0.77 for VRFBs (i.e. transmission, peaker replacement and distribution substation).

Lazard’s estimations were based on a single charge-discharge cycle per day for most applications and the levelised cost of solar PV plants coupled with energy storage was not investigated. The studies by Lazard further do not disclose the algorithm used to derive the LCOS estimates, which makes reverse calculations and learning difficult and is also an issue noted by Lai *et al.* (2017:194) and Obi *et al.* (2017:910). Nonetheless, the studies by Lazard offer insight into the extent to which energy storage costs can differ by technology and use application, which is similarly emphasised by Battke *et al*. (2013:247).

Jülch (2016:1596-1605) assessed the LCOS for PHS, diabatic and adiabatic CAES, underground hydrogen energy storage with combined cycle gas turbine and lithium-ion, lead-acid and VRFB batteries. The LCOS was estimated for 2016 and projected to 2030. The applications investigated for the LCOS included long-term or seasonal energy storage requiring 70 000 MWh storage capacity and short-term energy storage requiring 400 MWh storage capacity.

Jülch (2016:1602) estimated that the average LCOS per kWh for seasonal energy storage, requiring 100 MW and 700 hours discharge duration once a year, in 2016 could have been approximately EUR 1.40 for PHS and EUR 2.40 for diabatic CAES. The LCOS per kWh in 2030 could be EUR 0.40 for hydrogen gas turbine storage and EUR 3.25 for adiabatic CAES. Jülch (2016:1603) further estimated that the LCOS per kWh in 2016 for the short-term application requiring 100 MW, four hours electrical energy discharge capability and 365 cycles per year was approximately EUR 0.11 for PHS, EUR 0.13 for diabatic CAES, EUR 0.21 for lead-acid batteries, EUR 0.30 for lithium-ion batteries and EUR 0.38 for VRFBs. By 2030, the average LCOS per kWh could potentially be EUR 0.13 for adiabatic CAES and VRFBs, EUR 0.15 for lead-acid batteries, EUR 0.18 for lithium-ion batteries and EUR 0.30 for hydrogen gas turbine storage. The potential 2030 LCOS was not disclosed for PHS and diabatic CAES for both applications.

Jülch (2016:1600-1603) did not consider replacement costs for the electrochemical batteries investigated and assumed that the components of such systems will last throughout their contract lifetime. This assumption is likely to result in lower LCOS values than will be the case in practice. The impact of more than one daily charge-discharge cycle on the LCOS was also not considered.

The World Energy Council (2016a:16-26) evaluated the LCOS for energy storage technologies in isolation and when such technologies are co-located with solar PV and wind-based electrical production plants to perform energy time shifting. The LCOS is estimated for 2015 and projected to 2030 in order to test the current and potential future competitiveness of different energy storage technologies. The technologies under consideration included PHS, CAES, sensible heat thermal energy storage, latent heat thermal energy storage, thermochemical energy storage, supercapacitors, flywheels, hydrogen energy storage and lithium-ion, NaS, lead-acid and VRFB batteries.

The LCOS per kWh in 2015 for stand-alone energy storage systems was estimated to range between EUR 0.06 and EUR 0.12 for PHS, EUR 0.06 and EUR 0.09 for flywheels, EUR 0.07 and EUR 1.80 for various thermal energy storage mediums, EUR 0.08 and EUR 0.14 for CAES, EUR 0.11 and EUR 0.70 for different electrochemical batteries, EUR 0.17 and EUR 0.34 for supercapacitors and EUR 0.31 and EUR 0.41 for hydrogen energy storage. By 2030, the LCOS per kWh could decline to around EUR 0.02 for flywheels, EUR 0.04 and EUR 0.57 for various thermal energy storage mediums, EUR 0.05 and EUR 0.19 for different electrochemical batteries, EUR 0.07 and EUR 0.08 for CAES, EUR 0.06 and EUR 0.12 for PHS, EUR 0.09 and EUR 0.17 for supercapacitors and EUR 0.12 and EUR 0.23 for hydrogen energy storage (World Energy Council, 2016a:22).

The application requirements for renewables integration with solar PV plants is for the energy storage systems to perform one cycle per day over 365 days a year with an electrical energy discharge capability of six hours. In this application, the estimated LCOS per kWh in 2015 ranged between EUR 0.05 and EUR 0.09 for PHS, EUR 0.07 and EUR 0.14 for CAES, EUR 0.07 and EUR 1.64 for various thermal energy storage mediums, EUR 0.24 and EUR 0.70 for different electrochemical batteries, EUR 0.28 and EUR 0.38 for hydrogen energy storage, EUR 1.10 and EUR 1.78 for flywheels and EUR 3.40 and EUR 6.80 for supercapacitors. By 2030, the LCOS per kWh might decline to levels between EUR 0.04 and EUR 0.53 for various thermal energy storage mediums, EUR 0.05 and EUR 0.19 for different electrochemical batteries, EUR 0.05 and EUR 0.09 for PHS, EUR 0.07 and EUR 0.08 for CAES, EUR 0.11 and EUR 0.21 for hydrogen energy storage, EUR 0.39 and EUR 0.51 for flywheels and EUR 1.40 and EUR 3.50 for supercapacitors. The high LCOS for flywheels and supercapacitors is due to those technologies being more suited for electrical power intensive applications, such as frequency and voltage regulation, than for energy intensive applications (World Energy Council, 2016a:23-24).

The application requirements for renewables integration with wind turbines is for the energy storage systems to perform one cycle per day over 183 days a year with an electrical energy discharge capability of 24 hours. The LCOS is higher for technologies coupled with wind turbine-based electrical generators due to more infrequent cycling requirements, since they are assumed to perform only one charge-discharge cycle every two days. The required energy discharge capability is also excessive relative to the technical capability of many technologies, which necessitates surplus capital investment. Cycling frequency and adequate discharge durations have an important influence on the LCOS (World Energy Council, 2016a:16-25).

The analysis by the World Energy Council (2016a:16-36), however, excludes the cost of the renewable energy generators and also assumes zero electrical input charging costs, which does not adequately reflect the practical lifetime cost of energy storage systems coupled with renewable energy technologies. It is also not clear whether energy capacity degradation has been taken into account in the LCOS modelling.

Obi *et al.* (2017:908-918) recently proposed a methodology for a standardised LCOE formula for utility-scale energy storage systems. According to the authors, the rapidly declining costs and increased implementation of energy storage technologies and renewable energy electrical production options are becoming a threat to traditional utilities and warrant the development of a uniform economic metric for energy storage. The proposed levelised cost metric is intended to enable practitioners and policymakers to better evaluate different energy storage systems.

The methodology suggested by Obi *et al.* (2017:909-917) was applied to mechanical and electrochemical energy storage technologies, including PHS, CAES and lead-acid, advanced lead-acid, lithium-ion and flow batteries. Obi *et al.* (2017:915-918) further compared the levelised cost estimates of the energy storage technologies under consideration to simple cycle combustion turbines, commonly used for energy arbitrage, to challenge traditional views supporting the use of gas turbines for emergency and peak electricity provision. It was found that PHS, CAES and lead-acid batteries have the most competitive levelised cost values. The mean results per kWh were around USD 0.05 for PHS and USD 0.06 for both CAES and lead-acid batteries, which are lower than the LCOE values of USD 0.09 per kWh and USD 0.13 per kWh for simple cycle combustion turbines with capacity factors of 30% and 10%, respectively.

For the PHS, Obi *et al.* (2017:911-916) observed that factors such as geological siting, plant size, turbine speed, roundtrip efficiency and electricity charging input prices have a significant impact on project costs and thereby levelised cost results. Similarly, for CAES, it was found that geological siting, plant size, type of storage medium (e.g. above ground or underground), hours of electrical energy provision, capacity factor, project lifetime, load period, roundtrip efficiency and electricity charging input prices are substantial cost influencers. The levelised costs of electrochemical batteries were found to be mostly influenced by technology type, utilisation rates, battery storage size, application discharge requirements, external funding, roundtrip efficiency and electricity charging input prices.

The LCOE of energy storage metric proposed by Obi *et al.* (2017:914-918) includes incentive support measures, which have a downward impact on cost estimates and superficially improve technology cost competitiveness. According to Lai *et al.* (2017:195), the metric proposed by Obi *et al.* (2017:914-918) assumes that the total annual electrical energy production from the system is supplied by the storage medium. This assumption is unrealistic in light of efficiency losses as it is unlikely that total electrical energy produced will be provided by an energy storage system. It further appears that the number of daily charge and discharge cycles has been excluded from the formula proposed by Obi *et al.* (2017:918), which could potentially result in overstated cost estimates if more than one cycle is performed per day (Battke *et al*., 2013:247-249; Zakeri *et al.*, 2015:573; World Energy Council, 2016a:5).

Lai *et al.* (2017:191-199) proposed a levelised cost of delivery (LCOD) metric to determine the LCOE for energy storage systems incorporated with a solar PV electrical production plant. The equation takes account of electrical energy output, and related costs, from the solar PV plant that is fed directly into the electricity grid and surplus energy that is fed into the energy storage system for later use. It is observed that the levelised cost of both solar PV and energy storage can decline as the installed solar PV plant capacity rises, since more energy is likely to be stored and delivered by the energy storage system.

Lai *et al.* (2017:191-202) used the proposed levelised cost metric to evaluate the competitiveness of hybrid VRFB and lithium-ion battery systems that are coupled independently from one another with solar PV plants. It is found that, at a discount rate of 8% or less, VRFBs coupled with a solar PV plant have a lower LCOD in comparison to a combined solar PV and lithium-ion electrical production and storage system. A discount rate of 8% or more has to be imposed for lithium-ion coupled with solar PV plants to be the lower cost option. The authors also do not show the LCOS for the VRFB and lithium-ion battery systems in isolation. It is, nonetheless, graphically illustrated that the LCOD for both the VRFB and lithium-ion battery systems coupled with a 5 MW solar PV plant at a discount rate of 8% could range between USD 0.45 per kWh and USD 0.75 per kWh for both technologies (Lai *et al.*, 2017:200).

Lai *et al.* (2017:191-202), however, do not reveal the detailed parameters included in the proposed levelised cost formula, although it is noted that roundtrip efficiency, calendar life, capital costs, operations and maintenance costs, charging costs and discount rates were included. Similar to Obi *et al.* (2017:918), Lai *et al*. (2017:200) further convey that the number of daily cycles were excluded from the levelised cost metric and that this should be incorporated in future work. Including the number of cycles in the LCOS formulation could have a significant impact on levelised cost estimates (Battke *et al*., 2013:247-249; Zakeri *et al.*, 2015:573; World Energy Council, 2016a:5). Lai *et al.* (2017:191-200) additionally established that the levelised cost metric can assist policymakers to make better informed decisions regarding factors such as an appropriate discount rate, energy storage technologies and system installation size of a solar PV electrical production plant coupled with energy storage capability.

The studies by Poonpun *et al.* (2008:530-531), Battke *et al*. (2013:240-249), Pawel (2014:68-77), Zakeri *et al.* (2015:569-596), Jülch *et al*. (2015:19-24), Lazard (2015:1-29), Lazard (2016:1-34), Jülch (2016: 1596-1605), the World Energy Council (2016a:16-26), Mundada *et al*. (2016:693-700), Lai *et al.* (2017:191-202) and Obi *et al.* (2017:908-918) were the only publications with cost estimations obtained during the literature review that resemble the LCOS to some extent. The findings in these studies exemplify the degree to which such lifecycle cost evaluations can differ between available publications and according to various technologies, applications, formulas, input parameters, data, assumptions and technological advances.

Kondziella *et al.* (2016:20) highlight the need for further analyses on the economic potential of implementing a cost regime to improve the reliability of variable renewable energy-based electrical generators. Zakeri *et al.* (2015:590) propose that further work should offer improved analysis by accounting for costs at different stages of a battery energy storage plant's lifetime and considering more parameters in levelised cost calculations, such as the optimal number of possible cycles given a particular technology's service lifetime. Battke *et al*. (2013:249) support the notion that further research should better account for more technical complexities of battery energy storage technologies in LCOS estimations. They also stress the need for future work to include forecasts of costs and technological performance. The need for an improved understanding of future energy storage costs has also been recognised by Kaun *et al.* (2013:86). Hameer *et al.* (2015:1191) propose that an innovative methodology is needed to compare thermal energy storage with other energy storage technologies.

Sioshansi *et al.* (2009:277), He *et al.* (2011:1575-1584), Strbac, Aunedi, Pudjianto, Djapic, Teng, Sturt, Jackravut, Sansom, Yufit and Brandon (2012:33-39), Kaun *et al.* (2013:25-85), Infield *et al.* (2014:24-27), Castillo *et al.* (2014:888-889), De la Rubia *et al*. (2015:7-8), Fitzgerald *et al.* (2015:14-38), Zakeri *et al.* (2015:571) and Kondziella *et al.* (2016:20-21) have pointed out that energy storage economics should also account for the additional value derived from the applications that energy storage technologies can meet sequentially and/or simultaneously, which would otherwise have required isolated investments in alternative electrical energy generation, transmission and/or distribution infrastructure. Sioshansi *et al.* (2009:276-277) also deduce that the value of energy storage technologies can be significantly underestimated if the multiple applications it can fulfil are not quantified. It has further been recognised that demand-side management measures, investments in flexible electrical generation plants and grid interconnections with neighbouring countries might reduce the value offered by energy storage technologies, depending on the cost associated with such measures and investments relative to energy storage and environmental considerations (Strbac *et al.*, 2012:67; Infield *et al.*, 2014:24-26; Kondziella *et al.*, 2016:15-17).

Zhang (2013:42-109) contributed to the valuation of energy storage through an economic modelling analysis approach to study the benefits derived from energy time shifting to assist in supplying periods of peak demand for electricity, electrical energy outage avoidance and distribution grid investment deferral (Zhang, 2013:12). Between the three applications under consideration, it was found that energy storage derives the most value or maximum economic benefit through its ability to defer investments in distribution infrastructure to a later stage, especially for longer distribution lines with higher capital cost requirements. The results, however, indicate that the greatest economic benefit is derived when all three value applications are combined (Zhang, 2013:107-108).

Fitzgerald *et al.* (2015:6-22) indicate that energy storage value estimates differ widely, depending on the context for which the use application and investment will be required, assumptions made in deriving the estimates and the location where the energy storage system will be sited. At the utility scale, the authors show that per kilowatt (kW) a year the service value of energy storage could be up to USD 100 for energy time shifting or price arbitrage, USD 210 for frequency regulation, USD 80 for spinning and non-spinning reserves, USD 70 for voltage support, USD 10 for black start services, USD 165 for resource adequacy, USD 175 for transmission and distribution grid investment deferral and USD 15 for transmission congestion relief. Kaun *et al.* (2013:27) show that the value benefits offered by energy storage technologies could be summed for the multiple applications that an energy storage system could deliver sequentially and/or simultaneously, which is similar to the multi-use concept illustrated in Figure 4.1 in sub-section 4.2.11 of Chapter 4.

Kaun *et al.* (2013:25-75) estimated the potential value of energy storage technologies, mainly for lithium-ion and flow batteries, servicing multiple use cases in California's electricity market simultaneously. The value of energy storage is mainly derived from deferring investments in alternative generation and grid supply options required to meet each use case individually. In 2013, Kaun *et al.* (2013:81-85) already found that energy storage technologies mostly have positive benefit-to-cost ratios of between 1.05 and 1.5 under a series of scenarios for utility-scale applications that can be serviced by energy storage systems sequentially and/or simultaneously. Such applications include electric energy time shifting, regulation services, spinning and non-spinning reserves and distribution and transmission grid upgrade deferral. This implies that the NPV of the quantifiable benefits of energy storage exceeds the quantifiable costs over the lifetime of the asset (Kaun *et al.*, 2013:81-83). They also indicate that the value relative to cost is likely to continue to increase significantly by 2020 given the higher penetration rates of renewables, rapid technology cost reductions and improved performance innovations.

Neuhoff (2005:92), Sioshansi *et al.* (2009:277), Strbac *et al.* (2012:33-76), Infield *et al.* (2014:24-27) and Günter *et al.* (2016:234) support Kaun *et al.* (2013:25-75) by noting that the economic value derived from energy storage technologies will become increasingly greater in future. This is likely as energy storage technology prices continue to decline and the need for secure, stable, efficient and low carbon energy systems grows, driven by higher levels of intermittent renewable energy-based electrical production, climate change mitigation objectives and more expensive fossil fuels relative to renewables.

5.3 APPLICABILITY OF ENERGY STORAGE TECHNOLOGIES TO ECONOMIC THEORY

Economic theory can be regarded as a structured framework representing a simplification of views about the manner in which the economy operates (Mohr & Fourie, 2004:104; Snowdon & Vane, 2005:4; Mankiw, 2012:24). From the outset, it is worth noting that mainstream economic theory has not explicitly considered energy as a primary factor of production in the process of economic growth (Stern, 2011:26-28; Bee, 2016:20-24). This is despite the importance of energy, including electrical energy, as a resource that makes all productive economic activity possible as informed by the laws of thermodynamics (Simon, 1996:162-163; Stern, 2011:26-46; Hu & Hu, 2013:2-3; Bee, 2016:16).

In this section, a novel attempt is made to contextualise energy storage systems in light of economic theory, mainly through its linkage to technological progress. The aim is not to provide an exhaustive assessment of the theoretical linkages, as it is not the primary focus of this study, but rather to identify some economic philosophies that can accommodate for energy storage systems within the framework of the general research objective for this dissertation. In that regard, a detailed exploration of energy storage systems in economic hypotheses could be considered an area for further research.

5.3.1 Theoretical association of energy storage technologies

There are three basic, but essential, drivers of economic growth and development, namely human and physical capital accumulation, population and labour force growth and technological progress (Stern, 1991:122-123; Todaro & Smith, 2009:142-146; Farmer & Lafond, 2016:647). This section focuses on the third component, technological progress, by considering the role of advancements in energy storage systems within some economic theories.

As with electricity, energy storage technologies could potentially be classified as general purpose technologies that contribute to sustained improvements in economic growth, since they are utilised across multiple economic sectors, influence production techniques and productivity in various industries and stimulate secondary innovations (Bresnahan & Trajtenberg, 1995:84; Aghion & Howitt, 2009:193; Johnstone *et al.*, 2013:144; Hammond *et al.*, 2015:559-569; Lund *et al.*, 2015:795; Amrouche *et al.*, 2016:20916; Gallo *et al.*, 2016:806-817; Tanner, 2016:629-631; Ardito, Petruzzelli & Albino, 2016:81-84). In this section, however, the emphasis is on energy storage technologies for utility-scale applications in alignment with the general research objective of this study.

Technological progress involves new, innovative and/or improved methods and knowledge of fulfilling traditional economic activities (Blanchard, 2006:270; Todaro *et al.*, 2009:144; Stern, 2011:33; Comin *et al.*, 2014:565; Farmer *et al.*, 2016:647). It refers to advances made in the state of technology that enables the production of higher quantities and/or quality of outputs with given input quantities of factors of production, such as capital, labour, land, entrepreneurship and electricity (Mohr *et al.*, 2004:25-28; Blanchard, 2006:216-272; Hu *et al.*, 2013:15-16; Comin *et al.*, 2014:565; Bee, 2016:20-28).

The central concept of economic development is concerned with the enhancement of human living conditions (Sen, 1988:11; Todaro & Smith, 2015:5), which, in turn and among other factors, is directly influenced by technological change or progress (Lucas, 1988:15-16; Romer, 1990:72-99; Grossman & Helpman, 1994:24; Ranis, 2011:2-7). Given this relationship, the increased penetration of renewable energy-based electrical production plants and adoption of utility-scale battery energy storage technologies around the world could potentially be regarded as technological progress, and therefore a natural feature of the process of economic development and human well-being.

More specifically, utility-scale energy storage systems could be considered capital-augmenting technological progress, since such systems mainly support existing capital assets to be utilised more productively (Todaro *et al.*, 2009:145; Stern, 2011:42; Bee, 2016:9-10). For example, energy storage systems can enhance the electrical energy output capabilities of variable and intermittent renewable energy-based electrical production plants and/or improve the utilisation of electricity transmission infrastructure (Suberu *et al.*, 2014:510; Lund *et al.*, 2015:792-793; Battke *et al.*, 2015:338; Günter *et al.*, 2016:227; Gallo *et al.*, 2016:815; Malhotra *et al.*, 2016:718; Berrada *et al.*, 2017:95; Amirante *et al.*, 2017:372-373; Lai *et al.*, 2017:191; Obi *et al.*, 2017:909-910; Lazkano *et al.*, 2017:1-2). The various applications that can be performed by utility-scale energy storage systems are explained in section 4.2 of Chapter 4.

The technological relatedness between energy storage systems and economic growth could possibly be traced to the economic theory of endogenous growth, which is also often referred to as new growth theory (Jones & Manuelli, 1997:1-2; Snowdon *et al.*, 2005:627; Meier & Rauch, 2005:79; Todaro *et al.*, 2009:151; Lazkano *et al.*, 2017:1-16).

Whereas neoclassical economic theory regards technological change as an exogenous or independent factor of long-run economic growth, endogenous growth theory internalises technological change in an attempt to better explain dynamic features of economic growth and development arising from disequilibrium conditions (Arrow, 1962:155; Stern, 1991:125; Jones *et al.*, 1997:7-8; Antonelli, 2003:34; Snowdon *et al.*, 2005:622-633; Howitt, 2008:1; Todaro *et al.*, 2009:128-152; Aghion *et al.*, 2009:13; Stern, 2011:28; Sredojević, Cvetanović & Bošković, 2016:178-179).

A central feature of endogenous growth theory is that technological innovation and knowledge accumulation, through investments in human capital, can significantly improve productivity levels of total input factors of production and thereby raise per capita output and economic growth over the long run (Hicks, 1932:121; Arrow, 1962:155-172; Romer, 1986:1002-1004; Lucas, 1988:39-41; Antonelli, 2003:154-155; Barro & Sala-i-Martin, 2004:62-67; Meier *et al.*, 2005:79; Howitt, 2008:1-5; Todaro *et al.*, 2009:152-154; Stern, 2011:28; Sredojević *et al.*, 2016:188).

In models of endogenous growth, knowledge accumulation and technological progress are brought about by interrelated factors. These include imperfect firm competition, globalisation and international trade, savings, domestic and foreign investment in knowledge-intensive activities, education and training, research and development, learning by doing and observing, incentives, non-rivalrous and partially excludable ideas, imitation, innovation and the related inter-firm, industry and sectoral spillover effects (Hicks, 1932:121-125; Arrow, 1962:155-156; Romer, 1986:1003; Stern, 1991:125-129; Grossman *et al.*, 1994:32-42; Antonelli, 2003:157-163; Barro *et al.*, 2004:61-66; Aghion, 2004:3-22; Snowdon *et al.*, 2005:625-631; Meier *et al.*, 2005:79; Blanchard, 2006:242; Howitt, 2008:1-5; Aghion *et al.*, 2009:13-17; Todaro *et al.*, 2009:152-153; Stern, 2011:28-29; Comin *et al.*, 2014:565; Sredojević *et al.*, 2016:184-191).

According to the theory of innovation economics, which fits within the framework of endogenous growth theory, out-of-equilibrium conditions induce knowledge accumulation and technological innovation within the control of individuals and firms, in both product and factor markets, in order to improve their competitiveness and profitability through creative responses (Grossman *et al.*, 1994:32-33; Antonelli, 2003:34; Agion, 2004:8; Aghion *et al.*, 2009:15; Stern, 2011:28; Sredojević *et al.*, 2016:185-189). Knowledge and technological innovations affect the operational characteristics and production functions of heterogeneous firms through the potential for lower production costs, more efficient production processes, new and/or superior products and services, better management and organisation, higher productivity and/or improved cost competitiveness (Grossman *et al.*, 1994:32; Antonelli, 2003:151-162; Agion, 2004:8; Howitt, 2008:1-2; Aghion *et al.*, 2009:14-16; Stern, 2011:34; Comin *et al.*, 2014:565; Sredojević *et al.*, 2016:187).

Endogenous growth theory concludes that, on an aggregate firm level, productivity improvements and spillover effects that result from knowledge generation and technological progress are both a cause and consequence of increasing returns to scale and long-term economic growth, which drives continuous increases in standards of living (Romer, 1986:1002-1004; Stern, 1991:125-129; Grossman *et al.*, 1994:24; Antonelli, 2003:35-37; Barro *et al.*, 2004:65-67; Snowdon *et al.*, 2005:626; Meier *et al.*, 2005:79; Todaro *et al.*, 2009:152; Sredojević *et al.*, 2016:183-191).

From the perspective of endogenous growth theory, energy storage systems, particularly modern electrochemical batteries, can be considered a consequence of ongoing knowledge accumulation, innovation and technological progress. The technological progress induced by energy storage systems has an important role in the process of sustainable economic development, which concerns the maximisation of human welfare for existing and future generations, while accounting for finite natural resources and substitution between various forms of technologies or capital goods (Aghion, 2004:6).

The technical advances and cost reductions achieved in energy storage systems support the gradual transition from non-renewable to renewable energy-based electrical energy industries. This transition is especially encouraged by improving the electric output capabilities of variable and intermittent electrical energy generation plants, conserving finite natural resources and reducing negative environmental and health externalities (Grossman *et al.*, 1994:42; Tahvonen *et al.*, 2001:1380-1395; Hall, 2008:4367; Kumar & Managi, 2009:335-352; Stern, 2011:28-42; Evans *et al.*, 2012:4142; Hittinger *et al.*, 2012:436; Johnstone *et al.*, 2013:143; Mahlia *et al.*, 2014:533-534; Lund *et al.*, 2015:793; Bee, 2016:19-20; Amrouche *et al.*, 2016:20914; Wiebe *et al.*, 2016:740-744; Aneke *et al.*, 2016:350-354; Lai *et al.*, 2017:191-192; Obi *et al.*, 2017:908-913). Energy storage systems entail further endogenous economic growth and development benefits by promoting increased domestic electrical energy security, reliability, flexibility, access and relative affordability (Akinyele *et al.*, 2014:74-88; Infield *et al.*, 2014:1; Dehdashti, 2016:3-8; Aneke *et al.*, 2016:350-352; World Energy Council, 2016a:6-7; Amrouche *et al.*, 2016:20914-20922).

Energy storage systems can also support sustainable economic growth and development by enhancing the potential for industrial development and expansion, renewable energy and distributed electrical energy generation, environmental conservation, cost reductions, encouraging foreign direct investment, infrastructure development, increased research and development opportunities, further sectoral innovation spillovers, improved resource utilisation and the prospective employment opportunities associated with these dynamics (Stern, 1991:131-132; Grossman *et al.*, 1994:42; Snowdon *et al.*, 2005:630; Stern, 2011:29-39; Johnstone *et al.*, 2013:143; Akinyele *et al.*, 2014:74-75; Wiebe *et al.*, 2016:740; Amrouche *et al.*, 2016:20914; Kyriakopoulos *et al.*, 2016:1064; Aneke *et al.*, 2016:350-355; Tanner, 2016:629-631; Sredojević *et al.*, 2016:184-188; Astarloa *et al.*, 2017:6-11; Lazkano *et al.*, 2017:16).

Moreover, it has been found by Lazkano *et al.* (2017:1-16) that energy storage systems stimulate supplementary innovations in both renewable energy and conventional electrical generation technologies. These innovation spillovers in the electricity industry emanating from energy storage technology advances, however, are estimated to involve greater potential for additional innovations in renewable energy-based electrical production technologies than for conventional, fossil fuel-based, electrical generators. Such innovation spillovers from energy storage systems are likely to improve the efficiency of the entire electricity industry. In addition, innovation spillovers to renewable energy technologies involve a response for further innovations in energy storage technologies in a mutually reinforcing process, while such feedback effects to energy storage are not observed for conventional electrical generation technologies.

Energy storage systems further essentially relate to the economic theory of structural change, which could be categorised within endogenous growth theory (Antonelli, 2003:166; Blanchard, 2006:279; Gabardo, Pereima & Einloft, 2017:2-3). Progressive structural change essentially involves the socio-economic transformation towards a more developed, educated, modern, industrialised and service-oriented society during the process of economic growth (Todaro *et al.*, 2009:115-122; Guilló, Papageorgiou & Perez-Sebastian, 2011:1393; Herrendorf, Rogerson & Valentinyi, 2014:857; Gabardo *et al.*, 2017:1-2). External and internal environments are characterised by continuous change, including in new industries and production methods, environmental awareness and finite resources, and consequently require economic systems with sufficient complexity to cope with and adapt to such change (Jackson, 2003:740; Gabardo *et al.*, 2017:1).

Structural change and technological innovation are interdependent and complementary features in the process of economic development (Antonelli, 2003:157; Blanchard, 2006:279; Gabardo *et al.*, 2017:3). Technological change and progress are brought about by structural change, which is induced by disequilibrium conditions. The responsive technological changes, in turn, entail further alterations in the structure of an economic system, interior industries and markets, which stimulates additional technological innovations in a recursive, mutually reinforcing, process (Antonelli, 2003:157-166).

Increasing shares of renewable energy-based electrical production methods represent a structural change of the electricity supply industry away from society's dependence on exhaustible fossil fuels (Wiebe *et al.*, 2016:744). Energy storage systems act as disruptors to traditional, relatively rigid, fossil fuel-based electricity industries through technical flexibility that can improve the reliability and efficiency of renewable energy-based electricity production systems in pursuit of greater energy security, environmental conservation and optimal resource utilisation (Evans *et al.*, 2012:4142; Akinyele *et al.*, 2014:74-75; Kempener *et al.*, 2015:2; Lund *et al.*, 2015:793-799; Dehdashti, 2016:3-8; Aneke *et al.*, 2016:350-354; World Energy Council, 2016a:6-7; Kyriakopoulos *et al.*, 2016:1065; Amrouche *et al.*, 2016:20914; Lazkano *et al.*, 2017:3-16; Amirante *et al.*, 2017:373; Astarloa *et al.*, 2017:10-11; Lai *et al.*, 2017:191-194).

Socio-economic change and improvement are driven by new production knowledge, methods and technologies, which, in turn, necessitate institutional reforms to adapt to changes brought about by innovation and technological progress (Jackson, 2003:741-744; Antonelli, 2003:150; Agion, 2004:22; Stern, 2011:29; Sredojević *et al.*, 2016:186). Conversely, institutional reforms could also lead and necessitate societal, technological and productive adjustment and innovation (Jackson, 2003:743). Economic growth-enhancing institutions are fundamental for development and include interrelated aspects such as quality policies, politics, laws, property rights, contact enforcement, governance, regulations, financial systems, education and societal norms and standards (Acemoglu, Johnson & Robinson, 2005:388-412; Snowdon *et al.*, 2005:635-647; Aghion *et al.*, 2009:237-239; Ogilvie & Carus, 2014:487-488). The functioning of markets depends on the quality of the various public and private institutional structures in society that influence their operational potential (Ogilvie *et al.*, 2014:487).

While social acceptance, behavioural adaptation and institutional change are likely to be required for the successful adoption of improved technologies or production techniques brought about by energy storage systems, it could be noted that such changes are often difficult to realise in developing countries. This is because dominant firms and policymakers with vested interests in existing production processes might tend to resist change and thereby potentially restrict technological diffusion, total factor productivity and accelerated economic growth (Aghion, 2004:21; Snowdon *et al.*, 2005:630-642; Parente & Prescott, 2006:18-19; Stern, 2011:40; Comin *et al.*, 2014:594-596). In that regard, the successful implementation of energy storage technologies in South Africa will also depend on the growth-enhancing institutional commitment to their integration into an electricity system characterised by rising shares of variable and intermittent renewable energy-based electrical production techniques (Grossman *et al.*, 1994:27; Jackson, 2003:741; Snowdon *et al.*, 2005:635-647; Aghion *et al.*, 2009: 237-239; South Africa, 2011:7-14; Comin *et al.*, 2014:594; Pollet *et al.*, 2015:16686-16689; Tanner, 2016:631; Minnaar, 2016:1140; Department of Energy, 2016a:24-26).

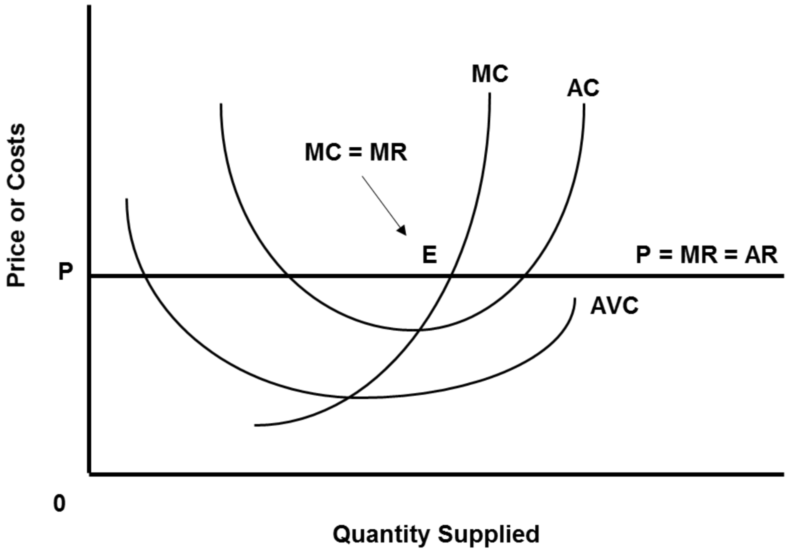
In a supportive institutional environment, the selection and adoption of new technologies are ultimately informed by their relative price levels, knowledge, demand and superiority to alternatives in enhancing total factor productivity for the performance of required applications. The pace and direction of technological diffusion following innovation are influenced, among other factors, by the rates at which technology costs change, which, in turn, are shaped by relative input factors prices (Antonelli, 2003:152-160; Howitt, 2008:1; Kumar *et al.*, 2009:335-352; Stern, 2011:35-39; Johnstone *et al.*, 2013:143; Comin *et al.*, 2014:585-597; Wiebe *et al.*, 2016:740). The levelised or lifetime costs of select energy storage systems in comparison to alternative electrical energy generation options in 2016 and projected to 2020 are the focus of Chapters 6 and 7, which provide indications regarding the pace and direction of their technological diffusion.

5.3.2 Theoretical representation of energy storage technologies in relation to the empirical analysis

According to the production cost theory of the firm, the long-term sustainability of firms and industries depends on their pursuit for maximum profitability, which is, in turn, influenced by their ability to minimise prices and consequently production costs, while delivering the optimal cost-minimising quantity of output (Viljoen, 1998:86; Mohr *et al.*, 2004:223-252; Mankiw, 2012:283-295). Figure 5.1 provides a hypothetical illustration of the economic cost curves of firms in their pursuit for maximum profitability under perfectly competitive conditions (adapted from Mohr *et al.*, 2004:240-263; Mankiw, 2012:282-295).

The vertical axis indicates price or costs, while the horizontal axis signifies total output quantity supplied. The relationship between cost and quantity supplied influences the shape of the cost curves in that costs decrease as output increases until a minimum point is achieved before each additional unit of output has an upward impact on cost (Viljoen, 1998:112; Mohr *et al.*, 2004:242-263; Pindyck & Rubinfeld, 2009:230-231).

Figure 5.1: Economic cost curves of firms



Source: Adapted from Mohr *et al.* (2004:240-263); Mankiw (2012:282-295)

In Figure 5.1, firms maximise their profitability at point E, where marginal cost (MC) equals marginal revenue (MR) at the optimum level of output (Viljoen, 1998:140; Mohr *et al.*, 2004:256-263; Pindyck *et al.*, 2009:277-280; Mankiw, 2012:283-284). Marginal cost refers to the amount added to total cost due to the production of one additional output unit of product or service, while marginal revenue refers to the added amount earned in total revenue due to the sale of one additional output unit of product or service (Viljoen, 1998:108-138; Mohr *et al.*, 2004:225-256; Pindyck *et al.*, 2009:276; Mankiw, 2012:282). Under the assumption of perfect competition, MR equals average revenue (AR), which is equivalent to the market price (P) and represents the horizontal or perfectly elastic demand curve (P = MR = AR) for a firm's product or service offering (Viljoen, 1998:135-136; Mohr *et al.*, 2004:253-259; Pindyck *et al.*, 2009:278-279; Mankiw, 2012:281-283).

In order for firms to enhance their profitability and survive in their respective industries, they have to strive for the minimisation of prices and thereby production costs in order to maximise the difference between income (P = MR = AR) and expenses during the production of the optimum level of output (Viljoen, 1998:138; Mohr *et al.*, 2004:229-256;

Pindyck *et al.*, 2009:276; Mankiw, 2012:286-289). In Figure 5.1, this suggests that firms have to minimise their average cost (AC) curves, which comprise the sum of average fixed and variable cost (AVC) curves, in order for them to maintain positive AR levels, maximise economic profitability and thereby enhance their cost competitiveness relative to rival firms and industries (Viljoen, 1998:138-140; Mohr *et al.*, 2004:236-263; Pindyck *et al.*, 2009:230-298; Mankiw, 2012:286-289).

Accordingly, energy storage system providers have to minimise the costs of their respective product and service offerings in order to enhance their competitiveness relative to alternative technologies and thereby increase potential market share gains. This is required to support the long-term sustainability of energy storage systems in the electricity industry. Correspondingly, energy storage systems could also be presented within the framework of economic theory through the production possibilities frontier hypothesis (Viljoen, 1998:220-227; Pindyck *et al.*, 2009:585-614; Besanko, Braeutigam & Gibbs, 2011:678-687). In doing so, it is necessary for purposes of comprehension to briefly recapitulate the research outline for the empirical analysis of this study as summarised in sub-section 1.7.2 of Chapter 1.

The general research objective of this dissertation is to assess the competitive ability and economic feasibility of utility-scale energy storage technologies for South Africa. This is completed in Chapters 6 and 7 by developing and applying the methods for estimating and projecting the cost competitiveness of select utility-scale energy storage systems with one another and, in combination with solar photovoltaic (PV) plants, with alternative electrical energy generation options.

As indicated in Chapter 1, the primary application investigated in the economic feasibility assessment for the empirical analysis is utility-scale renewables integration with solar PV plants. This application is assumed to require energy storage systems to provide four hours of electrical energy discharge capability at a 50 megawatt (MW) electrical power rating for 350 days a year. The purpose of the primary application is to overcome issues of solar resource variability and intermittency, supply electricity during periods of peak demand, enable electricity price arbitrage opportunities and integrate more renewable generators into the electric grid. Four hours' electrical energy discharge at a 50 MW power rating is equivalent to 200 megawatt hours (MWh) electrical energy output capacity.

Chapters 1 to 4 contextualised this study through background information on the potential for energy storage technologies as the share of renewable energy-based electrical generation options rises, as well as by providing an overview of energy storage systems, technologies, technical characteristics, applications and cost considerations. Section 5.2 supplied a review of literature that has considered the economic feasibility of utility-scale energy storage systems. Chapters 6 and 7 clarify the methods, selected technologies, rationale for integrating energy storage systems with solar PV plants, primary application scenarios considered and modelling results for the economic feasibility assessment completed for the empirical analysis of this study.

A production possibilities frontier approach can be utilised as a hypothetical example in order to illustrate energy storage systems within the context of economic theory and in alignment with the general research objective for this dissertation (Kumar *et al.*, 2009:334-352). A production possibilities frontier, or curve, is a simplistic graphical representation of the maximum attainable combinations of any two output commodities or services that can be efficiently produced in an economy with available resources, given fixed input factors of production and constant technology (Viljoen, 1998:226; Mohr *et al.*, 2004:9; Pindyck *et al.*, 2009:601; Todaro *et al.*, 2009:835; Besanko *et al.*, 2011:777; Mankiw, 2012:837). It reduces the complexity of an economy to explain some essential economic principles, such as efficiency, resource scarcity, trade-offs, opportunity cost, choice and economic growth (Mohr *et al.*, 2004:8-9; Todaro *et al.*, 2009:146; Mankiw, 2012:837).

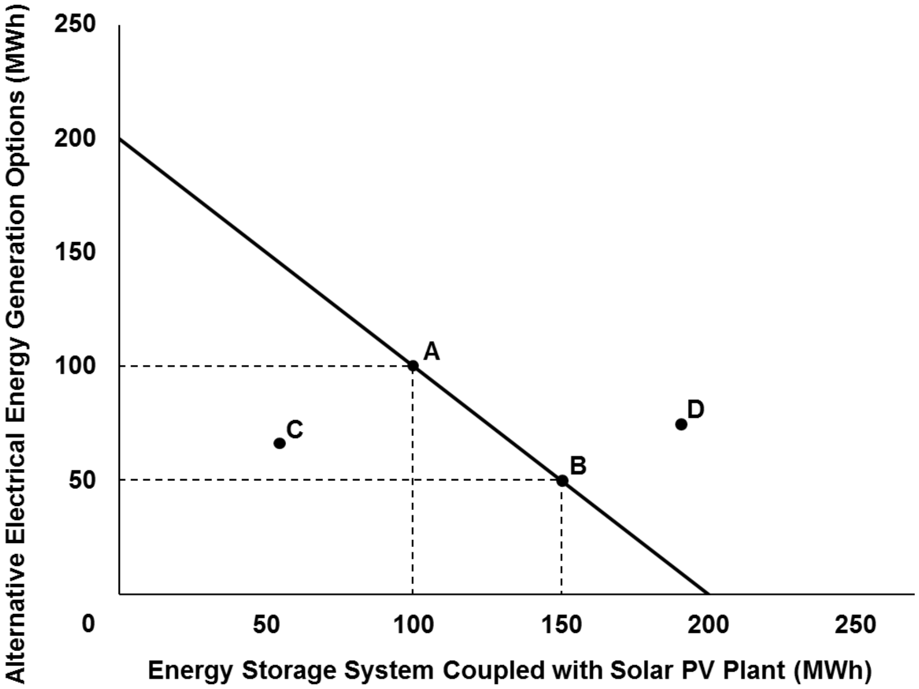
To connect the illustrative example to the empirical analysis for this dissertation in Chapters 6 and 7, an innovative approach is applied in the construction of the production possibilities frontier. In this regard, the two commodities are assumed as energy storage systems coupled with solar PV plants, on one axis, and alternative electrical energy generation options, on the other. Both commodity combinations are assumed to be required to perform an application requiring 200 MWh electrical energy output capacity, which characterises the production possibilities frontier.

Trade-offs between the two commodities are also assumed to be perfectly substitutable, since one additional MWh unit electrical energy from a combined energy storage system and solar PV plant necessitates one MWh unit less from alternative generation options in fulfilling an application requirement of 200 MWh as represented by the production possibilities frontier. In that regard, since the two commodities are perfectly substitutable, the production possibilities frontier takes the shape of a straight line. This is also known as a production possibilities frontier with a constant marginal rate of transformation (Besanko *et al.*, 2011:678-679; Mankiw, 2012:52; Lazkano *et al.*, 2017:2-15).

The marginal rate of transformation refers to the absolute quantity of one output good that must be sacrificed in order to produce a single additional unit of another good and thereby defines the shape of a production possibilities frontier (Viljoen, 1998:227; Mohr *et al.*, 2004:22; Pindyck *et al.*, 2009:602; Besanko *et al.*, 2011:775; Mankiw, 2012:27-28). Given the perfect substitutability of electrical energy produced by solar PV plants coupled with energy storage systems and alternative electrical generation options, the marginal rate of transformation equals one unit (Pindyck *et al.*, 2009:602; Besanko *et al.*, 2011:678).

Figure 5.2 adapts a conventional production possibilities frontier with a constant marginal rate of transformation to illustrate the possible trade-offs between energy storage systems coupled with solar PV plants and alternative electrical energy generation options to perform an application requiring 200 MWh electrical energy output capacity (adapted from Besanko *et al.*, 2011:678-679; Mankiw, 2012; 51-54). In the figure, electrical energy output possibilities for an energy storage system coupled with a solar PV plant are located on the horizontal axis, while the electrical production possibilities for alternative generation options are located on the vertical axis.

Figure 5.2: Production possibilities frontier with a constant marginal rate of transformation for an application requiring 200 MWh electrical energy output capacity



Source: Author's compilation

All points along the production possibilities frontier represent technically efficient potential output opportunities, *ceteris paribus* or all other things being equal. Both electric output commodities, in combination or separately, have the technical capability to perform an application requiring 200 MWh electrical energy production capacity as informed by the production possibilities frontier, which implies that actual output corresponds to potential output (Mohr *et al.*, 2004:22). The straight-line production possibilities frontier therefore indicates all efficient combinations of electrical energy output for an application requiring 200 MWh electrical energy capacity (Mohr *et al.*, 2004:22-24; Pindyck *et al.*, 2009:601-602; Mankiw, 2012:27).

For example, at point A, the required 200 MWh application could be fulfilled by a combination of a 100 MWh alternative electrical generation option and a 100 MWh energy storage system coupled with a solar PV plant. At point B, however, the use application can be accomplished with a 50 MWh electrical generator and 150 MWh combined energy storage and solar PV plant (Mohr *et al.*, 2004:22; Mankiw, 2012:26-27).

The trade-off associated with moving from point A to point B on the production possibilities frontier involves an opportunity cost. The economic theory of opportunity cost refers to the quantity of one production commodity that has to be foregone as a result of moving to a greater quantity of another production commodity (Mohr *et al.*, 2004:9-10; Todaro *et al.*, 2009:833). The opportunity cost of increasing the electrical energy output capacity of energy storage coupled with a solar PV plant to perform the required use application by moving from point A, 100 MWh, to point B, 150 MWh, is equal to 50 MWh that could have been generated by an alternative electrical generation option (Mohr *et al.*, 2004:8-9).

Any electrical production capacity combination within the production possibilities frontier, for example point C, represents an inefficient allocation of resources, given the technical capability to perform the required 200 MWh application. Conversely, points outside the production possibilities frontier, say point D, are not possible with given factor inputs and constant technology or existing production techniques, nor necessary, since the application electrical energy output requirement is limited to 200 MWh for the purposes of the illustrative example depicted in Figure 5.2 (Viljoen, 1998:227; Mohr *et al.*, 2004:22-24; Pindyck *et al.*, 2009:602; Mankiw, 2012:26-27).

The extent of the marginal rate of transformation from alternative electrical energy generation options to energy storage systems coupled with solar PV plants depends on societal preference and the least cost option, especially given the fundamental economic premise of resource scarcity and quantity demanded, q, as an inverse function of price, p, or $q = f(p)$. In that regard, the technology choice for electricity production is likely to shift in the direction of those technologies with the lowest levelised or lifetime cost associated with the performance of required use applications in order to minimise production costs (Antonelli, 2003:152-160; Mohr *et al.*, 2004:21-24; Pindyck *et al.*, 2009:602-605; Lipczynski, Wilson & Goddard, 2009:189; Stern, 2011:35-39; Weyman-Jones, 2011:21; Bhattacharyya, 2011:47-50; Bee, 2016:23-24). This shift is also known as price-induced technological change and innovation (Kumar *et al.*, 2009:335-352; Wiebe *et al.*, 2016:749).

Energy storage systems will be increasingly utilised if their levelised costs prove more economically feasible, in terms of cost competitiveness, relative to alternative electrical generation options (Pindyck *et al.*, 2009:602-605; Lipczynski *et al.*, 2009:189; Branker *et al.*, 2011:4470-4471; Johnstone *et al.*, 2013:143; Dehdashti, 2016:3; Wiebe *et al.*, 2016:740-749; Hartley & Medlock, 2017:57; Zou *et al.*, 2017:66; Lazkano *et al.*, 2017:15-16; Foster, Contestabile, Blazquez, Manzano, Workman & Shah, 2017:262-263). In relation to this, it can be appreciated that energy storage systems enhance the elasticity of technical substitution between intermittent renewable energy and conventional electrical generation alternatives (Johnstone *et al.*, 2013:143; Lazkano *et al.*, 2017:2-15).

As explained in sub-section 4.2.11 of Chapter 4, energy storage systems further have the technical capability to perform more than one application sequentially and/or simultaneously, which significantly enhances the value of energy storage relative to cost (Sioshansi *et al.*, 2009:277; He *et al.*, 2011:1575-1584; Zhang, 2013:39; Carnegie *et al.*, 2013:14-19; Kaun *et al.*, 2013:25-85; Pawel, 2014:69; Castillo *et al.*, 2014:888; Battke *et al.*, 2015:334-339; Lambruschi, 2015:24-26; De la Rubia *et al.*, 2015:7-8; Kempener *et al.*, 2015:15; Kondziella *et al.*, 2016:15-20; Jülch, 2016:1604; Lazard, 2016:4; Malhotra *et al.*, 2016:706-717; Ferroukhi *et al.*, 2017:80-81). The economic feasibility of energy storage technologies relative to alternative electrical generation options within the South African context, in terms of cost competitiveness, is the focus of Chapters 6 and 7 and suggests the likely direction of the marginal rate of transformation.

The influence of cost on the marginal rate of transformation can also be viewed in relation to the economic theory of cost-benefit analysis. A cost-benefit analysis involves the quantification of costs and anticipated benefits over the lifetime of a proposed investment and assessing whether the net favourable consequences of the proposed investment are likely to outweigh its associated monetary disbursements, as well as the costs and benefits of alternative investment options (Drèze *et al.*, 1987:911; Layard *et al.*, 1994:1-4; Boardman *et al.*, 2006:7-17; Cellini *et al.*, 2010:494-495; Schoenung, 2011:12; Bhattacharyya, 2011:163; Sullivan *et al.*, 2015:444-467; Berrada *et al.*, 2017:101). The purpose of cost-benefit analyses is to evaluate the economic feasibility of different potential investments or projects in order to attain the most optimal allocation of scarce resources in the interest of improving social welfare (Drèze *et al.*, 1987:910-911; Bhattacharyya, 2011:165).

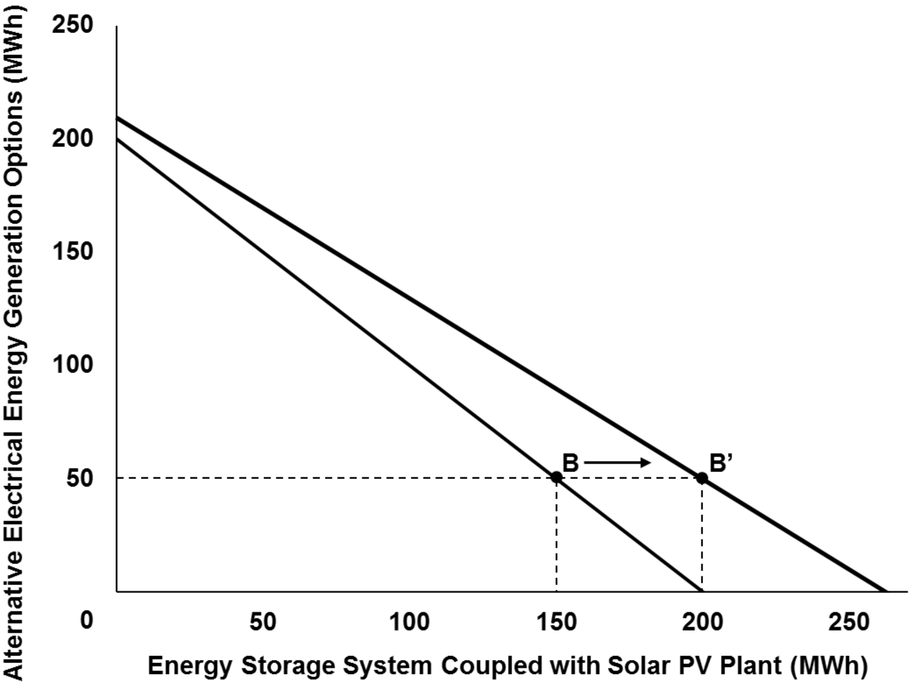
As explained in sub-section 1.7.2 of Chapter 1, according to Watson’s dictum, benefits arising from electrical output are equal regardless of the energy source used to produce such output and cost-benefit analyses of electrical energy infrastructure could therefore be based on cost comparisons alone (Donald *et al.*, 1971; Bhattacharyya, 2011:177; Lombaard *et al.*, 2016:3). From the perspective of this maxim, the reflective lifetime cost of energy storage systems coupled with solar PV plants relative to alternative electrical energy generation options is a primary driver of the marginal rate of transformation between them.

It could be noted, however, that the assumption of equal benefits from electrical output disregards positive externalities emanating from renewable energy-based electrical production options relative to fossil fuel-based electrical generators, especially those related to the environment and human health (Donald *et al.*, 1971; Lombaard *et al.*, 2016:7-8). Accounting for such externalities could potentially further support the marginal rate of transformation to energy storage systems coupled with solar PV plants, since social costs emanating from fossil fuel-based electrical generators, mainly in the form of environmental damage and pollution, are higher than those associated with renewable energy technologies (Roth *et al.*, 2004:2138-2142; Sklar-Chik *et al.*, 2016:130).

When the assumption of constant technology or existing production techniques is abandoned, it is possible to attain output combinations outside of the original production possibilities frontier by raising potential output (Mohr *et al.*, 2004:22-24). Technological advancements cause an outward shift of the production possibilities frontier due to productivity or efficiency improvements for available factors of production, which enables the production of more output goods and services from a given level of input combinations (Mohr *et al.*, 2004:22-24; Todaro *et al.*, 2009:144; Besanko *et al.*, 2011:778). On an economy-wide basis, it is the outward shift of the production possibilities frontier that supports economic growth, since more output commodities can be efficiently produced with the same amount of factor inputs, which, in turn, contributes to lower unitary costs and higher gross domestic product (GDP) on an aggregate level (Mohr *et al.*, 2004:23-24; Todaro *et al.*, 2009:143-144; Besanko *et al.*, 2011:778; Mankiw, 2012:28).

Figure 5.3 broadens the production possibilities frontier concept illustrated in Figure 5.2 to allow for technological progress in energy storage systems. Such progress could result from a variety of techno-economic improvements, of which some examples include advances in technical characteristics such as roundtrip efficiency, degradation, depth of discharge, cycle life and energy density (Hittinger *et al.*, 2012:436; Luo *et al.*, 2015:531; World Energy Council, 2016a:12-13; Dehdashti, 2016:1; REN21, 2017:140; Ferroukhi *et al.*, 2017:80-81; Obi *et al.*, 2017:913-914;). The main technical characteristics associated with energy storage technologies are clarified in Chapters 2 and 3.

Figure 5.3: Production possibilities frontier with a constant marginal rate of transformation and technological progress in energy storage systems



Source: Author’s compilation

While conventional and renewable energy-based electrical generation options may also benefit from technological advancements, it is assumed for illustrative purposes that energy storage systems, especially electrochemical batteries, are likely to experience greater technological progress. This could be considered a reasonable assumption given the rapid technical developments and cost reductions experienced by energy storage systems, while conventional electrical generation options are at a higher level of maturity and thereby undergo substantially diminished learning rates (Hittinger *et al.*, 2012:436; Nykvist *et al.*, 2015:329-331; Dehdashti, 2016:1-7; Covert *et al.*, 2016:127-130; Wiebe *et al.*, 2016:741; REN21, 2017:138-141; Obi *et al.*, 2017:908-913; Foster *et al.*, 2017:258-263; Astarloa *et al.*, 2017:10-11; Lazkano *et al.*, 2017:2-16; Saboori *et al.*, 2017:1108).

It can be observed from Figure 5.3 that technological progress in energy storage systems result in an outward shift of the production possibilities frontier along the horizontal axis. For example, improvements in aspects such as technological roundtrip efficiency, depth of discharge and/or cycle life enable energy storage systems to provide higher electrical energy output levels than would be the case prior to such technical advancements. This would cause the production possibilities frontier to shift, since electrical energy output capability would be enhanced as indicated by a move from point B to B' of the production possibilities frontier indicated in Figure 5.3 (Mohr *et al.*, 2004:22-23; Todaro *et al.*, 2009:145-146; Mankiw, 2012:28). To conceptually allow for a possible transfer of technical benefits to alternative electrical generation options that arise from technological progress in energy storage systems, the production possibilities frontier also shifts marginally along the vertical axis (Todaro *et al.*, 2009:144; Lazkano *et al*., 2017:1-16).

5.4 SUMMARY AND CONCLUSION

This chapter provided a literature review of studies that have considered the economic feasibility of utility-scale energy storage technologies, outlined levelised cost estimates for such technologies by relevant application from existing research and contextualised the technologies in light of economic theory and the primary thesis for this study. The literature review verified the degree to which the economic feasibility of energy storage systems has been investigated as necessary to inform the empirical analysis for this dissertation. The theoretical contextualisation offered a unique preliminary perspective regarding the relevance and role of modern energy storage technologies in the process of sustainable economic growth and development.

Section 5.1 introduced the content to Chapter 5. Section 5.2 supplied a review of literature that has involved the economic feasibility of utility-scale energy storage systems. From the literature review, it is noted that economic feasibility assessments of energy storage technologies have only recently benefited from increased attention. It is further observed that levelised cost estimations and analyses are preferred to assess the economic feasibility of energy storage systems in terms of cost competitiveness with one another and with alternative electrical generation options.

The literature review confirmed that research into the reflective levelised cost of energy storage technologies (LCOS) has been insufficient, inappropriate and/or obscure and future projections of such costs have been inadequate. Lifecycle cost estimates have also primarily accounted for single charge-discharge cycles per day, although the technical capability of energy storage technologies allows for more than one daily cycle to be performed and thereby influences lifetime costs. Very little research was furthermore identified on the existing and future economic feasibility of energy storage systems relative to alternative electrical generation options. This is an area that warrants further analysis and in which this study provides additional value to available literature.

The literature review therefore confirmed the need for detailed levelised cost estimations, projections and analyses for energy storage systems in isolation and when such systems are coupled with intermittent renewable energy electrical production plants in order to enable cost comparisons with alternative electrical generation options. The main shortcomings identified during the literature review and addressed through the empirical analysis are specified in section 6.2 of Chapter 6.

Section 5.3 contextualised the applicability of energy storage technologies to economic theory within the framework of the general research objective for this dissertation. The theoretical association and role of advancements in energy storage technologies was explained within some established economic growth and development hypotheses, including endogenous growth theory and the related innovation economics and structural change theories. The technological progress experienced by energy storage systems was further represented in relation to the empirical analysis of Chapters 6 and 7 through the production cost theory of the firm and adaptation and use of the production possibilities frontier hypothesis, as well as the related opportunity cost and cost-benefit theories.

The information presented in Chapter 5 enabled the attainment of the specific objective set for this study that requires a literature review of previous investigations into the economic feasibility of energy storage technologies and description of how such technologies relate to economic theory. The content conveyed throughout Chapters 1 to

5 contributed to addressing the research problem specified in section 1.4 of Chapter 1 and provided the necessary context to perform the empirical analysis in Chapters 6 and 7. The focus of Chapter 6 is to clarify the methods developed and applied to assess and project the economic feasibility of select utility-scale energy storage systems for South Africa in Chapter 7.

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CHAPTER 6:

APPLIED METHODS FOR THE EMPIRICAL ANALYSIS

6.1 INTRODUCTION

Chapter 6 explains the methods undertaken to perform the empirical analysis for this dissertation. The information supplied throughout the preceding Chapters 1 to 5 provided the necessary context to assess the economic feasibility of utility-scale energy storage technologies for South Africa. The literature review in section 5.2 of Chapter 5 further verified the degree to which the competitive viability of such technologies have been studied and informs the methodological needs and framework for the empirical analysis.

In that regard, the goal of this chapter is to contribute to the attainment of the specific objectives set for the study in Chapter 1 by improving on methods to calculate and assess the economic feasibility of energy storage systems. This is completed through a novel techno-economic mathematical levelised cost of energy storage (LCOS) model formulation, extension and analysis. Levelised cost analyses are appropriate for assessing the economic feasibility or cost competitiveness of different technologies (Dufo-López *et al*., 2009:129-130; Branker *et al.*, 2011:4471; Battke *et al*., 2013:240-249; Bortolini *et al.*, 2014:85; Zakeri *et al.*, 2015:570-573; Jülch, 2016:1595-1605; Hoff *et al.*, 2016:2; Obi *et al.*, 2017:908-918; Lai *et al*., 2017:191-202). Accordingly, the methods described in this chapter enables an assessment of the cost competitiveness of utility-scale energy storage systems for South Africa, which is the focus of Chapter 7.

This chapter is structured according to eight sections. The next section (6.2) clarifies the methodological outline for the empirical analysis. Section 6.3 provides more detail on the selection of energy storage technologies for the empirical part of this study. Section 6.4 elaborates on the need to integrate energy storage systems with solar photovoltaic (PV) electrical production plants within the South African context. Section 6.5 explains the methods applied for the LCOS model. Section 6.6 extends the LCOS model by discussing the approach followed to determine the weighted average levelised cost of energy storage systems coupled with solar PV plants (LCOS-PV). Section 6.7 describes the method to assess the economic feasibility of the select energy storage systems by comparing the LCOS-PV to the levelised cost of electricity (LCOE) for concentrating solar power (CSP) plants with thermal energy storage capability. Section 6.8 summarises and concludes Chapter 6.

6.2 METHODOLOGICAL OUTLINE

Methodology can be regarded as a systematic way of explaining the procedures followed in a field of study. The methodology developed is applied to a detailed levelised cost of energy storage (LCOS) model to estimate and project the present value of lifecycle costs per unit of electrical energy for select energy storage systems in isolation and when such systems are coupled with solar photovoltaic (PV) electrical generation plants. The model was formulated through research, industry experience and external networking. It has also been reviewed and received input from researchers and practitioners in the electrical energy industry familiar with energy modelling and storage technologies.

The levelised cost analysis is performed for energy storage technologies in isolation to enable comparison between different technologies and for such technologies coupled with solar PV plants to enable comparison with alternative generation options with similar electrical output dispatch characteristics. The results are presented for 2016 and further projected to 2020 under four scenarios to evaluate the current and potential future competitive ability of select energy storage systems at the utility scale. The scenarios are evaluated in terms of daily charge-discharge cycling requirements and project contract lifetime specifications.

The technologies selected for the modelling include lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries. These batteries are regarded as prominent electrochemical technologies for utility-scale electrical energy storage and can generally serve multiple applications (Battke *et al*., 2013:241-24; Suberu *et al.*, 2014:509; Akinyele *et al.*, 2014:80-85; Hameer *et al.*, 2015:1193-1194; Malhotra *et al*., 2016:709-710; Lai *et al.*, 2017:194-201). Sub-section 3.2.5 of Chapter 3 contains an overview of these battery technologies and the next section (6.3) elaborates more on their selection for the empirical analysis.

The primary use application that the selected energy storage systems will be required to perform within the South African context is assumed as renewables integration with solar PV plants requiring four hours of energy discharge capability at a 50 megawatt (MW) electrical power rating for 350 days a year. The purpose of the primary application is to overcome issues of solar resource variability and intermittency, supply electrical energy during periods of peak demand, enable electricity price arbitrage opportunities and integrate more renewable generators into the electricity grid. This primary application could potentially be complemented by additional value applications, such as energy time shifting and arbitrage, load levelling and peak shaving, operating reserves, black start capability and/or transmission grid congestion relief and investment upgrade deferral. The various value applications that can be performed by energy storage technologies are discussed in section 4.2 of Chapter 4.

The economic feasibility of the select energy storage systems is tested in Chapter 7 by comparing the estimated and projected total weighted average levelised cost of such systems combined with solar PV plants (LCOS-PV) to the 2016 and anticipated 2020 levelised costs of concentrating solar power (CSP) plants with thermal energy storage capability. CSP plants with thermal energy storage were chosen as a case study, since it enables a fair basis for comparison as both energy storage systems coupled with solar PV plants and CSP plants with thermal energy storage capability produce and store solar-based electrical energy for later use. CSP plants with thermal energy storage capability are also considered mature technology (Grobbelaar *et al.*, 2014:479; Khan *et al.*, 2016:419; Van Ravenswaay *et al.*, 2015:1839; Chaanaoui *et al.*, 2016:782-789).

The novelty of the LCOS model used in this study is that it allows for improved economic estimates, analyses and feasibility assessments of energy storage technologies by building on the work of previous authors who have undertook similar studies. As identified during the literature review outlined in section 5.2 of Chapter 5, this includes building on the methodology, shortcomings and recommendations of authors such as Poonpun *et al*. (2008:530-533), Battke *et al*. (2013:246-249), Kaun *et al.* (2013:86), Pawel (2014:68-77), Zakeri *et al*. (2015:573-596), Jülch *et al*. (2015:24), Lazard (2015:1-24), Lazard (2016:1-34), Mundada *et al.* (2016:692-701), Jülch (2016:1596-1605), the World Energy Council (2016a:16-26), Lai *et al.* (2017:195-197) and Obi *et al*. (2017:908-918).

Shortcomings of previous levelised cost formulations and related analyses identified during the literature review, which are addressed by the LCOS model developed and utilised for this study, include a failure to incorporate the following factors:

- Disclose detailed formulae, parameters, uncertainties and assumptions used;
- Adequately elaborate on value application requirements;

- Appropriately account for all technical operational parameters of energy storage technologies, including cycling frequency, roundtrip efficiency losses, capacity degradation, charging costs and depth of discharge (DoD) limitations;
- Accommodate for energy storage technology replacement rates and costs;
- Allow for more than one daily charge-discharge cycle;
- Project potential future LCOS estimates;
- Estimate and forecast the levelised costs when energy storage systems are integrated with solar PV technologies; and
- Determine the extent to which energy storage systems coupled with solar PV plants could compete with alternative electrical generation options.

6.3 SELECT ENERGY STORAGE TECHNOLOGIES

To identify and select primary competing energy storage technologies that will be most suited to perform particular applications, it is necessary to evaluate their respective strengths, weaknesses and future prospects (Berrada *et al.*, 2017:103). The selection criteria, characteristics, capabilities, applications and cost considerations of utility-scale energy storage technologies summarised in Chapters 2 to 4 assist in the selection of promising technologies to perform utility-scale applications in South Africa.

Of the technologies outlined in section 3.2 of Chapter 3, electrochemical batteries are ideally suited for renewables integration, which is the primary value application investigated in this study (Suberu *et al.*, 2014:504-512; Lund *et al.*, 2015:795; World Energy Council, 2016a:11; Malhotra *et al.*, 2016:710). Of these, lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries have overall been selected as the most competitive, technically advanced and promising electrochemical energy storage technologies for performing utility-scale applications, including renewables integration (Dunn *et al.*, 2011:928-934).

The select technologies are modularly scalable to provide high energy and/or electrical power capacity (Dunn *et al.*, 2011:928-934). In addition to their technical capabilities, they also have favourable cost characteristics, as can be seen in Table 4.2 in section 4.3 of Chapter 4, with prospects for further significant cost reductions. Although lithium-ion, VRFB and NaS batteries are the technologies chosen for the empirical analysis in this dissertation, the methods developed for the levelised cost of energy storage (LCOS) model can be applied to most energy storage technologies.

Lithium-ion, VRFB and NaS batteries have further been widely recognised in literature as superior utility-scale electrochemical energy storage technologies in comparison to alternatives. In this regard, a few examples of confidence from literature can be provided and more information for each technology is supplied in sub-sections 3.2.5.5, 3.2.5.7 and 3.2.5.8 of Chapter 3.

Hameer *et al.* (2015:1193-1194) deduce that lithium-ion, flow and NaS batteries, in addition to thermal energy storage, pumped hydroelectric energy storage (PHS) and compressed air energy storage (CAES), are appropriate for utility-scale energy storage of 10 to more than 100 megawatt hours (MWh) electrical energy output capacity. Suberu *et al.* (2014:509) and Akinyele *et al.* (2014:80-85) support this by indicating that lithium-ion, VRFB and NaS batteries possess high roundtrip efficiencies and are suitable for utility-scale applications ranging between 10 and 100 megawatt (MW) or more.

Malhotra *et al*. (2016:709-710) compiled a comprehensive database of 1 279 energy storage project installations around the world up to February 2015, of which 612 were electrochemical technologies. They found that lithium-ion, flow, NaS and lead-acid battery systems have been the most widely deployed electrochemical technologies to date in terms of number of projects, energy capacity and electric power capacity. Of a total 2 444 MWh energy capacity, NaS batteries accounted for approximately 43% of all electrochemical energy storage installations, which was followed by lithium-ion with 39.2% and flow batteries with 11.1%.

Review studies by Dunn *et al.* (2011:928-934) and Battke *et al*. (2013:241-248) focused on lithium-ion, VRFB, NaS and lead-acid batteries as technically developed and commercialised technologies with high potential for grid-scale energy storage. Battke *et al*. (2013:241-248) also indicated that lithium-ion, VRFB and NaS batteries have a comparative lifetime cost and operational advantage for applications requiring frequent cycling capability.

Amirante *et al.* (2017:374-385) reviewed and compared the most promising mechanical, chemical, electrical and electrochemical energy storage technologies for utility-scale applications over the long term. Among these, lithium-ion and VRFB batteries were the only electrochemical energy storage technologies included in the review, signifying their importance for future environmentally sustainable electrical energy systems.

Battke *et al.* (2015:339-344) regard VRFBs as a core technology with significant potential to serve both power and energy intensive utility-scale value applications. Suberu *et al.* (2014:511) indicate that NaS and flow batteries are receiving the most attention for maintaining the reliability and continuity of electrical energy supply at the utility scale. Hittinger *et al.* (2012:437) and Luo *et al*. (2015:517-518) point out that lithium-ion and NaS batteries are likely the most prominent utility-scale rapid response and scalable technologies with excellent potential for market share gains, cost reductions and performance improvements.

Hameer *et al.* (2015:1193-1194), Kyriakopoulos *et al.* (2016:1063) and Lai *et al.* (2017:194-201) state that lithium-ion batteries are the most common storage technology and are likely to form an integral part of future utility-scale energy storage systems and applications due to rapidly declining costs and technical improvements. Lai *et al.* (2017:194-201) and Mandelli *et al.* (2016:291) further state that lithium-ion and lead-acid batteries are appropriate for applications requiring short discharge durations, while VRFB and NaS batteries are more appropriate for applications requiring longer discharge durations. Lai *et al.* (2017:194-201) also mention that VRFBs are growing in importance and are the most mature and commercially available electrochemical technology for utility-scale energy storage applications.

Obi *et al*. (2017:913) highlight that the independent power and energy profiles of flow batteries give them a comparative advantage over other energy storage technologies. The reason for this is mainly that the power and energy capabilities can be sized separately from one another and the external storage of active materials enables a much longer lifetime, permits the absence of self-discharge, allows for higher roundtrip efficiency and lowers maintenance requirements as system components can be replaced partially, rather than replacing the entire energy storage medium. This relative advantage of flow batteries is also noted by authors such as Krivik *et al.* (2013:94), Akinyele *et al.* (2014:89), Mahlia *et al.* (2014:539), Luo *et al.* (2015:518), Pan *et al.* (2015:20499-20500), Akhil *et al.* (2015:55), Lund *et al*. (2015:795), Cunha *et al.* (2015:907), Aneke *et al.* (2016:361), Amrouche *et al.* (2016:20917), Gallo *et al.* (2016:809), Amirante *et al.* (2017:380-385) and Lai *et al.* (2017:202).

Dunn *et al.* (2011:932), Suberu *et al.* (2014:504), Hameer *et al.* (2015:1193-1194) and Kyriakopoulos *et al.* (2016:1063) recognise that utility-scale NaS batteries are highly commercialised in Japan and the United States due to advanced technical performance characteristics, but that a lack of supplier competition has restricted technology growth and rapid price declines. Hittinger *et al.* (2012:437) and Poullikkas (2013:781) note that utility-scale commercially available NaS batteries are limited to one manufacturer, namely NGK Insulators from Japan. Increased technology deployment and the expiry of NGK Insulators' patent on NaS batteries could provide room for increased competition and commercial production, innovation and accelerated cost reductions for these batteries (Suberu *et al.*, 2014:504; World Energy Council, 2016a:37).

Gallo *et al.* (2016:808) and Hittinger *et al.* (2012:437) refer to the comparative advantage of NaS batteries to provide pulse power. Pulse power is the capability to deliver electrical energy in excess of a technology's nominal power rating for limited periods. Gallo *et al.* (2016:808) and Hittinger *et al.* (2012:437) indicate that NaS batteries can supply 500% more electrical energy than the specified power rating for 30 seconds, but that this capability diminishes to 150% of the technical power rating if pulse power is provided for up to three hours.

Kempener *et al.* (2015:26-27), Amrouche *et al.* (2016:20916) and Gallo *et al.* (2016:808) explain that NaS batteries have been the leading utility-scale electrochemical technology, but presently have to compete with lithium-ion and VRFB batteries for market share. Amrouche *et al.* (2016:20916) note that lithium-ion batteries represented approximately 85.6% of total energy storage installations in 2015 and are presently the most popular energy storage technology being deployed globally due to their use in various industries. Hammond *et al.* (2015:559-569) infer that lithium-ion batteries are likely to remain the dominating electrochemical technology over the short term due to their good overall performance and widespread deployment in several sectors.

Amrouche *et al.* (2016:20916) indicate that while lithium-ion batteries have relatively high initial capital costs, they are appropriate for renewables integration and involve some of the lowest capital costs per cycle compared to other electrochemical technologies, which is a point also noted by Malhotra *et al*. (2016:710), Berrada *et al.* (2017:97) and Obi *et al*. (2017:914). Akinyele *et al.* (2014:89) and Obi *et al*. (2017:914) further state that the suitability of lithium-ion batteries for utility-scale applications is enhanced by excellent roundtrip efficiency, high energy density and low self-discharge rates.

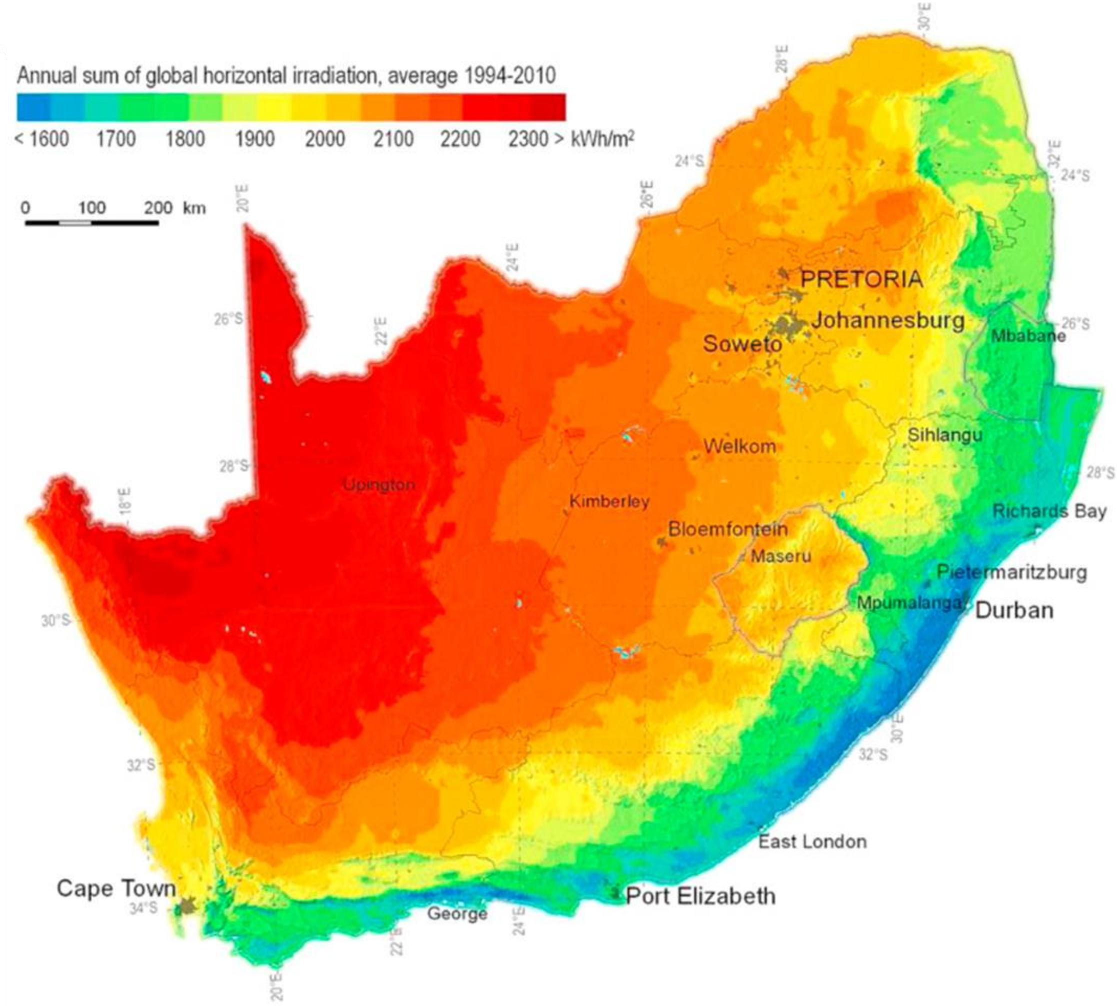
Hill (2016:1) shows that lithium-ion battery cell prices have declined sharply, between 10 and 15% annually, from around USD 1 200 per kWh in 2008 to USD 350 per kWh in 2016. Similar annual price decline rates and costs for lithium-ion batteries have been reported by Nykvist *et al.* (2015:329), Amirante *et al.* (2017:381) and Lazard (2016:17-19). Hill (2016:1) also states that flow batteries have declined at similar annual rates over the same eight-year period. It is further noted that the deployment and price declines of these technologies have been encouraged by significant cost reductions experienced by solar photovoltaic (PV) technologies, which is also supported by the World Energy Council (2016a:6). Overall, costs for all three select technologies are expected to continue declining sharply into the future (Jülch *et al.*, 2015:26; Kyriakopoulos *et al.*, 2016:1063; Günter *et al.*, 2016:234; Dehdashti, 2016:1-3; Lazard, 2016:19-21; World Energy Council, 2016a:16; Malhotra *et al.*, 2016:706; Jülch, 2016:1594-1604; Obi *et al.*, 2017:909).

6.4 SOLAR PHOTOVOLTAIC (PV) PLANTS COUPLED WITH ENERGY STORAGE TECHNOLOGIES

The national electric grid is most constrained during periods when demand for electricity is at its highest (Kohler, 2014:536; Pollet *et al.*, 2015:16686). In South Africa, the peak or maximum load demand persists for around three hours in the mornings, between 07:00 and 10:00, and four hours in the evenings, between 18:00 and 22:00 in summer and between 17:00 and 21:00 in winter (Eskom, 2016a:112; Department of Energy, 2017:30; Lai *et al.*, 2017:197; Pan *et al.*, 2017:387). During these periods, Eskom, the national electric utility, primarily has to rely on expensive fossil fuel-based peaking and mid-merit generation plants, such as diesel-fired open cycle gas turbines and inefficient coal power stations, as well as conventional hydroelectric and pumped hydroelectric energy storage (PHS) plants to supply much needed electrical energy (Kusakana *et al.*, 2013:467; Eskom, 2014:1; Eskom, 2015:19-81; Kenny, 2015:21; Pollet *et al.*, 2015:16698; Eskom, 2016a:112; Eberhard *et al.*, 2016:164-169).

Solar photovoltaic (PV) is an environmentally sustainable renewable energy technology that converts irradiation from the sun directly into electricity (Branker *et al.*, 2011:4471; Nhamo *et al.*, 2016:71; Khan *et al.*, 2016:419). Solar irradiation levels in South Africa are among the highest in the world, especially in the Northern Cape Province, as can be seen in Figure 6.1 (Gauché, Brent & von Backström, 2014:693-705; Walwyn *et al.*, 2015:391-393; Van Ravenswaay *et al.*, 2015:1843; Busse *et al.*, 2016:52-55; Minnaar, 2016:1140-1141; Department of Energy, 2017:23-24). This has attracted substantial investment interest from domestic and international solar-based electrical generation project developers as it enables relatively higher electrical energy output levels and thereby significant lifetime cost reductions (Battke *et al.*, 2013:247-249; Grobbelaar *et al.*, 2014:479; Hurtado Munoz, Huijben, Verhees & Verbong, 2014:180; Kenny, 2015:19; Walwyn *et al.*, 2015:391-393; Van Ravenswaay *et al.*, 2015:1838-1843; Pfenninger *et al.*, 2015:306-307; Eskom, 2015:66-73; Bortolini *et al.*, 2015:1024-1025; Busse *et al.*, 2016:52-53; Gielen *et al.*, 2016:14; Minnaar, 2016:1140; Nakumuryango *et al.*, 2016:1000; Department of Energy, 2017:23-24; Lai *et al.*, 2017:193-194).

Figure 6.1: Quality of solar irradiation in South Africa



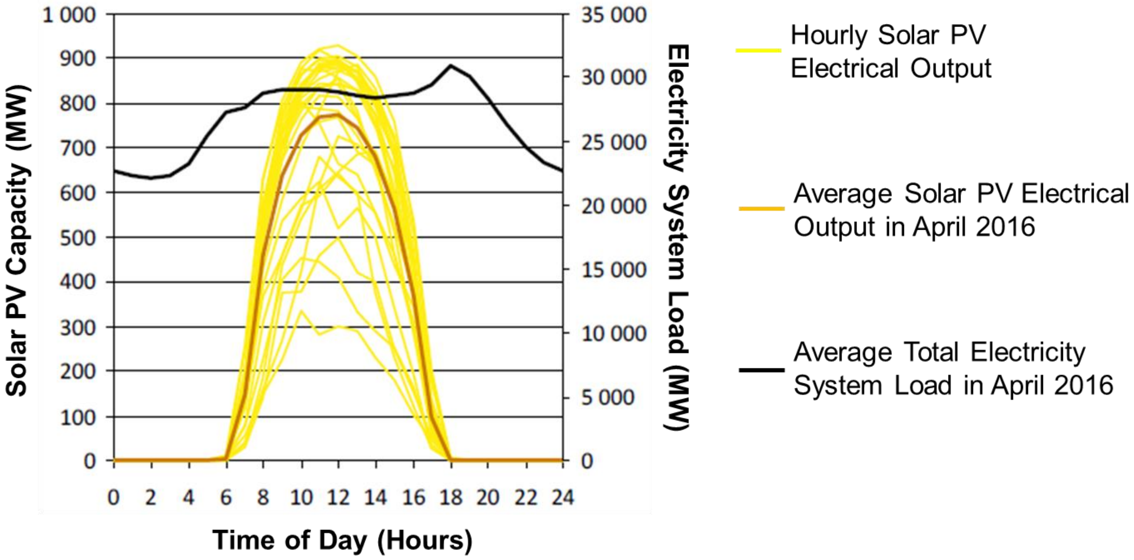
Source: Gauché *et al.* (2014:693-705); Walwyn *et al.* (2015:391-393); Van Ravenswaay *et al.* (2015:1843); Busse *et al.* (2016:52-55); Minnaar (2016:1140-1141); Department of Energy (2017:23-24)

Electrical energy generated by solar PV plants, however, cannot be dispatched upon request and has to be utilised or wasted as soon as it is produced (Evans *et al.*, 2012:4142; Kaltschmitt *et al.*, 2013:1664; Akinyele *et al.*, 2014:74; Delarue *et al.*, 2015:5; Amirante *et al.*, 2017:373; Lai *et al.*, 2017:192-194). The dispatchability of a generator refers to its ability to change its electrical output as needed to meet varying electricity supply requirements in line with prevailing demand conditions (Akhil *et al.*, 2015:153).

Electrical energy output from solar PV plants is maximised around midday at 12:00, whereas it fades gradually toward the early morning and late afternoon hours as solar irradiation dissipates. Solar-based electrical energy therefore follows a pattern of an inverted-u and contributes to daytime demand for electricity, even if this contribution is uneven. When the sun has set, however, solar PV plants do not generate electrical energy at all in the absence of energy storage capability, thereby preventing them from supporting the evening peak demand period. Electrical energy from solar PV plants is further restricted during periods of cloud cover (Neuhoff, 2005:92; Zahedi, 2011:866; Evans *et al.*, 2012:4142; Giglmayr *et al.*, 2015:783-784; Eskom, 2015:20; Kempener *et al.*, 2015:15; Bortolini *et al.*, 2015:1031; Eskom, 2016a:52; Nhamo *et al.*, 2016:72; Gielen *et al.*, 2016:14; Huang *et al.*, 2016:633; Lai *et al.*, 2017:194-199; Pan *et al.*, 2017:386).

Figure 6.2 shows actual hourly electrical energy produced by solar PV plants with a combined 1 040 megawatt (MW) capacity supplied to the South African electricity grid for 30 days in April 2016 (Council for Scientific and Industrial Research, 2016c:25). The figure illustrates the variability, intermittency and typical electrical supply duration and profile associated with solar PV plants on a daily basis due to changing solar irradiance levels and cloud movements. It can be seen that electrical energy from solar PV plants naturally contribute to the total system load or demand for electricity during the day between 06:00 and 18:00 in a parabolic fashion. As such, electrical output from solar PV plants generally contributes to the morning peak demand period, albeit growingly from relatively low levels, but not to the evening peak demand period.

Figure 6.2: Electrical energy supplied by solar PV in April 2016



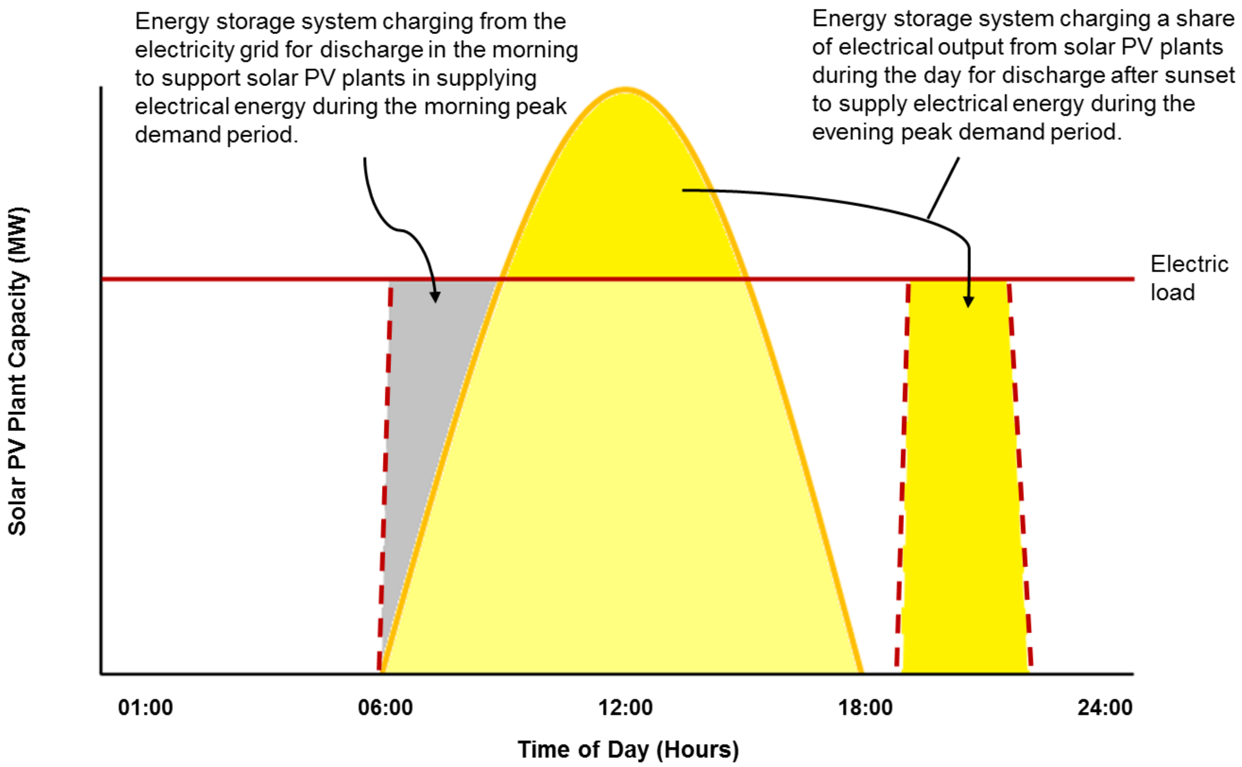
Source: Council for Scientific and Industrial Research (2016c:25)

The extent to which solar-based electrical production plants can be integrated into the national electricity grid is limited by the stochastic nature of their resources (Beaudin *et al.*, 2010:303-304; Zahedi, 2011:866-870; Ibrahim *et al.*, 2013:1; Akinyele *et al.*, 2014:74; Rejc *et al.*, 2014:655; Zou *et al.*, 2017:57; Amirante *et al.*, 2017:373). This is due to the relative resource unavailability during cloud cover and peak demand hours and surplus availability during periods of relatively lower demand during the day (Zahedi, 2011:866-868; Eskom, 2015:20; Kenny, 2015:15-18; Nhamo *et al.*, 2016:72; Rycroft, 2017:24).

As explained in sub-section 4.2.5 of Chapter 4, in order for solar PV plants to provide electrical energy upon demand in spite of prevailing weather conditions, solar energy could be harnessed, stored and dispatched through the use of energy storage technologies, such as those selected for this study. This would enable constant stable, reliable and dispatchable electrical energy availability from solar PV plants by utilising energy storage technologies to overcome issues of solar resource unavailability, variability and intermittency. The fundamental idea of storing electrical energy at the utility-scale is described in section 2.2 of Chapter 2 (Rydh & Sandén, 2005:1958; Neuhoff, 2005:92; Poonpun *et al.*, 2008:529; Zahedi, 2011:866-870; Sørensen, 2011:892; Hittinger *et al.*, 2012:439; Evans *et al.*, 2012:4142; Ibrahim *et al*., 2013:1; Carnegie *et al.*, 2013:9-79; Suberu *et al.*, 2014:510; Castillo *et al.*, 2014:888; Akinyele *et al.*, 2014:74-76; Pfenninger *et al.*, 2015:303; Hammond *et al.*, 2015:560; Luo *et al.*, 2015:529; Lund *et al.*, 2015:793; Battke *et al.*, 2015:338; Gielen *et al.*, 2016:14; Günter *et al.*, 2016:227; Kyriakopoulos *et al.*, 2016:1062; Aneke *et al.*, 2016:350-366; Chaanaoui *et al.*, 2016:783; Amrouche *et al.*, 2016:20914-20922; Malhotra *et al.*, 2016:718; Gallo *et al.*, 2016:815; Dehdashti, 2016:1-7; Amirante *et al.*, 2017:372-376; Rycroft, 2017:24; Lai *et al.*, 2017:191-199; Obi *et al.*, 2017:909-910; Berrada *et al.*, 2017:97).

A portion of the electrical energy generated by a solar PV plant could be fed into an energy storage system for later discharge and use. The energy storage solution could also charge from excess electricity in the grid when it is not consuming a portion of the electrical energy produced by the solar PV plant (Chen *et al.*, 2009:293-294; Infield *et al.*, 2014:22-23; Pawel, 2014:70; Zakeri *et al.*, 2015:572; Bortolini *et al.*, 2015:1028). This concept is visually illustrated under perfect irradiance or clear sky conditions by Figure 6.3 (adapted from Kempener *et al.*, 2015:15; Lai *et al.*, 2017:197-199; Pan *et al.*, 2017:381-382).

Figure 6.3: Concept of using energy storage systems coupled with solar PV plants to support peak demand periods



Source: Adapted from Kempener *et al.* (2015:15); Lai *et al.* (2017:197-199); Pan *et al.* (2017:381-382)

As can be seen from Figure 6.3, an energy storage system could charge a share of the electrical energy output directly produced by a solar PV plant and discharge the associated stored energy during the evening peak demand period when the solar PV plant is no longer generating electricity. After the energy storage device has discharged the solar-based electrical energy, it could continue to charge at night from excess electricity in the grid and discharge the associated stored energy during the morning peak demand period. Thereafter, the daily charge-discharge cycle from the solar PV plant and electricity grid could be repeated (Dufo-López *et al*., 2009:126-137; Whittingham, 2012:1518-1519; Pawel, 2014:73; Bortolini *et al.*, 2015:1029; Dehdashti, 2016:5-6; Lai *et al.*, 2017:197-199).

It is this technical capability of energy storage solutions, to charge from both solar PV plants and the electric grid, that allows for a double charge-discharge cycle per day (Dufo-López *et al*., 2009:126-137; Battke *et al*., 2013:247-249; Jülch *et al*., 2015:20; World Energy Council, 2016a:5). Existing research on the costs of energy storage technologies is mostly based on a single charge-discharge cycle per day, but the technical operation of such technologies allows for more than one daily cycle to be performed, which could enable significant cost reductions over a project lifetime basis (Battke *et al.*, 2013:247-249; Zakeri *et al.*, 2015:573; World Energy Council, 2016a:5). The lifetime cost impact of performing one and two charge-discharge cycles per day is explored in Chapter 7.

Grid capacity constraints, particularly in the Northern Cape Province, have further restricted the incorporation of additional solar-based electrical generation plants (Eskom, 2015:13-73; Eskom, 2016a:52; Minnaar, 2016:1140). By integrating energy storage systems with solar PV plants, more solar-based generation options could be incorporated into the electricity grid by improving transmission capacity utilisation (Suberu *et al.*, 2014:510; Akinyele *et al.*, 2014:76; Lazard, 2016:6). Sub-sections 4.2.5 and 4.2.10 of Chapter 4 provide further information on the need for energy storage to alleviate issues of renewable energy resource variability and intermittency, as well as provide electricity grid congestion relief so that investments in alternative transmission and/or generation infrastructure can be accommodated or delayed.

It is also possible for a situation to arise in which a share of maximum electrical generation from solar PV plants cannot be accommodated into the electricity grid, especially if prolonged weakness in economic growth results in significantly less load demand for electricity. In such a situation, energy storage could maintain maximum electrical output and efficiency from solar PV plants by storing a share of solar-based electrical energy production, which would otherwise be wasted due to insufficient demand, for later discharge and use (Evans *et al.*, 2012:4142; Kaltschmitt *et al.*, 2013:1664; Akinyele *et al.*, 2014:74; Pfenninger *et al.*, 2015:303; Delarue *et al.*, 2015:5; Chaanaoui *et al.*, 2016:783; Dehdashti, 2016:1-7; Amirante *et al.*, 2017:373-376; Berrada *et al.*, 2017:97; Lai *et al.*, 2017:192-194).

Energy storage technologies that are integrated with renewable energy electrical generation options do not have to be sized to the equivalent nominal or nameplate capacity of the generators. On the contrary, they have to be sized according to application requirements to supply a share of generated electricity for multi-hour periods to reduce resource variability and intermittency, which could require electrical energy levels below generation plant nameplate capacity (Rycroft, 2017:22-24; Obi *et al.*, 2017:909).

6.5 LEVELISED COST OF ENERGY STORAGE (LCOS)

The empirical study aims to improve the methods to determine and assess the economic feasibility or cost competitiveness of different energy storage technologies. This should ideally be completed through levelised cost estimations and analyses (Dufo-López *et al*., 2009:129-130; Branker *et al.*, 2011:4471; Battke *et al*., 2013:240-249; Bortolini *et al.*, 2014:85; Zakeri *et al.*, 2015:570-573; Jülch, 2016:1595-1605; Hoff *et al.*, 2016:2; Obi *et al.*, 2017:908-918; Lai *et al*., 2017:191-202).

In that regard, a novel contribution of this study is the development and use of a detailed techno-economic mathematical model with Microsoft Excel computer software to estimate, project and assess the levelised cost of energy storage systems (LCOS) in isolation and when such systems are coupled with solar photovoltaic (PV) plants. This section describes the LCOS model formulation, parameters, formulae, technical and financial data inputs and relevant assumptions. These were derived from various sources of academic (i.e. primary) and technical (i.e. secondary) literature, which is documented accordingly in this and preceding chapters.

The model was applied to the technical and economic characteristics of lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries, which are the technologies selected for the empirical analysis in this dissertation as described in section 6.3. The model was further applied to the primary value application investigated in this study, namely renewables integration, in which the select technologies are combined with solar PV electrical production plants. Under the primary application considered, the select technologies are required to provide four hours of electrical energy discharge capability at a 50 megawatt (MW) electrical power rating for 350 days a year to overcome issues of solar resource variability and intermittency, supply electricity during periods of peak demand, enable electricity price arbitrage opportunities and integrate more renewable generators into the electricity grid.

While lithium-ion, VRFB and NaS batteries are the focus of the empirical analysis, the mathematical framework and associated methodology of the LCOS model can be applied to most energy storage technologies and associated value applications. Over and above the LCOS of the select energy storage technologies in isolation, section 6.6 elaborates more on the model's extension for estimating the combined levelised cost of energy storage coupled with solar PV plants (LCOS-PV). This is required to appropriately assess the economic feasibility of energy storage technologies relative to alternative generation options and is described in more detail in section 6.7.

Levelised cost is a common term used in the energy environment that refers to the breakeven price at which electrical energy could be sold over the lifetime of a technology so that losses are not experienced following all initial and future expenditures. It is the net present value (NPV) per unit of electrical output, most often expressed in cents per kilowatt hour (kWh), and entails an assessment of the economic cost and production of electrical energy that can be applied to any technology for comparative purposes (Dufo-López *et al*., 2009:129-130; Darling *et al.*, 2011:3133; Sørensen, 2011:795; Branker *et al.*, 2011:4470-4472; Pawel, 2014:69; Mandelli *et al.*, 2016:293; World Energy Council, 2016a:46; Jülch, 2016:1604). Present value calculations entail determining the beginning cost of an investment by discounting all future expenditures over the lifetime of that investment to account for the time value of money (Schoenung & Eyer, 2008:13-16; Pindyck *et al.*, 2009:553-556; Schoenung, 2011:12; Bhattacharyya, 2011:176-177; Kost, Mayer, Thomsen, Hartmann, Senkpiel, Philipps, Nold, Lude, Saad & Schlegl, 2013:36).

It is important to distinguish between the levelised costs of electrical energy generation technologies (i.e. LCOE) and that of energy storage technologies (i.e. LCOS) when determining whether a particular technology has reached grid parity. Grid parity refers to a situation in which the lifetime cost of a particular alternative technology is equivalent to or lower than the costs of conventional electrical generation options, such as fossil fuel and nuclear energy-based generators, as an indicator for cost effectiveness (Branker *et al.*, 2011:4470-4471; Kost *et al.*, 2013:6; Hurtado Munoz *et al.*, 2014:180; Choi, Park, Park & Hong, 2015:718; World Energy Council, 2016a:46; Papaefthimiou, Souliotis & Andriosopoulos, 2016:264).

The levelised cost of electricity (LCOE) is a metric that expresses the constant, or levelised, price per kWh over the applicable lifetime of an electrical energy generation plant in present value terms. It represents the minimum price at which electricity should be sold in order to break even with total initial and future costs, including upfront and replacement investment, operations and maintenance and fuel costs over the lifetime of a generator. The LCOE metric enables a meaningful comparison of different generation technologies despite varying project sizes, calendar lifetimes, capital investment costs, risks and return structures. The formula for determining the LCOE can be expressed through equation 1 (Darling *et al.*, 2011:3133-3134; Bhattacharyya, 2011:237-238;

Branker *et al.*, 2011:4472; Battke *et al.*, 2013:246; Kost *et al.*, 2013:36; Bortolini *et al.*, 2014:85-86; Pawel, 2014:69; Blumsack, 2015; Akhil *et al.*, 2015:157; Bortolini *et al.*, 2015:1029; Busse *et al.*, 2016:52; Yelland, 2016; World Energy Council, 2016a:46; Wiebe *et al.*, 2016:743; Lai *et al.*, 2017:192; Obi *et al.*, 2017:910-918).

$$LCOE = \frac{CAPEX_0 + \sum_{n=1}^{N} \frac{CAPEX_n + O\&M_n + F_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{E_n}{(1+r)^n}} \tag{eq. 1}$$

Where:

$LCOE$ = Levelised cost of electricity generation (USD per kWh).
$CAPEX_0$ = Total initial capital expenditure cost incurred in year 0 (USD per kWh). Initial capital expenditure is not discounted as it represents present value costs before the time value of money diminishes the investment value.
$CAPEX_n$ = Replacement capital expenditure cost incurred in year n, if applicable (USD per kWh).
$O\&M_n$ = All fixed and variable operations and maintenance expenditure incurred in year n (USD per kWh).
F_n = Fuel expenditure incurred in year n, if applicable (USD per unit).
n = Year n (year).
N = Project lifetime in years (years).
r = Discount rate (%).
E_n = Total electrical energy produced by plant in year n (kWh).

The LCOE metric is well researched, understood and commonly used to compare the economic viability or cost competitiveness of different electrical energy generation technologies (Darling *et al.*, 2011:3133; Battke *et al.*, 2013:246-247; Bortolini *et al.*, 2015:1029; Akhil *et al.*, 2015:157; United States Energy Information Administration, 2016:115). The LCOE metric, however, does not allow for comparisons between generation (i.e. non-storage) and energy storage solutions, since they have different technical functionalities, modes of operation and, as a consequence, dissimilar lifetime cost determinants. To overcome this cross-comparative issue, it is necessary to estimate the LCOS for different energy storage technologies in isolation, as well as when such technologies are coupled with intermittent renewable energy-based electrical production options (Poonpun *et al.*, 2008:529-534; Kaun *et al.*, 2013:25; Pawel, 2014:72-73; Bortolini *et al.*, 2015:1029; Jülch *et al.*, 2015:19-26; Zakeri *et al.*, 2015:588; Busse *et al.*, 2016:52-53; Mayr *et al.*, 2016; World Energy Council, 2016a:18-26; Jülch, 2016:1594-1595; Mundada *et al*., 2016:692-700; Lai *et al.*, 2017:200; Obi *et al.*, 2017:908-918).

The LCOS is a metric that expresses the constant, or levelised, price per kWh over the applicable lifetime utilisation of an energy storage system in terms of present value. It represents the minimum price at which electrical energy should be sold in order to break even with total initial and future costs, including upfront and replacement investment, operations and maintenance and charging costs over the lifetime of an energy storage system. The metric includes all cost and performance parameters associated with such systems and enables a fair and meaningful comparison of distinct energy storage technologies according to the applications they are required to perform, regardless of technological specifications or chemical composition (Battke *et al*., 2013:242-247; Pawel, 2014:68-77; Battke *et al.*, 2015:340-341; Jülch *et al*., 2015:19; Zakeri *et al.*, 2015:573-588; Lazard, 2015:20-29; Hoff *et al.*, 2016:2; World Energy Council, 2016a:46; Jülch, 2016:1594-1604; Lai *et al.*, 2017:194; Obi *et al.*, 2017:910-918).

The LCOS makes it possible to benchmark and evaluate the reflective costs of different energy storage technologies per kWh usable energy storage capacity. It does this by taking into account all known technology-specific costs, characteristics and technical limitations from installation through to the termination of service (Zakeri *et al.*, 2015:573; Hoff *et al.*, 2016:2; Lai *et al.*, 2017:194; Obi *et al.*, 2017:910). The metric further enables comparison between storage and non-storage solutions (Poonpun *et al.*, 2008:529-534; Pawel, 2014:72-73; Bortolini *et al.*, 2015:1029; Zakeri *et al.*, 2015:588; World Energy Council, 2016a:5-6; Mundada *et al*., 2016:692-700; Obi *et al.*, 2017:908-918).

The formula for determining the LCOS can be expressed through equation 2 (adapted from Battke *et al*., 2013:246-247; Pawel, 2014:69-70; Zakeri *et al.*, 2015:573; Jülch *et al*., 2015:19; Hoff *et al.*, 2016:1-22; Mayr *et al.*, 2016; Jülch, 2016:1596-1597; World Energy Council, 2016a:18; Lai *et al.*, 2017:194; Obi *et al.*, 2017:918). The parameters, formulae, data inputs and relevant assumptions used to formulate the LCOS model, as well as how they were derived, are described in sub-sections 6.5.1 to 6.5.12.

$$\mathrm{LCOS} = \frac{\mathrm{CAPEX}_0 + \sum_{n=1}^{N} \frac{\mathrm{CAPEX}_n + \mathrm{O\&M}_n + \mathrm{Charge}_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{\#\mathrm{Days} * \#\mathrm{Cycles} * \mathrm{DoD} * \mathrm{ES}_s * \mathrm{DEG}}{(1+r)^n}} \qquad \text{(eq. 2)}$$

Where:

LCOS = Levelised cost of energy storage (USD per kWh).

$CAPEX_0$ = Total initial capital expenditure cost incurred in year 0 (USD per kWh). Initial capital expenditure is not discounted as it represents present value costs before the time value of money diminishes the investment value.

$CAPEX_n$ = Replacement capital expenditure cost incurred in year n (USD per kWh).

$O\&M_n$ = All fixed and variable operations and maintenance expenditure incurred in year n (USD per kWh).

$Charge_n$ = Charging cost in year n given the charging electricity tariff and required electrical energy input to accommodate for efficiency losses (USD per kWh).

#Days = Number of days per year that the system will be operated (days per year).

#Cycles = Number of full charge-discharge cycles per day (cycles per day).

DoD = Maximum depth of discharge (%).

ES_s = Energy capacity size of storage to enable maximum electrical discharge (kWh).

DEG = Capacity degradation coefficient over the project life (%).

n = Year n (year).

N = Project contract lifetime in years (years).

r = Discount rate (%).

The LCOS varies for different technologies and between the applications they are required to fulfil (Poonpun *et al*., 2008:532-533; Battke *et al*., 2013:247-248; Zakeri *et al*., 2015:588-589; Lazard 2016:31-40; Jülch, 2016:1600-1604; Obi *et al*., 2017:917). The metric should be interpreted with caution and in line with the value of the specific use applications it is applied to. LCOS values should only be compared in instances where the exact same methods were applied, since levelised cost estimations depend on different assumptions and can have dissimilar input parameters, which lead to ambiguous results (Branker *et al.*, 2011:4471; Akhil *et al.*, 2015:32; Mandelli *et al.*, 2016:291; Obi *et al.*, 2017:910-917). In other words, the LCOS for different energy storage systems should be calculated and compared on the same level of detail, based on similar assumptions, within realistic and commensurable limits and according to common value applications (Battke *et al*., 2013:242-247; Pawel, 2014:72-73; Zakeri *et al.*, 2015:573-589; Hoff *et al.*, 2016:1-22; Mayr *et al.*, 2016; World Energy Council, 2016a:4; Obi *et al.*, 2017:910).

While the LCOS is a superior metric to compare the competitive ability of various energy storage technologies with one another and with alternative generation options, additional value is derived for energy storage solutions that perform more than one application sequentially and/or simultaneously (Sioshansi *et al.*, 2009:277; Strbac *et al.*, 2012:33-39; Battke *et al*., 2013:246-247; Kaun *et al.*, 2013:25-85; Infield *et al.*, 2014:24-26; Jülch *et al*., 2015:19-26; Battke *et al.*, 2015:334-339; Zakeri *et al.*, 2015:571-588; Lazard, 2015:3; De la Rubia *et al*., 2015:7-8; Kondziella *et al.*, 2016:15-20; Jülch, 2016:1604).

For example, an energy storage system that is used for renewables integration to smooth the variability and intermittency of renewable energy-based electrical production plants could also perform energy time shifting to help meet peak demand for electricity, enable electricity price arbitrage opportunities, integrate more renewable generators into the electricity grid, relieve grid congestion and defer investments in alternative generation and transmission infrastructure. Such multi-use capabilities significantly enhance the value of energy storage technologies relative to cost due to different potential revenue streams (He *et al.*, 2011:1575; Carnegie *et al.*, 2013:14-19; Zhang, 2013:39; Castillo *et al.*, 2014:888; Pawel, 2014:69; Lambruschi, 2015:24-26; De la Rubia *et al.*, 2015:7-8; Kempener *et al.*, 2015:15; Lazard, 2016:4; Günter *et al.*, 2016:231-234; Dehdashti, 2016:6; Malhotra *et al.*, 2016:706-717; Ferroukhi *et al.*, 2017:80-81). The various value applications that can be performed by energy storage systems sequentially and/or simultaneously are discussed in section 4.2 of Chapter 4.

6.5.1 Initial capital costs ($CAPEX_0$)

Initial capital costs refer to all the upfront investment expenses related to the installation of the entire energy storage system to deliver the usable electrical energy (Dufo-López *et al*., 2009:130-131; Zakeri *et al.*, 2015:572; Hameer *et al.*, 2015:1188; Bortolini *et al.*, 2015:1029; Hoff *et al.*, 2016:3; Aneke *et al.*, 2016:367; Günter *et al.*, 2016:229). The empirical part of this study necessitates an investigation of the recent and likely future initial capital costs associated with the select electrochemical energy storage systems. In that regard, the 2016 and prospective 2020 costs of three leading electrochemical technologies penetrating the market for utility-scale energy storage could be considered, namely lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries.

As explained in sub-section 4.3.1 of Chapter 4, the total capital cost of an energy storage system can be divided into the cost of the energy storage medium, also referred to as battery cell costs in the case of electrochemical technologies, and the cost of the balance of plant features (Dufo-López *et al*., 2009:130-131; Zakeri *et al.*, 2015:572; Hameer *et al.*, 2015:1188; Kempener *et al.*, 2015:28; Bortolini *et al.*, 2015:1029; Hoff *et al.*, 2016:3; Aneke *et al.*, 2016:367; Lazard, 2016:5; Günter *et al.*, 2016:229).

Table 6.1 indicates the 2016 and projected 2020 costs, in United States dollars (USD) per kWh, of the energy storage medium, or battery cells, and balance of plant features that make up the total initial energy capital costs of the select technologies used for the levelised cost of energy storage (LCOS) modelling in this dissertation (derived from Zakeri *et al.*, 2015:590-593; Lazard, 2016:5-31). Summation and percentage differences are due to rounding.

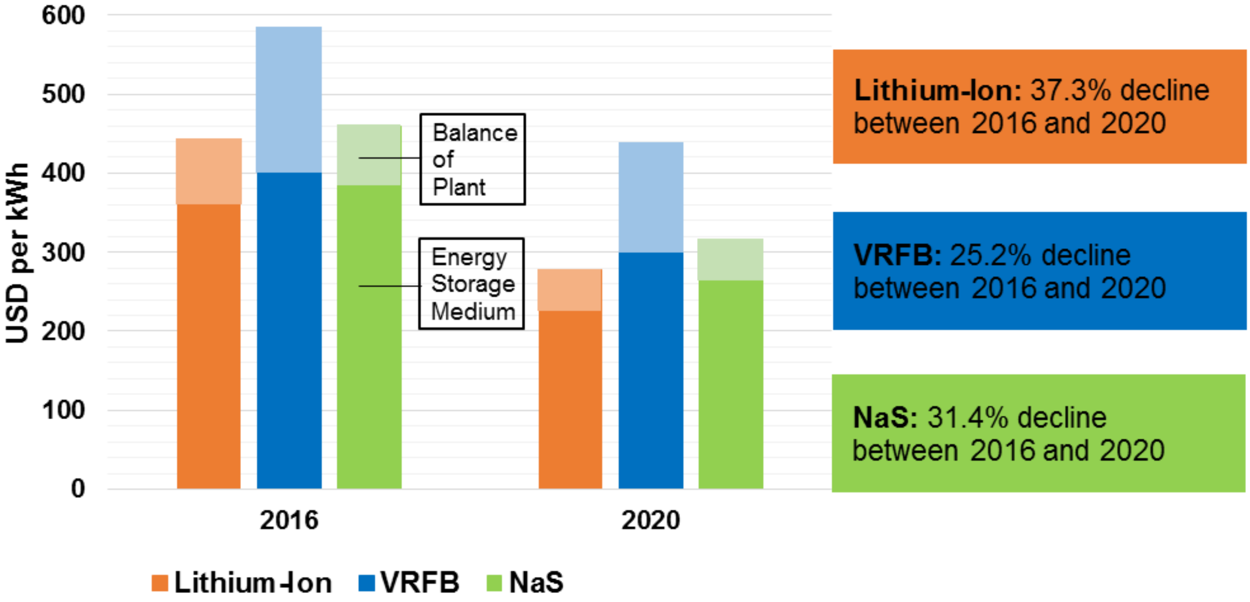
Table 6.1: Utility-scale energy storage system capital costs in 2016 and projected for 2020 (USD per kWh)

Year	**2016**			**2020**		
Technology	**Lithium-ion**	**VRFB**	**NaS**	**Lithium-ion**	**VRFB**	**NaS**
Energy storage medium	361	400	385	226	299	264
Balance of plant	82	183	75	51	137	51
Total initial capital cost	**443**	**583**	**460**	**278**	**436**	**315**
Projected % change				-37.26	-25.19	-31.43

Source: Author’s estimates

Figure 6.4 graphically depicts the 2016 and 2020 projected energy storage system capital costs included in Table 6.1. The solid colours in each column represent the capital costs of the energy storage mediums or battery cells of the select technologies, while the shaded colours of each respective column denote the share of capital costs for balance of plant features.

Figure 6.4: Utility-scale energy storage system capital costs in 2016 and projected for 2020 (USD per kWh)



Source: Author's configuration

Following the literature review, the cost data for the respective energy storage mediums in 2016 and projected price decline rates to 2020 were selected from Lazard (2016:19-31). The study by Lazard was chosen for the cost data as it provides a common source for both the capital costs in 2016 and projected price decline rates to 2020 for the energy storage mediums of lithium-ion, VRFB and NaS battery systems. The capital cost outlook in Lazard (2016:19-21) is also aligned to the period under consideration for this study, namely 2016 to 2020. Alternative literature sources highlighting up-to-date, reliable and realistic present and future cost estimates encompassing the period under consideration for all three of the select energy storage technologies were not detected during the research for this dissertation and could be regarded as scarce information.

While the study by Lazard (2016:31-40) involves a number of value applications, the 'transmission system' application was utilised for the cost estimates included in Table 6.1 and Figure 6.4. The 'transmission system' application examined by Lazard (2016:6) is a utility-scale service that incorporates transmission stability, investment deferral, energy time shifting and renewable integration support. It is therefore closely aligned to the primary value application investigated for the levelised cost analysis in this study, namely renewables integration, as well as potential secondary applications such as energy time shifting and arbitrage, load levelling and peak shaving and/or transmission grid congestion relief and investment upgrade deferral. These and other utility-scale value applications are described in section 4.2 of Chapter 4.

The lower-bound battery cell cost estimates in the ‘transmission system’ application of Lazard (2016:31) were used as representative technology price estimates in 2016 and included in Table 6.1 as USD 361 per kWh for lithium-ion, USD 400 per kWh for VRFB and USD 385 per kWh for NaS batteries. Prior to their inclusion in Table 6.1, the lower-bound estimates by Lazard (2016:31) were tested against cost estimates from numerous literature sources scrutinised to formulate the energy storage system cost indicators in Table 4.2 in section 4.3 of Chapter 4. This was mainly done by comparing the energy storage medium share ranges of total capital costs in Table 4.2 with the total energy storage medium capital costs of Lazard (2016:31).

It was observed that the lower bound estimates by Lazard (2016:31) were aligned to the cost ranges in Table 4.2 and can therefore be deemed realistic and appropriate to use for the mathematical modelling in this study. Higher cost estimates would be in excess of prevailing technology prices. The 2016 cost thresholds in Table 6.1 are further likely under competitive procurement conditions, given the rapid techno-economic advances taking place with energy storage technologies and taking into account outdated cost estimates in literature as noted in section 4.3 of Chapter 4.

The 2016 cost estimates included in Table 6.1 were further extrapolated to 2020 by using the compound annual decline rates that the capital cost of each technology is expected to reduce with as disclosed by Lazard (2016:19-21). These rates, between 2016 and 2020, are specified as minus 11% for lithium-ion, minus 7% for VRFB and minus 11% for NaS batteries. While the compound annual decline rates to 2020 for the capital costs of lithium-ion and VRFB batteries appear realistic (Hill, 2016:1), those for NaS batteries have been adjusted to minus 9%. As noted by Kempener *et al.* (2015:26-29), Amrouche *et al.* (2016:20916) and Gallo *et al.* (2016:808), NaS batteries have a higher level of maturity than lithium-ion and flow batteries do and more limited opportunities to gain market share growth, which implies that they are likely to experience less rapid cost reductions over the next five years, particularly relative to lithium-ion batteries. The energy storage medium costs were estimated to decline to USD 226 per kWh for lithium-ion, USD 299 per kWh for VRFB and USD 264 per kWh for NaS batteries by 2020.

The balance of plant capital costs in Table 6.1, as a portion of total energy capital costs of the select energy storage systems, were primarily determined from Zakeri *et al.* (2015:590-593). As noted in sub-section 2.3.4 of Chapter 2 and sub-section 4.3.1 of Chapter 4, balance of plant system features and costs include all expenses additional to the energy storage medium, such as those related to the power conversion system (PCS), energy storage management, monitoring and control systems and other engineering and construction related outlays.

The study by Zakeri *et al.* (2015:590-593) provides a common source to determine the balance of plant share of total energy capital costs of various energy storage systems, including those selected for this study. It was determined that the balance of plant costs could represent approximately 18.4% of total energy capital costs for lithium-ion batteries, 31.4% for VRFB batteries and 16.2% for NaS batteries. These balance of plant cost shares are further aligned to those indicated by, or estimated from, Ibrahim *et al.* (2013:5), Kousksou *et al*. (2014:68), Lazard (2016:19-21) and Gallo *et al.* (2016:814). This implies that the portion of energy storage medium costs of total energy capital cost is equivalent to 81.6% for lithium-ion, 68.6% for VRFB and 83.8% for NaS batteries.

To test the accuracy of these findings, the respective energy storage medium cost shares derived from Zakeri *et al.* (2015:590-593) were compared to the energy storage medium cost share ranges obtained and estimated during the literature review as summarised in Table 4.2 in section 4.3 of Chapter 4. It was observed that the energy storage medium cost shares derived from Zakeri *et al.* (2015:590-593) for lithium-ion, VRFB and NaS batteries were within the likely ranges outlined in Table 4.2 and can therefore be deemed realistic and appropriate to use for the mathematical modelling in this study.

Lastly, the energy storage medium costs and projected capital cost decline rates to 2020 from Lazard (2016:19-31), together with the energy storage medium and balance of plant cost shares determined from Zakeri *et al.* (2015:590-593), were used to calculate and forecast the total initial capital expenditure, in USD per kWh, for lithium-ion, VRFB and NaS battery systems. Given the capital cost of the energy storage medium and its respective share of total upfront capital expenditure, the total initial capital cost of the energy storage system installation can be calculated with equation 3.

$$\mathrm{CAPEX}_0 = \frac{\mathrm{Cost}_{esm}}{\mathrm{Share}_{esm}} \qquad \text{(eq. 3)}$$

Where:

CAPEX_0 = Total initial capital expenditure cost incurred in year 0 (USD per kWh).

Cost_{esm} = Capital cost of the energy storage medium or battery cell (USD per kWh).

Share_{esm} = Energy storage medium capital cost share of total initial capital cost of energy storage system (%).

The respective shares of energy storage medium and balance of plant costs, as a portion of total energy capital costs of each selected technology, were assumed to remain constant over the forecast period. The effect of this is that balance of plant costs decline proportionally to the costs of the energy storage mediums, at minus 37.3%, 25.2% and 31.4% for lithium-ion, VRFB and NaS batteries, respectively. This could be considered a relatively conservative, but practical, assumption as it has been estimated that utility-scale energy storage system balance of plant costs could decline by 40% between 2015 and 2020 (Ortiz, 2016:1; Palmintier, Krishnamurthy & Wu, 2016:4).

The total initial capital costs per kWh in 2016 were determined to be around USD 443 for lithium-ion, USD 583 for VRFB and USD 460 for NaS battery systems. These estimates are aligned to the total energy capital cost ranges for the select technologies summarised from the literature review and included in Table 4.2 in section 4.3 of Chapter 4. By 2020, these costs were further projected to decline to approximately USD 278 per kWh for lithium-ion, USD 436 per kWh for VRFB and USD 315 per kWh for NaS battery energy storage systems. The total initial capital costs estimated for 2016 and forecast to 2020 were assumed representative and included in the LCOS modelling.

As can be seen from equation 2, the total initial capital expenditure is not discounted to present value terms in the calculation of the LCOS. This is because the initial upfront capital investment cost is incurred in year zero, which implies that it represents the present costs before the time value of money diminishes the investment value. All subsequent future expenditures over the lifetime of an energy storage system are discounted to present value terms to take account of the time value of money, including replacement capital, operations and maintenance and charging costs (Schoenung *et al.*, 2008:13-16; Pindyck *et al.*, 2009:554; Branker *et al.*, 2011:4472; Sørensen, 2011:797; Jülch *et al.*, 2015:19; Mandelli *et al.*, 2016:293; Parrado *et al.*, 2016:510; Hoff *et al.*, 2016:2-3; Mundada *et al.*, 2016:694-695; World Energy Council, 2016a:18; Jülch, 2016:1596; Obi *et al.*, 2017:911-918; Lai *et al.*, 2017:192). Sub-section 6.5.12 provides further information on the discount rate that was used for the present value calculations.

The upfront balance of plant capital expenditure is then the difference between the cost of the energy storage medium and the total initial capital cost of the energy storage system installation. This can be calculated with equation 4. The balance of plant costs per kWh were determined to be around USD 82 for lithium-ion, USD 183 for VRFB and USD 75 for NaS batteries in 2016, which declines to approximately USD 51 for lithium-ion and NaS batteries and USD 137 for VRFBs by 2020.

$$\text{Cost}_{bop} = \text{CAPEX}_0 - \text{Cost}_{esm} \qquad \text{(eq. 4)}$$

Where:

Cost_{bop} = Capital cost of balance of plant features (USD per kWh).

CAPEX_0 = Total initial capital expenditure cost incurred in year 0 (USD per kWh).

Cost_{esm} = Capital cost of the energy storage medium or battery cell (USD per kWh).

6.5.2 Replacement capital costs (CAPEX_n)

Replacement capital costs comprise all expenses related to the periodic replacement of energy storage system components as necessary to maintain the energy capacity, operational functionality and expected lifetime of an energy storage system in order to deliver the usable energy (Ibrahim *et al*., 2013:13-14; Günter *et al.*, 2016:229). As described in sub-section 4.3.2 of Chapter 4, the replacement of energy storage system components is informed by the calendar and cycle life of the asset. Replacement rates increase with deeper and more frequent charge-discharge cycles, since it accelerates the degradation of an energy storage system towards the upper limit of its calendar or cycle life, whichever is reached first during the course of operation (Poonpun *et al.*, 2008:533; Dufo-López *et al*., 2009:129-131; Schoenung, 2011:7-17; Battke *et al*., 2013:246-248; Bortolini *et al.*, 2015:1029; Lund *et al.*, 2015:795; Mandelli *et al.*, 2016:293; Mayr *et al.*, 2016; Jülch, 2016:1597; Berrada *et al.*, 2017:101; Obi *et al.*, 2017:913).

For the levelised cost of energy storage (LCOS) modelling, a calendar life of 10 years for lithium-ion and 15 years for both vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries has been assumed. A minimum cycle life of 3 500 cycles for both lithium-ion and NaS batteries and 10 500 cycles for VRFBs has also been assumed. These assumptions inform the periodic capital replacement expenditure in the mathematical modelling.

The assumptions are considered to be conservative as it is often reported that lithium-ion and NaS batteries have a cycle life in excess of 4 500 cycles, while VRFBs could potentially perform more than 12 000 cycles over their lifetime. It has also been reported that lithium-ion and VRFB batteries could have a calendar life of up to 15 and 20 years, respectively. They are nonetheless practical as they are within the technical ranges obtained from the literature review summarised in Table 3.1 in section 3.2 of Chapter 3 and more specifically authors such as Beaudin *et al.* (2010:310), Akinyele *et al.* (2014:85), Castillo *et al.* (2014:887), Luo *et al.* (2015:526), Lund *et al.* (2015:795), Battke *et al.* (2015:344), Akhil *et al.* (2015:45-46), Hameer *et al.* (2015:1187), Liao, Sun, Liu, Sun and Zhou (2016:242), Kyriakopoulos *et al.* (2016:1060-1061), Zakeri *et al.* (2015:592), Gallo *et al.* (2016:815), Amirante *et al.* (2017:384), Lai *et al.* (2017:197-202) and Peters, Baumann, Zimmermann, Braun and Weil (2017:493-494).

The replacement period, or number of years that elapse before the energy storage medium needs to be replaced, can be calculated with equation 5 (Poonpun *et al.*, 2008:531; Jülch *et al*., 2015:19).

$$n = \frac{\text{Cycle Life}}{\text{\#Cycles} * \text{\#Days}} \qquad \text{(eq. 5)}$$

Where:

n = Replacement period in years to asset renewal (year).

Cycle Life = Number of charge-discharge cycles that can be performed over the life of the energy storage system (lifetime cycles).

#Cycles = Number of full charge-discharge cycles required per day (cycles per day).

#Days = Number of days per year that the system will be operated (days per year).

In the LCOS modelling, over a 350-day operational period and performing one cycle per day, it is estimated that both lithium-ion and NaS batteries will have to be replaced in year 10, while VRFBs would only necessitate replacement in year 30 given its very long cycle life, although this is limited to a calendar life of 15 years assumed for VRFBs. When the cycling frequency is increased to two cycles a day, lithium-ion and NaS batteries would be replaced in year five and VRFBs in year 15. These estimates are aligned to those of Lazard (2016:31-35), Zakeri *et al.* (2015:590-591) and Zhang, Li, Skyllas-Kazacos and Bao (2016:857).

The LCOS modelling also requires inputs over five-year intervals, based on the model formulation, initial and replacement capital cost estimates and project contract lifetimes, which will be evaluated with scenarios in Chapter 7. The replacement intervals based on one or two cycles performed per day for 350 operational days per year over 10- and 20-year project contract lifetimes that will be used for the LCOS modelling are indicated in Table 6.2 for each of the technologies under consideration.

Table 6.2: Energy storage medium replacement period according to daily cycle and contract lifetime requirements

Daily cycle number	**Project contract lifetime (years)**	**Lithium-ion**	**VRFB**	**NaS**
		Replace in year	**Replace in year**	**Replace in year**
1	10	No replacement	No replacement	No replacement
2	10	5	No replacement	5
1	20	10	15	10
2	20	5, 10 and 15	15	5, 10 and 15

Source: Author's estimates

Future cost projections are inevitably characterised by uncertainty. It is nonetheless necessary to make such predictions in order to perform lifecycle cost estimates and analyses. As with all technologies, energy storage replacement cost projections need to account for foreseen technological improvements and learning rates for potential cost reductions (Dufo-López *et al*., 2009:130; Nykvist *et al.*, 2015:329-331; Obi *et al.*, 2017:916).

As described in sub-section 6.5.1, it has been estimated from Lazard (2016:19-31) that the capital cost of the energy storage medium for lithium-ion batteries is projected to decline from approximately United States dollars (USD) 361 per kWh in 2016 to USD 226 per kWh in 2020. Beyond this point, it has been forecast that lithium-ion battery cell prices are likely to reach USD 150 per kWh by 2025 due to widespread industry demand growth and technological improvements. Thereafter, lithium-ion battery costs could possibly stabilise around USD 150 as the technology is deemed fully commercialised (Nykvist *et al.*, 2015:329-331; World Energy Council, 2016a:36; Astarloa *et al.*, 2017:7-9; Obi *et al.*, 2017:909). In this regard, lithium-ion battery replacement costs have been assumed to remain at USD 150 per kWh from 2025 onwards in the LCOS modelling.

It is also indicated in sub-section 6.5.1 that the energy storage medium of VRFBs is expected to decline from around USD 400 per kWh in 2016 to USD 299 per kWh in 2020, while NaS batteries are projected to decline from approximately USD 385 per kWh to USD 264 per kWh over the same period. Clearly specified projections beyond 2020, however, for the potential future replacement costs of VRFB and NaS batteries were not obtained during the literature review, which necessitates the use of judgement to formulate assumptions regarding their possible future values. Such practical assumptions are mainly based on their technical characteristics, anticipated demand and current level of technological maturity (Dufo-López *et al*., 2009:130-131; Zakeri *et al.*, 2015:577).

The capital replacement cost of VRFBs is assumed to continue declining at high rates as the technology experiences further techno-economic innovation and improvements, benefits from supplier integration and is increasingly commercialised from lower project installation levels in comparison to lithium-ion and NaS batteries. Another attractive feature of VRFBs is that only the battery cell stack warrants replacement, since the independent electrolyte solution does not degrade over time, which results in lower capital replacement costs as the entire energy storage medium does not have to be replaced (Akhil *et al.*, 2015:55-58; Cunha *et al.*, 2015:907; Lazard, 2016:31; Obi *et al.*, 2017:913).

It has been determined that the electrochemical cell stack accounts for approximately 40% of the total initial capital costs for VRFBs (Noack, Wietschel, Roznyatovskaya, Pinkwart & Tübke, 2016:627). As explained in sub-section 6.5.1, the total initial capital cost for VRFB systems is estimated to decline from USD 583 per kWh in 2016 to USD 436 per kWh in 2020. This denotes that the battery cell stack represented USD 233 per kWh in 2016 and is projected to decline to around USD 175 per kWh in 2020. According to the World Energy Council (2016a:37), VRFB costs could be reduced by 50% by 2030, mainly due to increased deployment and competition, technical improvements and manufacturing advances. As such, the capital replacement cost of electrochemical cells for VRFBs is assumed to decline further from USD 233 per kWh in 2016 to approximately

USD 117 per kWh by 2030. Beyond this point in time, replacement capital costs have been assumed to remain at 2030 levels due to uncertainty of further cost developments.

Even though NaS batteries are more mature relative to lithium-ion and flow batteries, their capital costs are likely to decline sharply once current patents on the technology expire, since it would stimulate increased supplier competition and technical enhancements (Suberu *et al.*, 2014:504; World Energy Council, 2016a:37). The World Energy Council (2016a:37) anticipates that the capital cost of NaS batteries would decline by 75% by 2030, mainly due to increased competition and technological improvements. This suggests that the energy storage medium replacement capital cost of NaS batteries could decline from USD 385 per kWh in 2016 to around USD 96 per kWh by 2030. As with VRFBs, replacement capital costs have been assumed to remain at 2030 levels due to the uncertainty of further cost developments.

Table 6.3 summarises the replacement capital costs of the energy storage mediums assumed for the select technologies that are included in LCOS modelling. The replacement costs are shown according to the replacement period from the relevant 2016 and projected 2020 LCOS estimation year (extrapolated from Nykvist *et al*., 2015:329-331; World Energy Council, 2016a:37; Noack *et al.*, 2016:627; Obi *et al*., 2017:909).

Table 6.3: Energy storage medium replacement period and associated capital cost (USD per kWh)

Replacement period relevant to initial cost		**Year**	**Projected replacement capital cost (USD per kWh)**		
			Lithium-ion	**VRFB**	**NaS**
2016	**2020**	**2016**	No replacement	No replacement	No replacement
Year 5		**2020**	226	No replacement	264
Year 10	Year 5	**2025**	150	No replacement	180
Year 15	Year 10	**2030**	150	117	96
	Year 15	**2035**	150	117	96

Source: Author's estimates

It is not expected that balance of plant features will experience adequate deterioration to warrant complete replacement, since such components are assumed to remain largely functional throughout the required project contract lifetime of each energy storage system. As such, it is assumed that in the event that balance of plant components might require renewal, it would be addressed through general operations and maintenance expenditure. This assumption is also aligned to Poonpun *et al.* (2008:530-531), Schoenung (2011:7), Akhil *et al.* (2015:B-31-B-33), Lazard (2016:31-34), Díaz-González, Sumper & Gomis-Bellmunt (2016:149-150), Mundada *et al*. (2016:696-697), Jülch (2016:1603) and Obi *et al.* (2017:913).

6.5.3 Operations and maintenance costs (O&M_n)

Including operations and maintenance expenditure in levelised cost estimations is necessary for improved economic analyses (Schoenung, 2011:7). As described in sub-section 4.3.2 of Chapter 4, operations and maintenance costs refer to all fixed and variable expenses that have to be incurred to ensure the continuous operation of an energy storage system as necessary for delivering the required usable electrical energy over its service lifetime (Ibrahim *et al*., 2013:13-14; Hoff *et al.*, 2016:4; Günter *et al.*, 2016:229; Obi *et al.*, 2017:913).

Examples of operations and maintenance expenses include scheduled and unplanned repairs to preserve the state of charge and discharge, monitoring the energy storage systems, management and labour costs and electricity purchases for lights, temperature control and other equipment (Dufo-López *et al*., 2009:130-131; Battke *et al*., 2013:244; Ibrahim *et al*., 2013:13-14; Bortolini *et al.*, 2015:1029; Zakeri *et al.*, 2015:573; Jülch *et al*., 2015:19; Mayr *et al.*, 2016; Günter *et al.*, 2016:229; Hoff *et al.*, 2016:4; Aneke *et al.*, 2016:373; Obi *et al.*, 2017:913). Charging costs, brought about by electricity input prices and technology roundtrip efficiency losses, are an important input parameter in the mathematical modelling and treated separately from other operations and maintenance expenditure and assumptions (Poonpun *et al.*, 2008:530-531; Schoenung, 2011:7-13; Pawel, 2014:69-70; Zakeri *et al.*, 2015:573; Lazard, 2016:31; Jülch, 2016:1595-1604; Obi *et al.*, 2017:913). More information about charging costs is provided in sub-section 6.5.4.

For the levelised cost of energy storage (LCOS) modelling, annual operations and maintenance costs in 2016 and 2020 are assumed to comprise 2% of the total initial capital costs of the energy storage systems under consideration. This assumption has also been adopted by Jülch (2016:1598) and the World Energy Council (2016a:40-41), but is further aligned to the propositions included in Zhang *et al.* (2016:857), Lazard (2016:24-25), Obi *et al*. (2017:912) and the cost indicators summarised in Table 4.2 in section 4.3 of Chapter 4. Table 6.4 indicates the operations and maintenance costs in United States dollars (USD) per kWh as a 2% share of total initial capital expenditure for the select technologies between 2016 and 2020.

Table 6.4: Operations and maintenance cost (USD per kWh)

Year	Lithium-ion	VRFB	NaS
2016	8.86	11.66	9.20
2020	5.54	8.72	6.30

Source: Author's estimates

To account for the impact of the time value of money on operations and maintenance expenditure over the lifetime of an energy storage system, it is necessary to make assumptions regarding the future inflation rate in present value calculations. While the estimation of prospective inflation rates entails uncertainty, the average of past inflation rates can be assumed and utilised as being indicative of potential future price escalations (Schoenung *et al.*, 2008:13-14; Schoenung, 2011:7; Sørensen, 2011:796; Zhang, 2013:109; Battke *et al*., 2013:245; Akhil *et al.*, 2015:9; Zakeri *et al.*, 2015:586).

In that regard, annual operations and maintenance costs have been escalated for inflation in the net present value (NPV) calculations by 5.23%, which represents the average year-on-year growth in the headline consumer price index (CPI) for South Africa between January 2010 and January 2016 (IHS Global Insight, 2017; Statistics South Africa, 2017). This assumption is near the upper end of the official inflation target for South Africa of 3 to 6% (Kabundi & Schaling, 2013:346; South African Reserve Bank, 2016:24). The assumed projected inflation rate could also be regarded as conservative, albeit practical, since it has been forecast that inflation in South Africa is likely to stabilise within the inflation target, approximately 5% year-on-year, from 2021 onwards (Business Monitor International Research, 2016:11-12).

6.5.4 Charging costs and associated efficiency losses (Charge$_n$)

Charging costs refer to all expenses related to the electrical input and charging of an energy storage medium and energy consumption while the technology remains in charged state. Charging costs depend on both the source of charge and roundtrip efficiency. The source of charge denotes whether an energy storage system receives electricity input directly from an electrical generation plant, the electricity grid or both (Chen *et al.*, 2009:293-294; Dufo-López *et al*., 2009:126-137; Whittingham, 2012:1518-1519; Ibrahim *et al.*, 2013:13; Infield *et al.*, 2014:22-23; Pawel, 2014:70-74; Mandelli *et al*., 2016:291; Zakeri *et al.*, 2015:572; Jülch *et al*., 2015:19-24; Bortolini *et al*., 2015:1027-1029; Dehdashti, 2016:5-6; Lai *et al.*, 2017:195-196; Berrada *et al.*, 2017:97-99).

Roundtrip efficiency denotes the amount of electrical energy that can be discharged relative to that needed to charge an energy storage system, since such systems experience losses during charge-discharge cycles. More energy therefore has to be purchased when charging than what can be sold while discharging (Zhang, 2013:42; Battke *et al*., 2013:246; Ibrahim *et al.*, 2013:31; Pawel, 2014:70-72; Kousksou *et al.*, 2014:73; Zakeri *et al*., 2015:572-573; Mayr *et al*., 2016; Jülch, 2016:1603; Obi *et al.*, 2017:913; Amirante *et al.*, 2017:384).

The amount of electrical energy that can be discharged per year is obtained by multiplying the maximum capacity size of the energy storage medium (see equation 8 in sub-section 6.5.8) with the number of cycles that will be performed per annum as indicated by equation 6. Reduced electrical output caused by depth of discharge (DoD) and capacity degradation limitations for some technologies is accounted for in the denominator of the levelised cost of energy storage (LCOS) formula as shown by equation 2 in section 6.5.

$$ES_{out} = ES_s * \#Cycles * \#Days \qquad \text{(eq. 6)}$$

Where:

ES_{out} = Total electrical energy discharged per year as output from energy storage system (kWh per year).

ES_s = Energy capacity size of storage to enable maximum electrical discharge (kWh).

#Cycles = Number of full charge-discharge cycles per day (cycles per day).

#Days = Number of days per year that the system will be operated (days per year).

The annual electrical input required by an energy storage system can then be calculated by dividing the electrical energy output discharged per year by the associated roundtrip efficiency as indicated by equation 7 (adapted from Jülch *et al*., 2015:20; Jülch, 2016:1597).

$$ES_{in} = \frac{ES_{out}}{\eta} \qquad \text{(eq. 7)}$$

Where:

ES_{in} = Electrical energy charged per year as input to energy storage system (kWh per year).
ES_{out} = Total electrical energy discharged per year as output from energy storage system (kWh per year).
η = Roundtrip efficiency (%).

For the levelised cost of energy storage (LCOS) modelling, a roundtrip efficiency of 93% for lithium-ion batteries and 80% for both VRFB and NaS batteries has been assumed in 2016. It is further assumed that roundtrip efficiency will improve to 95% for lithium-ion batteries and 83% for both VRFB and NaS batteries by 2020. These assumptions are within existing technical ranges as summarised in Table 3.1 from the literature review in section 3.2 of Chapter 3 and more specifically authors such as Beaudin *et al.* (2010:310), Poullikkas (2013:786), Mahlia *et al*. (2014:542), Castillo *et al.* (2014:887), Akinyele *et al.* (2014:86), Kousksou *et al.* (2014:72-74), Zakeri *et al.* (2015:592), Lund *et al.* (2015:795), Hameer *et al.* (2015:1187), Jülch (2016:1598), Kyriakopoulos *et al.* (2016:1060-1061), Aneke *et al.* (2016:368), Amrouch *et al.* (2016:20922), Gallo *et al.* (2016:815), Lai *et al.* (2017:202), Berrada *et al.* (2017:102) and Amirante *et al.* (2017:384).

Charging costs can be included in operations and maintenance costs or addressed separately in lifecycle cost analyses (Zakeri *et al.*, 2015:573). As can be seen from equation 2, charging costs are addressed separately in the LCOS modelling, since it is an important parameter with a large influence on cost (Poonpun *et al.*, 2008:530-531; Schoenung, 2011:7-13; Pawel, 2014:69-70; Zakeri *et al.*, 2015:573; Jülch *et al*., 2015:24; Lazard, 2016:31-34; Jülch, 2016:1595-1604; Obi *et al.*, 2017:913).

Charging costs are influenced by the specific application that an energy storage system is required to fulfil (Battke *et al*., 2013:245; Zakeri *et al*., 2015:584). To perform the primary application investigated in this study, namely renewables integration with solar photovoltaic (PV) plants, an energy storage system could charge from both the solar PV plant directly and/or from the electricity grid by means of Eskom, each with their own associated electrical input prices. The source of charge can depend on the application discharge requirements and times, as well as the source availability of electrical energy that can be utilised for charging at any given moment (Chen *et al.*, 2009:293-294; Dufo-López *et al*., 2009:126-137; Whittingham, 2012:1518-1519; Infield *et al.*, 2014:22-23;

Pawel, 2014:70-74; Zakeri *et al.*, 2015:572; Bortolini *et al.*, 2015:1028-1029; Jülch *et al.*, 2015:24; Dehdashti, 2016:5-6; Lai *et al.*, 2017:195-196).

In order to overcome issues of resource variability and intermittency, supply electricity during peak demand periods and enable electricity price arbitrage opportunities, the energy storage systems considered for the primary application are likely to charge at relatively lower electricity prices. This is a result of charging directly from the solar PV plants and/or from the electricity grid by means of Eskom, the national electric utility, during low demand periods when excess electricity is available and electricity prices are more moderate (Zhang, 2013:43; Battke *et al.*, 2013:242; Lai *et al.*, 2017:196-197; Berrada *et al.*, 2017:100). It is assumed that the selected technologies can fully charge their maximum capacity within less than five hours, which is plentiful time given the required discharge duration for the primary application of four hours and sufficient for servicing both the morning and evening peak demand periods (Hittinger *et al.*, 2012:439; Ibrahim *et al.*, 2013:16).

For the LCOS modelling, a charging electricity price in 2016 of United States dollars (USD) 0.049 has been assumed for the technologies selected for the empirical analysis. This represents the average of both Eskom's electricity revenue, or standard average tariff, of South African rand (ZAR) 0.83 (USD 0.06) per kWh for 2016/17 and the average of solar PV tariffs of ZAR 0.62 (USD 0.04) per kWh as bid in November 2015 under the Department of Energy's Renewable Energy Independent Power Producers Procurement Programme (Council for Scientific and Industrial Research, 2016a:3-7; Council for Scientific and Industrial Research, 2016b:6-13; Council for Scientific and Industrial Research, 2016d:4; Eskom, 2016a:92; Council for Scientific and Industrial Research, 2017b:8-88; Ehlers, 2017; National Energy Regulator of South Africa, 2017:1). An average exchange rate of ZAR 14.71 to the USD in 2016 was used for the currency conversions (IHS Global Insight, 2017).

A charging cost of USD 0.053 per kWh has further been assumed for 2020 in the mathematical modelling. This represents the projected average of Eskom's average electricity price increases and average solar PV prices per kWh to 2020. Eskom's anticipated electricity tariff by 2020 has been estimated to be USD 0.08 per kWh, which was derived from the National Energy Regulator of South Africa's (NERSA) allowable tariff escalations that have been officially granted to the national electric utility over the multi-year price determination period 2013/14 to 2017/18 (National Energy Regulator of

South Africa, 2017:1) and Eskom's own preliminary requisite electricity price increases (Eskom, 2012:13-14). The projected solar PV tariffs by 2020 have been extrapolated to be USD 0.03 per kWh, which were derived from anticipated annual declines from 2015 levels by Farmer *et al.* (2016:658), Taylor, Ralon and Ilas (2016:12-15), Gielen *et al.* (2016:34-38) and the Council for Scientific and Industrial Research (2016b:13). Further information regarding potential future solar PV prices is provided in sub-section 6.6.2.

The assumptions are considered practical for energy storage systems that are required to charge both during the day and night in order to discharge the stored energy during the evening and morning peak demand periods, respectively. As explained in section 6.4, this is because they are likely to charge from both the solar PV electrical generation plant and the electricity grid governed by Eskom prices. The assumptions are, however, deemed conservative if such systems would only charge from solar PV plants during the day in order to discharge during the evening peak demand periods. This is because they are likely to charge primarily from solar PV electrical generation plants characterised by lower electricity tariffs, although electrical input from the electricity grid could also be utilised during times of excessive solar resource intermittency.

Charging costs should ideally be aligned to projected electricity input price movements over the lifetime of an energy storage system in present value or levelised cost estimations (Sørensen, 2011:796-797; Mundada *et al*., 2016:697; Zakeri *et al.*, 2015:586; Lazard, 2016:312; Obi *et al.*, 2017:913). Future electricity prices as a proxy for anticipated charging costs, however, are subject to high uncertainty (Obi *et al*., 2017:915).

In South Africa, the electricity prices or tariffs of privately-owned renewable energy electrical generation plants, commonly known as independent power producers (IPPs), escalate annually by the inflation rate (Eberhard, Kolker & Leigland, 2014:13-17; Eberhard *et al.*, 2016:78-80; Council for Scientific and Industrial Research, 2016a:4; Eberhard & Naude, 2016:4-5). Electricity price increases for the national electric utility, Eskom, however, are less straightforward. NERSA has approved 8% annual electricity price increases for Eskom between 1 April 2013 and 31 March 2018. In that regard, the national electric utility was granted an 8% increase in 2013 and 2014, 12.7% in 2015, 9.4% in 2016 and 2.2% for the 2017 financial year, which reflect an average of approximately 8% over the multi-year price determination period (National Energy Regulator of South Africa, 2013:1; Eskom, 2016a:83-95; National Energy Regulator of South Africa, 2017:1).

Officially approved average price increases beyond 2018 are not presently available and subject to high uncertainty. Eskom has nonetheless indicated that above-inflation electricity price increases are required of around 9% per year between 2018 and 2022 before such annual escalations could retract to approximately 5%, which is within the national inflation target range of 3 to 6%. Such pleas for above-inflation tariff escalations, however, are at the mercy of NERSA (Eskom, 2012:13-14; Kabundi *et al.*, 2013:346; Eskom, 2016a:82-92; South African Reserve Bank, 2016:19-24).

Given the uncertainty surrounding future inflation rates that could inform solar PV price movements and that encompassing likely future average electricity tariff escalations for Eskom, charging costs have been assumed to escalate with the average of past inflation rates for the net present value (NPV) calculations in the LCOS modelling. The assumed inflation rate is equivalent to the rate anticipated for future operations and maintenance cost escalations of 5.23%. This rate represents the average annual growth in the headline consumer price index (CPI) for South Africa between January 2010 and January 2016 (IHS Global Insight, 2017; Statistics South Africa, 2017). The anticipated inflation rate was applied to the NPV calculations for 2016 and 2020 in the mathematical modelling to accommodate for increasing electricity prices that would be used as input to charge the select energy storage technologies over their service contract lifetime.

6.5.5 Number of days (#Days)

Number of days refers to the daily sum that the select energy storage systems will be operated per year. As can be seen from the literature review summarised in section 5.2 of Chapter 5, the annual number of days that an energy storage system will be utilised depends on the application requirements.

For the levelised cost of energy storage (LCOS) modelling, it has been assumed that the select technologies will be required to fully charge and discharge for 350 days a year in order to perform the primary application investigated in this study, namely renewables integration with solar photovoltaic (PV) plants. While the select technologies are assumed to continuously provide system flexibility to smooth variable and intermittent electrical output from solar PV plants, they will also charge and store a portion of the solar energy for discharge during periods of peak demand to enable dispatchable electrical output from solar PV plants, price arbitrage opportunities and/or more renewable generators into constrained electric grids.

As can be seen from the sundry levelised cost estimates summarised in Table 5.1 in section 5.2 of Chapter 5 obtained during the literature review, the number of operational days for use applications that correspond to the primary application and select technologies investigated in this study has ranged from 250 days a year assumed by Poonpun *et al.* (2008:532-533) to 350 days by Lazard (2015:8-24) and Lazard (2016:8-32) and up to 365 annual days by authors such as the World Energy Council (2016a:20), Jülch (2016:1601-1604) and Pawel (2014:72). The reason for assuming a technology functional requirement of 350 days as opposed to 365 days in this study is to allow for the possibility of system maintenance, while still maximising the utilisation of the energy storage system. As noted in the literature review in section 5.2 of Chapter 5, higher battery utilisation rates entail lower lifetime costs (Poonpun *et al.*, 2008:532-533; Battke *et al.*, 2013:247-249; Pawel, 2014:76; Fitzgerald *et al.*, 2015:6-22; Jülch, 2016:1600-1601; Kondziella *et al.*, 2016:16; Lai *et al.*, 2017:199-200).

6.5.6 Number of cycles (#Cycles)

Number of cycles refers to the daily charge-discharge cycling frequency that energy storage systems are required to perform. The number of required cycles, in turn, depends on the application requirements. The primary application investigated in this study requires the use of energy storage technologies to overcome the variability and intermittency associated with solar resources, improve the dispatchability of solar photovoltaic (PV) plants in order for them to supply electrical energy during peak demand periods, enable the incorporation of more solar-based electrical generators into geographic areas characterised by electricity transmission capacity constraints and defer investments in additional transmission and/or generation infrastructure.

As explained in section 6.4, energy storage systems could charge from both solar PV plants and the electricity grid to assist such inherently intermittent electricity producers to be dispatchable and supply electrical energy during peak demand periods (Chen *et al.*, 2009:293-294; Dufo-López *et al.*, 2009:126-137; Infield *et al.*, 2014:22-23; Pawel, 2014:70-73; Jülch *et al.*, 2015:20; World Energy Council, 2016a:5-11). As such, for the levelised cost of energy storage (LCOS) modelling, scenarios are considered in which the select energy storage technologies will be required to perform a single and double charge-discharge cycle per day, while accounting for increased capital replacement rates.

It is assumed that a single daily cycle would require energy storage systems to charge during the day, mainly from solar PV plants and/or use the electricity grid for the duration of cloud cover, for discharge during the evening peak demand period. A double daily charge-discharge regime would require an energy storage system to primarily charge from the solar PV plant during the day for discharge during the evening peak demand period and thereafter during the night from excess electricity in the grid for discharge during the morning peak demand period.

It was observed during the literature review that existing research mostly focuses on one charge-discharge cycle per day. Energy storage technologies, however, have the technical capability to perform more than one daily cycle, which could potentially entail significant lifetime cost reductions by improving battery utilisation and total system electrical output (Battke *et al*., 2013:247-249; Zakeri *et al.*, 2015:573; World Energy Council, 2016a:5).

6.5.7 Depth of discharge (DoD)

Depth of discharge (DoD) refers to the usable energy storage capacity or share of total stored energy that can be discharged relative to full capacity before being recharged in order to maintain the optimum performance lifetime of the energy storage medium. For example, if it is ideal to retain 20% of total stored energy capacity in the storage medium, then the DoD is equal to 80% (Battke *et al*., 2013:246; Ibrahim *et al.*, 2013:11-15; Carnegie *et al.*, 2013:13; Pawel, 2014:72; Infield *et al.*, 2014:29; Hammond *et al.*, 2014:570; Bortolini *et al.*, 2015:1027; Jülch *et al*., 2015:19; Kempener *et al.*, 2015:6; Akhil *et al.*, 2015:153; Mayr *et al.*, 2016; World Energy Council, 2016a:47; Jülch, 2016:1597).

Since the cycle life of many batteries can be reduced substantially with very deep discharges, the levelised cost of energy storage (LCOS) modelling accounts for the maximum DoD associated with each select energy storage technology and assumed cycle life (Dufo-López *et al*., 2009:130-131; Carnegie *et al.*, 2013:13; Zhang, 2013:27; Infield *et al.*, 2014:42; Hammond *et al.*, 2014:570; Kempener *et al.*, 2015:6; Akhil *et al.*, 2015:55; Mandelli *et al.*, 2016:293-294). In that regard, a maximum DoD of 80% for lithium-ion, 100% for vanadium redox flow (VRFB) and 90% for sodium-sulphur (NaS) batteries is assumed in the empirical analysis. This represents the maximum DoD percentages summarised in Table 3.1 in section 3.2 of Chapter 3 from the literature review. Lithium-ion batteries are expected to undergo improvements in DoD in future and a maximum DoD of 85% is assumed for them by 2020, which is aligned to Jülch *et al*. (2016:1598). DoD limitations have an important influence on energy storage technology lifecycle costs and the methodology is therefore an improvement on existing studies that have assumed 100% DoD or equal lower DoD capability for all technologies investigated.

6.5.8 Energy capacity size of storage (ES_s)

Energy capacity size of storage refers to the adequate capacity of an energy storage medium as required to enable the maximum dischargeable electrical energy. The maximum amount of electrical energy that can be discharged per year is obtained with equation 6, specified in sub-section 6.5.4. It is generally assumed in lifecycle cost analyses that all energy available, as governed by maximum depth of discharge (DoD) and degradation in capacity, is discharged from an energy storage medium in a single charge-discharge cycle to perform primary applications (Battke *et al.*, 2013:245). This implies that energy storage systems complete full charge-discharge cycles and it is also the assumption applied in the levelised cost of energy storage (LCOS) modelling.

The energy capacity size of storage could be calculated by multiplying an energy storage system's power rating with the required energy storage discharge duration to perform an application (Battke *et al.*, 2013:246; Battke *et al.*, 2015:345; Lazard, 2016:31-40; Obi *et al.*, 2017:918). This is indicated by equation 8.

$$ES_s = \text{Hours} * \text{Rating} \qquad \text{(eq. 8)}$$

Where:

ES_s = Energy capacity size of storage to enable maximum electrical discharge (kWh).
Hours = Required energy storage discharge duration (hours).
Rating = Required electrical power rating of energy storage system (kW).

6.5.9 Degradation (DEG)

Degradation refers to the accepted deterioration in an energy storage medium's rated capacity. It indicates the usable energy over the lifetime of the asset or the complete charge-discharge cycles an energy storage medium can perform before its nominal energy capacity falls below a certain percentage, say 80%, of its initial rated capacity, irrespective of whether it is used or not. Most energy storage systems degrade over time due to ageing and general wear and tear, with the rate of degradation increasing with frequency of use and operating temperature (Ibrahim *et al.*, 2013:15; Thorbergsson, Knap, Swierczynski, Stroe & Teodorescu, 2013:3; Jülch *et al*., 2015:19-20; Mayr *et al.*, 2016; Lai *et al.*, 2017:198-202).

Lithium-ion batteries are assumed to reach the end of their useful life once the usable energy storage capacity declines to around 80% of the initial rated capacity, which implies a lifetime degradation rate of approximately 20% (Pawel, 2014:72; Jülch *et al*., 2015:20; Peters *et al.*, 2017:499). This denotes an average linear degradation rate of 10% over the lifetime of the energy storage system, since the batteries will progressively degrade from 0 to 20%. A linear energy storage capacity degradation coefficient of 90% is therefore assumed for the levelised cost of energy storage (LCOS) modelling for lithium-ion batteries.

Vanadium redox flow batteries (VRFBs) are assumed to lose zero energy storage capacity over their lifetime, since they are tolerant to overcharge and discharge and the external electrolyte solution can easily be replaced, which implies a linear energy storage capacity degradation rate of 0% (Hadjipaschalis *et al.*, 2009:1517; Carnegie *et al.*, 2013:48-50; Pawel, 2014:72; Kempener *et al.*, 2015:44; Lazard, 2016:10; Lai *et al.*, 2017:198). Similarly, sodium-sulphur (NaS) batteries are also assumed to experience 0% degradation (Rydh *et al.*, 2005:1968; Akhil *et al.*, 2015:B-16). A linear degradation coefficient of 100% is therefore assumed for both VRFB and NaS batteries in the LCOS modelling.

6.5.10 Relevant year (n)

Relevant year refers to the specific year(s) in which expenditure is incurred over the lifetime of an energy storage system. This is needed to take account of the time value of money by discounting future costs to present value terms in the levelised cost of energy storage (LCOS) modelling (Layard *et al.*, 1994:4-26; Schoenung *et al.*, 2008:13-15; Schoenung, 2011:12; Bhattacharyya, 2011:176-177; Zhang, 2013:12; García-Gusano *et al.*, 2016:57; Berrada *et al.*, 2017:97). Sub-section 6.5.12 provides further information on the discount rate.

6.5.11 Project contract lifetime (N)

Project contract lifetime (N) refers to the total number of years that an energy storage system is contractually required or useful (Pawel, 2014:69; Lazard, 2016:31-40). In that regard, the lifetime cost impact of operating the select energy storage systems over both 10- and 20-year project contract periods is considered with scenarios in the levelised cost of energy storage (LCOS) modelling and disclosed in Chapter 7.

6.5.12 Discount rate (r)

A discount rate is the interest rate at which all anticipated capital, operations, maintenance and charging costs over a project's life are discounted as necessary to express them in present value terms. Discounting future cashflows is required, since a specific amount of money has less value in the future than the same amount has in the present (Layard *et al.*, 1994:4; Dufo-López *et al.*, 2009:130; Pindyck *et al.*, 2009:553-561; Branker *et al.*, 2011:4475; South Africa, 2011:8; Zhang, 2013:40; Zakeri *et al.*, 2015:585; García-Gusano *et al.*, 2016:57; Berrada *et al.*, 2017:97).

The discount rate takes account of the time value of money through currency depreciation and investment risks by equating future expense streams in terms of current costs (South Africa, 2011:8; Lai *et al.*, 2017:200). Discount rates escalate with higher perceived investor financial risk associated with macroeconomic circumstances and unfamiliar technologies relative to conventional generation options, such as energy storage systems (Branker *et al.*, 2011:4475; Mundada *et al.*, 2016:695; Berrada *et al.*, 2017:107; Lai *et al.*, 2017:200). A higher discount rate implies a lower net present value (NPV) and thereby a higher levelised cost of energy storage (LCOS). The opposite is also true (Schoenung *et al.*, 2008:13; Pindyck *et al.*, 2009:553-556; Pawel, 2014:76; Celiker, Kayacetin, Kumar & Sonaer, 2016:241; Mundada *et al.*, 2016:697; Berrada *et al.*, 2017:107).

A real discount rate of 8.2% has been assumed for the LCOS modelling. This corresponds to the Department of Energy's draft Integrated Resource Plan for Electricity (IRP) 2016 to 2050 Base Case, which is undergoing public consultation (Department of Energy, 2016a:10), and a mere 0.2% higher than the official 8% discount rate adopted in the IRP 2010 to 2030 (South Africa, 2011:38). Once the IRP 2016 to 2050 has undergone public consultation and been policy adjusted, it will replace the IRP 2010 to 2030 as the official and primary policy document that provides South Africa's long-term plan for electricity.

6.6 WEIGHTED AVERAGE LEVELISED COST OF ENERGY STORAGE COUPLED WITH SOLAR PHOTOVOLTAIC PLANTS (LCOS-PV)

While it is arithmetically possible, the levelised cost of energy storage systems (LCOS) in isolation should ideally not be directly compared to the levelised cost of electricity generation options (LCOE), since they have different functionalities. Electrical generators produce electricity for immediate use, while energy storage technologies are net users of electricity and store electrical energy produced by a generation plant for later discharge and use. They also have different modes of operation. While electrical energy generation options have a single use application, namely to produce electricity, energy storage technologies have a variety of uses that influence their respective reflective costs, value and comparability (Poonpun *et al.*, 2008:530; Chen *et al.*, 2009:291; He *et al.*, 2011:1575; Zahedi, 2011:866-870; Kaun *et al.*, 2013:25-85; Pawel, 2014:69-70; Castillo *et al.*, 2014:888; Suberu *et al.*, 2014:500-501; Zakeri *et al.*, 2015:571-588; Günter *et al.*, 2016:231-234; Kondziella *et al.*, 2016:15-20; Malhotra *et al.*, 2016:707-711; Lai *et al.*, 2017:191-195). The various value applications that can be performed by energy storage systems sequentially and/or simultaneously are discussed in section 4.2 of Chapter 4.

Given the technical differences between electrical energy generation and storage technologies, innovative methods are required to appropriately determine the competitive ability and economic viability of energy storage solutions. LCOS estimates should also be compared with competing technologies that offer similar application flexibility, such as backup generators, peaking plants, additional grid investment costs and other generation options not entirely representative of base load electricity (Pawel, 2014:76; Bortolini *et al.*, 2015:1026-1029; Zakeri *et al.*, 2015:588; De la Rubia *et al*., 2015:7).

One approach to fairly determine the competitive ability of energy storage technologies with electrical generators is to weight the sum of the LCOS and LCOE of an intermittent electrical energy production option with their combined electrical output contributions and compare this with the levelised cost of any generation alternative with similar dispatch characteristics (Pawel, 2014:68-76; Bortolini *et al.*, 2015:1029; Jülch *et al*., 2015:24; World Energy Council, 2016a:26; Lai *et al.*, 2017:196-197). In this regard, the primary application investigated in this study, namely renewables integration with solar photovoltaic (PV) plants, necessitates the determination of the weighted average levelised cost of energy storage technologies coupled with solar PV plants (LCOS-PV).

Section 6.4 describes the need to integrate energy storage technologies with solar PV plants in the South African electricity generation and supply environment.

During the literature review, as summarised in section 5.2 of Chapter 5, a need was identified for further research into the LCOS-PV. Authors such as Lai *et al.* (2017:192) have also emphasised that research and analyses into the levelised cost of solar PV plants coupled with energy storage systems have generally been inadequate and obscure. The empirical study would therefore further contribute to existing literature by estimating the LCOS-PV for 2016 and projecting it to 2020 in order to assess the existing and potential future economic feasibility or cost competitiveness of energy storage systems within the South African context.

The levelised cost of a combined solar PV and energy storage power plant is equivalent to the weighted average of the LCOE of a solar PV plant and the LCOS. This can be determined by dividing the sum of the respective levelised costs of both the solar PV plant and energy storage system's individual electrical output contributions by the combined electrical energy output from both technologies. It would yield the LCOS-PV and could be regarded as the reflective cost of the packaged solution (Pawel, 2014:73-76; Jülch *et al*., 2015:24; Lai *et al.*, 2017:196-197). According to Pawel (2014:76), the LCOS-PV would be somewhere between the LCOE for a solar PV plant and the LCOS.

The formula to determine the LCOS-PV can be expressed through equation 9 (adapted from Pawel, 2014:69-76; Bortolini *et al.*, 2015:1029; Lai *et al.*, 2017:196-197). The parameters, formulae and relevant assumptions used to derive the LCOS-PV are described in sub-sections 6.6.1 to 6.6.5. Section 6.7 explains the approach that will be followed to assess the economic feasibility of the select energy storage technologies co-located with solar PV plants relative to concentrating solar power (CSP) plants with thermal energy storage capability.

$$\text{LCOS-PV} = \frac{(\text{PV}_{\text{out}} * \text{LCOE}_{\text{pv}}) + (\text{ES}_{\text{out}} * \text{LCOS})}{\text{PVES}_{\text{out}}} \qquad \text{(eq. 9)}$$

Where:

LCOS-PV = Total weighted average levelised cost of energy storage coupled with solar PV plants (USD per kWh).

PV_{out} = Electrical energy output from solar PV plant per year that is directly utilised for the electricity grid and not used to charge the energy storage system (kWh per year).

$LCOE_{pv}$ = Levelised cost of electricity for solar PV plant (USD per kWh).

ES_{out} = Total electrical energy discharged per year as output from energy storage system (kWh per year).

LCOS = Levelised cost of energy storage system (USD per kWh).

$PVES_{out}$ = Total electrical energy available to the electricity grid per year from both the solar PV plant and energy storage system combined (kWh per year).

6.6.1 Electrical energy output from solar photovoltaic plant (PV_{out})

This parameter represents the electrical energy produced by a solar photovoltaic (PV) plant per year for direct output into the electricity grid. In other words, it denotes the annual share of electrical output from a solar PV plant that is not used as input to charge an energy storage medium for later use (Pawel, 2014:70-74; Jülch *et al.*, 2015:24; Lai *et al.*, 2017:195-197).

For the modelling, it is assumed that 30% of the electrical energy generated by a solar PV plant is stored in the select energy storage technologies, with the remainder being sent directly into the electric grid for immediate consumption. This can be considered a reasonable assumption, since energy storage system installations of 30% of total solar PV plant capacity are common in practice (Rycroft, 2017:22). Mathematically, this implies that the total electrical energy produced by the solar PV plant, for use in the electricity grid and to charge the energy storage medium, can be calculated with equation 10.

$$PV_{prod} = \frac{ES_{out}}{PV_{es}} \qquad \text{(eq. 10)}$$

Where:

PV_{prod} = Total electrical energy produced by solar PV plant for use in electricity grid and to charge energy storage medium (kWh per year).

ES_{out} = Total electrical energy discharged per year as output from energy storage system (kWh per year).

PV_{es} = Share of electrical energy produced by solar PV plant stored in energy storage medium (%).

The electrical energy that can be discharged from the energy storage system per year (ES_{out}) is given by equation 6 in sub-section 6.5.4. The electrical energy produced by the solar PV plant per year for direct output into the electricity grid (PV_{out}) can then be calculated with equation 11.

$$PV_{out} = PV_{prod} - ES_{in} \qquad \text{(eq. 11)}$$

Where:

PV_{out} = Electrical energy output from solar PV plant per year that is directly utilised for the electricity grid and not used to charge the energy storage system (kWh per year).
PV_{prod} = Total electrical energy produced by solar PV plant for use in electricity grid and to charge energy storage medium (kWh per year).
ES_{in} = Electrical energy charged per year as input to energy storage system, accommodating for roundtrip efficiency losses (kWh per year).

The electrical input required to fully charge an energy storage system per year to account for roundtrip efficiency losses (ES_{in}) is given by equation 7 in sub-section 6.5.4.

6.6.2 Levelised cost of electricity for solar photovoltaic plant ($LCOE_{pv}$)

As can be inferred from section 6.5, the levelised cost of electricity (LCOE) metric for solar photovoltaic (PV) technologies articulates the breakeven price per kWh over the applicable lifetime of a solar PV plant in present value terms. The metric makes it possible to compare the LCOE for solar PV plants to that of alternative electrical generation options as an indicator of economic feasibility in terms of cost competitiveness (Dufo-López *et al*., 2009:129-130; Darling *et al.*, 2011:3133-3134; Bhattacharyya, 2011:237-238; Branker *et al.*, 2011:4471-4472; Battke *et al*., 2013:246; Kost *et al.*, 2013:36; Bortolini *et al.*, 2014:85-86; Akhil *et al.*, 2015:157; Bortolini *et al.*, 2015:1029; World Energy Council, 2016a:46; Lai *et al.*, 2017:191-202; Obi *et al*., 2017:908-918).

It has been estimated that the LCOE of solar PV plants has reached grid parity or a situation in which the cost of solar PV plants is equivalent or lower than the costs of conventional electricity generators (Hurtado Munoz *et al.*, 2014:180; Bortolini *et al.*, 2014:81-82; Choi *et al.*, 2015:718; Papaefthimiou *et al.*, 2016:264; Branker *et al.*, 2011:4470-4471). The excellent solar irradiation intensity in South Africa enables solar-based electrical production plants to sustain lower lifetime costs relative to regions with less irradiation potential, since it enables higher electrical energy output levels (Grobbelaar *et al.*, 2014:479; Walwyn *et al.*, 2015:391-393; Busse *et al.*, 2016:52-53; Gielen *et al.*, 2016:14; Minnaar, 2016:1140; Lai *et al.*, 2017:193-194). Highly competitive procurement conditions for privately-owned electrical generation bids under the Renewable Energy Independent Power Producers Procurement Programme (REIPPPP) of the Department of Energy has further stimulated rapid cost declines (Eberhard *et al.*, 2014:17; Montmasson-Clair & Ryan, 2014:508-520; Walwyn *et al.*, 2015:391-399; Eberhard *et al.*, 2016:1; Department of Energy, 2017:7-21).

In that regard, South Africa’s superb irradiation potential and a competitive bidding environment has enabled solar PV plants to be cost competitive with fossil fuel-based electrical generators in the absence of subsidies (Montmasson-Clair *et al.*, 2014:508-520; Nhamo *et al.*, 2016:70; Eberhard *et al.*, 2016:1; Ehlers, 2017). Solar PV electrical production prices will furthermore continue to decline, while prices for conventionally generated electricity, such as from fossil fuels and nuclear energy, continue to rise, thereby making solar PV plants a more economical source for the production of electrical energy (Tahvonen *et al.*, 2001:1396; Branker *et al.*, 2011:4470; Covert *et al.*, 2016:128-129; Kost *et al.*, 2013:6; Busse *et al.*, 2016:55).

As indicated in sub-section 6.5.4, a solar PV LCOE of United States dollars (USD) 0.04 per kWh in 2016 has been assumed for the modelling. This represents the average of actual solar PV tariffs of South African rand (ZAR) 0.62 per kWh in November 2015 as bid under the Department of Energy’s REIPPPP at an average exchange rate of ZAR 14.71 to the USD in 2016 (Council for Scientific and Industrial Research, 2016a:3-7; Council for Scientific and Industrial Research, 2016b:6-13; Council for Scientific and Industrial Research, 2016d:4; Council for Scientific and Industrial Research, 2017b:8-88; Ehlers, 2017; IHS Global Insight, 2017).

It is further assumed in the modelling that the LCOE for solar PV plants will decline to USD 0.03 per kWh by 2020. Farmer *et al.* (2016:657-658) have forecast that solar PV prices are likely to continue declining at approximately 10% per year to 2030. This suggests that the LCOE for solar PV plants could decrease to USD 0.03 per kWh by 2020 from the average solar PV tariffs bid in South Africa of USD 0.04 per kWh in November

2015. Similarly, Taylor *et al.* (2016:10-14) estimated the global weighted average LCOE of solar PV plants to reduce by 59% from 2015 levels to a low of USD 0.03 per kWh by 2025. This downward trajectory for solar PV LCOE is also supported by Gielen *et al.* (2016:34-38) and aligned to the Council for Scientific and Industrial Research (2016b:13).

South Africa's powerful irradiation levels are likely to result in a lower LCOE for solar PV plants in comparison to countries with less intense irradiation levels. As such, solar PV LCOE in South Africa could reach USD 0.03 per kWh sooner than anticipated for the global average as estimated by Taylor *et al.* (2016:10-14). In fact, Dubai, with slightly lower irradiation levels than South Africa, already attracted solar PV tariff bids as low as USD 0.03 per kWh in the first half of 2016 (Taylor *et al.*, 2016:49; Gielen *et al.*, 2016:9-10; Poudineh, Sen & Fattouh, 2016:9).

6.6.3 Electrical energy discharged from energy storage system (ES_{out})

This parameter represents the total amount of electrical energy that can be discharged from an energy storage system per year as output for input to the electricity grid and can be calculated with equation 6 as specified in sub-section 6.5.4. In other words, it denotes the electrical energy that can be discharged from an energy storage system in a year that is enabled by charging from the electric grid and/or solar PV plant, according to the required daily charge-discharge cycling regime and after accounting for roundtrip efficiency losses. Reduced electrical output caused by depth of discharge (DoD) and capacity degradation limitations for some technologies is accounted for in the denominator of the levelised cost of energy storage (LCOS) formula as shown by equation 2 in section 6.5.

6.6.4 Levelised cost of energy storage system (LCOS)

The levelised cost of energy storage (LCOS) is a metric that articulates the present value cost or breakeven price per kWh over the applicable lifetime of an energy storage system. It includes all cost and performance parameters associated with an installation through to the termination of service and enables comparison between different energy storage technologies, as well as with electrical generation options, according to the applications they are required to perform (Poonpun *et al.*, 2008:529-534; Battke *et al.*, 2013:242-247; Pawel, 2014:68-77; Bortolini *et al.*, 2015:1029; Zakeri *et al.*, 2015:573-588; Battke *et al.*, 2015:340-341; Jülch *et al.*, 2015:19; Hoff *et al.*, 2016:2; World Energy Council, 2016a:5-

46; Mundada *et al.*, 2016:692-700; Jülch, 2016:1594-1604; Lai *et al.*, 2017:194; Obi *et al.*, 2017:908-918). Section 6.5 provides a detailed description of the LCOS metric and the associated parameters, formulae, data inputs and relevant assumptions used to formulate the LCOS model.

6.6.5 Total electrical energy available from solar photovoltaic plant and energy storage system ($PVES_{out}$)

The total combined electrical energy output available per year from a solar photovoltaic (PV) plant with energy storage capability is equal to the annual sum of the electrical energy produced by the solar PV plant for direct output into the electricity grid (PV_{out}) and the electrical energy that can be discharged from the energy storage system as output into the electricity grid (ES_{out}). This can be determined with equation 12.

$$PVES_{out} = PV_{out} + ES_{out} \qquad \text{(eq. 12)}$$

Where:

$PVES_{out}$ = Total electrical energy available to the electricity grid per year from both the solar PV plant and energy storage system combined (kWh per year).

PV_{out} = Electrical energy output from solar PV plant per year that is directly utilised for the electricity grid and not used to charge the energy storage system (kWh per year).

ES_{out} = Total electrical energy discharged per year as output from energy storage system (kWh per year).

The solar PV plant-based electrical output per year for direct utilisation in the electricity grid (PV_{out}) can be calculated with equation 11 as specified in sub-section 6.6.1. The total electrical energy discharged by the energy storage system per year (ES_{out}) can be calculated with equation 6 as specified in sub-section 6.5.4.

As explained in section 6.4 and sub-section 6.6.3, the electrical energy that can be discharged from an energy storage system (ES_{out}) could be enabled by charging from a solar PV plant and/or from excess electricity in the grid. The total weighted average levelised cost of energy storage systems coupled with solar PV plants (LCOS-PV) could be reduced in the event that an energy storage system charges from both the solar PV plant during the day and the electricity grid during the night in performing more than one daily charge-discharge cycle. This is due to the greater amount of electrical energy that would be available from both the solar PV plant and energy storage system in combination as a result of also charging from the electricity grid.

6.7 ASSESSING THE ECONOMIC FEASIBILITY OF ENERGY STORAGE TECHNOLOGIES

As described in section 6.6, innovative methods are required to fairly assess the economic feasibility of energy storage technologies in terms of cost competitiveness with electrical generators. In that regard, and to compare commensurable factors, the total weighted average levelised cost of energy storage systems combined with solar photovoltaic (PV) plants (LCOS-PV) could be estimated, projected and compared to the prevailing and anticipated levelised cost of electricity (LCOE) for concentrating solar power (CSP) plants with thermal energy storage capability.

By doing this, it is possible to compare both alternatives on a fair basis as both options produce electrical energy from solar energy as a source and store a portion of the electrical energy produced for later discharge or use. CSP, especially parabolic trough and solar tower plants, is also considered mature electrical energy generation technology (Grobbelaar *et al.*, 2014:479; Desideri & Campana, 2014:424; Khan *et al.*, 2016:419; Van Ravenswaay *et al.*, 2015:1839; Chaanaoui *et al.*, 2016:782-789).

As indicated in sub-section 3.2.2 of Chapter 3, a CSP plant with energy storage capability typically involves storing excess solar thermal energy produced during the day in tanks by using mirrors or lenses to concentrate sunlight onto a small area or receiver containing heat transfer fluid, such as molten salts and/or synthetic oil. The concentrated sunlight heats the heat transfer fluid to very high temperatures, approximately 290 to 570°C or higher, to produce steam. When electrical energy is required, the steam is dispatched and used to drive a turbine to generate electricity (Desideri *et al.*, 2014:424; Grobbelaar *et al.*, 2014:477; Gauché *et al.*, 2014:698-699; Khan *et al.*, 2016418; Busse *et al.*, 2016:51-55; Amrouche *et al.*, 2016:20922; Viebahn, Lechon & Trieb, 2016:4420-4421; Chaanaoui *et al.*, 2016:783; Liu *et al.*, 2016:1412-1414).

CSP plants with thermal energy storage are further used in alignment with the primary application investigated in this study. This is due to its technical capability to generate, store and dispatch thermal-based electrical energy to overcome issues of solar resource variability and intermittency, supply electrical energy during periods of peak demand and enable electricity price arbitrage opportunities (Desideri *et al.*, 2014:423-424; Viebahn *et al.*, 2016:4420-4421; Busse *et al.*, 2016:51-52; Chaanaoui *et al.*, 2016:782-783; Amrouche *et al.*, 2016:20919; Liu *et al.*, 2016:1411-1414; Pan *et al.*, 2017:379-381). Privately-owned CSP plants with thermal energy storage capability have already been procured and incentivised, through higher peak tariffs, in South Africa to supply electrical energy during periods of maximum demand for electricity in order to alleviate pressure on the national electricity grid (Eberhard *et al.*, 2016:8; Busse *et al.*, 2016:56-57).

As indicated in section 6.3, the energy storage technologies selected for the empirical analysis in this dissertation comprise lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries. The competitive ability, affordability and economic feasibility of these select electrochemical energy storage technologies are assessed in Chapter 7 by determining whether the LCOS-PV is equal to or lower than the LCOE of CSP plants with thermal energy storage capability.

The most recent average LCOE for CSP plants with thermal energy storage capability in South Africa was equivalent to approximately United States dollars (USD) 0.14 per kWh in 2016. This represents the weighted average of base and peak tariffs of South African rand (ZAR) 2.02 per kWh in November 2015 as bid under the Department of Energy's Renewable Energy Independent Power Producers Procurement Programme (REIPPPP) at an average exchange rate of ZAR 14.71 to the USD in 2016 (Council for Scientific and Industrial Research, 2016d:4; Council for Scientific and Industrial Research, 2017a:33; IHS Global Insight, 2017). Similar LCOE values for CSP plants with thermal energy storage capability in South Africa have been reported by Taylor *et al.* (2016:18-90), Busse *et al.* (2016:56-57) and Pan *et al.* (2017:380-387).

It is further anticipated that the LCOE for CSP plants with thermal energy storage capability in South Africa would decline to approximately USD 0.12 per kWh by 2020. This is aligned to the 2020 projected average LCOE for CSP plants with thermal energy storage capability of ZAR 1.46 (USD 0.10) per kWh in 2020 by the Council for Scientific and Industrial Research (2017:37), USD 0.12 per kWh extrapolated from Taylor *et al.* (2016:99-100), ZAR 1.75 (USD 0.12) per kWh from Busse *et al.* (2016:57) and USD 0.13 per kWh from the International Energy Agency (2014:24).

6.8 SUMMARY AND CONCLUSION

This chapter explained the applied methods to assess the economic feasibility of utility-scale energy storage technologies for South Africa. The information supplied in the preceding Chapters 1 to 5 provided the necessary context for a description of the methods undertaken to perform the empirical analysis. The information conveyed in this Chapter 6 enabled the attainment of the specific objective set for the study that requires examining the method through which energy storage technologies could reasonably be compared with one another and with prevailing alternative electrical energy generation options. More specifically, a proposed procedure to determine the reflective levelised cost of energy storage systems (LCOS) was developed and the means through which such systems can be compared with alternative electrical generation options was established.

Section 6.1 introduced the content to Chapter 6. Section 6.2 clarified the methodological outline for the empirical analysis and the novelty of the LCOS model developed and used for this study. Section 6.3 provided a motivation for the selection of lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries for the empirical analysis. These electrochemical energy storage mediums are regarded as the most competitive, technically advanced and promising technologies for performing utility-scale applications in South Africa, particularly renewables integration with solar photovoltaic (PV) plants.

Section 6.4 discussed the need to integrate energy storage systems with solar PV plants within the South African context. Generally, energy storage systems can be used to support the morning and/or evening peak demand for electricity; enable constant, stable, reliable and dispatchable electrical energy output from solar PV plants; provide electricity grid congestion relief; defer investments in alternative electric transmission and generation infrastructure; accommodate more solar-based electrical production options into the electricity grid and/or limit the wastage of surplus electrical energy availability from solar PV plants.

Section 6.5 explained the methods applied for the LCOS model to determine and assess the cost competitiveness of the select energy storage systems in 2016 and projected 2020. It described the model formulation, parameters, formulae, technical and financial data inputs, relevant assumptions and interpretation. The main explanatory variables pertaining to the LCOS include total initial and replacement capital costs, operations and maintenance costs, roundtrip efficiency and charging costs, operational days, number of charge-discharge cycles, depth of discharge (DoD), energy capacity size of storage, capacity degradation, project contract lifetime and the discount rate.

Section 6.6 elaborated on the extension of the LCOS model to estimate the weighted average levelised cost of energy storage systems coupled with solar PV plants (LCOS-PV) in 2016 and projected 2020. This is required to determine the competitive ability of energy storage technologies relative to alternative electrical generation options with similar dispatch characteristics. The main explanatory variables pertaining to the LCOS-PV are described as the electrical energy output from a solar PV plant, levelised cost of electricity (LCOE) for the solar PV plant, electrical energy discharged from the energy storage system, LCOS and total electrical energy available to the electricity grid from both the solar PV plant and energy storage system.

Section 6.7 clarified the method used to assess the economic feasibility of energy storage systems in terms of cost competitiveness with electrical generators. To allow for a fair basis of comparison, the assessment is primarily performed by comparing the LCOS-PV to the LCOE for concentrating solar power (CSP) plants with thermal energy storage capability as a case study, especially since both energy storage coupled with solar PV plants and CSP plants with thermal energy storage capability produce and store solar-based electrical energy. CSP, particularly parabolic trough and solar tower plants, is also considered mature technology.

The applied methods derived in this chapter is demonstrated in Chapter 7. The focus of Chapter 7 is to disclose, examine and analyse the LCOS modelling results through four scenarios based on project calendar life and daily charge-discharge cycling regimes. The LCOS modelling results for the select energy storage systems, in isolation and when such systems are coupled with solar PV plants, will further be utilised to test the economic feasibility of energy storage technologies in terms of cost competitiveness with one another and with CSP plants with thermal energy storage capability as an alternative generation option with similar electrical output dispatch characteristics. The LCOS-PV relative to other electrical generators beyond CSP plants with thermal energy storage capability is also considered within the South African context for conceptual purposes.

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CHAPTER 7:

EMPIRICAL ANALYSIS OF THE ECONOMIC FEASIBILITY OF UTILITY-SCALE ENERGY STORAGE SYSTEMS FOR SOUTH AFRICA

7.1 INTRODUCTION

Chapter 7 assesses the economic feasibility of select utility-scale electrochemical energy storage technologies for South Africa in 2016 and projected 2020. The research conducted during the compilation of Chapters 1 to 6 provided sufficient information to estimate, project and assess the economic feasibility of energy storage systems through a levelised cost of energy storage (LCOS) analysis. Chapter 6 described the methods developed and used to formulate the LCOS model for energy storage systems in isolation and when such systems are coupled with solar photovoltaic (PV) plants. As explained in sections 6.5 to 6.7, this is necessary to adequately assess the economic feasibility of energy storage technologies in terms of cost competitiveness with one another and with alternative electrical generation options.

In that regard, the goal of this chapter is to fulfil the attainment of the specific objectives set for the study in Chapter 1. This is accomplished by using the applied methods described in Chapter 6 to disclose the LCOS modelling results and assess the economic feasibility, in terms of cost competitiveness, of the select energy storage technologies for South Africa at the utility scale. The assessment is performed under four scenarios by estimating the competitive ability of select utility-scale energy storage systems with one another and, coupled with solar PV plants, with alternative generation options in 2016 and projected 2020. Chapter 7 completes the research for this dissertation by addressing the research problem, answering the general research question and attaining the general research objective set for this study in Chapter 1.

This chapter is structured according to six sections. The next section (7.2) clarifies the outline for the empirical analysis and related scenarios. Section 7.3 elaborates on the LCOS modelling results for each select technology as a standalone system. Section 7.4 explains the findings for the weighted average levelised cost of the select energy storage systems coupled with solar PV plants (LCOS-PV). Section 7.5 uses the appropriate lifetime and levelised cost scenarios to test the 2016 and likely future competitive ability of the select energy storage systems coupled with solar PV plants relative to concentrating solar power (CSP) plants with thermal energy storage capability as a case study. The potential cost competitiveness of the select technologies in comparison to alternative electrical generators is also considered. Section 7.6 summarises and concludes Chapter 7.

7.2 EMPIRICAL STUDY OUTLINE

In Chapter 7, the economic feasibility of the energy storage systems selected for the empirical analysis is assessed for 2016 and projected to 2020 by utilising the levelised cost of energy storage (LCOS) modelling methodology developed and described in Chapter 6. The select energy storage technologies include lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries. The motivation for the selection of these technologies as competitive, technically advanced and capable electrochemical energy storage mediums for performing utility-scale applications, including renewables integration, is provided in section 6.3 of the preceding chapter.

The empirical study will mainly be performed in two ways. The first is by estimating and analysing the cost competitiveness between the select technologies as standalone energy storage systems under different scenarios. The second is to estimate and analyse the cost competitiveness of the select energy storage systems coupled with solar photovoltaic (PV) plants and to compare the results to the 2016 and anticipated 2020 lifetime costs of concentrating solar power (CSP) plants with thermal energy storage capability as an alternative electrical generation option with similar dispatch characteristics. The conceivable competitive ability of the select technologies combined with solar PV plants relative to other electrical generators is also referred to. The outcome of the empirical analysis is to provide an indication of the affordability, cost competitiveness and economic viability of the select utility-scale electrical energy storage technologies for South Africa.

The LCOS modelling results are assessed for the primary application investigated in this study, namely renewables integration with solar PV electrical production plants. As explained in Chapter 6, the purpose of the primary application is to use the select energy storage systems to overcome issues of solar resource variability and intermittency, supply electrical energy during periods of peak demand, enable electricity price arbitrage opportunities and integrate more renewable generators into the electricity grid. These services are important for economic growth and development by supporting increased electrical energy security, reliability, flexibility and relative affordability.

The LCOS modelling results for the select technologies in isolation and when they are combined with solar PV plants are evaluated under four scenarios. In each scenario, the primary application requires the select energy storage systems to operate for 350 days a year, have a 50 megawatt (MW) electrical power rating and provide a minimum of four hours energy discharge capability. The four scenarios investigated are a function of daily charge-discharge cycling requirements and project contract lifetime specifications, as follows:

- Scenario 1: Energy storage system performing one full charge-discharge cycle per day over a 10-year project contract lifetime to support the evening peak demand period;
- Scenario 2: Energy storage system performing two full charge-discharge cycles per day over a 10-year project contract lifetime to support both the morning and evening peak demand periods;
- Scenario 3: Energy storage system performing one full charge-discharge cycle per day over a 20-year project contract lifetime to support the evening peak demand period; and
- Scenario 4: Energy storage system performing two full charge-discharge cycles per day over a 20-year project contract lifetime to support both the morning and evening peak demand periods.

Table 9.1 to Table 9.4 in Annexure A disclose the detailed techno-economic parameters, units of measurement, data inputs, costs and associated estimations that informed the mathematical modelling calculations and results under each scenario as clarified in Chapter 6. Annexure A details the modelling scenarios for the levelised costs of the select energy storage systems in isolation (i.e. LCOS) and when such systems are coupled with solar PV plants (i.e. LCOS-PV) in 2016 and projected to 2020.

7.3 LEVELISED COST OF ENERGY STORAGE (LCOS): RESULTS AND DISCUSSION

The levelised cost of energy storage (LCOS) is a metric that articulates the present value cost or breakeven price per kilowatt hour (kWh) over the applicable lifetime of an energy storage system. The LCOS makes it possible to benchmark and evaluate the reflective costs of different energy storage technologies per unit of usable energy storage capacity. It does this by including all cost and performance parameters associated with an installation through to the termination of service and enables comparison between different energy storage technologies, as well as with electrical generation options, according to the applications they are required to perform (Poonpun *et al.*, 2008:529-534; Battke *et al.*, 2013:242-247; Pawel, 2014:68-77; Bortolini *et al.*, 2015:1029; Zakeri *et al.*, 2015:573-588; Battke *et al.*, 2015:340-341; Jülch *et al*., 2015:19; Hoff *et al.*, 2016:2; World Energy Council, 2016a:5-46; Mundada *et al*., 2016:692-700; Jülch, 2016:1594-1604; Lai *et al.*, 2017:194; Obi *et al.*, 2017:908-918).

Section 6.5 of Chapter 6 provides a detailed description of the LCOS metric and the associated parameters, explanatory variables, formulae, technical and financial data inputs, calculations and relevant assumptions used to formulate the LCOS model. The methods outlined in section 6.5 was utilised to derive the lifetime cost results at the utility scale for the select technologies investigated for the empirical analysis in this study. As motivated in section 6.3 of Chapter 6, these include lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries.

Table 7.1 indicates the LCOS results, in United States dollars (USD) per kWh, for the select electrochemical energy storage technologies under consideration as estimated for 2016 and projected to 2020. The results are shown for four scenarios based on one or two charge-discharge cycles per day and 10- or 20-year project contract lifetimes. As indicated in section 7.2, each scenario requires the select technologies to be operational for 350 days a year, have an electrical power rating of 50 megawatt (MW) and discharge electrical energy for four hours during periods of peak demand for electricity. The detailed modelling parameters, inputs and results are shown in Table 9.1 to Table 9.4 in Annexure A. Percentage differences in Table 7.1 are due to rounding.

Table 7.1: LCOS scenario results for select energy storage systems (USD per kWh)

Year	Lithium-ion	VRFB	NaS
Scenario 1: One cycle per day over a 10-year project contract lifetime			
2016	0.41	0.37	0.35
2020	0.28	0.30	0.27
% Change 2016 to 2020	-31.8%	-19.3%	-22.7%
Scenario 2: Two cycles per day over a 10-year project contract lifetime			
2016	0.30	0.23	0.26
2020	0.21	0.19	0.21
% Change 2016 to 2020	-27.9%	-15.5%	-19.9%
Scenario 3: One cycle per day over a 20-year project contract lifetime			
2016	0.38	0.33	0.33
2020	0.28	0.28	0.26
% Change 2016 to 2020	-26.6%	-16.3%	-21.7%
Scenario 4: Two cycles per day over a 20-year project contract lifetime			
2016	0.29	0.21	0.25
2020	0.22	0.19	0.21
% Change 2016 to 2020	-22.2%	-12.1%	-17.3%

Source: Author’s estimates

As noted in section 6.5 of Chapter 6, as well as in sub-section 4.3.3 of Chapter 4 and section 5.2 of Chapter 5, LCOS values should only be compared in instances where the exact same methodology was applied, since differences across assumptions, input parameters, calculations and application requirements are likely to result in ambiguous results (Branker *et al.*, 2011:4471; Akhil *et al.*, 2015:32; Mandelli *et al.*, 2016:291; Obi *et al.*, 2017:910-917). While the sundry levelised costs for lithium-ion, VRFB and NaS batteries summarised in Table 4.2 in section 4.3 of Chapter 4 and Table 5.1 in section 5.2 of Chapter 5 from the literature review are based on different methodological procedures, it could nonetheless be informative to view them against the LCOS estimates indicated in Table 7.1.

The LCOS values in Table 7.1 for the select energy storage systems in 2016 correspond to the majority of sundry levelised cost ranges summarised in Table 4.2 and Table 5.1 from the literature review for the same technologies and similar application requirements. Nearly all value applications identified during the literature review involve a single charge-discharge cycling regime per day, which can also be observed from Table 5.1 in section 5.2 of Chapter 5. It is therefore found that the 2016 LCOS estimates under scenarios 1 and 3 in Table 7.1, based on one charge-discharge cycle per day, are aligned to those indicated in Table 4.2 and Table 5.1 from the literature review.

The LCOS results summarised in Table 7.1 appear high under each scenario for the select technologies as standalone energy storage systems. The LCOS for each technology in isolation is, however, anticipated to continue declining sharply between 2016 and 2020. Energy storage technologies should further be viewed in terms of the number of applications they can perform sequentially and/or simultaneously, since the multi-use capability of such technologies can enhance the overall value of energy storage systems relative to cost, depending on the net economic benefits provided (Sioshansi *et al.*, 2009:277; He *et al.*, 2011:1575-1584; Carnegie *et al.*, 2013:14-19; Zhang, 2013:39; Kaun *et al.*, 2013:25-85; Pawel, 2014:69; Lambruschi, 2015:24-26; De la Rubia *et al.*, 2015:7-8; Battke *et al.*, 2015:334-339; Lazard, 2016:4; Günter *et al.*, 2016:231-234; Kondziella *et al.*, 2016:15-20; Malhotra *et al.*, 2016:706-717; Ferroukhi *et al.*, 2017:80-81; Berrada *et al.*, 2017:95). Additional information regarding the overall value of energy storage systems relative to cost is provided in sub-section 4.2.11 of Chapter 4.

From Table 7.1, it has also been identified that the LCOS varies widely between the scenarios and technologies under consideration. Scenarios 1 and 4 display the widest disparity in results for all three energy storage systems. In scenario 1, the select technologies are required to perform one charge-discharge cycle per day to mainly support the evening peak demand period over a 10-year project contract lifetime. Under this application scenario, the LCOS per kWh for lithium-ion batteries is expected to decline by approximately 31.8% from USD 0.41 in 2016 to USD 0.28 by 2020. The LCOS for VRFBs could decrease by 19.3% from USD 0.37 per kWh in 2016 to USD 0.30 per kWh by 2020, while NaS batteries are anticipated to experience a reduction of 22.7% from USD 0.35 per kWh to USD 0.27 per kWh over the same period.

Scenario 4 requires the select technologies to perform two charge-discharge cycles a day to mainly support both the morning and evening peak demand periods over a 20-year project contract lifetime. The anticipated lifecycle cost declines for the select technologies in scenario 4 are less drastic, although the LCOS associated with each technology is substantially lower in comparison to scenario 1. Under scenario 4, the LCOS per kWh for lithium-ion batteries is expected to decline by approximately 22.2% from USD 0.29 in 2016 to USD 0.22 by 2020. The LCOS for VRFBs could decrease by 12.1% from USD 0.21 per kWh in 2016 to USD 0.19 per kWh by 2020, while NaS batteries are anticipated to experience a reduction of 17.3% from USD 0.25 per kWh to USD 0.21 per kWh over the same period.

The results exemplify the extent to which the cost competitiveness of energy storage technologies can vary according to application requirements and over time. For example, NaS batteries are more competitive relative to VRFB and lithium-ion batteries for applications requiring one charge-discharge cycle a day in scenarios 1 and 3. On the other hand, VRFBs are more competitive when the cycling frequency is increased to two charge-discharge cycles per day as in scenarios 2 and 4, which could be attributed to the technology's relatively longer cycle lifetime and thereby warranting less capital replacement. It is therefore important to estimate and project the LCOS metric for energy storage technologies according to the specific applications they are required to fulfil, within the particular context they will be applied and in line with their respective technical capabilities during economic evaluations of potentially superior technologies.

Lithium-ion batteries arise as the least competitive technology, especially in 2016, in each scenario on a lifetime cost basis when all known technology-specific costs, characteristics and technical limitations are accounted for at the utility scale. This could mainly be attributed to technical limitations to potential electrical output, such as a maximum depth of discharge (DoD) of 80% and accelerated degradation in capacity, despite having a higher roundtrip efficiency relative to VRFB and NaS batteries. This is a noteworthy finding and challenges views in which it is purported that existing lithium-ion batteries are the most technically and economically competitive electrochemical technology for utility-scale energy storage applications. Lithium-ion batteries are also the only electrochemical energy storage technology included in the Department of Energy's draft Integrated Resource Plan for Electricity (IRP) 2016 to 2050 Base Case undergoing public consultation and reviews in 2017 (Department of Energy, 2016a:20-21), while the LCOS values in Table 7.1 suggest that other battery technologies should also be considered in the national electricity policy, regulatory and planning framework.

Over time, however, competition between all three select technologies is likely to intensify. As can be seen from Table 7.1, the gap between the LCOS for each technology under all application scenarios in 2016 is much narrower by 2020. The decline in the LCOS for each select technology between 2016 and 2020 suggests that the energy storage systems will become increasingly cost competitive with one another at the utility scale. For example, it is projected that the select energy storage systems will be the most competitive by 2020 under scenario 2, in which the technologies are required to perform two cycles per day over a 10-year project calendar lifetime. In this scenario, VRFBs would have the lowest LCOS of around USD 0.19 per kWh, which is closely followed by both lithium-ion and NaS batteries with a LCOS of approximately USD 0.21 per kWh.

The finding that the select technologies are competitive on a levelised or lifecycle cost basis despite differing capital costs, as indicated in sub-section 6.5.1 of Chapter 6, confirms the view that simply comparing the quoted USD per kilowatt (kW) or kWh across different technologies could be misleading. As stressed in sub-section 4.3.3 of Chapter 4, this could be ascribed to the fact that the capital cost of such technologies, as an indicator of cost competitiveness, does not fully and harmoniously account for differences in key parameters, such as cycle life, depth of discharge (DoD) limitations, capacity degradation, size of storage, discharge duration and roundtrip efficiency (Zakeri *et al.*, 2015:573; Battke *et al.*, 2015:340; Jülch *et al*., 2015:18-26; Lazard, 2015:8-29; Obi *et al.*, 2017:910-911). In order to account for these parameters in the economic evaluation of energy storage systems, it is necessary to determine the LCOS (Dufo-López *et al*., 2009:129-130; Branker *et al.*, 2011:4471; Battke *et al*., 2013:240-249; Pawel, 2014:68-76; Battke *et al.*, 2015:340-341; Zakeri *et al.*, 2015:570-573; Hoff *et al.*, 2016:2; Jülch, 2016:1594-1605; Lai *et al.*, 2017:191-202; Obi *et al.*, 2017:908-918).

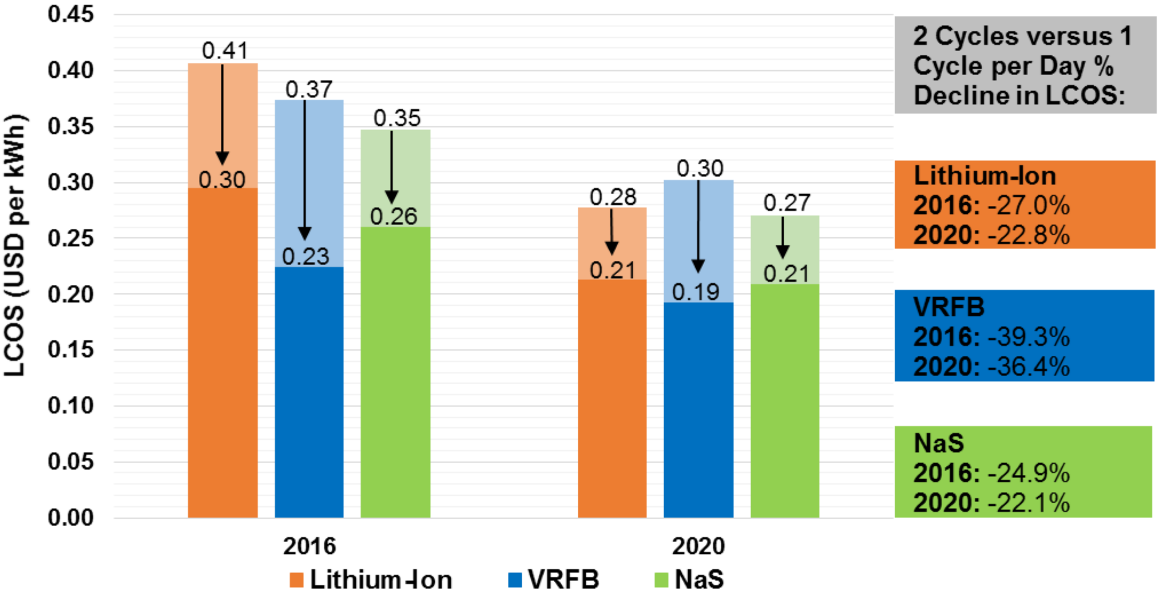
A further noticeable aspect observed from the LCOS estimates in Table 7.1 is the stark contrast between application scenarios requiring one and two charge-discharge cycles per day, irrespective of project contract lifetime. As noted in the literature review section 5.2 of Chapter 5, levelised cost estimates to date have primarily accounted for single daily charge-discharge cycling regimes. This can also be observed from the applications summarised in Table 5.1 from the literature review. The technical capability of energy storage technologies, however, allows for more than one daily cycle to be performed, which has a significant downward impact on LCOS estimates, despite raising capital replacement rates.

In this regard, it has been found that the LCOS for the select technologies in scenarios 2 and 4, in which two daily cycles are performed, is between 19.2 and 39.3% lower than the estimates for the single daily charge-discharge cycle regimes in scenarios 1 and 3. The lower LCOS estimates for applications requiring double daily charge-discharge cycles are a result of improved battery utilisation and total system electrical output. This has also been noted in section 5.2 of Chapter 5 and sub-section 6.5.6 of Chapter 6, as well as by authors such as Poonpun *et al.* (2008:532-533), Battke *et al*. (2013:247-249), Pawel (2014:75), Zakeri *et al.* (2015:573), Fitzgerald *et al.* (2015:6-22), Jülch (2016:1600-

1601), Kondziella *et al.* (2016:16), World Energy Council (2016a:5) and Lai *et al.* (2017:199).

The LCOS estimates and percentage differences for each technology between the scenarios requiring two daily cycles and one daily cycle are shown in Figure 7.1 and Figure 7.2 for 2016 and projected 2020. In both figures, the upper LCOS values per kWh of each shaded column area represent the total LCOS per unit of electrical energy when the select energy storage systems are required to perform one charge-discharge cycle a day. The arrows pointing to the LCOS values above each solid column represent the decline in the LCOS per kWh for the select technologies when they are required to perform two charge-discharge cycles per day. The associated percentage decline in the LCOS for each technology when two daily cycles are performed as opposed to one is shown to the right of the figures.

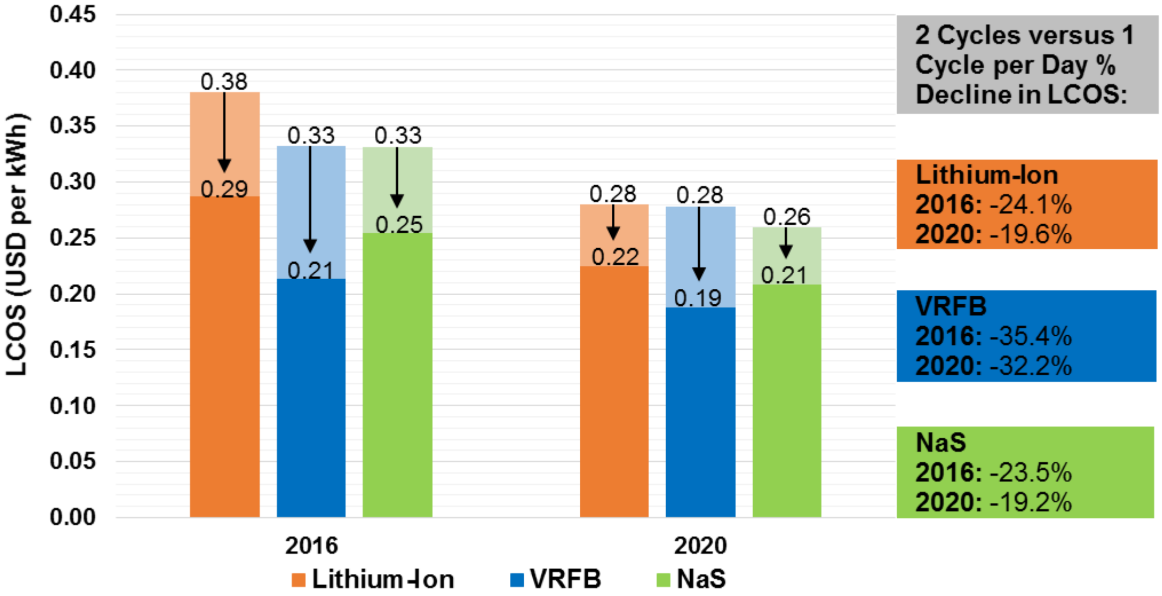
Figure 7.1: LCOS decline in scenario 2 compared to scenario 1 due to increasing cycling frequency to two cycles per day over a 10-year project contract lifetime



Source: Author's configuration

Figure 7.1 illustrates the extent of decline in the LCOS estimates for the select technologies under scenario 2, in which two charge-discharge cycles are required per day, relative to scenario 1, in which one daily charge-discharge cycle is required. A project contract lifetime of 10 years applies for both scenarios.

Figure 7.2: LCOS decline in scenario 4 compared to scenario 3 due to increasing cycling frequency to two cycles per day over a 20-year project contract lifetime



Source: Author's configuration

Similar to Figure 7.1, Figure 7.2 illustrates the extent of decline in the LCOS estimates for the select technologies under scenario 4, in which two charge-discharge cycles are required per day, relative to scenario 3, in which one daily charge-discharge cycle is required. The difference between the two figures is that a project contract lifetime of 20 years applies for both scenarios represented in Figure 7.2.

As can be seen from both Figure 7.1 and Figure 7.2, increasing the cycling frequency to two cycles per day has a significant downward impact on the LCOS, irrespective of project contract lifetime. While the percentage decline in the LCOS by raising the cycling frequency to two charge-discharge cycles a day is greater under a 10-year project calendar lifetime for all three technologies, the LCOS values per kWh are generally lower under a 20-year project calendar lifetime, despite necessitating increased replacement capital outlays. This can also be observed in Annexure A by comparing the replacement capital costs and intervals in Table 9.4 to those in Table 9.2.

Lithium-ion batteries are the only technology that does not have a lower LCOS by 2020 in scenario 4 relative to the other scenarios under consideration. As can be seen from the figures, the LCOS for lithium-ion batteries is projected to decline from approximately USD 0.30 per kWh in 2016 to USD 0.21 per kWh in 2020 under scenario 2 in Figure 7.1, while it is anticipated to decline from a relatively lower USD 0.29 per kWh in 2016 to a marginally higher USD 0.22 per kWh by 2020 under scenario 4 in Figure 7.2. This can be attributed to the need for three capital replacement intervals of the energy storage medium of lithium-ion battery systems in years five, 10 and 15 under a 20-year project contract lifetime, while only one replacement is required in year five under a 10-year project contract lifetime. The replacement intervals, costs and related assumptions for the select energy storage technologies are explained in sub-section 6.5.2 of Chapter 6.

In both Figure 7.1 and Figure 7.2, the extent of decline in the LCOS due to increasing the cycling frequency is greater for VRFBs in comparison to lithium-ion and NaS batteries in 2016 and 2020. For example, as shown in Figure 7.2, the LCOS for VRFBs of USD 0.21 per kWh in 2016 under scenario 4, in which two charge-discharge cycles are required over 20 years, is approximately 35.4% lower than the USD 0.33 per kWh in scenario 3, in which one daily cycle is required over 20 years. This represents a sharper decline in the LCOS for VRFBs relative to the 24.1 and 23.5% decline for lithium-ion and NaS batteries, respectively, in 2016 when the cycling frequency is increased to two per day.

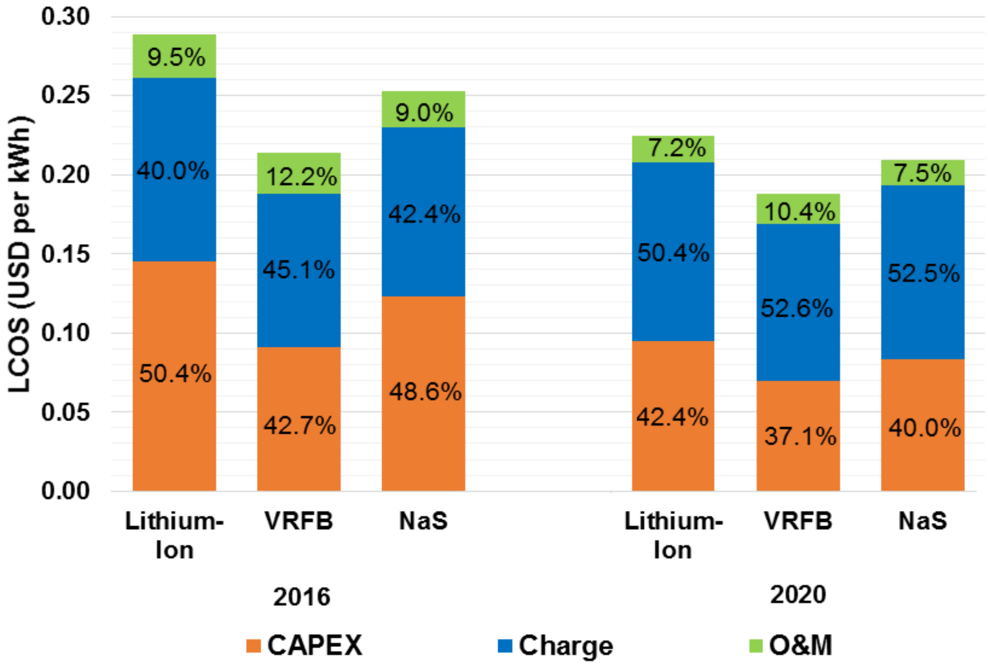
VRFBs entail a substantially long cycle life, which necessitates the replacement of the electrochemical cell stack only in year 15 under a 20-year project contract lifetime and double cycling regime. Lithium-ion and NaS batteries require more frequent replacement capital expenditure as explained in sub-section 6.5.2 of Chapter 6, which reduces their competitiveness on a lifecycle cost basis. VRFBs are therefore the most competitive technology in scenarios 2 and 4, in which two charge-discharge cycles are required per day to supply electrical energy during the morning and evening peak demand periods.

In South Africa, privately-owned renewable energy electrical production plants, commonly referred to as independent power producers (IPPs), enter into 20-year project contract lifetimes through a power purchase agreement (PPA) with the national electric utility, Eskom, as the sole buyer of electricity produced by the private sector (Eberhard *et al.*, 2014:11-25; Montmasson-Clair *et al.*, 2014:517; Eberhard *et al.*, 2016:3-4; Department of Energy, 2017:35-72). In order to align the project contract lifetime of energy storage technologies to the 20-year PPA tenure for renewable energy IPPs, scenario 4 would be the main focus throughout the remainder of the empirical analysis. Scenario 4 is furthermore the least-cost or most price-competitive scenario, especially in 2016, while the LCOS values tend to converge to those of scenario 2 by 2020. Scenario 3, which requires one charge-discharge cycle per day, correspondingly entails a 20-year project contract lifetime and will also be referred to during the economic feasibility assessment.

As noted in sub-section 4.3.3 of Chapter 4, however, energy storage costs are likely to decline at faster rates than anticipated as their commercial uptake and technical progress accelerate, which has also been the experience with solar photovoltaic (PV) and wind-based electrical production technologies, including in South Africa (Nykvist *et al.*, 2015:329; the World Energy Council, 2016a:26; Council for Scientific and Industrial Research, 2017b:40-43). While scenarios involving 20-year lifetimes would be prioritised for the economic feasibility assessment in this study, 10-year project contract lifetimes could be considered for modern energy storage systems in practice. By doing this, the likelihood of technological innovation, progress and cost reductions beyond levels foreseen could be accommodated and the risk of entering into longer-term agreements at higher prices than would be reasonable in future could be circumvented.

Figure 7.3 shows the division of the main cost components comprising the total LCOS per kWh for each select technology under scenario 4. The composition of the LCOS is shown for the total initial and replacement capital expenditure (CAPEX), operations and maintenance expenditure (O&M) and charging costs (charge) portions over the lifetime of each energy storage system. The decomposition of the LCOS for each technology in 2016 and projected 2020 under all scenarios is provided by Table 10.1 to Table 10.4 in Annexure B.

Figure 7.3: Cost component share of total LCOS under scenario 4, requiring two cycles per day over a 20-year project contract lifetime



Source: Author's configuration

From Figure 7.3, it can be observed that the share of initial and replacement capital expenditure of the total LCOS for the select utility-scale technologies in 2016 range between a low of 42.7% for VRFBs to a high of 50.4% for lithium-ion batteries. This is followed by charging costs, with the portion of the total LCOS ranging between 40% for lithium-ion batteries and 45.1% for VRFBs. Operations and maintenance expenditure contribute the least to the total LCOS for each technology, ranging from 9% for NaS batteries to 12.2% for VRFBs.

The order of magnitude for the largest cost contributors to overall lifetime cost is expected to change for the select technologies by 2020. While the share of capital and operations and maintenance expenditure of the total LCOS diminishes over time, the relative contribution of charging costs is anticipated to grow. This could be attributed to declining initial and replacement capital costs, as explained in sub-sections 6.5.1 and 6.5.2, while charging costs would increase over the period under consideration due to electricity price escalations as explained in sub-section 6.5.4 of Chapter 6. The LCOS estimates indicated in Figure 7.3 and Table 10.4 in Annexure B for each technology show that the combined LCOS per kWh for the capital and operation and maintenance cost components decline between 2016 and 2020, while that of charging costs remain relatively constant.

More specifically, the combined levelised capital and operations and maintenance costs per kWh for lithium-ion batteries are expected to decline from approximately USD 0.17 in 2016 to USD 0.11 in 2020, while the LCOS charging costs are expected to remain between USD 0.12 and USD 0.11 over the same period. Similarly, albeit from a lower base, the lifetime capital and operations and maintenance costs for VRFBs are expected to decline from approximately USD 0.12 per kWh in 2016 to USD 0.09 per kWh in 2020, while the LCOS charging costs are expected to remain constant around USD 0.10 per kWh over the same period. NaS batteries exhibit a similar LCOS pattern between that of lithium-ion and VRFBs for capital, operations and maintenance and charging costs.

The LCOS component configuration applies for all select energy storage systems under scenarios 1 to 3 as shown in Table 10.1 to Table 10.3 in Annexure B. The rising electricity prices from Eskom are likely to limit the cost competitiveness of energy storage systems within the South African context if such systems primarily charge from the electricity grid. On the other hand, the declining or relatively lower tariffs associated with solar PV plants would improve the competitiveness of energy storage systems if such systems primarily charge from solar PV plants.

In absolute terms, the capital cost component of the total LCOS is the lowest for VRFBs relative to lithium-ion and NaS batteries in both 2016 and 2020 under scenarios 2 and 4, when two charge discharge cycles are required per day. This is a result of the favourable impact that the long cycle and calendar life of VRFBs have on the technology's relative cost competitiveness under frequent cycling regimes, since it entails substantially lower capital replacement rates in comparison to lithium-ion and NaS batteries as explained in sub-section 6.5.2 of Chapter 6.

While total electricity input costs are higher for VRFBs and NaS batteries due to a lower roundtrip efficiency compared to lithium-ion batteries, they nonetheless entail lower charging costs on an LCOS basis. This can be attributed to a higher maximum depth of discharge (DoD) of 100% for VRFBs and 90% for NaS batteries compared to 80% for lithium-ion batteries, as well as the absence of degradation in capacity, while lithium-ion batteries are assumed to reach the end of their useful life once the usable energy storage capacity declines to approximately 80% of the initial rated capacity. Sub-sections 6.5.7 and 6.5.9 of Chapter 6 outline the assumptions governing the depth of discharge (DoD) and capacity degradation associated with the select energy storage systems.

7.4 WEIGHTED AVERAGE LEVELISED COST OF ENERGY STORAGE SYSTEMS COUPLED WITH SOLAR PHOTOVOLTAIC PLANTS (LCOS-PV): RESULTS AND DISCUSSION

To perform the primary value application investigated in this study, namely renewables integration with solar photovoltaic (PV) plants, the select energy storage technologies can be coupled with solar PV electrical production plants. The rationale for integrating energy storage systems with solar PV plants is to overcome issues of solar resource variability and intermittency, supply electrical energy during periods of peak demand, enable electricity price arbitrage opportunities and incorporate more solar-based electrical generation plants into the electricity grid. Energy storage systems could further be used to accommodate or delay investments in alternative electricity transmission and/or generation infrastructure. This is discussed in more detail in sub-sections 4.2.5 and 4.2.10 of Chapter 4, as well as in section 6.4 of Chapter 6.

As indicated in section 1.4 of Chapter 1, the economic feasibility of utility-scale electrical energy storage technologies not only depends on the ability of such technologies to compete with one another, but also with alternative generation options in terms of levelised cost per unit of electrical energy (Pawel, 2014:73; Jülch *et al*., 2015:19-26; Bortolini *et al.*, 2015:1026-1029; Zakeri *et al.*, 2015:588; De la Rubia *et al*., 2015:7; Kondziella *et al.*, 2016:12; Lai *et al.*, 2017:191-202; Obi *et al.*, 2017:910). In that regard, as explained in Chapter 6 and section 6.6 in particular, the combined levelised cost of energy storage systems and solar PV electrical production plants is an appropriate measure to determine the cost competitiveness between energy storage technologies and alternative generation options with similar electrical output dispatch characteristics. The primary application investigated in this study therefore necessitates the determination of the weighted average levelised cost of energy storage systems coupled with solar PV plants (LCOS-PV) in South Africa.

The LCOS-PV can be regarded as the reflective cost of the packaged solution and would be somewhere between the levelised cost of energy storage (LCOS) and the levelised cost of electricity (LCOE) for a solar PV plant (Pawel, 2014:73-76; Jülch *et al*., 2015:24; Lai *et al.*, 2017:196-197). Section 6.6 of Chapter 6 provides a detailed description of the model parameters, formulae and relevant assumptions used to derive the LCOS-PV. The applied methods outlined in sections 6.5 and 6.6 was utilised to derive the lifetime cost results at the utility-scale for the select technologies, namely lithium-ion, vanadium-redox flow (VRFB) and sodium-sulphur (NaS) batteries, coupled with solar PV plants when 30% of the electrical energy produced by solar PV plants is stored in these select technologies.

The LCOS-PV is estimated for 2016 and projected to 2020 in order to assess the recent and potential future economic feasibility of energy storage technologies within the South African context. As with the LCOS, the modelling results for the select technologies coupled with solar PV plants are evaluated under the four scenarios described in section 7.2. Each application scenario requires the select technologies to be operational for 350 days a year, have an electrical power rating of 50 megawatt (MW) and discharge electrical energy for four hours during periods of peak demand for electricity.

Table 7.2 indicates the LCOS-PV results, in United States dollars (USD) per kilowatt hour (kWh), for the select energy storage systems coupled with solar PV plants as estimated for 2016 and projected to 2020. The results are shown for four scenarios based on one or two charge-discharge cycles per day and 10- or 20-year project contract lifetimes. The detailed modelling parameters, inputs and results are shown in Table 9.1 to Table 9.4 in Annexure A. Percentage differences in Table 7.2 are due to rounding.

Table 7.2: LCOS-PV scenario results for select energy storage systems coupled with solar PV plants (USD per kWh)

Year	Lithium-ion and solar PV	VRFB and solar PV	NaS and solar PV
Scenario 1: One cycle per day over a 10-year project contract lifetime			
2016	0.15	0.15	0.14
2020	0.11	0.12	0.11
% Change 2016 to 2020	-31.6%	-21.9%	-24.8%
Scenario 2: Two cycles per day over a 10-year project contract lifetime			
2016	0.12	0.10	0.11
2020	0.09	0.08	0.09
% Change 2016 to 2020	-28.4%	-19.9%	-22.9%
Scenario 3: One cycle per day over a 20-year project contract lifetime			
2016	0.15	0.14	0.14
2020	0.11	0.11	0.10
% Change 2016 to 2020	-27.4%	-19.8%	-24.0%
Scenario 4: Two cycles per day over a 20-year project contract lifetime			
2016	0.12	0.10	0.11
2020	0.09	0.08	0.09
% Change 2016 to 2020	-24.2%	-17.7%	-21.0%

Source: Author's estimates

From Table 7.2, it is observed that the LCOS-PV estimated for 2016 and projected to 2020 is similar for applications requiring the same daily charge-discharge cycling regime. For example, the LCOS estimates for the select technologies are the highest under scenario 1, in which one daily cycle is required over a 10-year project contract lifetime. In this scenario, the LCOS-PV per kWh is anticipated to decline by 31.6% from approximately USD 0.15 to USD 0.11 for lithium-ion batteries coupled with solar PV plants, 21.9% from USD 0.15 to USD 0.12 for VRFBs coupled with solar PV plants and 24.8% from USD 0.14 to USD 0.11 for NaS batteries coupled with solar PV plants. The LCOS-PV estimates are similar, albeit slightly lower, under scenario 3, in which a single cycle per day is also required, but over a longer project contract lifetime of 20 years.

The results are even more alike for scenarios 2 and 4, with differences occurring only after the third decimal and making the LCOS-PV estimates under scenario 2 marginally higher than those of scenario 4, especially in 2016. Under both scenarios, the select energy storage systems are required to perform two charge-discharge cycles per day, while scenario 2 entails a 10-year project contract life and scenario 4 a 20-year project contract life. In both scenarios, the LCOS-PV is anticipated to decline from approximately USD 0.12 per kWh to USD 0.09 per kWh for lithium-ion battery and solar PV systems, USD 0.10 per kWh to USD 0.08 per kWh for VRFB and solar PV systems and USD 0.11 per kWh to USD 0.09 per kWh for NaS battery and solar PV systems.

Generally, the results suggest a higher degree of competitiveness between the select technologies on a levelised or lifetime cost basis across all application scenarios when energy storage systems are combined with solar PV plants in comparison to such systems in isolation. This is a mainly a result of the lower solar PV LCOE, which lowers and reduces the disparity between the respective LCOS-PV of the select technologies on a weighted average basis. The order of competitiveness further remains the same for each technology as explained in section 7.3. NaS batteries tend to be more competitive under scenario applications requiring one charge-discharge cycle a day, while VRFBs are more competitive when the cycling frequency is increased to two cycles a day.

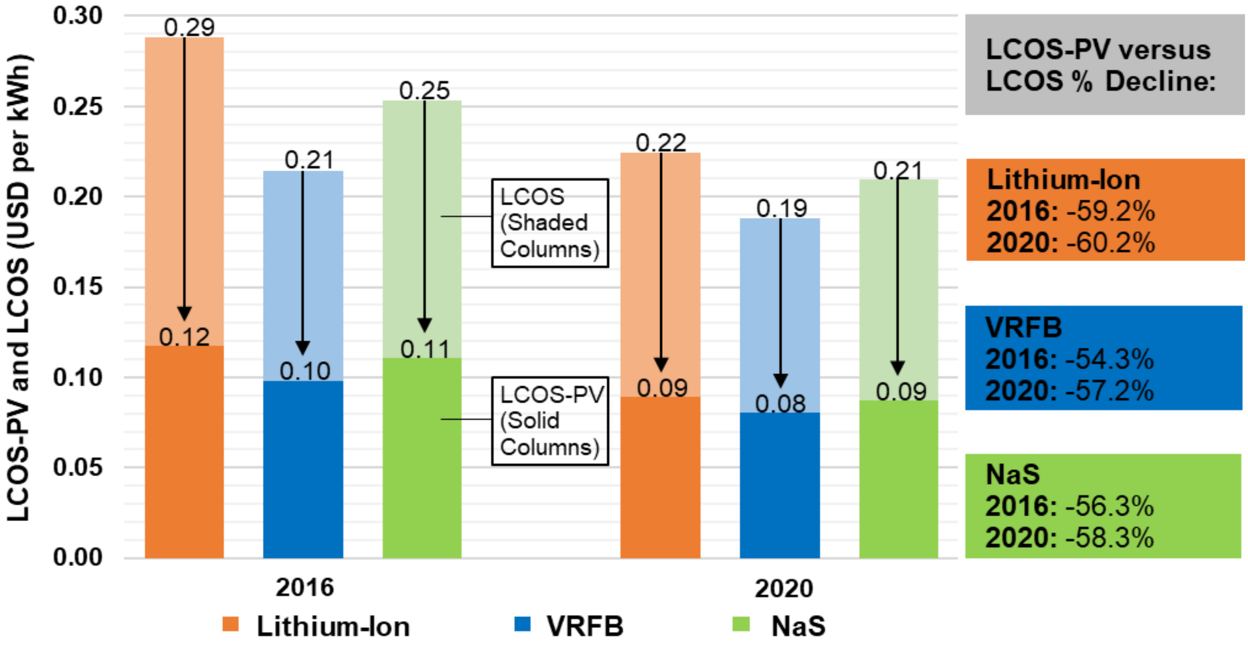
Similar to the LCOS, the LCOS-PV is lower for scenarios requiring two cycles per day relative to a single daily charge-discharge cycle. Although the difference is marginally smaller for the LCOS-PV relative to the LCOS, it nonetheless remains significant. In this regard, the LCOS-PV in scenarios 2 and 4 is between 15.4% and 31.8% lower than the estimates for the select technologies coupled with solar PV plants in scenarios 1 and 3.

The most noticeable observation from Table 7.2 is the significant difference between the LCOS for energy storage systems in isolation, indicated in Table 7.1, and the LCOS-PV when such systems are coupled with solar PV plants in all four scenarios. The modelling results confirm the finding by Pawel (2014:78) that the combined levelised cost of energy storage technologies coupled with solar PV plants is likely to be somewhere between the LCOE of a solar PV plant and the LCOS of an energy storage system. More specifically, the results for all four scenarios show that the LCOS-PV can be between 54.3 and 62.1% lower in comparison to the LCOS.

This is an outcome of the combined system output and low solar PV plant tariffs in South Africa that has been enabled by excellent solar irradiation levels and highly competitive procurement conditions for privately-owned electrical generation bids under the Renewable Energy Independent Power Producers Procurement Programme (REIPPPP) of the Department of Energy (Grobbelaar *et al.*, 2014:479; Eberhard *et al.*, 2014:17; Montmasson-Clair *et al.*, 2014:508-520; Walwyn *et al.*, 2015:391-399; Busse *et al.*, 2016:52-53; Eberhard *et al.*, 2016:1; Department of Energy, 2017:7-21; Lai *et al.*, 2017:193-194). A solar PV LCOE of USD 0.04 per kWh in 2016 and USD 0.03 per kWh by 2020 has been assumed for the mathematical modelling. Further information regarding the 2016 and projected 2020 LCOE for solar PV plants in South Africa is provided in sub-section 6.6.2 of Chapter 6, while sub-section 6.6.5 clarifies the combined electrical energy output available from a solar PV plant and energy storage system.

Figure 7.4 illustrates the difference between the LCOS and LCOS-PV under scenario 4 for 2016 and 2020. In this scenario, the select technologies are required to perform two charge-discharge cycles per day to support both the morning and evening peak demand periods over a 20-year project lifetime. The upper values of each shaded column area represent the LCOS per kWh for the select energy storage systems in isolation, while the arrows pointing to the values above each solid column represent the lower LCOS-PV per kWh when such systems are coupled with solar PV plants. The associated percentage decline in the LCOS-PV in comparison to the LCOS is shown to the right of the figure.

Figure 7.4: LCOS-PV relative to LCOS under scenario 4, requiring two cycles per day over a 20-year project contract lifetime



Source: Author’s compilation

As motivated in section 7.3, application scenario 4 would be prioritised for the economic feasibility assessment in the next section (7.5), while scenario 3 would also be referred to. The reason for this is to align the project contract lifetime of the energy storage systems under consideration to the 20-year power purchase agreement (PPA) tenure for solar PV and concentrating solar power (CSP) independent power producers (IPPs) in South Africa. Scenario 4 is also the most cost competitive scenario being investigated.

From Figure 7.4, it can be seen that the LCOS-PV is significantly lower than the LCOS for all three energy storage technologies under consideration. For example, the smallest difference is estimated for VRFBs in 2016 where the LCOS-PV of USD 0.10 per kWh was approximately 54.3% lower than the LCOS of USD 0.21 per kWh. The largest difference is estimated for lithium-ion batteries in 2020, where the projected LCOS-PV of USD 0.09 per kWh could be approximately 60.2% lower than the LCOS of USD 0.22 per kWh. While these results are shown for scenario 4, the same principle applies for scenarios 1 to 3 when energy storage technologies are coupled with solar PV plants.

Similar to section 7.3, VRFBs arise as the most cost competitive technology coupled with solar PV in scenario 4. When combined with solar PV plants, the LCOS-PV per kWh for VRFBs is anticipated to decline by approximately 17.7% from around USD 0.10 in 2016 to USD 0.08 by 2020. VRFBs are followed by the LCOS-PV for NaS batteries, which is expected to decline by approximately 21% from around USD 0.11 per kWh in 2016 to USD 0.09 per kWh by 2020. Lithium-ion batteries coupled with solar PV appear to be the least competitive option, since its LCOS-PV is estimated to decline by approximately 24.2% from around USD 0.12 per kWh in 2016 to USD 0.09 per kWh by 2020.

When viewed as standalone systems, energy storage technologies are commonly perceived as uncompetitive relative to alternatives, even though such direct comparisons are inappropriate due to different technological characteristics, functionalities, modes of operation and, as a consequence, dissimilar cost determinants as explained in section 6.6 of Chapter 6. The modelling results, however, demonstrate the improved cost competitiveness of energy storage systems in combination with solar PV plants. Energy storage technologies coupled with solar PV plants furthermore make it possible to test the economic feasibility of such technologies in terms of cost competitiveness with alternative generation options with similar electrical output dispatch characteristics. In that regard, the background, research, methodology and modelling results described throughout this dissertation have made it possible to appropriately assess the economic feasibility of the select energy storage systems. This is the focus of the next section (7.5).

7.5 ECONOMIC FEASIBILITY ASSESSMENT: RESULTS AND DISCUSSION

As explained in sections 6.6 and 6.7 of Chapter 6 and section 7.4, innovative approaches are required to equitably determine the competitive ability and economic viability of energy storage technologies relative to electrical generators. One approach to fairly assess the economic feasibility of utility-scale energy storage systems in terms of cost competitiveness with electrical generators is to compare the total weighted average levelised cost of such systems combined with solar photovoltaic (PV) plants (LCOS-PV) to the levelised cost of electricity (LCOE) for alternative generation options with similar electrical output dispatch characteristics.

In that regard, and to compare commensurable factors, the LCOS-PV estimated and projected in section 7.4 is compared to the prevailing and anticipated LCOE for concentrating solar power (CSP) plants with thermal energy storage capability as a case study. This allows for a fair basis of comparison, since both energy storage coupled with solar PV plants and CSP plants with thermal energy storage produce electrical energy from solar energy as a source and store a portion of the electrical energy generated for later discharge or use. CSP plants with thermal energy storage are also considered mature electrical energy generation technology, especially parabolic trough and solar tower plants, which provide an established electrical production alternative to perform the lifetime cost comparisons (Grobbelaar *et al.*, 2014:479; Desideri *et al.*, 2014:424; Khan *et al.*, 2016:419; Van Ravenswaay *et al.*, 2015:1839; Chaanaoui *et al.*, 2016:782-789). CSP plants with thermal energy storage are further used in alignment with the primary application. Section 6.7 of Chapter 6 elaborates more on CSP plants with thermal energy storage capability and its selection for the economic feasibility assessment in this study.

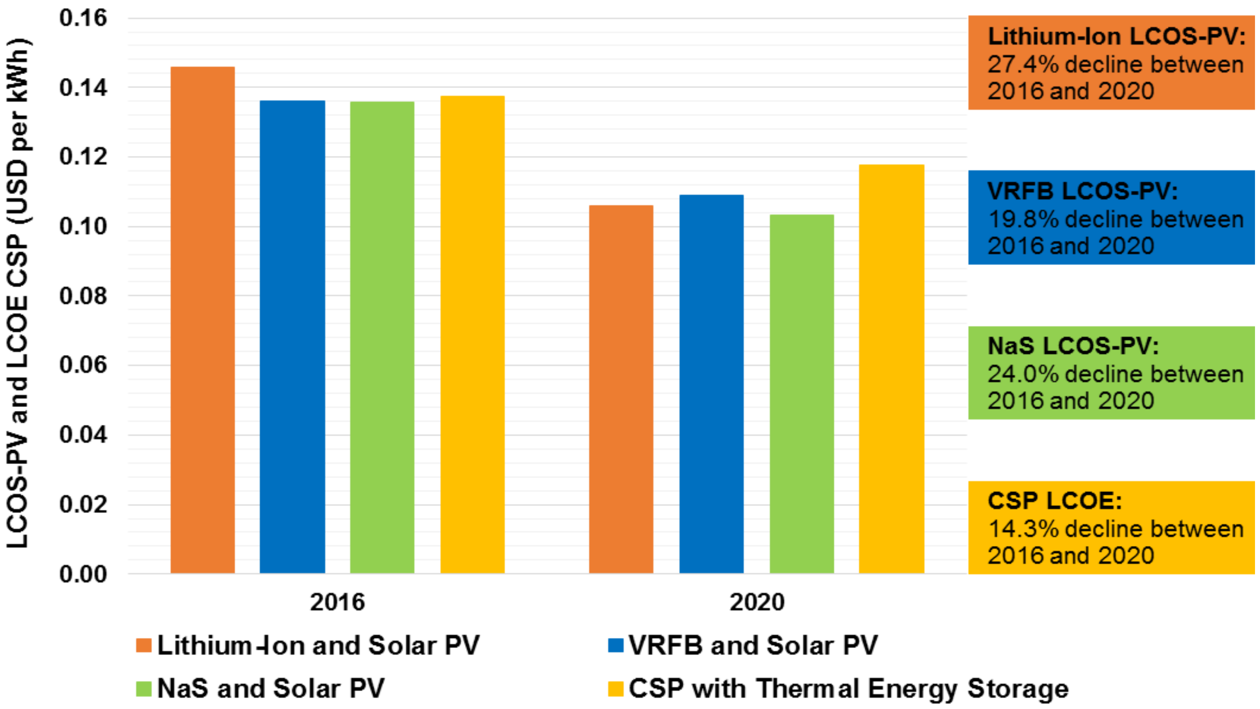
As motivated in section 7.3, application scenario 4 would be prioritised for the economic feasibility assessment. Scenario 4 requires the select energy storage systems to perform two charge-discharge cycles per day to mainly support both the morning and evening peak demand periods over a 20-year project contract lifetime. Scenario 4 is the most cost competitive scenario and the 20-year project contract lifetime is aligned to the 20-year power purchase agreement (PPA) tenure for solar PV and CSP independent power producers (IPPs) in South Africa. Scenario 3, however, also entails a 20-year project contract lifetime and will be referred to, notwithstanding the requirement for a single daily charge-discharge cycle from the select energy storage technologies to mainly support the evening peak demand period.

Figure 7.5 and Figure 7.6 depict the cost competitiveness, in United States dollars (USD) per kilowatt hour (kWh), of the select utility-scale energy storage systems coupled with solar PV plants in comparison to CSP plants with thermal energy storage capability. As advocated in section 6.3 of Chapter 6, the select energy storage technologies for the empirical analysis in this study include lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) batteries.

The economic feasibility of the select energy storage systems is assessed within the South African context by comparing the LCOS-PV to the LCOE of CSP plants with thermal energy storage capability. As explained in section 6.7, a weighted average LCOE of USD 0.14 per kWh in 2016 and projected USD 0.12 per kWh by 2020 is used for CSP plants with thermal energy storage to perform the comparative analysis. The anticipated percentage decline in the levelised cost estimates for each technology combination between 2016 and 2020 is shown to the right of both Figure 7.5 and Figure 7.6.

Figure 7.5 illustrates the cost competitiveness of the select energy storage systems coupled with solar PV plants relative to CSP plants with thermal energy storage capability under scenario 3. Application scenario 3 requires the select technologies to perform one charge-discharge cycle per day to mainly support the evening peak demand period over a 20-year project contract lifetime. As explained in sections 7.3 and 7.4, scenarios requiring one daily charge-discharge cycle have higher lifetime cost estimates relative to scenarios requiring two daily cycles.

Figure 7.5: LCOS-PV relative to LCOE for CSP plants with thermal energy storage capability under scenario 3, requiring one cycle per day over a 20-year project contract lifetime



Source: Author’s compilation

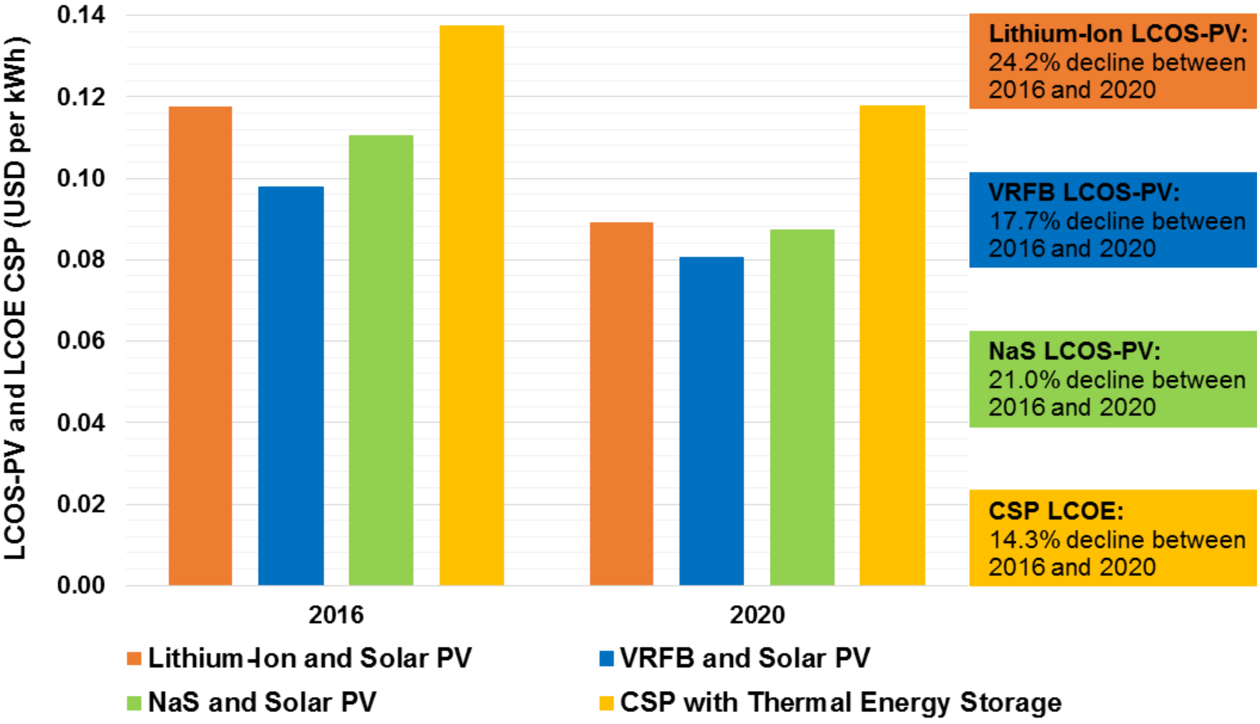
From Figure 7.5, the LCOS-PV in 2016 for VRFB and NaS batteries under scenario 3 was already competitive with the LCOE for CSP plants with thermal energy storage capability of approximately USD 0.14 per kWh. Lithium-ion batteries coupled with solar PV plants were slightly less competitive in 2016 with an LCOS-PV of approximately USD 0.15 per kWh in comparison to the lower LCOE of USD 0.14 per kWh for CSP plants with thermal energy storage capability.

Over time, the LCOS-PV for all three select technologies is projected to be lower than the LCOE for CSP plants with thermal energy storage capability. The modelling results indicate that NaS battery systems are likely to be the most competitive by 2020 under a single charge-discharge regime, but its LCOS-PV is closely followed by that of lithium-ion and VRFBs. More specifically, the LCOS-PV for NaS batteries is anticipated to decline by approximately 24% to around USD 0.10 per kWh by 2020, while that of lithium-ion and VRFB batteries are projected to decline to around USD 0.11 per kWh. The higher projected percentage decline in the LCOS-PV for lithium-ion battery systems of 27.4%, however, suggests that lithium-ion batteries might become the most competitive technology of the three select energy storage systems beyond 2020 for applications requiring one charge-discharge cycle per day.

The LCOS-PV for all three select technologies is projected to be between 7.3 and 12.3% lower than the LCOE for CSP plants with thermal energy storage capability of USD 0.12 per kWh by 2020. The results depicted in Figure 7.5 imply that the select energy storage systems coupled with solar PV plants are more cost competitive than CSP plants with thermal energy storage capability, even in application scenarios that only require a single charge-discharge cycle per day, which entails higher levelised cost estimates relative to scenarios involving increased cycling frequency.

Figure 7.6 illustrates the cost competitiveness of the select energy storage systems coupled with solar PV plants relative to CSP plants with thermal energy storage capability under scenario 4. Application scenario 4 requires the select technologies to perform two charge-discharge cycles per day to mainly support both the evening and morning peak demand periods over a 20-year project contract lifetime. As explained in sections 7.3 and 7.4, scenarios requiring two daily charge-discharge cycles have lower lifetime cost estimates relative to scenarios requiring one daily cycle. In that regard, application scenario 4 emerged as the most cost competitive scenario being investigated.

Figure 7.6: LCOS-PV relative to LCOE for CSP plants with thermal energy storage capability under scenario 4, requiring two cycles per day over a 20-year project contract lifetime



Source: Author's compilation

As observed from Figure 7.6, the LCOS-PV in 2016 for all three select energy storage systems under scenario 4 was already more competitive in comparison to the LCOE for CSP plants with thermal energy storage capability. VRFBs coupled with solar PV plants arise as the most competitive alternative with an LCOS-PV of approximately USD 0.10 per kWh, which is 28.7% lower than the LCOE for CSP plants with thermal energy storage capability of USD 0.14 per kWh in 2016. VRFBs are followed by NaS and lithium-ion battery systems with an LCOS-PV of around USD 0.11 per kWh and USD 0.12 per kWh, respectively, which is approximately 19.5% and 14.3% lower than the LCOE for CSP plants with thermal energy storage capability.

The economic feasibility of the select energy storage technologies coupled with solar PV plants will become increasingly attractive over time. The LCOS-PV for VRFBs under application scenario 4 is anticipated to decline by approximately 17.7% to around USD 0.08 per kWh by 2020, which would be about 31.6% lower than the expected LCOE for CSP plants with thermal energy storage capability of USD 0.12 per kWh. Similarly, the LCOS-PV for NaS and lithium-ion battery systems is projected to decline to around USD

0.09 per kWh by 2020, which would be about 25% lower than the expected LCOE for CSP plants with thermal energy storage capability in 2020.

The modelling results for the case study represented in Figure 7.5 and Figure 7.6 demonstrate the superior economic feasibility of the select energy storage systems in comparison to CSP plants with thermal energy storage capability within the South African context. In other words, lithium-ion, VRFB and NaS battery technologies combined with solar PV plants offer improved investment alternatives in comparison to CSP plants with thermal energy storage capability as appropriate electrical energy system solutions. This is a result of the enhanced cost competitiveness of the select energy storage technologies coupled with solar PV plants relative to CSP plants with thermal energy storage capability. CSP plants with thermal energy storage capability are further expected to become progressively less competitive over time as energy storage and solar PV technologies benefit from more rapid commercialisation, technical improvements and cost reductions.

Table 7.3 provides a concluding summary of the levelised cost of energy storage (LCOS) and LCOS-PV modelling results under application scenario 4 relative to CSP plants with thermal energy storage capability as disclosed and discussed throughout this chapter. Scenario 4, which requires the select energy storage systems to perform two charge-discharge cycles per day over a 20-year project contract lifetime, is the most cost competitive and economically viable scenario investigated in this study. Percentage differences are due to rounding.

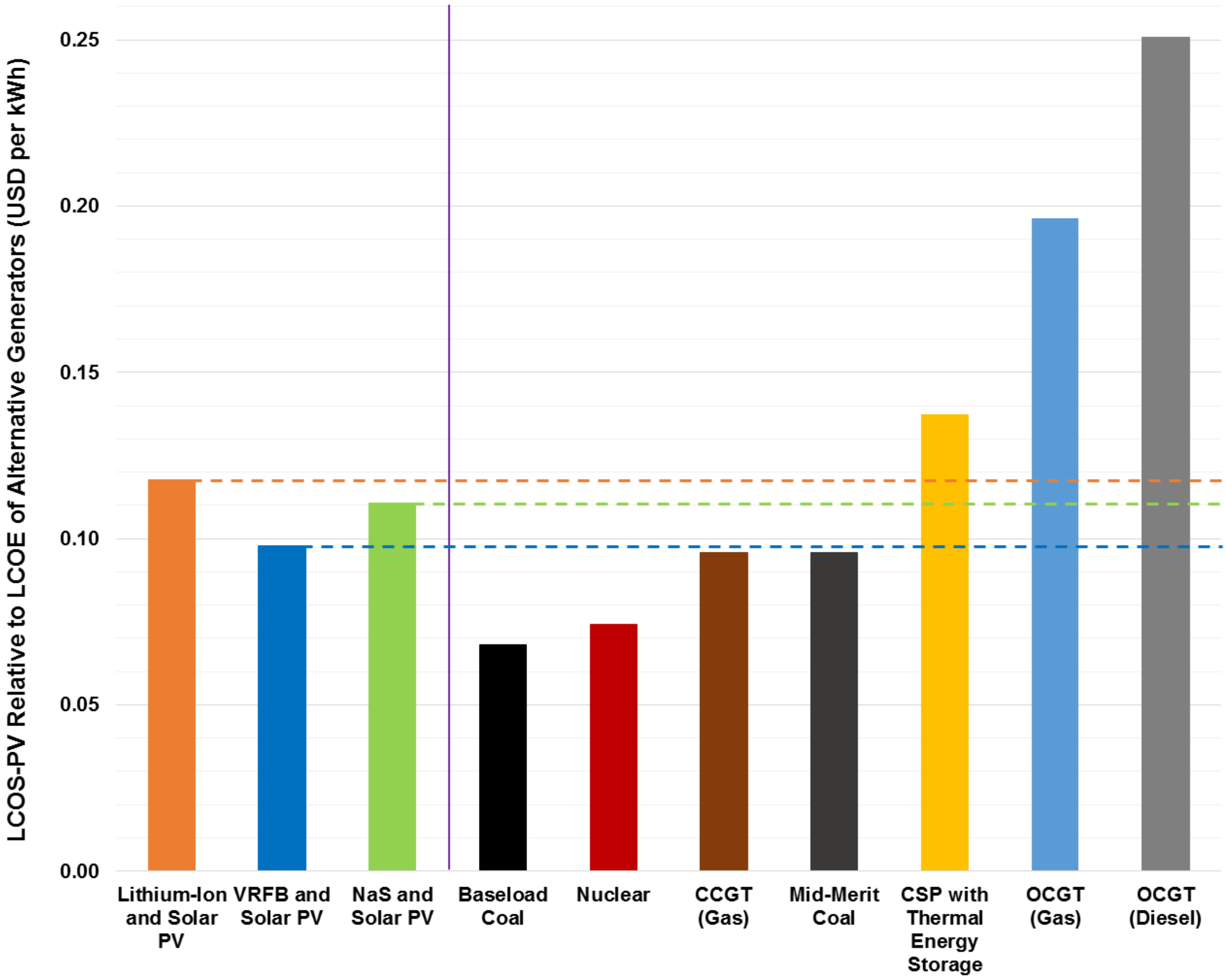
Table 7.3: Summary of levelised cost estimates under scenario 4 (USD per kWh)

Year	**2016**			**2020**		
Technology	**Lithium-ion**	**VRFB**	**NaS**	**Lithium-ion**	**VRFB**	**NaS**
LCOS	0.29	0.21	0.25	0.22	0.19	0.21
% Change				-22.2%	-12.1%	-17.3%
Solar PV plants						
LCOE PV	0.04			0.03		
% Change				-28.8%		
	Lithium-ion and solar PV	**VRFB and solar PV**	**NaS and solar PV**	**Lithium-ion and solar PV**	**VRFB and solar PV**	**NaS and solar PV**
LCOS-PV	0.12	0.10	0.11	0.09	0.08	0.09
% Change				-24.2%	-17.7%	-21.0%
CSP plants with thermal energy storage capability						
LCOE CSP	0.14			0.12		
% Change				-14.3%		
LCOS-PV versus LCOE CSP (%)	-14.3%	-28.7%	-19.5%	-24.2%	-31.6%	-25.8%

Source: Author’s estimates

While it is not the principal focus of this study, additional insight into the economic feasibility of energy storage systems could be gained by comparing the LCOS-PV under scenario 4, as indicated in Table 7.2, Figure 7.6 and Table 7.3, to the LCOE for alternative electrical generators. In that regard, Figure 7.7 indicates the standard LCOE values for alternative electrical generation options in South Africa against the LCOS-PV estimated for the select technologies under scenario 4 in 2016 (Council for Scientific and Industrial Research, 2017b:38). An average exchange rate of South African rand (ZAR) 14.71 to the USD in 2016 was used for the currency conversions (IHS Global Insight, 2017).

Figure 7.7: LCOS-PV under scenario 4 in comparison to alternative electrical generation options in South Africa in 2016



Source: Author’s configuration and Council for Scientific and Industrial Research (2017b:38)

It can be observed from Figure 7.7 that the LCOS-PV for the select energy storage systems in 2016 already appears more cost competitive than some alternative electrical generation options. This is particularly the case in comparison to generators that typically involve similar electrical output dispatch characteristics, such as peaking diesel- and gas-fired turbines and CSP plants with thermal energy storage capability as explained above. Such cost comparisons, however, are only indicative and should be treated with caution as they need to be based on the exact same electrical output and financial methodological detail. Figure 7.7 is therefore intended for conceptual purposes and the economic feasibility of energy storage systems relative to electrical generation options beyond CSP plants with thermal energy storage capability is an area that warrants further research.

The LCOE values represented in Figure 7.7 support the finding by Busse *et al.* (2016:56-58) that CSP plants with thermal energy storage capability are more cost competitive electrical generation alternatives than open cycle gas turbines (OCGTs) within the South African context. In that regard, the finding that the LCOS-PV for the select energy storage systems is lower than the LCOE for CSP with thermal energy storage capability suggests that the economic feasibility of such systems is also greater in comparison to OCGTs.

While the select energy storage technologies coupled with solar PV plants have lower levelised cost estimates in comparison to CSP plants with thermal energy storage capability, it further appears that all three select energy storage systems could be more cost competitive than gas- and diesel-based OCGTs. For example, the higher LCOS-PV for lithium-ion batteries coupled with solar PV plants of USD 0.12 per kWh in 2016 is approximately 40.1% lower than the LCOE of USD 0.20 per kWh for gas-based OCGTs and 53.1% lower than the LCOE of USD 0.25 per kWh for diesel-based OCGTs.

Similarly, the lowest LCOS-PV for VRFBs of USD 0.10 per kWh is approximately 50.2% lower than the LCOE of USD 0.20 per kWh for gas-based OCGTs and 61% lower than the LCOE of USD 0.25 per kWh for diesel-based OCGTs. VRFB systems coupled with solar PV plants further appear cost competitive with combined cycle gas turbines (CCGT) and mid-merit coal-based electrical power stations at approximately USD 0.10 per kWh. All select technologies, however, require further lifetime cost reductions to be cost competitive with base load coal and nuclear electricity generators.

As indicated in section 1.3 of Chapter 1, economically viable utility-scale energy storage systems combined with renewable energy electrical production plants will increasingly replace the need for conventional fossil fuel-based electricity generators. This is especially the case as the prices associated with energy storage and renewable energy technologies continue to decline sharply, while prices for conventionally generated electricity, such as from fossil fuels and nuclear energy, continue to rise amidst the need for South Africa to increasingly transition to a more environmentally sustainable national electricity system (Tahvonen *et al.*, 2001:1396; Shafiee & Topal, 2009:185-186; Chen *et al*., 2009:292; Branker *et al.*, 2011:4470; Zahedi, 2011:866-870; Kost *et al.*, 2013:5-6; Eberhard *et al.*, 2014:17; Pollet *et al.*, 2015:16696; Lund *et al.*, 2015:799; Walwyn *et al.*, 2015:390-394; Covert *et al.*, 2016:128-129; Nhamo *et al.*, 2016:69; Busse *et al.*, 2016:57-58; Aneke *et al*., 2016:350-352; Dehdashti, 2016:3; Zou *et al.*, 2017:66; United States Energy Information Administration, 2017:28; Amirante *et al.*, 2017:373; Foster *et al.*, 2017:262-263; Lai *et al.*, 2017:193; Hartley *et al.*, 2017:57; Lazkano *et al.*, 2017:2-16).

The competitive LCOS-PV estimates in comparison to the LCOE values for alternative electrical generation options shown in Figure 7.7 are further enhanced by the multi-use capability of energy storage technologies relative to electrical generators. As explained in sub-section 4.2.11 of Chapter 4, energy storage systems can perform a number of use applications sequentially and/or simultaneously, which significantly enhances the value of energy storage relative to cost, depending on the net economic benefits provided (He *et al.*, 2011:1575-1584; Carnegie *et al.*, 2013:14; Zhang, 2013:39; Kaun *et al.*, 2013:25-85; Pawel, 2014:69; Lambruschi, 2015:24-26; De la Rubia *et al.*, 2015:7-8; Battke *et al.*, 2015:334-339; Lazard, 2016:4; Günter *et al.*, 2016:231-234; Kondziella *et al.*, 2016:15-20; Malhotra *et al.*, 2016:706-717; Ferroukhi *et al.*, 2017:80-81; Berrada *et al.*, 2017:95).

The economic feasibility assessment conducted for the empirical analysis in this study suggests that the select energy storage technologies are viable utility-scale electricity system solutions. This was mainly demonstrated through the improved lifetime cost competitiveness of such technologies coupled with solar PV plants relative to alternative electrical generation options and in particular CSP plants with thermal energy storage capability. The outcome of the empirical analysis therefore establishes the economic feasibility of the select utility-scale electrical energy storage technologies for South Africa. The cost competitiveness of such technologies will further improve over time and increasingly displace the need for conventional generation options (Lund *et al.*, 2015:799; Dehdashti, 2016:3; Zou *et al.*, 2017:66; Lai *et al.*, 2017:193-194; Hartley *et al.*, 2017:57; Lazkano *et al.*, 2017:2-16). It is consequently recommended to include lithium-ion, VRFB and NaS electrochemical energy storage systems at the utility scale into the domestic electricity planning, policy, regulatory, procurement, generation and supply landscape.

In practice, the cost competitiveness and technical ability of energy storage technologies could potentially be tested and enhanced in the market by allowing alternative electrical generation options to compete with solar PV plants coupled with energy storage systems for performing appropriate applications in future national IPP procurement initiatives, such as the Renewable Energy Independent Power Producers Procurement Programme (REIPPPP) of the Department of Energy. This would encourage qualifying bidders to refrain from submitting excessive tariffs through bidder competition and price ceilings that are aligned to current market conditions for similar application alternatives. Although the specific project details are not fully known, commercial indications in 2017 are that energy storage systems coupled with solar PV plants can possibly be contractually procured for less than USD 0.05 per kWh, which is below the cost of new fossil fuel-based electrical generators (see for example Maloney, 2017; Bade & Maloney, 2017; Spector, 2017).

Further research into the economic feasibility of other energy storage technologies not selected for the empirical analysis in this study will provide indications of their economic viability relative to alternative electrical generators. Additional academic research into the levelised cost competitiveness of energy storage systems relative to electrical generators beyond CSP with thermal energy storage capability, such as OCGTs and CCGTs, will provide further indications of their economic feasibility within the South African context.

7.6 SUMMARY AND CONCLUSION

This chapter assessed the economic feasibility of utility-scale lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) electrochemical energy storage systems for South Africa. It was accomplished through two primary methods. The first was by estimating and analysing the levelised cost of the select energy storage systems (LCOS) in isolation and comparing the results for an indication of their cost competitiveness with one another in 2016 and projected 2020.

The second was by estimating and analysing the weighted average levelised cost of the select energy storage technologies coupled with solar photovoltaic (PV) plants (LCOS-PV) and comparing the results to the levelised cost of electricity (LCOE) for concentrating solar power plants (CSP) with thermal energy storage capability as a case study for an indication of their cost competitiveness with alternative electrical generation options in 2016 and projected 2020. The LCOS-PV relative to the LCOE for electrical generators other than CSP plants with thermal energy storage capability was also referred to.

The empirical analysis in Chapter 7 enabled the attainment of the specific objectives set for this study in Chapter 1 that require an estimation and assessment of the competitive ability of select utility-scale energy storage technologies with one another and alternative electrical generation options. It further attained the specific objective of projecting when it could potentially be economically feasible to incorporate such technologies into the South African electrical energy environment at the utility scale.

Section 7.1 introduced the content to Chapter 7. Section 7.2 clarified the outline for the empirical analysis and related scenarios. The four scenarios investigated are a function of one or two charge-discharge cycles per day and 10- or 20-year project contract lifetimes. In each scenario, the primary utility-scale application is renewables integration with solar PV plants to overcome issues of solar resource variability and intermittency, supply electrical energy during periods of peak demand, enable electricity price arbitrage opportunities and integrate more solar-based electrical generators into the electricity grid.

Section 7.3 elaborated on the LCOS modelling results for each select technology as a standalone system under all four scenarios considered. The LCOS results vary widely and are relatively high for the select energy storage systems in isolation, although they are anticipated to continue declining sharply and thereby bring about intensified cost competitiveness. Increasing the cycling frequency to two charge-discharge cycles per day from one daily cycle, however, has a significant downward impact on the LCOS, irrespective of project contract lifetime and increased capital replacement requirements. Energy storage system costs should further be evaluated in terms of the specific applications they are required to perform, within the particular context they will be applied and according to their respective technical capabilities.

Generally, NaS batteries appear more competitive for scenario applications requiring one charge-discharge cycle a day, while VRFBs emerge as the most competitive technology when the cycling frequency is increased to two cycles per day. Lithium-ion batteries arise as the least competitive technology in all scenarios, although this could change beyond 2020, particularly under single daily cycling regimes. These findings are despite the lower roundtrip efficiency of VRFB and NaS batteries relative to lithium-ion batteries due to their other improved technical characteristics. Eskom’s electricity price escalations would hamper the cost competitiveness for energy storage systems that primarily charge from the national electricity grid, while their competitiveness would improve when mainly charging from solar PV plants due to lower tariffs.

Section 7.4 explained the findings for the LCOS-PV for the scenarios under consideration. The select energy storage systems are highly competitive in combination with solar PV plants, especially in relation to such systems in isolation, since the LCOS-PV is notably lower than the LCOS. The LCOS-PV is further considerably lower for applications that require two charge-discharge cycles per day. The LCOS-PV is an appropriate measure to determine the cost competitiveness of energy storage systems coupled with solar PV plants relative to other electrical generation options with similar dispatch characteristics.

Section 7.5 used the LCOS-PV to test the 2016 and likely future competitive ability of the select energy storage systems coupled with solar PV plants in comparison to CSP plants with thermal energy storage capability as a case study. The results demonstrate the improved economic feasibility, in terms of cost competitiveness, of the energy storage systems combined with solar PV plants relative to CSP plants with thermal energy storage capability. The divergence between the LCOS-PV and LCOE for CSP with thermal energy storage is anticipated to continue expanding and thereby further improve the economic feasibility of the select technologies coupled with solar PV plants. The modelling results therefore suggest that the select energy storage systems offer improved investment alternatives to CSP plants with thermal energy storage capability in South Africa.

The potential competitiveness of the select technologies relative to other electrical generators was also considered for conceptual purposes. The levelised cost comparisons imply that the select energy storage systems coupled with solar PV plants could further possibly be economic alternatives to some fossil fuel-based electrical generators. The cost competitiveness of energy storage systems relative to alternative electrical generation options beyond CSP with thermal energy storage capability, however, is an area that warrants further academic research before any definite conclusions can be made.

The information supplied throughout Chapters 1 to 7 jointly enabled the realisation of all the specific objectives set for this study as necessary to address the research problem, answer the general research question and attain the general research objective. The focus of Chapter 8 is to summarise the main findings throughout this dissertation, provide recommendations, clarify the limitations encountered, outline areas for further research and conclude the study.

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CHAPTER 8:

SUMMARY AND CONCLUSION

8.1 INTRODUCTION

Chapter 8 concludes this study. In that regard, the goal of this chapter is to summarise the key findings of this dissertation, provide recommendations and outline possible areas for further research. As stated in section 1.6 of the introductory Chapter 1, the general research objective for this dissertation was to assess the competitive ability and economic feasibility of utility-scale electrical energy storage technologies for South Africa. The information supplied in Chapters 1 to 7 enabled the attainment of this objective by addressing each of the specific objectives set for the study.

In particular, Chapters 1 to 4 attained the specific objective requiring an overview of the concept, characteristics, technical capability, value applications and reflective cost considerations associated with energy storage technologies. Chapter 5 attained the specific objective requiring a literature review of previous investigations into the economic feasibility of energy storage technologies and description of how such technologies relate to economic theory.

Chapter 6 attained the specific objective requiring an examination of the method through which energy storage technologies could reasonably be compared with one another and with prevailing alternative electrical energy generation options. A proposed method to determine the reflective levelised cost of energy storage systems (LCOS) was developed and the means through which such systems can be compared with alternative electrical generation options were established. Chapter 7 attained the specific objectives requiring an estimation, projection and assessment of the competitive ability of select utility-scale energy storage technologies with one another and alternative electrical generation options in order to determine when it could potentially be economically feasible to incorporate such technologies into the South African electrical energy environment.

This chapter is structured according to six sections. The next section (8.2) recapitulates this study by summarising the main findings of Chapters 1 to 7. Section 8.3 offers academic, practical and policy recommendations for consideration based on the findings from the research conducted for this thesis. Section 8.4 highlights limitations encountered during the research process. Section 8.5 outlines opportunities for further research. Section 8.6 ends this dissertation with a final concluding synopsis.

8.2 SUMMARY OF FINDINGS

A research need has been identified for improved empirical analyses into the performance characteristics and cost competitiveness of energy storage systems, in isolation and coupled with intermittent electrical production plants, as a measure of the economic feasibility of such systems. Accordingly, this study contributed to this need by assessing the economic feasibility of select utility-scale electrical energy storage technologies for South Africa in 2016 and projected 2020. It was mainly completed by estimating, projecting and analysing the cost competitiveness of utility-scale lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) battery energy storage systems with one another and alternative electrical generation options, which was realised by integrating the select technologies with solar photovoltaic (PV) electrical production plants.

In doing so, this research refined and improved on methods to calculate and assess the economic feasibility of energy storage systems. A novel contribution of this study is the development, extension, description and use of a detailed techno-economic levelised cost of energy storage (LCOS) model. The LCOS is a metric that articulates the comparable present value cost per kilowatt hour (kWh) over the applicable lifetime of an energy storage system in monetary terms, while accounting for all lifecycle cost and technical performance parameters. The mathematical modelling was utilised to appropriately estimate and project the LCOS for select energy storage systems in isolation and the weighted average levelised cost of such systems coupled with solar PV plants (LCOS-PV) in order to analyse their economic feasibility or cost competitiveness relative to alternative electrical generation options.

The importance of this research to academia, commerce and policymakers is manifested in the diffusion of contextual and empirical information on the performance characteristics and economic feasibility of utility-scale energy storage systems. The research contributes to an existing knowledge base on the economic viability of energy storage technologies and whether such technologies, together with renewable energy electrical production plants, can be affordably substituted for conventional electricity generators. This is especially relevant given the foreseen situation in which countries will increasingly transition to more innovative and environmentally conscious energy systems in support of sustainable economic growth and development.

The main considerations, findings and contributions of this dissertation can be outlined through a summary of each respective Chapter 1 to 7. Additional clarity can be obtained by referring to the content in the relevant chapters. The literature review was divided between Chapters 1 to 5, while the empirical assessment comprised Chapters 6 and 7.

Chapter 1 initiated this study by introducing the research conducted for this dissertation. It described the key terms; provided background information on the potential for utility-scale energy storage systems in the electrical energy landscape; clarified the research problem of insufficient knowledge about the cost competitiveness or economic feasibility of energy storage technologies in isolation and when such technologies are coupled with intermittent electrical production plants; stipulated the research questions and objectives followed in addressing the research problem; explained the research method applied for the literature review and empirical assessment; outlined the scope of research; and stated the academic, practical and policy contributions of this research.

Chapter 2 complemented Chapter 1 by articulating the fundamental aspects of energy storage. It supplied contextualising background information by explaining the essential concept and benefits of utility-scale energy storage; describing the main components of energy storage systems as the energy storage medium, electric power conversion system (PCS), management, monitoring and control systems and balance of plant features; and outlining common characteristics influencing the evaluation and selection of appropriate energy storage technologies as grouped under performance life, location, economic, supplier risk and policy and regulatory criteria.

Chapter 3 complemented Chapters 1 to 2 by providing a classification and overview of various distinct energy storage technologies that are appropriate for application at the utility scale. It described the technical characteristics, operations, developments, advantages, disadvantages and practical uses of different energy storage technologies grouped under mechanical, thermal, electrical, chemical and electrochemical mediums. The miscellaneous attributes of the technologies reviewed imply that each technology optimises differently into specific use applications and entails dissimilar cost implications.

Chapter 4 complemented Chapters 1 to 3 by elaborating on different utility-scale energy storage value applications and encompassing cost considerations. The applications that can be performed by energy storage systems at the utility-scale were explained as seasonal energy storage, energy time shifting and arbitrage, load levelling and peak shaving, load following, renewables integration, frequency regulation, voltage regulation, operating reserves, black start capability and electricity grid congestion relief and/or investment upgrade deferral. It was noted that no particular energy storage technology is superior in fulfilling all use applications, and energy storage systems should therefore be evaluated on a case-by-case basis. It was further recognised that the ability of energy storage systems to perform more than one application sequentially and/or simultaneously significantly enhances the value of energy storage relative to cost due to different potential revenue streams and maximising the productive utilisation of such systems.

The ranges of important cost indicators for each of the energy storage systems reviewed in Chapter 3 were also summarised and the main nominal lifetime cost contributors of such systems were explained as capital, operations and maintenance, replacement and disposal costs. Additional cost considerations for improved economic evaluation were further clarified. It was established that the LCOS should be estimated to appropriately evaluate the economic feasibility or cost competitiveness of energy storage systems due to their dissimilar technical performance characteristics and application suitability, which make nominal cost comparisons misleading and a relatively futile exercise. It was further emphasised that energy storage technology costs are likely to continue declining sharply and at faster rates than anticipated, especially for electrochemical batteries.

Chapter 5 complemented Chapters 1 to 4 by reviewing literature that has considered the economic feasibility of utility-scale energy storage technologies, outlining levelised cost estimates for such technologies by relevant application from existing research and contextualising their relevance to economic theory. The review identified shortcomings and verified the degree to which the economic feasibility of energy storage systems has been investigated. It was observed that research into the LCOS has been insufficient and/or obscure, have mostly focused on single daily charge-discharge cycling regimes, that future projections of such costs have been inadequate and have generally neglected the cost competitiveness of energy storage systems relative to electrical generators. The literature review therefore confirmed the need for LCOS estimates, projections and analyses for energy storage systems in isolation and when such systems are coupled with intermittent renewable energy electrical production plants, such as solar PV, in order to enable cost comparisons with alternative electrical generation options.

The theoretical contextualisation offered a unique preliminary perspective regarding the applicability of modern energy storage technologies within the framework of some related economic theories. It described the relevance of energy storage systems to economic theory in a manner that is aligned to the general research objective and primary thesis for this study. The role of advancements in energy storage technologies was explained within established economic growth and development hypotheses, such as endogenous growth, innovation economics and structural change theories. Energy storage systems were further represented in relation to the empirical assessment through the production cost theory of the firm and an innovative adaptation and analysis of the production possibilities frontier hypothesis and related opportunity cost and cost-benefit economic theories. The theoretical association supported the role of technological progress and cost declines in energy storage systems in the process of sustainable economic growth and development.

The information conveyed throughout Chapters 1 to 5 provided the necessary context for the completion of the empirical analysis in Chapters 6 and 7. In that regard, Chapter 6 improved on existing methods to assess and forecast the economic feasibility or cost competitiveness of select utility-scale energy storage systems for South Africa. A novel contribution was made by clarifying the method developed to formulate and apply an LCOS model and its extension to the LCOS-PV to estimate, project and analyse the reflective present value of lifecycle costs per unit of electrical energy for energy storage systems in isolation and coupled with solar PV plants between 2016 and 2020. This was required to determine the existing and likely future competitive ability of energy storage systems with one another, as well as with alternative generation options.

Shortcomings identified during the literature review and addressed by the LCOS model developed in this study include the failure to disclose detailed formulae, parameters, uncertainties and assumptions; adequately elaborate on value application requirements; appropriately account for all technical operational parameters of energy storage systems; accommodate for energy storage technology replacement rates and costs; allow for more than one charge-discharge cycle per day; project potential future LCOS values; estimate and forecast levelised costs when energy storage systems are integrated with solar PV plants; and determine the extent to which energy storage technologies coupled with solar PV plants could compete with alternative electrical generation options.

The methodological outline, novelty of the LCOS model, select technologies, primary application and rationale for integrating energy storage systems with solar PV plants in South Africa were clarified. Lithium-ion, VRFB and NaS battery technologies were selected for the empirical analysis due to their modular scalability to provide high energy and/or electrical power capacity and relative superiority to fulfil utility-scale applications, especially renewables integration. The primary application investigated for the empirical analysis was renewables integration with solar PV plants within the South African context to mainly overcome issues of solar resource variability and intermittency, supply electrical energy during peak demand periods, enable electricity price arbitrage opportunities and incorporate more renewable generators into the electric grid. These issues are important for economic growth and development by supporting increased electrical energy security, reliability, flexibility, access and relative affordability. To perform the primary application, the select energy storage systems were required to provide four hours of energy discharge capability at a 50 megawatt (MW) electrical power rating for 350 days a year.

The model formulation, parameters, explanatory variables, formulae, technical and financial data inputs, calculations, assumptions and interpretation were explained for both the LCOS and LCOS-PV as necessary to estimate and project the reflective lifecycle costs per kWh in 2016 and 2020. The method used to assess the economic feasibility of utility-scale energy storage systems in terms of cost competitiveness with alternative electrical generation options was also described. In that regard, the estimated 2016 and anticipated 2020 LCOS-PV was compared, for the same years, to the levelised cost of electricity (LCOE) for concentrating solar power (CSP) plants with thermal energy storage capability as an alternative generation option with similar electrical output dispatch characteristics. This case study provided a fair basis for comparison, since both energy storage systems coupled with solar PV plants and CSP plants with thermal energy storage capability produce and store solar-based electrical energy. CSP, particularly parabolic trough and solar tower plants, is further considered mature technology.

Chapter 7 applied the methods developed in Chapter 6 to disclose and analyse the LCOS and LCOS-PV modelling results in order to assess the economic feasibility of the select utility-scale electrochemical energy storage systems for South Africa in 2016 and projected 2020. The cost competitiveness of the select energy storage technologies in isolation and coupled with solar PV plants was examined and evaluated under four scenarios corresponding to the primary value application investigated in this study. The four scenarios were specified as a function of either one or two charge-discharge cycles per day and 10- or 20-year project contract lifetimes.

The LCOS scenario results for the select energy storage systems in isolation were found to vary widely and be relatively high, especially under single daily charge-discharge cycling regimes. The LCOS values, however, are anticipated to continue declining sharply and it is expected that the select technologies will become increasingly cost competitive over time at the utility scale, even as standalone systems. For example, the average LCOS for the three select technologies in application scenarios requiring one cycle per day was estimated to decline by approximately 23.3% from United States dollars (USD) 0.36 per kWh in 2016 to USD 0.28 per kWh in 2020. The LCOS was furthermore determined to be significantly lower, around 27.3% on average, when the cycling frequency is increased to two cycles per day, despite raising capital replacement rates. In this regard, the average LCOS for the energy storage systems in scenarios requiring two daily charge-discharge cycles was collectively estimated to decline by approximately 19.7% from USD 0.26 per kWh in 2016 to USD 0.21 per kWh in 2020.

Generally, it was found that NaS batteries are relatively more competitive in scenarios requiring one charge-discharge cycle per day and VRFBs in scenarios requiring two cycles per day, while lithium-ion batteries arose as the least competitive on a lifecycle cost basis, although this can change beyond 2020. This is despite the lower roundtrip efficiency of VRFB and NaS batteries relative to lithium-ion batteries due to their other improved technical characteristics. The LCOS should be evaluated in terms of the specific applications the technologies are required to perform, within the particular context they will be applied and according to their respective technical capabilities. A decomposition of the main LCOS components further suggested that the cost competitiveness of energy storage systems is likely to be restricted in South Africa when they primarily charge from the national grid due to escalating electricity prices emanating from the national electric utility, Eskom. Conversely, the cost competitiveness of such systems would be enhanced when they mainly charge from solar PV plants characterised by lower electricity tariffs.

The LCOS-PV scenario results for the select energy storage systems coupled with solar PV plants were found to be considerably more competitive relative to the systems in isolation. On average, the LCOS-PV was approximately 59.2% lower than the LCOS across all scenarios and technologies over the period under consideration. More specifically, the average LCOS-PV for the select energy storage systems was projected to decline by 25% from USD 0.14 per kWh in 2016 to USD 0.11 per kWh in 2020 under scenario applications requiring one charge-discharge cycle per day. Similar to the LCOS, the LCOS-PV was significantly lower, around 22% on average, under scenarios requiring two daily cycles and was anticipated to decline by approximately 22.6% from USD 0.11 per kWh in 2016 to USD 0.09 per kWh in 2020. While the LCOS and LCOS-PV modelling results summarised here are collectively averaged for the select technologies and application scenarios, it can be noted that the estimates are generally lower for 20-year project contract lifetimes relative to 10-year lifetimes.

The modelling results demonstrated the superior economic feasibility, in terms of cost competitiveness, of the select energy storage systems coupled with solar PV plants in comparison to CSP plants with thermal energy storage capability. More specifically, under the most cost competitive scenario 4, in which the select technologies are required to perform two charge-discharge cycles per day over a 20-year project contract lifetime, the average LCOS-PV of USD 0.11 per kWh in 2016 was estimated to be 20.8% lower than the LCOE of USD 0.14 per kWh for CSP plants with thermal energy storage capability. The average LCOS-PV projected for 2020 of USD 0.09 per kWh was furthermore estimated to be 27.2% lower than the expected LCOE for CSP plants with thermal energy storage capability of USD 0.12 per kWh. The divergence between the LCOS-PV and LCOE for CSP plants with thermal energy storage capability is anticipated to continue expanding over time as energy storage and solar PV technologies benefit from more rapid commercialisation, technical improvements and cost reductions.

The modelling results therefore confirmed that lithium-ion, VRFB and NaS battery energy storage systems coupled with solar PV plants offer improved investment alternatives to CSP plants with thermal energy storage capability in South Africa. While it was not the principal focus of this study, the results further suggested that the select technologies coupled with solar PV plants could also potentially be economic alternatives to some fossil fuel-based electrical generators within the South African context. This finding is supported by commercial contractual agreements in the United States in 2017. The research and empirical analysis for this dissertation consequently established the economic feasibility of the select utility-scale electrochemical energy storage technologies for South Africa. It supports the transition to a more environmentally sustainable electricity system in which utility-scale energy storage technologies and renewable energy electrical production plants will increasingly displace conventional fossil fuel-based electricity generators.

8.3 RECOMMENDATIONS

This dissertation has been completed with the aim of making a contribution to the knowledge accumulation and decision-making capabilities of policymakers, practitioners and academia. The research for this study therefore involves academic, practical and policy recommendations for consideration. As such, this section provides suggestions based on the information conveyed throughout Chapters 1 to 7.

Firstly, economic feasibility assessments of energy storage systems, in isolation and coupled with intermittent renewable energy electrical production plants, should be based on reflective levelised cost of energy storage (LCOS) comparisons. Simply comparing the quoted price or capital cost per kilowatt (kW) or kilowatt hour (kWh) across different technologies is misleading, since it does not fully and harmoniously account for differences in key parameters, such as cycle life, depth of discharge (DoD) limitations, capacity degradation, size of storage, discharge duration and roundtrip efficiency. These parameters should be realistically incorporated into the LCOS formulation.

The varying technical characteristics of diverse energy storage technologies imply that each technology optimises differently into specific applications. LCOS values can differ widely as a result, even for the same technologies, depending on the relevant context within which, and extent to which, they will be used. Energy storage system lifecycle costs should therefore be estimated on a case-by-case application basis. LCOS values should furthermore only be compared in instances where the same methodology was applied.

LCOS estimations should be based on practical or more realistic cycling regimes that would be required by relevant applications. Levelised cost estimates have mainly accounted for single daily charge-discharge regimes, while energy storage systems can, and are often required to, perform more than one full cycle per day. Increasing the cycling frequency could have a significant downward impact on the LCOS, despite raising capital replacement requirements. Similarly, LCOS estimates should also be based on practical expected project lifetime specifications, especially under contractual procurement structures, as it has an important influence on lifecycle costs. Appropriately accounting for these factors contributes to more realistic energy storage economics.

Since energy storage technologies and electrical generators have different technical characteristics, functionalities and modes of operation, the LCOS should ideally not be directly compared to the levelised cost of electricity generation (LCOE). To adequately compare the economic feasibility or cost competitiveness of energy storage systems with alternative electrical generation options, the weighted average levelised cost of such systems combined with appropriate intermittent electrical energy producers can be calculated to allow for a fair basis of comparison. In this study, it was demonstrated by clarifying and estimating the weighted average levelised cost of energy storage systems coupled with solar photovoltaic (PV) plants (LCOS-PV) and comparing the results to the LCOE for concentrating solar power (CSP) plants with thermal energy storage capability as an alternative generation option with similar electrical output dispatch characteristics. The LCOS-PV was further compared to the LCOE of some alternative fossil fuel-based electrical generators within the South African context for conceptual purposes.

The modelling results verified that vanadium redox flow (VRFB) and sodium-sulphur (NaS) battery energy storage systems are highly competitive with lithium-ion batteries on a lifecycle cost basis at the utility scale. Lithium-ion batteries, however, are the only electrochemical energy storage technology variant included in the South African Department of Energy's draft Integrated Resource Plan for Electricity (IRP) 2016 to 2050 Base Case, which is undergoing public consultation and reviews in 2017. The modelling results therefore suggest that other battery technologies should also be considered in the national electricity planning, policy and regulatory framework.

Energy storage systems can be integrated with solar PV plants to enable stable, reliable and dispatchable electrical energy output from otherwise variable and intermittent solar resources. This can, in turn, support morning and/or evening peak electricity demand periods, permit electricity price arbitrage opportunities, provide electric grid congestion relief, defer investments in electrical transmission and generation infrastructure, accommodate more solar-based generation options into the electric grid and/or limit the wastage of surplus electrical energy availability from solar PV plants.

Combining energy storage systems with solar PV plants would also improve the competitive ability of such systems on a lifecycle cost basis due to lower charging costs, in comparison to primarily charging from the national electric grid characterised by rising electricity prices, and the improved cost competitiveness brought about by the LCOS-PV. In addition to general technological progress, low and declining solar PV tariffs in South Africa have mainly resulted from excellent solar irradiation levels, particularly in the Northern Cape Province, and highly competitive procurement conditions under the

Renewable Energy Independent Power Producers Procurement Programme (REIPPPP) of the Department of Energy.

The technical capability and cost competitiveness of energy storage systems could be tested and improved in practice by allowing such systems coupled with solar PV plants to compete with alternative electrical generation options for the fulfilment of required applications. In this regard, the institutional structuring of the South African REIPPPP can be used as an appropriate national electrical energy procurement initiative that will encourage highly competitive tariff bids from domestic and foreign investors. The transparent, development-oriented and competitive procurement nature of the REIPPPP is likely to attract the most economical solutions for the performance of required applications in a manner that also contributes to broader socio-economic development. Commercial agreements in the United States in 2017 suggest energy storage systems coupled with solar PV plants can be contractually procured at lower prices than new fossil fuel-based electrical generation alternatives.

Moreover, while 20-year project contract lifetimes generally entail lower LCOS estimates in comparison to 10-year project lifetimes, despite necessitating increased replacement capital outlays, 10-year project contract lifetimes can nonetheless be considered for the procurement of modern energy storage systems in practice. By doing this, technological advancements and cost reductions beyond expectations can be more flexibly accommodated and the risk of entering into longer-term contractual agreements at higher prices than would be reasonable in future could be mitigated.

Lastly, the main outcome of the empirical analysis in this study is the finding that the select energy storage technologies are economically feasible utility-scale electricity system solutions for South Africa. This is a result of the improved cost competitiveness of the select energy storage systems with one another and with alternative electrical generation options, particularly CSP plants with thermal energy storage capability, when they are coupled with solar PV plants. The final and primary recommendation from this study is therefore to incorporate lithium-ion, VRFB and NaS electrochemical battery energy storage systems at the utility scale into the domestic electricity planning, policy, regulatory, procurement, generation and supply framework. These technologies can be combined with solar PV plants in national electricity planning for lower lifecycle costs and in support of transitioning to a more environmentally sustainable, renewable energy-based, electrical energy landscape.

8.4 LIMITATIONS ENCOUNTERED

A significant drawback experienced during the course of this research and formulation of the methodology was the large uncertainty regarding energy storage system costs. From the literature review, it was found that reported capital and operations and maintenance costs are likely outdated and subject to wide uncertainty. While it is recognised that lifecycle costs differ according to the utilisation and application of energy storage systems, research would benefit from up-to-date cost estimates. These include updated values by technology for power capital costs per kilowatt (kW), energy capital costs per kilowatt hour (kWh), capital costs per kWh per cycle, fixed and variable operations and maintenance costs per kW and kWh, levelised costs, replacement costs, disposal and recycling costs, power conversion system (PCS) costs and balance of plant costs. This drawback is exacerbated by a lack of future cost estimates. A global reputable public database with easily accessible and frequently updated costs and trends related to energy storage systems would be valuable for the advancement of future research efforts.

8.5 FURTHER RESEARCH

Possible areas for further academic research have been identified during the course of research for this dissertation. Suggestions for research topics related to energy storage systems can therefore be provided for consideration. Firstly, future research efforts should challenge, advance and improve upon the methods and findings developed in this study. Ongoing research on the topic for this study will provide added information regarding the economic feasibility or cost competitiveness of energy storage systems and the degree to which such systems can be incorporated into electricity frameworks.

While the applicability of energy storage technologies to economic theory was considered in a manner that is aligned to the general research objective for this dissertation, the aim was not to provide an exhaustive assessment of the theoretical linkages and implications. A detailed investigation of energy storage systems within economic theory could therefore be considered for research and further clarify the hypothetical role of such systems in the process of economic growth and development.

This study focused on assessing the economic feasibility of select energy storage technologies, namely lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) electrochemical batteries, at the utility scale with one another and alternative electrical generation options. Additional research into the cost competitiveness of energy storage technologies not considered for the empirical analysis in this dissertation would disseminate knowledge regarding their technical and economic viability for incorporation into the electrical energy environment.

Moreover, the cost competitiveness of the select energy storage systems relative to electrical generators was empirically tested by estimating the weighted average levelised cost of such systems coupled with solar photovoltaic (PV) plants (LCOS-PV) and comparing the results to the levelised cost of electricity (LCOE) for concentrating solar power (CSP) plants with thermal energy storage capability, as well as to some alternative electrical generation options for conceptual purposes. Further research can build on the empirical analysis supplied in this study by assessing the economic feasibility or cost competitiveness of energy storage systems coupled with other intermittent renewable energy-based electrical production plants, particularly wind turbines.

Similarly, the economic feasibility of energy storage systems coupled with renewable energy electrical production plants in comparison to electrical generation alternatives beyond CSP plants with thermal energy storage capability could be assessed in more detail. Further research into the cost competitiveness of energy storage systems combined with intermittent electrical energy producers relative to fossil fuel-based electricity generators would provide additional indications of their economic feasibility and inform the transition to a more environmentally sustainable electricity framework.

Further research could also assess the environmental and social externalities emanating from energy storage technologies integrated with renewable energy electrical production plants in comparison to fossil fuel-based electricity generators. Research efforts in this regard could consider an aggregate value chain approach, from resource extraction and value addition through to electrical production and output. While it could be anticipated that the value of energy storage systems will be enhanced through the improved environmental and human health implications of energy storage and renewable energy technologies relative to conventional generation options, societal awareness and policymaking would benefit from the quantitative evaluation of such suppositions.

Furthermore, South Africa’s economic growth and development aspirations are likely to be supported when there is a demand for energy storage systems that also benefit from domestic manufacture or value addition. In that regard, future research could investigate the local industrial development and global value chain participation opportunities associated with energy storage systems for both domestic use and export markets.

Energy storage systems that are co-located with solar PV plants are likely to share certain balance of plant features, which would reduce the relative overall capital costs associated with combined solar PV and energy storage electrical production plants in comparison to the implementation of the distinct technologies in isolation. Examples of common balance of plant features could include power conversions systems (PCS), land, buildings, equipment and environmental impact assessments (EIA). The modelling methodology developed in this study could therefore be improved for enhanced cost competitiveness by allowing for mutual capital and other costs that are likely to be shared in practical energy storage systems coupled with solar PV plants.

A further research opportunity also exists in assessing how varying electricity input prices could affect the economic feasibility of energy storage systems. More specifically, the cost competitiveness of energy storage systems charging from solar PV plants could be compared to such systems charging from the national electricity grid. In this study, it was found that the competitive ability of energy storage systems in South Africa could be restricted if they primarily charge from the electric grid due to electricity price increases from the national electric utility, whereas the competitiveness of such systems would be supported when they charge directly from solar PV plants due to relatively lower electrical energy tariffs. Empirical analyses in this regard would inform the implementation of energy storage systems according to the most cost effective source of charge.

Lastly, while this study investigated the economic feasibility of utility-scale energy storage systems within the South African context, a need exists for further research on the technical feasibility of such systems in the domestic electrical energy generation, supply and demand environment. In other words, future research should examine the pragmatic, least-cost, electricity system operational need and timing for utility-scale energy storage technologies in South Africa. This would indicate when, if not already, energy storage systems should start being implemented at the utility scale and is particularly important as the share of variable and intermittent renewable energy-based electrical production plants in total installed electricity generation capacity continues to grow.

8.6 CONCLUDING SYNOPSIS

The general research objective of this dissertation was to assess the competitive ability and economic feasibility of utility-scale electrical energy storage technologies for South Africa. In that regard, the focus of the literature review was to provide detailed background information on the utility-scale energy storage role, need, concept, benefits, system components, selection criteria, various technologies, technical characteristics, value applications, costs, economic feasibility and relevance to economic theory.

The focus of the empirical analysis was to improve on methods to assess the economic feasibility of energy storage systems through the development and explanation of a novel techno-economic levelised cost of energy storage (LCOS) model and its extension to the weighted average levelised cost of energy storage systems coupled with solar photovoltaic (PV) plants (LCOS-PV). The mathematical model was consequently utilised to estimate, project and assess the economic feasibility of select utility-scale lithium-ion, vanadium redox flow (VRFB) and sodium-sulphur (NaS) battery energy storage technologies for South Africa, in 2016 and 2020, in terms of their cost competitiveness with one another and alternative electrical energy generation options.

The modelling results accordingly established the economic feasibility of the select utility-scale electrochemical energy storage systems for South Africa. The economic feasibility of the select technologies coupled with solar PV plants within the South African context was mainly confirmed through their improved cost competitiveness in comparison to concentrating solar power (CSP) plants with thermal energy storage capability as a case study to enable a fair basis of comparison. The LCOS-PV further conceptually appeared cost competitive with other electrical generation options in South Africa. This research supports the transition to a more environmentally sustainable national electricity framework in which economically viable utility-scale energy storage systems combined with renewable energy electrical production plants will increasingly displace the need for conventional fossil fuel-based electricity generators. It further offered academic, practical and policy recommendations, as well as suggestions for future research.

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ANNEXURE A:

DETAILED MODELLING SCENARIO RESULTS

Table 9.1: Scenario 1: One cycle per day over a 10-year project contract lifetime

Parameter	Unit	Lithium-ion	VRFB	NaS	Lithium-ion	VRFB	NaS
		2016			2020		
Select energy storage technologies in isolation							
Power rating	MW	50	50	50	50	50	50
Required energy storage discharge duration	Hours	4	4	4	4	4	4
Size of storage to enable maximum discharge	MWh	200	200	200	200	200	200
Cycles per day at maximum depth of discharge (DoD)	Cycles per day	1	1	1	1	1	1
Maximum depth of discharge (DoD)	%	80.0%	100.0%	90.0%	85.0%	100.0%	90.0%
Operating days per year	Days per year	350	350	350	350	350	350
Project calendar life	Years	10	10	10	10	10	10
Roundtrip efficiency	%	93.0%	80.0%	80.0%	95.0%	83.0%	83.0%
Linear capacity degradation coefficient over project life	%	90.0%	100.0%	100.0%	90.0%	100.0%	100.0%
O&M cost % of total initial CAPEX of system	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Discount rate	%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
Headline inflation	%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Electrical energy charged per year (input)	MWh per year	75 269	87 500	87 500	73 684	84 337	84 337
Electrical energy discharged per year (output)	MWh per year	70 000	70 000	70 000	70 000	70 000	70 000
Electrical energy discharged over project calendar life	MWh	700 000	700 000	700 000	700 000	700 000	700 000
Initial capital cost of energy storage medium or battery cell	USD per kWh	361	400	385	226	299	264
Initial capital cost of balance of plant	USD per kWh	82	183	75	51	137	51
Total initial energy capital cost (CAPEX) of system	**USD per kWh**	**443**	**583**	**460**	**278**	**436**	**315**
Total initial CAPEX of system installation	USD	88 514 592	116 640 141	91 926 907	55 536 039	87 252 892	63 038 840
Initial capital cost of energy storage medium	USD per kW	1 444	1 600	1 540	906	1 197	1 056
Initial capital cost of balance of plant	USD per kW	326	733	299	205	548	205
Total initial electrical power CAPEX of system	USD per kW	1 770	2 333	1 839	1 111	1 745	1 261
Total initial CAPEX of system installation	**USD**	**88 514 592**	**116 640 141**	**91 926 907**	**55 536 039**	**87 252 892**	**63 038 840**

Replacement capital cost of energy storage medium							
Year 5	USD per kWh	0	0	0	0	0	0
Year 10	USD per kWh	0	0	0	0	0	0
Year 15	USD per kWh	0	0	0	0	0	0
Operations and maintenance (O&M) cost	**USD per kWh**	**9**	**12**	**9**	**6**	**9**	**6**
Charging cost of electricity input	**USD per kWh**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**
Levelised cost of energy storage (LCOS)	**USD per kWh**	**0.41**	**0.37**	**0.35**	**0.28**	**0.30**	**0.27**
Select energy storage technologies coupled with solar photovoltaic (PV) plants							
Solar PV levelised cost of electricity (LCOE)	USD per kWh	0.04	0.04	0.04	0.03	0.03	0.03
Share of electrical energy from solar PV stored in battery	%	30%	30%	30%	30%	30%	30%
Total electrical energy produced by solar PV plant	MWh per year	233 333	233 333	233 333	233 333	233 333	233 333
Solar PV electrical energy output directly utilised for grid	MWh per year	158 065	145 833	145 833	159 649	148 996	148 996
Total electrical energy available from solar PV and battery	MWh per year	228 065	215 833	215 833	229 649	218 996	218 996
Weighted average levelised cost of energy storage coupled with solar PV plant (LCOS-PV)	**USD per kWh**	**0.15**	**0.15**	**0.14**	**0.11**	**0.12**	**0.11**

Source: Author’s estimates

Table 9.2: Scenario 2: Two cycles per day over a 10-year project contract lifetime

Parameter	Unit	Lithium-ion	VRFB	NaS	Lithium-ion	VRFB	NaS
		2016			2020		
Select energy storage technologies in isolation							
Power rating	MW	50	50	50	50	50	50
Required energy storage discharge duration	Hours	4	4	4	4	4	4
Size of storage to enable maximum discharge	MWh	200	200	200	200	200	200
Cycles per day at maximum depth of discharge (DoD)	Cycles per day	2	2	2	2	2	2
Maximum depth of discharge (DoD)	%	80.0%	100.0%	90.0%	85.0%	100.0%	90.0%
Operating days per year	Days per year	350	350	350	350	350	350
Project calendar life	Years	10	10	10	10	10	10
Roundtrip efficiency	%	93.0%	80.0%	80.0%	95.0%	83.0%	83.0%
Linear capacity degradation coefficient over project life	%	90.0%	100.0%	100.0%	90.0%	100.0%	100.0%
O&M cost % of total initial CAPEX of system	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Discount rate	%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
Headline inflation	%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Electrical energy charged per year (input)	MWh per year	150 538	175 000	175 000	147 368	168 675	168 675
Electrical energy discharged per year (output)	MWh per year	140 000	140 000	140 000	140 000	140 000	140 000
Electrical energy discharged over project calendar life	MWh	1 400 000	1 400 000	1 400 000	1 400 000	1 400 000	1 400 000
Initial capital cost of energy storage medium or battery cell	USD per kWh	361	400	385	226	299	264
Initial capital cost of balance of plant	USD per kWh	82	183	75	51	137	51
Total initial energy capital cost (CAPEX) of system	**USD per kWh**	**443**	**583**	**460**	**278**	**436**	**315**
Total initial CAPEX of system installation	USD	88 514 592	116 640 141	91 926 907	55 536 039	87 252 892	63 038 840
Initial capital cost of energy storage medium	USD per kW	1 444	1 600	1 540	906	1 197	1 056
Initial capital cost of balance of plant	USD per kW	326	733	299	205	548	205
Total initial electrical power CAPEX of system	USD per kW	1 770	2 333	1 839	1 111	1 745	1 261
Total initial CAPEX of system installation	**USD**	**88 514 592**	**116 640 141**	**91 926 907**	**55 536 039**	**87 252 892**	**63 038 840**
Replacement capital cost of energy storage medium							
Year 5	**USD per kWh**	**226**	0	**264**	**150**	0	**180**
Year 10	USD per kWh	0	0	0	0	0	0
Year 15	USD per kWh	0	0	0	0	0	0
Operations and maintenance (O&M) cost	**USD per kWh**	**9**	**12**	**9**	**6**	**9**	**6**

Charging cost of electricity input	**USD per kWh**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**
Levelised cost of energy storage (LCOS)	**USD per kWh**	**0.30**	**0.23**	**0.26**	**0.21**	**0.19**	**0.21**
Select energy storage technologies coupled with solar photovoltaic (PV) plants							
Solar PV levelised cost of electricity (LCOE)	USD per kWh	0.04	0.04	0.04	0.03	0.03	0.03
Share of electrical energy from solar PV stored in battery	%	30%	30%	30%	30%	30%	30%
Total electrical energy produced by solar PV plant	MWh per year	466 667	466 667	466 667	466 667	466 667	466 667
Solar PV electrical energy output directly utilised for grid	MWh per year	316 129	291 667	291 667	319 298	297 992	297 992
Total electrical energy available from solar PV and battery	MWh per year	456 129	431 667	431 667	459 298	437 992	437 992
Weighted average levelised cost of energy storage coupled with solar PV plant (LCOS-PV)	**USD per kWh**	**0.12**	**0.10**	**0.11**	**0.09**	**0.08**	**0.09**

Source: Author’s estimates

Table 9.3: Scenario 3: One cycle per day over a 20-year project contract lifetime

Parameter	Unit	Lithium-ion	VRFB	NaS	Lithium-ion	VRFB	NaS
		2016			2020		
Select energy storage technologies in isolation							
Power rating	MW	50	50	50	50	50	50
Required energy storage discharge duration	Hours	4	4	4	4	4	4
Size of storage to enable maximum discharge	MWh	200	200	200	200	200	200
Cycles per day at maximum depth of discharge (DoD)	Cycles per day	1	1	1	1	1	1
Maximum depth of discharge (DoD)	%	80.0%	100.0%	90.0%	85.0%	100.0%	90.0%
Operating days per year	Days per year	350	350	350	350	350	350
Project calendar life	Years	20	20	20	20	20	20
Roundtrip efficiency	%	93.0%	80.0%	80.0%	95.0%	83.0%	83.0%
Linear capacity degradation coefficient over project life	%	90.0%	100.0%	100.0%	90.0%	100.0%	100.0%
O&M cost % of total initial CAPEX of system	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Discount rate	%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
Headline inflation	%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Electrical energy charged per year (input)	MWh per year	75 269	87 500	87 500	73 684	84 337	84 337
Electrical energy discharged per year (output)	MWh per year	70 000	70 000	70 000	70 000	70 000	70 000
Electrical energy discharged over project calendar life	MWh	1 400 000	1 400 000	1 400 000	1 400 000	1 400 000	1 400 000
Initial capital cost of energy storage medium or battery cell	USD per kWh	361	400	385	226	299	264
Initial capital cost of balance of plant	USD per kWh	82	183	75	51	137	51
Total initial energy capital cost (CAPEX) of system	**USD per kWh**	**443**	**583**	**460**	**278**	**436**	**315**
Total initial CAPEX of system installation	USD	88 514 592	116 640 141	91 926 907	55 536 039	87 252 892	63 038 840
Initial capital cost of energy storage medium	USD per kW	1 444	1 600	1 540	906	1 197	1 056
Initial capital cost of balance of plant	USD per kW	326	733	299	205	548	205
Total initial electrical power CAPEX of system	USD per kW	1 770	2 333	1 839	1 111	1 745	1 261
Total initial CAPEX of system installation	**USD**	**88 514 592**	**116 640 141**	**91 926 907**	**55 536 039**	**87 252 892**	**63 038 840**
Replacement capital cost of energy storage medium							
Year 5	USD per kWh	0	0	0	0	0	0
Year 10	**USD per kWh**	**150**	0	**180**	**150**	0	**96**
Year 15	**USD per kWh**	0	**117**	0	0	**117**	0
Operations and maintenance (O&M) cost	**USD per kWh**	**9**	**12**	**9**	**6**	**9**	**6**

Charging cost of electricity input	**USD per kWh**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**
Levelised cost of energy storage (LCOS)	**USD per kWh**	**0.38**	**0.33**	**0.33**	**0.28**	**0.28**	**0.26**
Select energy storage technologies coupled with solar photovoltaic (PV) plants							
Solar PV levelised cost of electricity (LCOE)	USD per kWh	0.04	0.04	0.04	0.03	0.03	0.03
Share of electrical energy from solar PV stored in battery	%	30%	30%	30%	30%	30%	30%
Total electrical energy produced by solar PV plant	MWh per year	233 333	233 333	233 333	233 333	233 333	233 333
Solar PV electrical energy output directly utilised for grid	MWh per year	158 065	145 833	145 833	159 649	148 996	148 996
Total electrical energy available from solar PV and battery	MWh per year	228 065	215 833	215 833	229 649	218 996	218 996
Weighted average levelised cost of energy storage coupled with solar PV plant (LCOS-PV)	**USD per kWh**	**0.15**	**0.14**	**0.14**	**0.11**	**0.11**	**0.10**

Source: Author’s estimates

Table 9.4: Scenario 4: Two cycles per day over a 20-year project contract lifetime

Parameter	**Unit**	**Lithium-ion**	**VRFB**	**NaS**	**Lithium-ion**	**VRFB**	**NaS**
		2016			**2020**		
Select energy storage technologies in isolation							
Power rating	MW	50	50	50	50	50	50
Required energy storage discharge duration	Hours	4	4	4	4	4	4
Size of storage to enable maximum discharge	MWh	200	200	200	200	200	200
Cycles per day at maximum depth of discharge (DoD)	Cycles per day	2	2	2	2	2	2
Maximum depth of discharge (DoD)	%	80.0%	100.0%	90.0%	85.0%	100.0%	90.0%
Operating days per year	Days per year	350	350	350	350	350	350
Project calendar life	Years	20	20	20	20	20	20
Roundtrip efficiency	%	93.0%	80.0%	80.0%	95.0%	83.0%	83.0%
Linear capacity degradation coefficient over project life	%	90.0%	100.0%	100.0%	90.0%	100.0%	100.0%
O&M cost % of total initial CAPEX of system	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Discount rate	%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
Headline inflation	%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Electrical energy charged per year (input)	MWh per year	150 538	175 000	175 000	147 368	168 675	168 675
Electrical energy discharged per year (output)	MWh per year	140 000	140 000	140 000	140 000	140 000	140 000
Electrical energy discharged over project calendar life	MWh	2 800 000	2 800 000	2 800 000	2 800 000	2 800 000	2 800 000
Initial capital cost of energy storage medium or battery cell	USD per kWh	361	400	385	226	299	264
Initial capital cost of balance of plant	USD per kWh	82	183	75	51	137	51
Total initial energy capital cost (CAPEX) of system	**USD per kWh**	**443**	**583**	**460**	**278**	**436**	**315**
Total initial CAPEX of system installation	USD	88 514 592	116 640 141	91 926 907	55 536 039	87 252 892	63 038 840
Initial capital cost of energy storage medium	USD per kW	1 444	1 600	1 540	906	1 197	1 056
Initial capital cost of balance of plant	USD per kW	326	733	299	205	548	205
Total initial electrical power CAPEX of system	USD per kW	1 770	2 333	1 839	1 111	1 745	1 261
Total initial CAPEX of system installation	**USD**	**88 514 592**	**116 640 141**	**91 926 907**	**55 536 039**	**87 252 892**	**63 038 840**
Replacement capital cost of energy storage medium							
Year 5	**USD per kWh**	**226**	0	**264**	**150**	0	**180**
Year 10	**USD per kWh**	**150**	0	**180**	**150**	0	**96**
Year 15	**USD per kWh**	**150**	**117**	**96**	**150**	**117**	**96**
Operations and maintenance (O&M) cost	**USD per kWh**	**9**	**12**	**9**	**6**	**9**	**6**

Charging cost of electricity input	**USD per kWh**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**
Levelised cost of energy storage (LCOS)	**USD per kWh**	**0.29**	**0.21**	**0.25**	**0.22**	**0.19**	**0.21**
Select energy storage technologies coupled with solar photovoltaic (PV) plants							
Solar PV levelised cost of electricity (LCOE)	USD per kWh	0.04	0.04	0.04	0.03	0.03	0.03
Share of electrical energy from solar PV stored in battery	%	30%	30%	30%	30%	30%	30%
Total electrical energy produced by solar PV plant	MWh per year	466 667	466 667	466 667	466 667	466 667	466 667
Solar PV electrical energy output directly utilised for grid	MWh per year	316 129	291 667	291 667	319 298	297 992	297 992
Total electrical energy available from solar PV and battery	MWh per year	456 129	431 667	431 667	459 298	437 992	437 992
Weighted average levelised cost of energy storage coupled with solar PV plant (LCOS-PV)	**USD per kWh**	**0.12**	**0.10**	**0.11**	**0.09**	**0.08**	**0.09**

Source: Author’s estimates

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ANNEXURE B:

SCENARIO COST COMPONENT SHARES OF TOTAL LEVELISED COST OF ENERGY STORAGE (LCOS)

Table 10.1: LCOS components for scenario 1: One cycle per day over a 10-year project contract lifetime

Year	Cost component	Lithium-ion		VRFB		NaS	
		LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share
2016	**CAPEX**	0.26	65.2%	0.25	67.1%	0.22	63.4%
	O&M	0.05	11.2%	0.04	11.5%	0.04	10.9%
	Charge	0.10	23.6%	0.08	21.4%	0.09	25.7%
	Total LCOS	**0.41**	**100.0%**	**0.37**	**100.0%**	**0.35**	**100.0%**
2020	**CAPEX**	0.16	56.4%	0.19	62.1%	0.15	56.3%
	O&M	0.03	9.7%	0.03	10.7%	0.03	9.7%
	Charge	0.09	33.9%	0.08	27.2%	0.09	34.0%
	Total LCOS	**0.28**	**100.0%**	**0.30**	**100.0%**	**0.27**	**100.0%**

Source: Author's estimates

Table 10.2: LCOS components for scenario 2: Two cycles per day over a 10-year project contract lifetime

Year	Cost component	Lithium-ion		VRFB		NaS	
		LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share
2016	**CAPEX**	0.18	60.0%	0.13	55.2%	0.15	58.6%
	O&M	0.02	7.7%	0.02	9.5%	0.02	7.3%
	Charge	0.10	32.3%	0.08	35.3%	0.09	34.2%
	Total LCOS	**0.30**	100.0%	**0.23**	100.0%	**0.26**	100.0%
2020	**CAPEX**	0.11	49.9%	0.09	48.9%	0.10	50.1%
	O&M	0.01	6.3%	0.02	8.4%	0.01	6.2%
	Charge	0.09	43.8%	0.08	42.7%	0.09	43.7%
	Total LCOS	**0.21**	100.0%	**0.19**	100.0%	**0.21**	100.0%

Source: Author's estimates

Table 10.3: LCOS components for scenario 3: One cycle per day over a 20-year project contract lifetime

Year	Cost component	Lithium-ion		VRFB		NaS	
		LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share
2016	**CAPEX**	0.21	55.2%	0.18	55.1%	0.18	53.7%
	O&M	0.05	14.5%	0.05	15.7%	0.05	13.8%
	Charge	0.12	30.4%	0.10	29.1%	0.11	32.5%
	Total LCOS	**0.38**	100.0%	**0.33**	100.0%	**0.33**	100.0%
2020	**CAPEX**	0.13	47.9%	0.14	50.3%	0.12	45.5%
	O&M	0.03	11.6%	0.04	14.1%	0.03	12.1%
	Charge	0.11	40.5%	0.10	35.7%	0.11	42.4%
	Total LCOS	**0.28**	100.0%	**0.28**	100.0%	**0.26**	100.0%

Source: Author's estimates

Table 10.4: LCOS components for scenario 4: Two cycles per day over a 20-year project contract lifetime

Year	Cost component	Lithium-ion		VRFB		NaS	
		LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share	LCOS (USD per kWh)	Total LCOS share
2016	**CAPEX**	0.15	50.4%	0.09	42.7%	0.12	48.6%
	O&M	0.03	9.5%	0.03	12.2%	0.02	9.0%
	Charge	0.12	40.0%	0.10	45.1%	0.11	42.4%
	Total LCOS	**0.29**	100.0%	**0.21**	100.0%	**0.25**	100.0%
2020	**CAPEX**	0.10	42.4%	0.07	37.1%	0.08	40.0%
	O&M	0.02	7.2%	0.02	10.4%	0.02	7.5%
	Charge	0.11	50.4%	0.10	52.6%	0.11	52.5%
	Total LCOS	**0.22**	100.0%	**0.19**	100.0%	**0.21**	100.0%

Source: Author's estimates

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